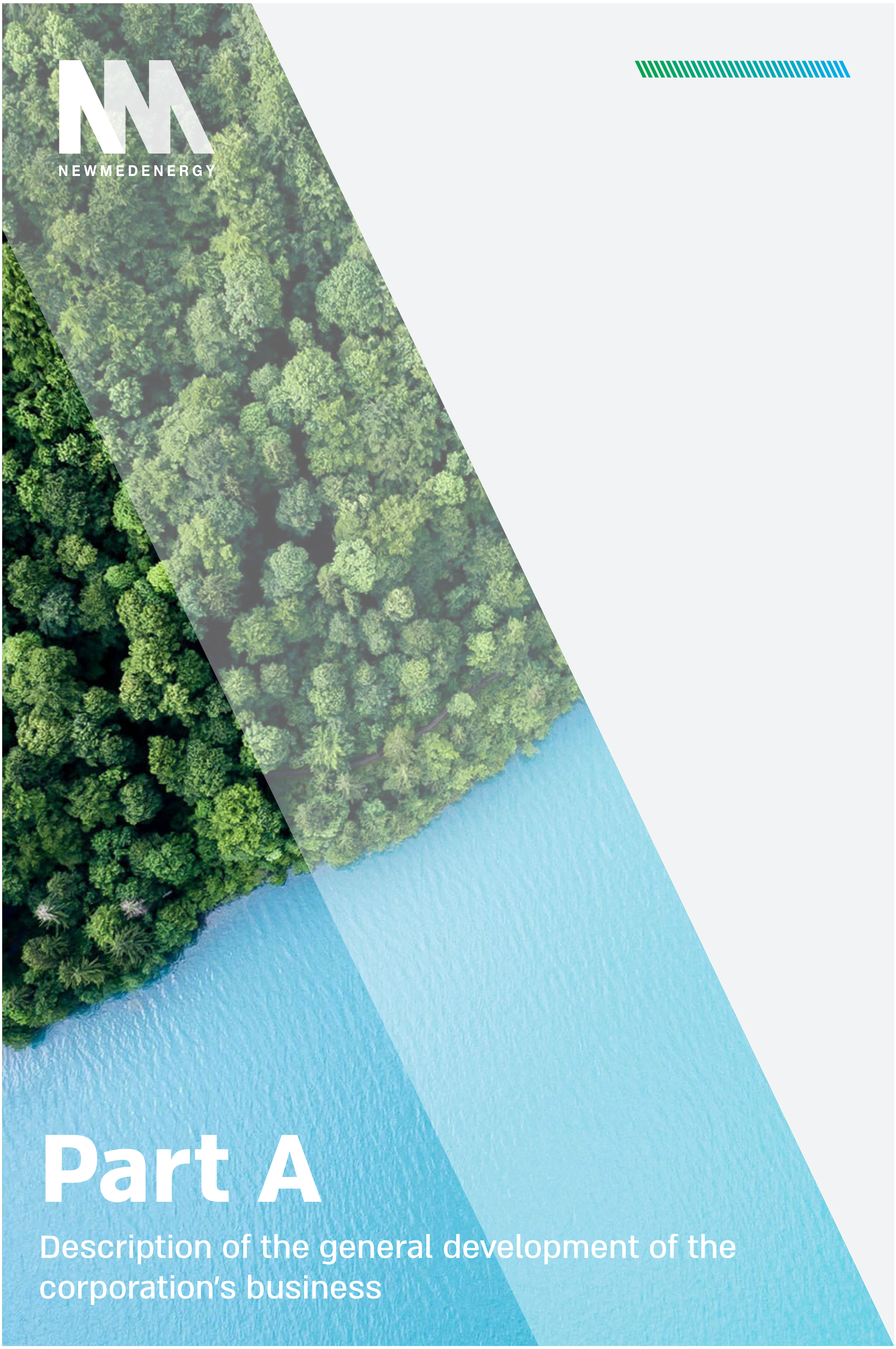
NEWMEDENERGY

2024 Periodic Report

Table of Contents



Part A

Description of the general development of the corporation's business

Chapter A – Description of the General Development of the Corporation's Business

This report is a translation of NewMed Energy - Limited Partnership's Hebrew-language Description of the General Development of the Partnership's Business, which is prepared solely for convenience purposes. Please note that the Hebrew version is the binding version and will prevail in any event of discrepancy.

Chapter A – Description of the General Development of the Corporation's Business

1. Description of the General Development of the Partnership's Business[1]

1.1. NewMed Energy – Limited Partnership (the "**Partnership**")[2] is a public limited partnership, within the meaning thereof in the Partnerships Ordinance [New Version], 5735-1975 (the "**Partnerships Ordinance**"). Since its establishment, the Partnership is engaged primarily in the exploration, development, production and marketing of natural gas, condensate and oil in Israel, Cyprus, Morocco and Bulgaria, as well as exploring and promoting possibilities for the making of investments in renewable energy projects and for the production of hydrogen from natural gas.

1.2. The Partnership was established under a partnership agreement signed on 1 July 1993 between NewMed Energy Management Ltd. as general partner, of the first part (the "**General Partner**"), and NewMed Energy Trusts Ltd. as limited partner, of the second part (the "**Limited Partner**")[3], as amended from time to time (the "**Partnership Agreement**")[4]. The Partnership was incorporated on 25 July 1993, under the Partnerships Ordinance, according to which the Partnership Agreement, as amended from time to time, constitutes the Partnership's articles of association.

1.3. In accordance with prospectuses released by the Partnership between the years 1993-2003, the Limited Partner issued participation units to the public which confer a right to participate in the rights of the Limited Partner in the Partnership (the "**Participation Units**" or the "**Units**"), which are listed for trade on the Tel Aviv Stock Exchange Ltd. ("**TASE**"). The Limited Partner serves as trustee and holds in trust for the unit holders the Participation Units issued thereby.

1.4. The current management of the Partnership is performed by the General Partner under the supervision of the supervisors, Fahn Kanne & Co., Accountants, together with Keidar Supervision & Management (jointly: the "**Supervisors**" or the "**Supervisor**").

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[1] For definitions of some of the professional terms included in this chapter, see the professional terms glossary at the end of the chapter as well as **Annex A** to this chapter.

[2] The Partnership's previous name was Delek Drilling – Limited Partnership. On 21 February 2022, the Partnership's name was changed to its current name.

[3] The General Partner's previous name was Delek Drilling Management (1993) Ltd. and the Limited Partner's previous name was Delek Drilling Trusts Ltd. On 24 February 2022, their names were changed to their current names.

[4] As published in the Partnership's immediate report of 9 January 2025 (Ref.: 2025-01-003243).

On 1 July 1993, the Limited Partner and the Supervisor signed a trust agreement, as amended from time to time (the "**Trust Agreement**")[5], which confers on the Supervisor powers of supervision over the Partnership's management by the General Partner, as well as powers of supervision over the fulfillment of the Limited Partner's obligations to the Unit holders.

1.5. The General Partner and the Limited Partner are subsidiaries of Delek Energy Systems Ltd. ("**Delek Energy**"), a private company wholly owned by Delek Group Ltd. ("**Delek Group**"), the controlling shareholder of which is Mr. Yitzhak Sharon (Tshuva)[6]. To the best of the Partnership's knowledge, as of the report approval date Delek Group holds, directly and indirectly (through Delek Energy and the General Partner, and through an indirect holding in Avner Oil & Gas Ltd.) approx. 54.66% of the Partnership's issued unit capital.[7]

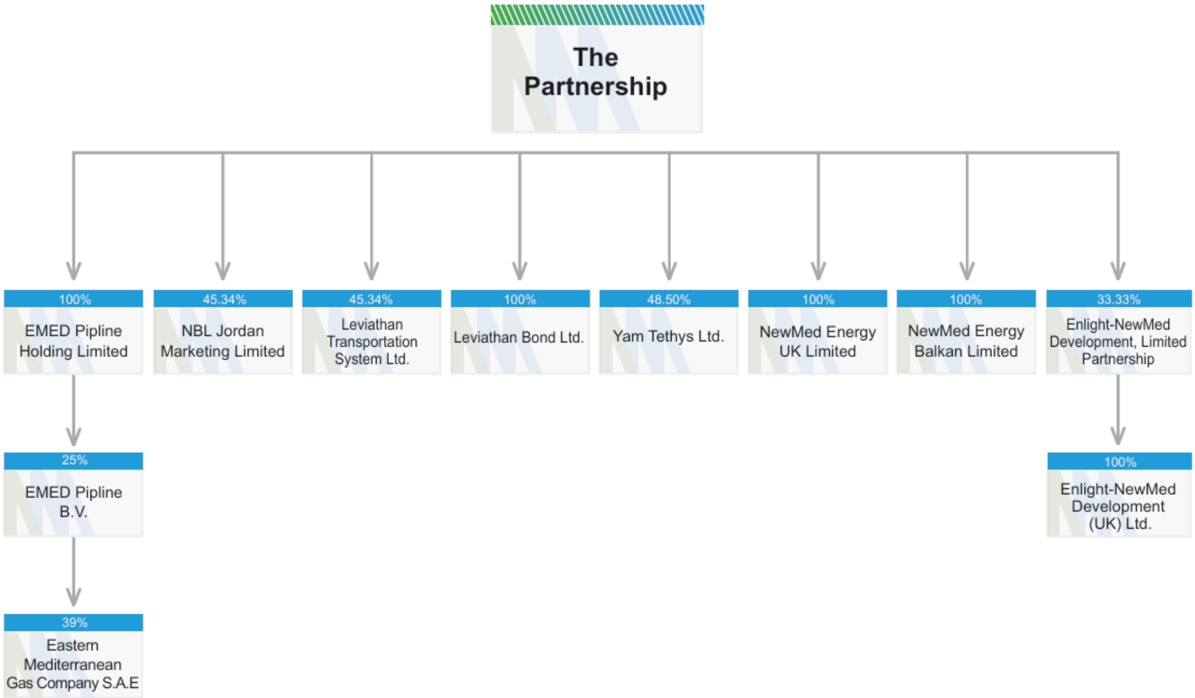
1.6. On 17 May 2017, a merger was closed between the Partnership and Avner Oil Exploration, Limited Partnership ("**Avner**" or the "**Avner Partnership**") such that all of Avner's assets and liabilities were transferred, as is, to the Partnership. The Limited Partner issued participation units to the holders of the participation units in the Avner Partnership, and the Avner Partnership was liquidated without dissolution, and struck off from the records of the Registrar of Partnerships (the "**Merger of the Partnerships**").

[5] As published in the Partnership's immediate report of 7 June 2020 (Ref.: 2020-01-058218).

[6] As of the report approval date, Mr. Yitzhak Sharon (Tshuva) holds approx. 50.12% of the issued capital and approx. 50.12% of the voting rights in Delek Group.

[7] To the best of the Partnership's knowledge, and in accordance with Delek Group's reports, as of the report approval date, the majority of the units held by Delek Group are pledged in favor of the holders of the bonds issued by Delek Group.

1.7. The structure of the Partnership's principal holdings:



1.7.1. Yam Tethys Ltd. is a special purpose company (SPC) which was established by the partners in the Yam Tethys project (the "**Yam Tethys Partners**") for receipt of a license for the transmission of gas from the Yam Tethys project's production platform to the Ashdod Onshore Terminal (AOT) (the "**Terminal**"), as mandated by the provisions of the Natural Gas Sector Law, 5762-2002 (the "**Natural Gas Sector Law**").

As of the report approval date, Yam Tethys Ltd. has no operations aside from its holding a construction and operation license for a gas transmission pipeline that was issued thereto by the Minister of Energy and Infrastructures (the "**Minister of Energy**") on 29 April 2002, and other operations relating to its being the license holder as aforesaid, including its being a party to various agreements in connection with the Terminal and security issues.

1.7.2. Leviathan Transmission System Ltd. is a special purpose company (SPC) ("**Leviathan Transmission System**"), whose shareholders are the partners in the Leviathan project (the "**Leviathan Partners**"), which hold the shares of the company according to the rate of their holdings in the I/14 Leviathan South and I/15 Leviathan North leases (the "**Leviathan South Lease**" and the "**Leviathan North Lease**", respectively. The Leviathan South and Leviathan North leases shall hereinafter be referred to collectively as: the "**Leviathan Leases**"). The company was established for the purpose of obtaining a license for the transmission of natural gas from the production platform of the Leviathan project to the northern entry point of the national transmission system of Israel

Natural Gas Lines Ltd. ("**INGL**"), as mandated by the provisions of the Natural Gas Sector Law.

1.7.3. NBL Jordan Marketing Limited is a special purpose company (SPC) whose shareholders are the Leviathan Partners, which hold the shares of the company according to the rate of their holdings in the Leviathan Leases. The company was established in connection with the engagement of the Leviathan Partners in a gas supply agreement with the national electric company of Jordan – The National Electric Power Company ("**NEPCO**"), whereby the company will purchase the natural gas from the Leviathan Partners at the entry point to INGL's transmission system and shall sell it to NEPCO at the delivery point near the Israel-Jordan border under the same terms and conditions set forth in the said gas supply agreement (back-to-back). For further details, see Section 7.12.3(b) below.

1.7.4. EMED Pipeline B.V. is an SPC ("**EMED**") which was established for the EMG Transaction (as defined in Section 7.26.6 below) and is registered in the Netherlands. Its shares are held as follows: EMED Pipeline Holding Limited, a wholly owned subsidiary of the partnership that is registered in Cyprus – 25%; Chevron Cyprus Limited – 25%; and Sphinx EG BV, a wholly owned subsidiary of East Gas Company S.A.E., which holds, *inter alia*, a gas pipeline and infrastructures in Egypt (the "**Egyptian Partner**") – 50%.

1.7.5. Eastern Mediterranean Gas Company S.A.E. ("**EMG**") is a private company, registered in Egypt, which owns a subsea natural gas transport pipeline that connects between the Egyptian natural gas transmission system in the el-Arish area and the Israeli transmission system in the Ashkelon area, whose shares are held, as follows: EMED – 39%; Snam S.p.A ("**SNAM**") – 25%; Egyptian Partner – 26%, Egyptian General Petroleum Corporation[8] – 10%. For further details, see Section 7.26.6 below.

1.7.6. Leviathan Bond Ltd. is a special purpose company (SPC) ("**Leviathan Bond**"), wholly owned by the Partnership, which was established for the purpose of the issue of bonds to the institutional market in Israel and overseas, which are secured by the Partnership's interests in the Leviathan Leases. For further details, see Section 7.21.2 below.

1.7.7. NewMed Energy UK Limited (formerly Delek Energy Limited) is a special purpose company (SPC) ("**NewMed Morocco**"), wholly owned by the Partnership, which holds interests in the Boujdour Atlantique exploration license located in the Atlantic Ocean offshore Morocco, and was incorporated in England. For further details, see Section 7.6 below.

1.7.8. NewMed Energy Balkan Limited is a special purpose company (SPC) ("**NewMed Balkan**"), wholly owned by the Partnership, which is

[8] An Egyptian state-owned company.

expected to hold interests in the exploration license in Block 1-21 Han Asparuh, which is located in the Exclusive Economic Zone (EEZ) of the Republic of Bulgaria in the Black Sea, and was incorporated in England. On 9 March 2025, the compensation committee and the board of directors of the General Partner, notwithstanding the objection of the general meeting of the Unit holders, approved the granting of equity compensation to Mr. Yossi Abu, CEO of the Partnership ("**Mr. Abu**"), which includes, *inter alia*, the allotment of 5% of the issued share capital of NewMed Balkan, such that following such allotment, the Partnership shall hold 95% of the issued share capital of NewMed Balkan. For further details, see Section 7.8 below.

1.7.9. Enlight-NewMed Development (UK) Ltd. is a special purpose company (SPC) ("**MedLight**") which was incorporated in England in the context of the collaboration with Enlight Renewable Energy Ltd. ("**Enlight**"), as specified in Section 7.10 below. MedLight is wholly owned by Enlight-NewMed Development, Limited Partnership (the "**Enlight Corporation**"), whose participation units are held as follows: the Partnership – 33.33%; Yes-Enlight Holdings, Limited Partnership – 66.66% (whose participation units are held by Enlight – 70%, and by Mr. Abu – 30%).

For further details with respect to the aforesaid companies and regarding other subsidiaries of the Partnership, see Regulation 11 of Chapter D hereof.

1.8. For details regarding an offer received by the General Partner from Abu Dhabi National Oil Company (ADNOC) P.J.S.C. and BP Exploration Operating Company Limited ("**BP**" and the "**Consortium**", respectively), regarding a possible transaction in which the Consortium will purchase for cash all of the Partnership's Participation Units held by the public and some of the units held by Delek Group, subject to certain conditions (the "**Consortium's Offer**") and regarding suspension of the discussions regarding the Consortium's Offer from March 2024, see the Partnership's immediate report of 28 March 2023 (Ref. 2023-01-032823) and Section 1.8 of Chapter A of the Partnership's 2023 periodic report which was released on 19 March 2024 (Ref. 2024-01-027798) (the "**2023 Periodic Report**"), the information in which is incorporated herein by reference.

1.9. Since 7 October 2023, the State of Israel has been at war on several fronts, as a result of which, in 2024, the Israeli economy operated under a routine overshadowed by the War. For further details, see Section 6.8 below and the risk factor relating thereto in Section 7.30.1 below.

2. Field of Business

2.1. As of the report approval date, the Partnership operates in the energy field and its primary business is exploration, development, production and marketing of natural gas, condensate and oil in Israel, Cyprus, Morocco and Bulgaria, and promotion of various natural gas-based projects, with the aim of increasing the volume of the sales of natural gas produced by the Partnership. At the same time, the Partnership is exploring business opportunities in the field of

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exploration, development, production and marketing of natural gas, condensate and oil in other countries, is exploring and promoting possibilities for investing in renewable energy projects in the context of the collaboration with Enlight, as specified in Section 7.10 below, and is also exploring possible projects for the production of hydrogen, including blue hydrogen, which is produced from natural gas, and which can be a low-carbon substitute for energy consumers. For further details, see Section 7.28 below.

2.2. The Partnership's primary petroleum asset on the report approval date, is a holding of 45.34% (out of 100%) of the Leviathan natural gas reservoir, the gas flow therefrom began in December 2019. The Leviathan reservoir currently supplies natural gas to a number of customers in the Israeli and regional market, and among its prominent customers are, *inter alia*, Blue Ocean Energy in Egypt ("**BOE**" or "**Blue Ocean**") and Jordan's national electricity company (NEPCO).
In addition to the rights in the Leviathan reservoir, the Partnership holds rights in the Aphrodite reservoir which was discovered in the area of Block 12 in Cyprus ("**Aphrodite**" or "**Block 12**") and in additional petroleum assets, as specified in Sections 7.2 to 7.8 below.

2.3. The operators of the Leviathan and Block 12 reservoirs are Chevron Mediterranean Limited ("**Chevron**" or the "**Operator in the Leviathan Project**") and Chevron Cyprus Limited ("**Chevron Cyprus**"), respectively, subsidiaries of a subsidiary wholly-owned by Chevron Corporation ("**Chevron Corp**").[9]

2.4. According to the directives of the Government Resolution on the "Gas Framework", as specified in Section 7.24.1 below, in December 2021, the Partnership completed the sale of the balance of its interests in the Tamar and Dalit leases. The operator in the Tamar project is Chevron, which holds 25% of the interests in the Tamar project. Following the aforesaid sale of the interests, the Tamar Reservoir and the partners therein are the Partnership's main competitors.[10] For further details with respect to the competition, see Section 7.15 below.

2.5. In accordance with the TASE Rules, the Partnership is entitled to only carry out gas and oil exploration, development and production projects, which were defined in the Partnership Agreement or in the amendment thereto to be approved by the meeting of the Unit holders. The Partnership Agreement defines the geographical areas included in the Partnership's existing petroleum assets, which are specified in Sections 7.2-7.8 below. Moreover, the TASE Rules allow the Partnership, under specific conditions, to invest in projects that were not expressly defined in the Partnership Agreement and to invest in renewable

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[9] Chevron Corp. is a foreign public corporation whose shares are traded on NYSE. To the best of the Partnership's knowledge, there is no single shareholder that holds more than 10% of Chevron Corp's issued share capital.

[10] To the best of the Partnership's knowledge, the partners in the Tamar project, as of the report approval date, are: Chevron (25%), Isramco Negev 2, Limited Partnership (28.75%) ("**Isramco**"), Tamar Petroleum Ltd. (16.75%) ("**Tamar Petroleum**"), Mubadala Energy (Tamar) RSC Ltd. (11%), Tamar Investment 2 Limited (11%), Dor Gas Exploration, Limited Partnership (4%) ("**Dor**"), and Union Energy & Systems 2 Ltd. (3.5%) ("**Union**", and collectively, the "**Tamar Partners**").

energy projects. Accordingly, on 21 September 2022, the general meeting of the Unit holders authorized the amendment of the Partnership Agreement, *inter alia*, to enable the Partnership to participate in renewable energy projects. For details on a collaboration agreement with Enlight, see Section 7.10 below.

2.6. It is further provided in the Partnership Agreement, *inter alia*, that the principal part of the Partnership's expenses would be in accordance with the Partnership's objectives, as defined in Section 5 of the Partnership Agreement.

2.7. Below are details with respect to the best estimate of the quantities of the reserves (2P), contingent resources (2C) and prospective resources (2U) attributed to the petroleum assets Leviathan, Block 12 in Cyprus and Block 1-21 Han Asparuh which is located in the EEZ of the Republic of Bulgaria in the Black Sea (the "**Bulgaria License**") (100%), as of 31 December 2024 with respect to Leviathan and Block 12 in Cyprus, and as of 30 November 2024 with respect to the Bulgaria License, as estimated by an independent evaluator, Netherland Sewell and Associates Inc. (the "**Evaluator**" or "**NSAI**").

	Rate of the Partnership's interests	Best Estimate (2U) of the Total Quantity of the Prospective Resources[11] (100%)			Best Estimate (2C) of the Quantity of Contingent Resources (100%)		Best Estimate (2P) of the Total Quantity of Reserves (100%)	
		Natural Gas BCF	Condensate Million Barrels	Oil Million Barrels	Natural Gas BCF	Condensate Million Barrels	Natural Gas BCF	Condensate Million Barrels
Leviathan Reservoir	45.34%	-	-	-	5,659.4	12.5	14,834	32.6
Leviathan Deep Prospects	45.34%	378.7	-	368	-	-	-	-
Aphrodite Reservoir	30.00%	79	0.1	-	3,537	7.9	-	-
Bulgaria License	50.00%	3,347.6	-	-	-	-	-	-

2.8. In addition to the said primary assets, the Partnership has rights in additional petroleum assets which, as of the report approval date, were classified by the Partnership as negligible petroleum assets, as follows:

2.8.1 Interests in the Yam Tethys project and in the I/7 Noa and I/10 Ashkelon leases (the "**Noa Lease**" and the "**Ashkelon Lease**", respectively), as specified in Section 7.4 below;

2.8.2 Rights to receive royalties from the I/16 Tanin and I/17 Karish leases (the "**Tanin Lease**" and the "**Karish Lease**", respectively), as specified in Section 7.5 below;

2.8.3 Interests in the Boujdour Atlantique exploration license located in the Atlantic Ocean offshore Morocco, as specified in Section 7.6 below;

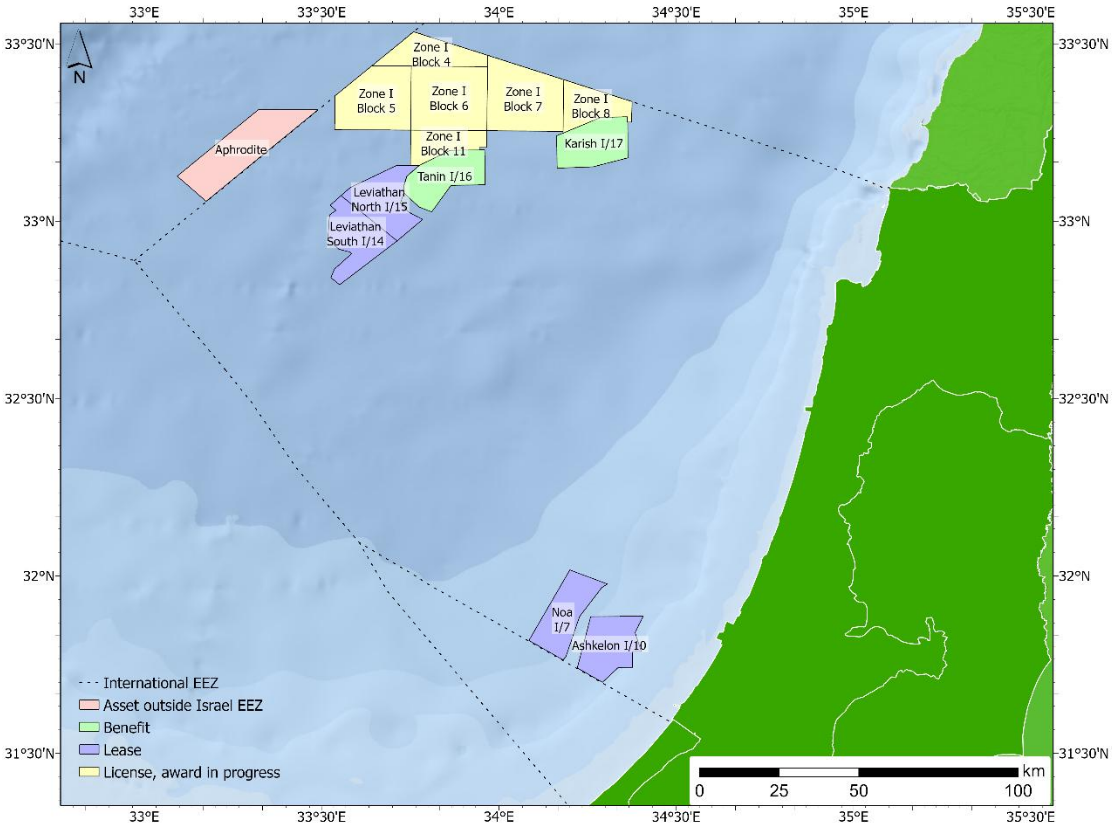
[11] The prospective resources stated below are located in several fault blocks and/or various prospects, the prospects of the presence of which vary.

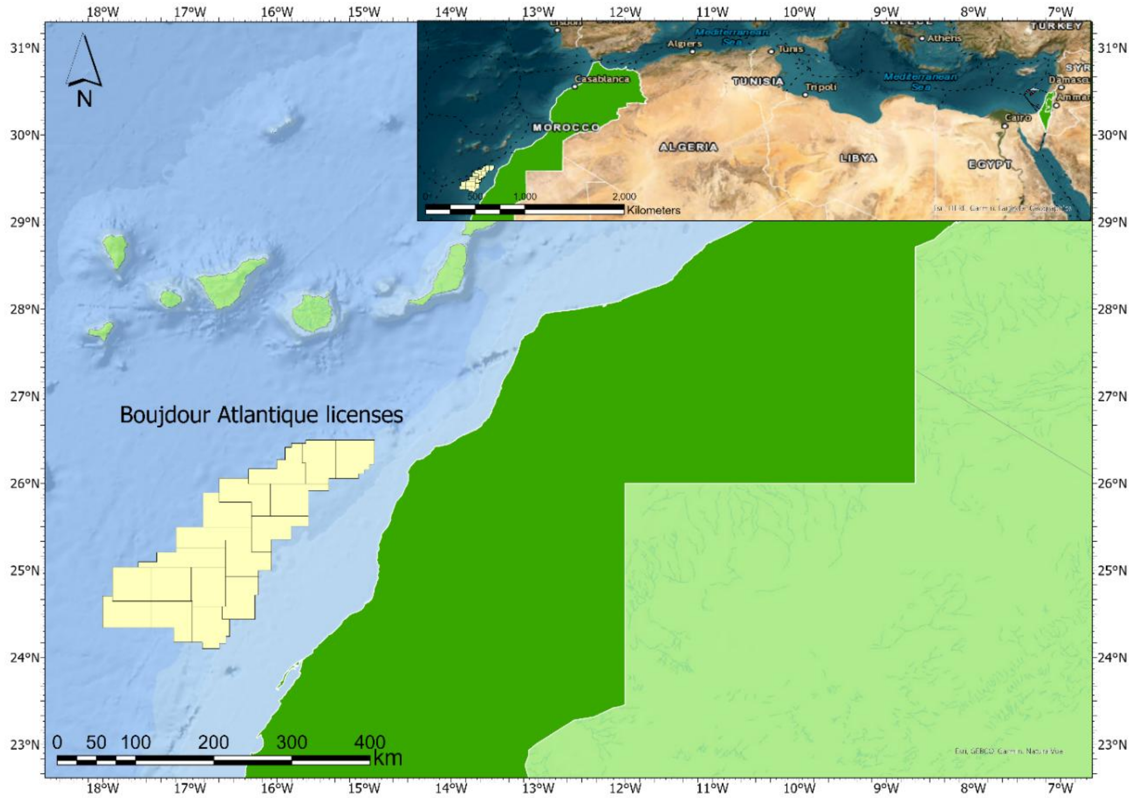
2.8.4 Interests in the exploration licenses in Zone I in the area of Blocks 4, 5, 6, 7, 8 and 11, in the EEZ of the State of Israel, which are expected to be received, as specified in Section 7.7 below.

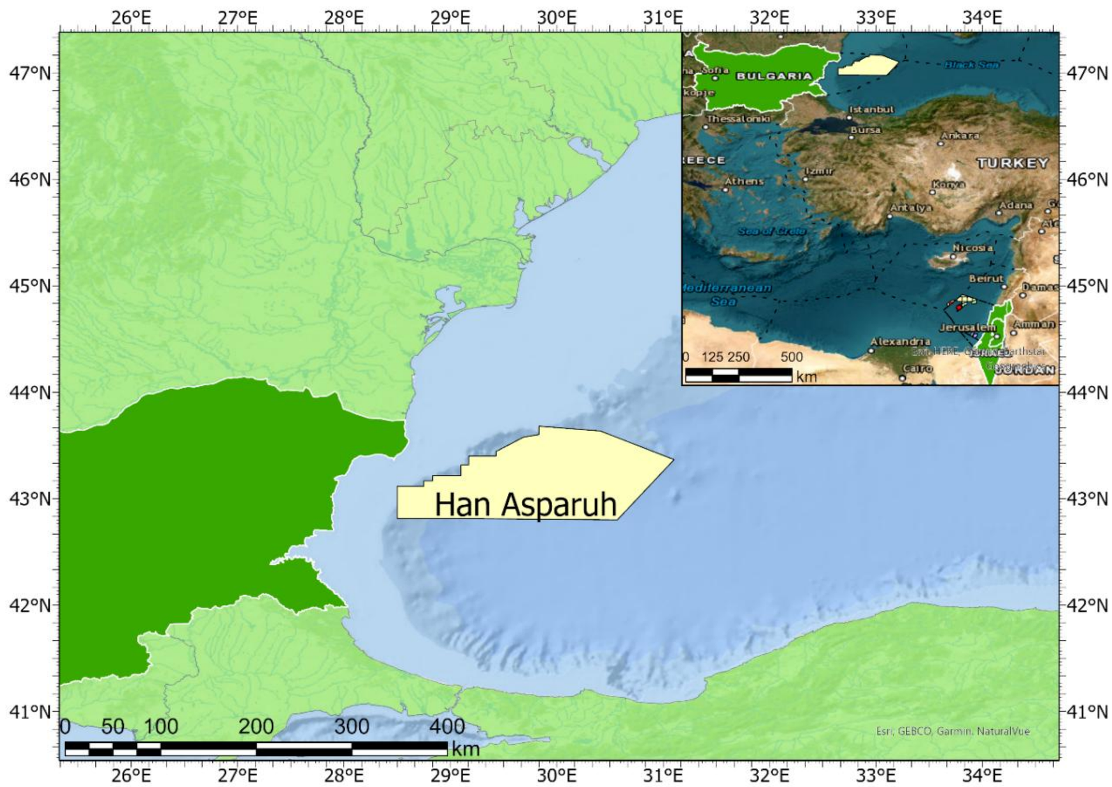
2.8.5 Interests in the 1-21 Han Asparuh exploration license which is located in the EEZ of the Republic of Bulgaria in the Black Sea, which are expected to be received, as specified in Section 7.8 below.

2.9 For details regarding the Partnership's petroleum assets on the report approval date, see Sections 7.2-7.8 below. For details regarding petroleum assets, the activity in which has been discontinued, see Section 7.9 below.

Below are maps showing the location of the Partnership's petroleum assets, as of the report approval date:







(*) The Bulgaria License is in the process of being granted as aforesaid.

3. <u>Investments in the Partnership's Capital and Off Exchange Transactions made by Interested Parties in the Participation Units</u>

To the best of the Partnership's knowledge and according to the reports of the Delek Group, as of the date of approval of the report, most of the participation units owned by Delek Group are pledged in favor of the holders of the bonds issued by Delek Group.

4. <u>Distribution of Profits</u>

4.1. In the period from 1 January 2023 until the report approval date, the Partnership declared profit distributions (as defined in the Partnership Agreement), as specified below:

Declaration Date	Distribution Date	Distribution Amount per Participation Unit (in $)	Total Distribution Amount ($ in Millions)	Immediate Report
27 March 2023	20 April 2023	0.05112	60	Ref.: 2023-01-033114
10 May 2023	15 June 2023	0.04260	50	Ref.: 2023-01-050355
20 August 2023	14 September 2023	0.04260	50	Ref.: 2023-01-095958
15 November 2023	21 December 2023	0.04260	50	Ref.: 2023-01-104098
18 March 2024	11 April 2024	0.05112	60	Ref.: 2024-01-027819
23 May 2024	20 June 2024	0.05112	60	Ref.: 2024-01-051454
7 August 2024	5 September 2024	0.05538	65	Ref.: 2024-01-085054
19 November 2024	12 December 2024	0.05538	65	Ref.: 2024-01-617108
9 March 2025	3 April 2025	0.05112	60	-

4.2. For details regarding the tax regime applicable to the Partnership, see Section 7.22 below.

4.3. As of 31 December 2024, the Partnership has profits available for distribution in the sum of approx. 1,602 million U.S. dollars ("**Dollars**" or "**$**").

4.4. Aside from the restrictions set forth in financing agreements, as specified in Section 7.21 below, as of the report approval date, there are no external restrictions that may affect the Partnership's ability to distribute profits in the future.

4.5. <u>The provisions of the Partnership Agreement regarding a profit distribution and resolutions of general meetings thereon:</u>

4.5.1 The Partnership Agreement provides that all of the Partnership's profits, which are distributable, by the Partnership under law, net of amounts (which were not taken into account for the purpose of determination of the profits) required for the Partnership, as per the discretion of the General Partner, for the purpose of or in connection with the Partnership's existing undertakings, including the repayment of loans, and including amounts which are required, in the opinion of the General Partner, in order to meet unforeseeable expenses, the amount of which shall not exceed $250,000 (in this section: the "**Profits**"), will be distributed to the partners in the Partnership according to their rights.

4.5.2 On 30 December 2013, the general meeting of the Unit holders approved a decision resolving, *inter alia*, to approve refraining from distribution of profits (as defined in Section 9.4 of the Partnership Agreement), for the purpose of investment thereof in the development of the Leviathan reservoir according to the work program and budgets approved and/or to be approved under the joint operating agreements that apply to the Leviathan Leases, and also to approve use of the surplus cash accumulated and to be accumulated by 31 December 2014, for the purpose of investment thereof in activities of exploration and evaluation in the Leviathan Leases and in Block 12 which is situated in the EEZ of Cyprus, according to a work program and budgets approved and/or to be approved under the joint operating agreements that apply to the aforesaid petroleum assets.

4.5.3 On 21 September 2022, the general meeting of the Unit holders approved a decision resolving, *inter alia*, to authorize refrainment from distribution of profits (as defined in Section 9.4 of the Partnership Agreement) for the purpose of performance of the Block 12 Development Plan, in accordance with a workplan and budgets which either were and/or will be approved by the Block 12 partners and according to the terms and conditions of the Production Sharing Contract (PSC) signed with the Cypriot government, as amended from time to time, and to approve use of the surplus cash which was and will be accrued for the purpose of investment thereof in the Development Plan.

In addition, in the context of the aforesaid general meeting, it was decided to authorize the Partnership to act and make investments in renewable energy projects in the context of the collaboration with Enlight and in accordance with the provisions of TASE Rules, up to the aggregate investment amount (only the Partnership's share) of $100 million (in equity and/or a shareholders' loan, including a capital note or by way of a guarantee for loans to be provided). For additional details see the Partnership's immediate reports dated 6 September 2022 and 21 September 2022 (Ref.: 2022-01-092520 and 2022-01-120358, respectively), the information in which is incorporated herein by reference.

4.5.4 On 2 January 2023, the general meeting of the Unit holders approved a decision resolving, *inter alia*, to approve the Partnership's engagement in agreements for the purchase of the rights in the Morocco license and participation in activities for oil and/or natural gas exploration and production in the license area, and to approve refrainment from distribution of profits (as defined in Section 9.4 of the Partnership

Agreement) for the purpose of performance of the aforesaid actions in accordance with a work program and budgets to be approved by the partners in the license and according to its terms. For additional details see the Partnership's immediate reports dated 12 December 2022 and 3 January 2023 (Ref.: 2022-01-150004 and 2023-01-002016, respectively), the information in which is incorporated herein by reference.

4.5.5 On 18 December 2023, the general meeting of the Unit holders approved a decision resolving, *inter alia*, to approve the Partnership's participation in oil and/or natural gas exploration and production activity in the area of the exploration licenses in Zone I in the area of Blocks 4, 5, 6, 7, 8 and 11, in the EEZ of the State of Israel (in this section: the "**New Licenses**"), and to approve refrainment from the distribution of profits (as defined in Section 9.4 of the Partnership Agreement) for the purpose of investment in actions in the area of the New Licenses, in accordance with the work programs as shall be approved by the partners in the New Licenses from time to time. For further details, see the Partnership's immediate reports of 22 November 2023 and 18 December 2023 (Ref.: 2023-01-105883 and 2023-01-137334, respectively), the information appearing in which is incorporated herein by reference.

4.5.6 On 9 January 2025, the general meeting of the unitholders approved a decision resolving, *inter alia*, to approve the Partnership's engagement in an agreement for the purchase of the interests in the Bulgaria License and participation in oil and/or natural gas exploration, development and production activities in the area of the Bulgaria License, and to approve refrainment from the distribution of profits (as defined in Section 9.4 of the Partnership Agreement) for purposes of performance of the said activities according to the work program and the budgets that shall be approved by the partners in the Bulgaria License. For further details, see the Partnership's immediate reports of 2 January 2025 and 9 January 2025 (Ref.: 2025-01-000782 and 2025-01-003240, respectively), the information appearing in which is incorporated herein by reference.

5. Financial Information regarding the Partnership's field of business

5.1. For figures with respect to revenues, costs, profit from ordinary activities in the field of business, see the statements of comprehensive income included in the financial statements (Chapter C hereof).

5.2. For details with respect to the total assets and liabilities of the Partnership as of 31 December 2024 and 31 December 2023, see the Statements of Financial Position included in the financial statements (Chapter C hereof).

5.3. For explanations with respect to the aforesaid financial data, see Part One of the board of directors' report (Chapter B hereof).

6. General Environment and the Effect of External Factors

6.1. The Petroleum Law, 5712-1952 (the "**Petroleum Law**") governs the regulation in the sector of oil and natural gas exploration, development and production in Israel and determines, *inter alia*, provisions in relation to payment of royalties to the State and that oil and gas exploration activities in Israel can be conducted in geographical areas in which the exploring entity was granted a gas and petroleum right under the Petroleum Law. The Natural Gas Sector Law mainly governs the issues of transmission, distribution, marketing and storage of natural gas and/or liquefied natural gas ("**LNG**") within the State of Israel. In addition, the Taxation of Profits from Natural Resources Law, 5771-2011 (the "**Natural Resources Tax Law**") regulates, *inter alia*, tax and petroleum profit levy issues. For further details with respect to the Petroleum Law, the Natural Gas Sector Law and the Natural Resources Tax Law, see Sections 7.24.4, 7.24.5 and 7.22.2 below, respectively.

6.2. The economic merit of investments in the exploration for and development of natural gas reservoirs is greatly affected by oil and gas prices in the world, *inter alia* LNG prices, by the demand for natural gas in the global, regional and domestic markets and by the ability to export natural gas (whether by pipes, in compressed form or in liquid form). The ability to export natural gas requires, *inter alia*, gas resources of considerable volumes, the grant of export permits by the Ministry of Energy and Infrastructures (the "**Ministry of Energy**") and engagement in long-term agreements for the sale of natural gas in substantial amounts, to justify the large investments required for construction of the appropriate infrastructures and/or the payments in respect of usage fees for preexisting infrastructures. In addition, the amount of the payment of royalties and taxes to the State has a material impact on the economic merit of investments in oil and gas projects.

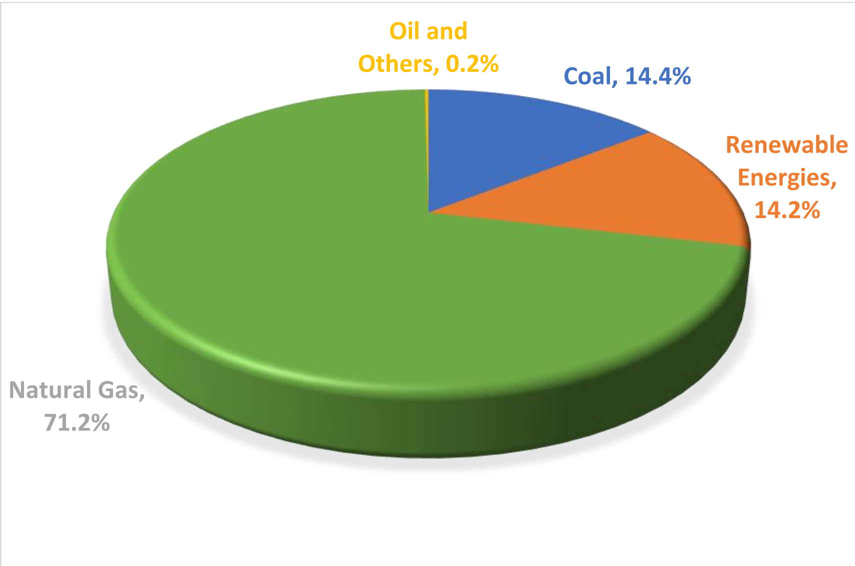
6.3. The development of the natural gas sector in Israel began in 1999-2000 upon the discovery of the Noa reservoir in the Noa Lease and the Mari B reservoir in the Ashkelon Lease (the Yam Tethys project). Later on, in 2009, the natural gas reservoirs Tamar and Dalit were discovered, in 2010, the Leviathan reservoir was discovered and thereafter, in 2012 and 2013, the Tanin and Karish reservoirs, respectively, were discovered. The Partnership participated in all of the aforesaid discoveries.

In 2004, natural gas began to flow from the Yam Tethys project through the transmission system of INGL. Initially, the facilities of the Israel Electric Corporation Ltd. (the "**IEC**") and large industrial plants were connected. Subsequently, with the start of gas flow from the Tamar project in 2013, private power plants and additional plants were connected, and the overall consumption of natural gas in Israel has increased concurrently with the progress in the construction of the transmission infrastructure of INGL and the connection of large consumers (including power plants of the IEC and private power plants) to the transmission system and of smaller consumers to the distribution network. In December 2019, commercial production from the Leviathan project began. In October 2022, Energean Oil and Gas Plc

("**Energean**") reported that the transmission of gas from the Karish reservoir had begun.

In addition, in 2023-2024, additional natural gas discoveries were made in reservoirs in the territory of Israel. For further details, see Section 7.15.1 below.

6.4. In the past two decades, the natural gas sector in Israel has undergone significant changes, which include, *inter alia*, regulatory, economic, commercial, fiscal and environmental changes. Thanks to the natural gas discoveries, the Israeli economy has become an independent economy in terms of energy. Within a few years, natural gas has become the primary component in the Israeli economy in the range of fuels for electricity production and a significant energy source for the industry. The natural gas resources that have been discovered in Israel can provide for all of Israel's gas needs in the next decades, thereby substantially reducing the State of Israel's dependence on foreign energy sources, as well as enabling export of natural gas in material quantities to regional and global markets, in accordance with the government resolutions adopted in this context. Below is the mix of the power production sources in Israel in 2024:

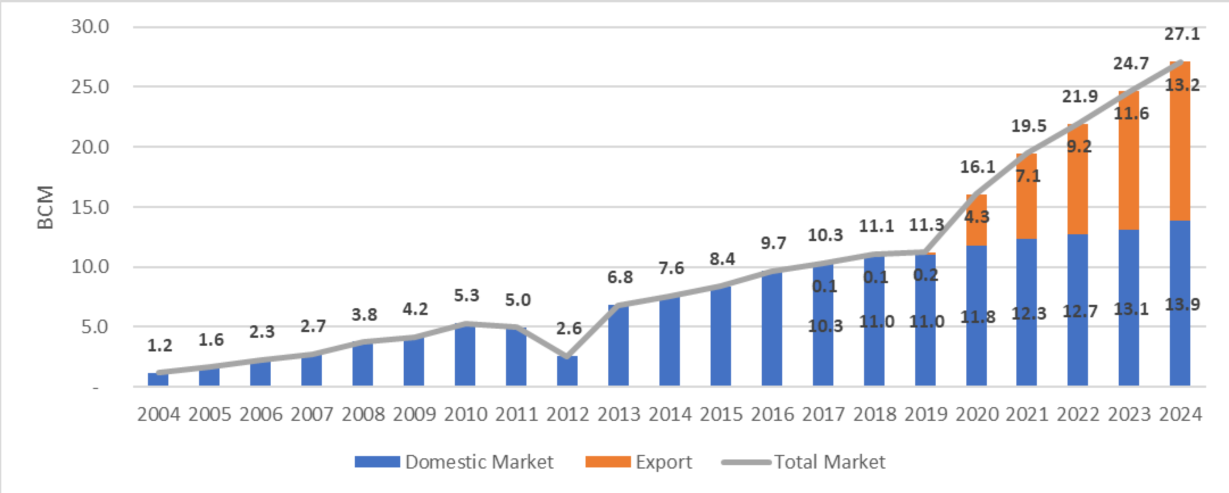


(*) Data Source: Analysis by BDO Consulting Group of data from Noga – Israel Independent System Operator Ltd. and the PUA-E.

6.5. According to a review of the natural gas sector for 2023 of 26 May 2024 of the Natural Gas Authority at the Ministry of Energy (the "**Natural Gas Authority**" and in this section below: the "**Review**"), and estimates of the Partnership in connection with 2024, since the Natural Gas Authority's data on 2024 have not yet been released, the volume of natural gas consumption in Israel increased from ~6.8 BCM in 2013 to ~13.9 BCM in 2024. In 2017, natural gas began to be exported, for the first time, from the Tamar reservoir to Jordan, in a limited volume, and in 2020 the export of natural gas began to Egypt from the Leviathan and Tamar reservoirs, as well as the export of natural gas from the

Leviathan reservoir to Jordan. In addition, the export quantity has risen from 4.25 BCM in 2020 to ~13.2 BCM in 2024.

Below is a chart presenting the growth in the gas quantities consumed in the domestic market and the gas quantities supplied for export, based on the Ministry of Energy's data and on the Partnership's estimates as aforesaid, in BCM[12]:

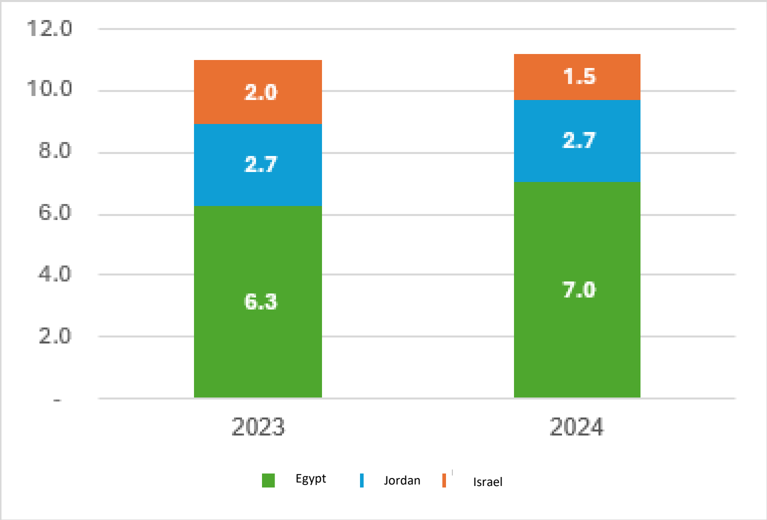


6.6. Below is a table presenting the sales figures in 2023-2024, broken down by the different gas suppliers and by sales to the domestic market and for export. The 2023 figures are based on the figures of the various gas suppliers, and the figures of the Tamar and Karish projects for 2024 are based on Ministry of Energy data[13]:

	2024			2023		
	Domestic market	Export	Total	Domestic market	Export	Total
Leviathan	1.48	9.72	11.20	2.04	8.93	10.97
Tamar	6.70	3.39	10.09	6.57	2.55	9.12
Karish	5.96	_	5.96	4.40	-	4.40

In 2023, ~2 BCM of natural gas was supplied from the Leviathan reservoir to the domestic market and ~2.7 BCM and ~6.3 BCM to Jordan and Egypt respectively, and in 2024, ~1.5 BCM of natural gas was supplied from the Leviathan reservoir to the domestic market, and ~2.7 BCM and ~7.0 BCM to Jordan and Egypt respectively, as specified in the graph below:

[12] https://www.gov.il/BlobFolder/reports/ng-overview/he/ng-2023.pdf
[13] https://www.gov.il/BlobFolder/reports/income_reporte/he/revenue-report-2024.pdf.



According to the Review, export in 2023 totaled 11.6 BCM, accounting for around 47% of the total natural gas supply, compared with export in 2022 of 9.2 BCM, accounting for around 42% of the total natural gas supply in that year, reflecting growth of around 25% between 2022 and 2023. The Review further stated that the increase in demand for Israeli natural gas mainly derived from the quantities designated for export to Egypt and Jordan[14].

The Review further presented a breakdown of consumption of natural gas produced in 2023 (in BCM) between the domestic market and the export markets, and according to the different uses, as specified below:

Domestic Market								
Industry				Electricity Production	Total	Export	Total	Year
CNG	Distribution	Industry Connected to Transmission Network	Total					
0.035	30.39	2.3	2.7	10.4	13.1	11.56	24.7	2023
0.030	350.3	2.2	2.6	10.1	12.7	9.2	21.9	2022
0.032	0.292	2.3	2.6	9.7	12.3	7.1	19.5	2021
0.036	0.254	2.2	2.5	9.3	11.8	4.3	16.1	2020
0.033	0.263	1.9	2.2	8.8	11.0	0.2	11.2	2019
0.041	0.188	1.7	1.9	9.1	11.0	0.1	11.1	2018
0.037	0.160	1.5	1.7	8.5	10.3	0.1	10.3	2017

6.7. In the Partnership's estimation, based, *inter alia*, on work performed by independent consulting firms, by 2040, natural gas consumption in Israel is expected to grow by some 60%, *inter alia* given the government policy with regards to a gradual phasing out of coal use for power production by the end of 2026, natural growth and external growth in the scope of the demand for electricity (*inter alia* as a result of significant penetration of electric vehicles, projects such as railway electrification, and continued construction of water

[14] https://www.gov.il/BlobFolder/reports/ng-2023/he/ng-2023.pdf.

desalination facilities), increased use of compressed natural gas ("**CNG**") in some transportation sectors, accessibility to natural gas for additional industrial enterprises throughout Israel and for the agricultural sector, inter alia, through a government-sponsored program to supports companies that received a government franchise to lay down a distribution pipeline and government legislative moves for changes in the distribution segment, for the purpose of upgrading the function of the distribution system, implementation of the use of natural gas in additional segments, such as services, development and tapping of industries based on natural gas as feedstock (such as production of blue hydrogen), all over and above the said natural growth in demand for natural gas and for electricity in the Israeli economy, as derived from natural population growth and the rise in the standard of living. Notwithstanding the aforesaid, the increase in the demand for natural gas may moderate in the coming years against the backdrop of the government policy on reducing greenhouse gas emissions and promoting the use of renewable energies for power production. For details see Section 7.24.10 below.

6.8. <u>The Swords of Iron war (the "Swords of Iron War" or the "War")</u>

6.8.1. Since 7 October 2023, and in 2024, Israel has been at war on several fronts, including against the Hamas terrorist organization in the Gaza Strip, the Hezbollah terrorist organization in Lebanon, the Houthi terrorist organization in Yemen, Shia militias in Iraq and military targets in Iran. In addition, during Q1/2025, fighting against terrorist activity originating from Judea and Samaria has intensified. At the same time, in 2024, the Israeli economy operated under a routine overshadowed by the War.

On 27 November 2024, a ceasefire agreement between Israel and Lebanon took effect, which was intended to halt the fighting on the northern front in the Swords of Iron War. As of the report approval date, the ceasefire on this front is generally being observed.

An agreement signed between Israel and the Hamas terrorist organization for the exchange of hostages and prisoners and restoration of a sustainable calm took effect on 19 January 2025. The deal comprises two stages: an initial stage of 42 days which has come to an end, and a second stage that has not yet begun. As of the report approval date, it is impossible to predict whether an agreement will be reached to extend the ceasefire, or alternatively whether fighting in Gaza will resume, and how it will develop.

6.8.2. In view of escalation of the War, on 18 April 2024, the credit rating agency S&P Global Ratings downgraded Israel's long-term credit rating by one notch, to A+ (from AA-), and also downgraded its short-term credit rating to A-1 (from A-1+), leaving a negative outlook regarding the long-term credit rating. On 1 October 2024, S&P Global Ratings downgraded the credit rating of Israel's government by one additional notch, to A (from A+), adding a negative outlook in view of the anticipated escalation of the War on the northern front.

In addition, in August 2024, the rating agency Fitch announced it was downgrading the Israeli government's credit rating to A (from A+), with a negative outlook.

On 27 September 2024, the credit rating agency Moody's also downgraded the credit rating of Israel's government by two notches, to Baa1 (from A2), and added a negative outlook in view of the anticipated escalation of the War on the northern front, the risk of broader escalation, including Iran, uncertainty regarding Israel's long-term growth prospects and security, and negative developments that may have a grave impact on the financial position of the Israeli government.

6.8.3. To the best of the Partnership's knowledge, upon the outbreak of the War on 7 October 2023 as aforesaid, Chevron received notice from the Ministry of Energy, whereby in view of the security situation in Israel due to the War, it was required to halt the production of natural gas from the Tamar reservoir. Gas production from the Tamar reservoir was subsequently resumed on 13 November 2023.

At the same time, due to the War, the transmission of gas in the EMG pipeline was halted, and resumed on 14 November 2023.

At the beginning of Q4/2024, in view of the escalation of the War on the northern front and vis-à-vis the Islamic Republic of Iran, the operator in the Leviathan project initiated several halts on production from the Leviathan reservoir, for short periods of time. Aside from the aforesaid, production from the Leviathan, Tamar and Karish reservoirs generally continued as usual in 2024.

In view of the initiated production halts, in October 2024, the operator in the Leviathan project notified customers of the occurrence of a *force majeur*e event that exempts the Leviathan Partners from their obligations to supply gas under the gas agreements, in respect of the non-supply of gas due to the War, and in December 2024 the operator notified customers that the said event had ended.

6.8.4. As a result of the War, the operating expenses entailed by gas production from the Leviathan reservoir have increased at a non-material rate, mainly due to the difficulty experienced by foreign companies in sending to the region work teams and vessels for the import of equipment and spare parts, which has led to a rise in the rates paid, including the insurance costs of the said companies, and to a need for additional logistics to transport manpower and equipment. In addition, scheduled maintenance actions have been delayed, changed and adapted, according to the instructions of the security agencies.

6.8.5. Due to the War, the availability of the equipment and contractors required for the performance of scheduled work in connection with the Leviathan project's work programs was impacted as aforesaid, and an increase was also recorded in the insurance premiums and the costs of foreign contractors. These factors, *inter alia*, in 2024 affected the timetables for the performance of scheduled projects and activities, including the suspension and delay of the timetable for the performance and completion of the project for the laying of a third subsea transmission pipeline from the Leviathan field to the platform (for further details, see Section 7.2.5(b) below), as well as delays in the schedule for the performance and completion of the project being carried out by INGL for the laying of a subsea pipeline in the new Ashdod-Ashkelon offshore transmission section (for further details, see Section 7.13.2(b) below). It is emphasized that aside from the aforesaid, the War did not have a material adverse effect on the Partnership's business in 2024, including on the volume of natural gas sales to customers, and the revenues and profitability in this period were not materially affected by the War.

6.8.6. As of the report approval date, it is impossible to predict whether the ceasefire on the northern front and in the Gaza Strip will hold, and whether the War is expected to resume and/or expand in 2025 and in the coming years, as well as the repercussions and consequences of such developments and their impact on the Partnership. Despite the fact that the War did not have a material impact on the Partnership's business in 2024 as aforesaid, in these circumstances, it is impossible to predict the chances of materialization of the risk factors deriving from the War and their possible effect, including the risk factors specified in Section 7.30.1 below, whose materialization could have a material adverse effect on the Partnership, its assets and its business.

Caution concerning forward-looking information - The Partnership's estimates specified above, including in relation to the potential impact of the War on the Partnership, are forward-looking information as defined in the Securities Law, 5728-1968 (the "Securities Law"). These estimates may not materialize, in whole or in part, or may materialize differently, including significantly differently than expected, mainly due to the considerable uncertainty at this time, including with respect to the War's duration, scope, and its repercussions for the Israeli economy, and also due to the occurrence of events beyond the Partnership's control.

6.9. <u>The principal external factors that affect this sector</u>

6.9.1. <u>Fluctuations in linkage components in the formulas of natural gas prices</u>

The gas prices stated in the agreements for the sale of natural gas from the Leviathan project are based on various pricing formulas which mainly include linkage to the Brent barrel price, linkage to the electricity production tariff as determined from time to time by the PUA-E (the "**Electricity Production Tariff**"), linkage to the shekel/dollar exchange rate, and linkage to the general TAOZ index published by the PUA-E (the "**TAOZ Index**") and the crack spread (jointly: the "**Linkage Components**")[15]. With the exception of agreements in which the natural gas price is fixed, natural gas sale agreements include floor prices. Therefore, the Partnership's exposure to fluctuations in the Linkage Components in such agreements is primarily hedged by a bottom threshold. For details on the possible effect of changes to the various Linkage Components on the Partnership's business, see Section 7.30.3 below.

6.9.2. Regulation

The sector of exploration, development, production, transportation and decommissioning of oil and natural gas assets is subject to regulation in countries where the activity is carried out. In Israel, the sector is subject to extensive regulation with respect to petroleum assets (including rules for granting, transferring and pledging the same), to conditions for development, production and supply (including the construction of transmission and distribution and consumer connection infrastructures), to royalties and taxation, export, environmental regulation, competition law, and so forth. Following the gas discoveries which were made by the Partnership and its partners throughout the years, in the various petroleum assets, in the State of Israel's EEZ, there has been a significant increase in the extent of regulation of the energy and environment sectors in Israel in general and in connection with the natural gas ventures in particular.

For details with respect to restrictions and supervision over the activities of exploration, development and production of natural gas and/or oil in Israel and in Cyprus, Bulgaria and Morocco, see Section 7.24 below.

6.9.3. Supply and demand conditions

For details on the supply and demand in the global markets and in the domestic market, see Sections 7.1.3, 7.13 and 7.16 below.

[15] In addition to the effect of the changes in the Brent barrel price, the Partnership's business is also indirectly affected by the prices of natural gas and other alternative energy products which are determined on the global markets. For further details, see Section 7.1.4 below.

7. Description of the Partnership's Business by field of business

7.1. General information about the field of business

7.1.1. Structure of the field of business and changes occurring therein

Operations of exploration, development, production, transportation and decommissioning of natural gas and oil facilities and reservoirs (in this section: the "**Operations**") are complex and dynamic operations, entailing substantial costs and considerable uncertainty with respect to costs, timetables, the presence of and the ability to produce oil or natural gas while protecting the environment and maintaining cost effectiveness. As a result, despite considerable investments, exploration activities, including exploration and appraisal wells, often fail to achieve positive results and fail to generate any revenues and may lead to the loss of most or all of the investment within a relatively short amount of time.

The Operations are usually conducted in the framework of joint ventures between several partners who sign a joint operating agreement (JOA), whereby one of the partners is appointed as the operator of the joint venture (for a description of a joint operating agreement, see, for example, the joint operating agreement that applies to the Leviathan project, which is described in Section 7.26.7 below).

The Operations may include, *inter alia*, the following stages:

(a) Initial analysis of existing geological and geophysical data, for the selection of areas presenting potential for oil and natural gas exploration.

(b) Formulation of an initial geological model (Play).

(c) Performance of various geophysical surveys, including seismic surveys, which assist in the location of geological structures that may contain oil and/or natural gas (Leads) and data processing and interpretation.

(d) Examination of the Leads and preparation of prospects fit for test drilling therefrom.

(e) Decision to perform test drilling and performance of activities in preparation for the drilling.

(f) Engagement with contractors for the performance of the drilling and for receipt of related services.

(g) Performance of the test drilling, including logs and additional tests.

(h) Performance of production tests (to the extent justified by the findings of the drilling).

(i) Analysis of the results of the drilling and, in the event of a finding, based on an initial evaluation of the features of the reservoir and the amount of oil and/or natural gas, an economic (including a market assessment) and fiscal analysis and an initial evaluation of the development format and cost. There may be additional seismic surveys and/or appraisal wells, as necessary, for the purpose of formulating a better estimate of the features of the reservoir and the amount of oil and/or natural gas present therein.

(j) Examination of the alternatives for commercialization of the oil and/or natural gas, identification of the target markets and examination thereof, formulation of a development plan and preparation of a financial plan for the project.

(k) A final analysis of the data and adoption of a final investment decision (FID).

(l) The projects for development of natural gas findings require, over and above engineering feasibility, also the signing of binding long-term sale agreements for appropriate quantities and prices with customers that have the financial ability that allows for obtaining project financing.

(m) Development of the reservoir, including the performance of production drilling, layout of transmission pipeline, construction of treatment facilities, building systems for transporting the gas and/or oil to customers and so forth.

(n) Production from the reservoir, including operation and ongoing maintenance, and performance of additional development and expansion work in the purpose of preserving and/or increasing the production volume.

(o) Decommissioning of the field facilities after the reservoir is depleted, and after weighing various technical, economic and regulatory parameters. Decommissioning actions may include, *inter alia*, plugging wells, rinsing, decommissioning and abandoning facilities and rehabilitating the lease area, insofar as necessary, in accordance with the various regulatory directives and local accepted standards.

Due to the various characteristics and data of each and every project, the aforesaid stages are not necessarily exhaustive of all of the stages of the Operations in a specific project, which may include, due to its quality and nature only some of the these stages and/or additional stages and/or stages in a different order.

In addition, the timeframes for performance of each of the stages vary according to the nature of the project.

As specified above, the commercial merit of oil and/or natural gas findings is complex and dependent upon numerous and various factors. In this context, there are material differences between an offshore finding, the development of which requires financial input and use of unique technologies, such as drilling at a considerable water depth or laying subsea facilities and pipelines which are able to operate at a high level of reliability in the sea depths, and an onshore discovery, whose development costs may be substantially lower. In addition, the financial, logistical and technical inputs required to develop a natural gas reservoir, including for building the components used for the transmission and/or transportation of the natural gas that is intended for export to the regional or international market, are generally significantly higher relative to those required for development and production from a natural gas reservoir which is designated solely for the local domestic market. An additional key variable is the demand and the price in the target markets. There is great difficulty in developing a project of significant scope when the demand for and prices of natural gas do not economically justify the costs of development of the project, as stated below, and/or allow the raising of project finance. Furthermore, there are substantial technological, marketing and financial differences between oil reservoirs and natural gas reservoirs. Thus, for example, the economic merit of a natural gas reservoir mostly derives from the ability to market it to a guaranteed attractive target over the course of years, due to the fact that unlike oil, natural gas is not a commodity which is sold for similar prices all around the world and, *inter alia*, since transportation thereof to the target markets may be complicated and entail liquefaction or compression. Moreover, the commerciality of an oil reservoir is highly impacted by global oil prices, thus, for example, a reservoir which is not commercial when the price of an oil barrel is X dollars, may become commercial when the price of an oil barrel rises to 1.5X dollars and vice versa. In light of the aforesaid, naturally, oil and/or natural gas reservoirs, which are not commercial under certain market conditions, may become, due to material changes in the regulation and market conditions, commercial reservoirs, and vice versa.

7.1.2. Restrictions, legislation, standardization, directives and special constraints applicable to the field of business

For details, see Section 7.24 below.

7.1.3. Developments in markets or changes in customer characteristics

As of the report approval date, the Partnership sells natural gas from the Leviathan project to various customers in the domestic and regional markets, and mainly Blue Ocean in Egypt and NEPCO in Jordan, as specified in Section 7.12.3 below. At the same time, and in light of the significant volume of resources discovered off the shores of Israel, mainly in the Leviathan and Tamar natural gas reservoirs, the Partnership is taking action to identify markets and increase natural gas sales to additional customers, in the domestic market and in neighboring countries, subject to restrictions on gas export, as specified in Section 7.24.8 below. The Partnership is also promoting use of infrastructures now in existence and/or that will exist in the foreseeable future and/or that will be built especially for natural gas export purposes and additional ways to export the natural gas, including by way of the liquefaction (LNG) and/or compression (CNG) thereof. For further details, see Section 7.13.4 below. It is noted in this context that on 15 June 2022, an MOU was signed between the governments of Israel and Egypt and the European Commission on collaboration in trade, transport and export of natural gas to the EU countries (in this section: the "**MOU**").[16] According to the MOU, the parties will act for regular supply of natural gas to the EU countries from Egypt, Israel and other locations, through liquefaction of natural gas in liquefaction facilities in Egypt, subject to preservation of the energy security in the domestic market of each of the countries that signed the MOU, and without Israel or Egypt impeding export of natural gas to other countries. In addition, according to the MOU, the EU will encourage European countries to participate in competitive processes and invest in natural gas exploration and production projects in Israel and Egypt.

The Partnership is also exploring and promoting possibilities for investing in renewable energy projects, in the context of the collaboration with Enlight, in which framework it has engaged with a local partner in Morocco and is exploring other potential projects, as specified in Section 7.10 below. In addition, the Partnership is exploring possibilities for the production of hydrogen and, *inter alia*, blue hydrogen produced from natural gas. In this context, it has engaged with Airovation Technologies, a private Israeli technology company (which is not an interested party of the Partnership ("**Airovation**"), as specified in Section 7.28.3 below.

[16] https://www.gov.il/he/departments/news/ng_150622.

7.1.4. Factors affecting the price of and demand for natural gas and other energy products

General

The demand for energy in general and natural gas in particular depends on a number of key factors, including the prices of the various energy products and their alternative products, any change in the variety and method of uses of natural gas, the GDP (gross domestic product) growth rate, population growth rate, living standards, weather conditions, and the energy efficiency of electricity and gas consumers and producers.

In addition, the Government's policy, and specifically that of the Ministry of Energy, may affect the market share of natural gas in the mix of electricity production sources in the Israeli economy, through, *inter alia*, encouraging development of energy sources that serve as alternatives to natural gas, such as renewable energies; energy storage measures; the rate of entry of electric vehicles; the rate of connection of plants to the natural gas system; construction of new natural gas-powered power plants; and the rate of closure and/or conversion to natural gas use of coal-fired power plants.

The prices of natural gas and LNG in the global markets and the prices of alternative energy products, including renewable energies, oil and coal, may also affect demand levels and the volume of the Partnership's natural gas sales and the sale prices of natural gas, thereby affecting the economic viability of promoting new projects or of expanding existing projects. Moreover, low LNG prices in the global markets may lead to increased LNG import into the regional markets, thus reducing the demand for natural gas produced in Israel in the regional markets relevant to the Partnership and adversely affecting the Partnership's revenues from the Leviathan reservoir. Accordingly, high LNG prices may reduce the import of LNG into the regional markets, and increase the demand for natural gas produced in Israel.

In recent years, there has been a significant global increase in the capacity to produce LNG, *inter alia* due to the operation of new liquefaction facilities, or expansion of existing facilities, such as liquefaction facilities in the U.S., Qatar, Russia (in the Arctic Circle) and Australia, and acceleration of the construction of liquefaction facilities and regasification facilities for LNG as a result, *inter alia*, of the Russia-Ukraine war and the significant decrease in the volume of natural gas sold by pipeline from Russia to the European market and replacement thereof by LNG cargos.

The global LNG market has characteristics of a commodity market, as distinct from the markets for natural gas that is supplied via pipelines, which are dependent on the trends of supply and demand in each and every region. As of the report approval date, it is estimated that approx. 14.3% of the global demand for gas is in the form of LNG. It is estimated that this market share is expected to grow to approx. 21.3% by 2045 as a result of a decrease in domestic gas production in certain regions, which will require the import of LNG in order to meet the demand for natural gas[17].

In 2024, the levels of global demand for LNG continued to grow and according to estimates totaled approx. 410 million tons (approx. 566 BCM), reflecting an increase of approx. 1.6% compared with the consumption in 2023. According to estimates, LNG demand is expected to grow by more than 55% until 2040, as a result, *inter alia*, of a transition to the use of natural gas instead of coal in China and in South Asian countries, and increased demand for LNG in Europe and in South-East Asian countries.

At present, Australia, Qatar and the United States are the world's largest LNG exporters, and in 2024 they provided approx. 60% of the global LNG supply.

<u>The volatility in energy prices in recent years</u>

Energy prices have been characterized, in recent years, by high volatility, mainly as a result of global changes and events. Following the outbreak of the Covid pandemic, which led, in H1/2020, to a decline in economic activity, a decrease was recorded in this period in LNG and natural gas prices on the spot markets in Europe and Asia, where natural gas prices developed independently of the oil price, and to which the LNG surpluses were directed. In 2021, with the global recovery of economic activity, the global energy sector experienced dramatic changes which led, *inter alia*, to a sharp rise in the prices of energy products during 2021.

The Russian army's invasion of Ukraine in early 2022, and the sanctions imposed on Russia as a result thereof, led to reduced import of Russian natural gas and oil into Europe, and consequently to a sharp rise in oil and natural gas prices.

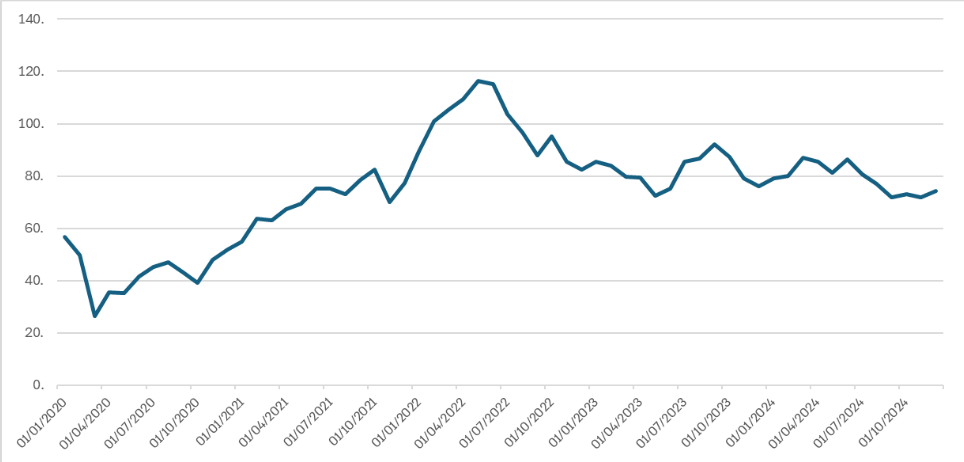
From mid-2022 and in 2023, the demand for natural gas declined along with a certain decline in energy prices in the global markets, which may be attributed to signs of slowdown in the global economy and to a concern of escalation of the recession, *inter alia* against the backdrop of a swift rise in the inflation rate, which has led to an increase in the base interest rate, as well as the effect of the weather, which was relatively mild in the winter months in Europe.

[17] The data in this section are based on the Partnership's analysis of reports of various consulting firms.

In 2023, relative stability was recorded in the Brent price fluctuations, and it was traded within a range of $70-$95 per barrel, and in 2024, it was traded within a range of $70-$91 per barrel.

At the end of 2023, liquefied natural gas was traded in Europe at an average price of approx. $13 per MMBTU, and at the end of 2024, the price was approx. $15 per MMBTU.

Below is a graph showing the monthly Brent prices in dollars in 2020-2024:



(*) Graph source: the Bizportal Terminal system.

The monetary policy and the inflation rate in Israel

The inflation rate in Israel in 2024 was approx. 3.2%[18], compared with inflation at a rate of approx. 3%[19] in 2023 and approx. 5.3%[20] in 2022.

According to a macroeconomic forecast document released by the Research Division at the Bank of Israel in January 2025[21], it is estimated that the GDP increased in 2024 by 0.6% and is expected to increase in 2025 by 4.0% and in 2026 by 4.5%. The rate of inflation in the upcoming four quarters (ending in Q4/2025) is expected to be 2.6% and the rate of inflation in 2026 - 2.3%. The interest rate level in Q4/2025 is expected to be, on average, 4.0/4.25%. The price of a Brent oil barrel was characterized by relative stability and decreased to approx. $74, compared with approx. $77 at the time of preparation of the October 2024 forecast.

This forecast was prepared under the assumption that the direct economic effect of the War will continue until the end of Q1/2025. This

[18] Link to CBS data for 2024 (in Hebrew).
[19] Link to CBS data for 2023 (in Hebrew).
[20] Link to CBS data for 2022 (in Hebrew).
[21] The Macroeconomic Forecast of the Research Division, January 2025.

assumption reflects moderate fighting also at the beginning of 2025. The lower growth forecast risk was reduced by the geopolitical developments in Q4/2024, and specifically the relative calm on the Lebanon front, reducing the probability attributed to security scenarios with graver economic repercussions. However, this risk is still very high compared with normal times. Therefore, the level of uncertainty surrounding the growth, inflation, interest rate and government deficit forecasts is still high.

The prices of energy products, the interest rate environment, trade wars, including in connection with the imposition of customs, and the inflation rate also affect the operating costs of the gas production, as well as the development costs in the Partnership's projects, including the drilling of development, appraisal and exploration wells. The Partnership, together with its partners in the various projects, and specifically the Leviathan and Aphrodite projects, is examining the effect of the said factors on the additional possibilities for development and/or expansion of its assets.

Caution concerning forward-looking information – The Partnership's estimates regarding the possible ramifications of the Ukraine war, the inflation and increase in interest constitute forward-looking information, as defined in Section 32A of the Securities Law. This information is based, *inter alia*, on the Partnership's estimations and assessments as of the report approval date, and on public reports in Israel and worldwide on this issue and on directives of the relevant authorities, the materialization of which is uncertain, in whole or in part, and beyond the Partnership's control.

7.1.5. Material technological changes

Recent decades have seen technological changes in the exploration, development, production, transportation and decommissioning of oil and natural gas facilities and reservoirs, both in the field of monitoring, collection and analysis of information, and in the drilling, development and production methods. These changes have improved the quality of the data available to oil and natural gas explorers and have allowed for more advanced identification of potential oil and natural gas reservoirs, and therefore may also reduce the risks of drilling. Furthermore, the technological improvements have increased the efficiency of the drilling and production work and also presently allow to operate in rougher conditions than before, including at significant water depths. Accordingly, corporations exploring for oil and natural gas, are able to invest exploration efforts in areas where drillings were not feasible in the past, or were feasible but at very high costs and at greater risks. The Partnership and the operators in the various projects in which it is a partner strive to use the best available technologies in all of the operation segments, and in this context invest considerable resources in reprocessing and reanalyzing seismic surveys by means of innovative technologies, in order to improve the database, update the maps of the reservoirs and the assessment of their characterizing parameters, and thereby accordingly update the volume of the resources therein, update the development plans and define new prospects. Furthermore, technologies defined as best available technologies are used, insofar as possible, in the Leviathan project in order to streamline the production system, enhance the facilities' safety and reduce their impact on the environment.

Technological changes in the natural gas production and transportation segment, such as newer and more efficient technologies for converting natural gas into LNG through an onshore or offshore liquefaction (FLNG) facility, compression into CNG and conversion of gas to liquid (GTL), may facilitate more efficient transportation and commercialization of natural gas. In this context it is noted that the Partnership is continuing to explore the possibility of building an offshore liquefaction (FLNG) facility for converting natural gas into LNG as aforesaid, as specified in Section 7.2.5(e) below.

In recent years, and particularly in 2024, an increase in the development and implementation of artificial intelligence (AI) and machine learning (ML) technologies was apparent, *inter alia* in the various economic sectors and in the energy industry specifically. These technologies are implemented, *inter alia*, to enhance large database analysis capabilities, streamline supply chains, optimize and automate information and optimize various workflows. In the Partnership's business segments, there is apparent continued penetration of AI and ML capabilities in the processing and interpretation of seismic information, interpretation of drilling logs, analysis of production, operation and environmental data, management and investigation of large databases, etc. The Partnership integrates AI and ML capabilities in its workflows and systems and regularly reviews other developments for purposes of implementation thereof. Growing use of AI and ML is leading to increased demand for energy generally, and for electricity specifically, for the operation of data centers. Thus, for example, the global power consumption of data centers in 2026 is expected to be double that of 2022. The said growth in the demand for energy is expected to trigger material changes in the markets and to affect the energy sources that are mainly used for power production.

7.1.6. Critical success factors in the field of business

(a) Identification and receipt of exploration rights (purchase or farm-in) in areas presenting a potential for commercial finding.

(b) Financial abilities and ability to raise considerable financial resources.

(c) Use of advanced technologies, e.g., 3D seismic surveys and advanced information processing for the identification and preparation of prospects for drilling, for improvement of the evaluation of drilling results and for the formulation of a development plan.

(d) Joining forces with highly knowledgeable and experienced entities which operate in the sector for the purpose of performing complex development plans and/or drillings, while being assisted by the professional knowledge possessed thereby and the contribution thereof to the considerable financial investments.

(e) Success of the exploration activity.

(f) In the event of a natural gas and/or oil find, engagement in agreements for the sale of gas in the appropriate quantities and for the appropriate prices.

(g) Existence of engineering, geological, financial and commercial knowledge, experience and ability to manage exploration, development and production projects at considerable financial scopes, including the construction of production and transmission infrastructures.

7.1.7. Changes in suppliers and raw materials

For details, see Section 7.18 below.

7.1.8. Barriers to entry and exit

The main barriers to entry into the business sector are the need for permits and licenses for the performance of oil and natural gas exploration, development production and transmission, compliance with the requirements of law and regulation, including the directives and criteria determined by the Petroleum Commissioner at the Ministry of Energy (the "**Petroleum Commissioner**") (and, in Cyprus – directives and criteria prescribed by legislation and arrangements under the PSC, as specified in Section 7.3.3(l) below), the ability to transfer and/or purchase interests in petroleum and natural gas assets, including as pertains to demonstration of the applicant's financial soundness and the operator's technical ability for the purpose of receipt thereof, and the existence of the financial and technical ability to make large-scale investments of billions of dollars characterized by a relatively high level of risk, which are entailed by the performance of the exploration, development and production activities.

The significant barriers to exit the business sector in Israel are mainly undertakings under long-term gas supply agreements in which the Partnership has engaged. In addition, both in and outside of Israel, there is a duty to plug and abandon wells and decommission all production facilities before returning the lease areas to the state, as specified in the lease deeds, the PSC in Cyprus, the terms and conditions of the licenses and the relevant provisions of the law.

Furthermore, as concerns exit from existing projects by way of partial or full sale, there may be exit barriers that derive from the regulatory requirements that will apply to the purchaser, and from the substantial financial scale of such sale.

In Bulgaria, the main barriers to entry and exit include the need to obtain the approval of the Council of Ministers for the transfer of interests in an oil and gas exploration and production license, pursuant to the applicable law. in this context, the applicant must prove compliance with strict financial, technical and professional requirements, as well as proving the hiring of professional manpower, and where a license is held by several parties, the consent of all of the current holders is required.

7.1.9. Substitutes for the products of the field of business

Natural gas is mainly used for electricity production and is sold in Israel and in the region mainly to electricity producers and industrial customers. In general, the alternatives to natural gas use are other fuels such as diesel oil, fuel oil, coal, LPG and petcoke, as well as energy from renewable sources, such as solar energy, wind energy and so forth, including renewable energy that may be produced in excess of market demand and stored in storage facilities for use when the energy source is unavailable (for example during night hours when it is not possible to produce energy from solar sources). Each of the aforesaid interchangeable fuels and alternative energy production methods have advantages and disadvantages, and they are subject to fluctuations in prices, availability, technical constraints, regulation, availability of land, etc. The transition from use of one energy source to another usually involves large investments. The principal advantages of the natural gas compared with coal and liquid fossil fuels, are the fact that the energy efficiency of power plants operated by natural gas is significantly higher than that of power plants operated by coal and fuel oil, and the fact that the emission of carbon dioxide, particles and nitrogen and sulfur oxides from the combustion of natural gas is significantly lower than that of coal and fuel oil. For details with respect to the resolutions of the Israeli government on the promotion of use of renewable energy and setting targets for reducing greenhouse gas emissions, see Section 7.24.10 below, respectively. It is noted that technologies that are under development and/or in initial stages of implementation (such as hydrogen, waste-to-energy and nuclear fusion) may change the global energy market in the coming decades.

7.1.10. Structure of competition in the field of business

For details, see Section 7.15 below.

Below are details regarding the Partnership's petroleum assets:

7.2. Leviathan project

7.2.1. General details

General Details with respect to the Petroleum Asset	
Name of the petroleum asset:	Leviathan North. Leviathan South.
Location:	Offshore assets situated approx. 130-140 km west of the shores of Haifa.
Area:	The overall area of the two leases combined is approx. 500 km^2.
Type of petroleum asset and description of the activities permitted for such type:	Lease; Permitted activities under the Petroleum Law – exploration and production.
Original grant date of the petroleum asset:	27 March 2014
Original expiration date of the petroleum asset:	13 February 2044
Dates on which an extension of the term of the petroleum asset was decided:	-
Current expiration date of the petroleum asset:	13 February 2044
Is there an additional option to extend the term of the petroleum asset; if so – what is the possible extension period:	Subject to the Petroleum Law, it may be extended by another 20 years.
The name of the operator:	Chevron
The names of the direct partners in the petroleum asset and their direct share in the petroleum asset, and, to the best of the Partnership's knowledge, the names of the control holders of such partners:	▪ The Partnership (45.34%). ▪ Chevron (39.66%). ▪ Ratio Energies – Limited Partnership ("**Ratio**") (15%). To the best of the Partnership's knowledge, the general partner of Ratio, Ratio Energies General Partner Ltd., is a company owned by D.L.I.N. Ltd. ("**D.L.I.N.**") (34%), Hiram Landau Ltd. ("**Hiram**") (34%), Eitan Aizenberg Ltd. ("**Aizenberg**") (8.5%), Eyal Zafriri (4.3%), Edo Porat (1.4%), Asher Porat (1.4%), Daniel Soldin (1.4%) and Adv. Boaz Ben-Zur and Adv. Robi Behar in trust for Mr. Shlomi Shukrun (15%). D.L.I.N. is a private company owned by Yair Rotlevy (1/3) and Ligad Rotlevy (2/3). Hiram is a private company, owned by Deborah Landau (1/2), Yigal Landau (1/6), Shlomit Landau (1/6), and Yuval Landau (1/6). Aizenberg is a private company controlled by Eitan Aizenberg[22].
General Details with respect to the Partnership's Share in the Petroleum Asset	
For a holding in a purchased petroleum asset – the purchase date:	-
Description of the nature and manner of the Partnership's holding in the petroleum asset:	The Partnership directly holds 45.34% of each of the Leviathan Leases.
The actual share in the revenues from the petroleum	Before investment recovery – 37.63%.

[22] To the best of the Partnership's knowledge, as of the report approval date, the rate of holdings of all of Ratio's interested parties (except holdings of institutional bodies, mutual funds and provident funds) is approx. 23.63%.

General Details with respect to the Petroleum Asset	
asset attributable to the holders of the equity interests of the Partnership:	After investment recovery – 35.37%.
The total share of the holders of the equity interests of the Partnership in the aggregate investment in the petroleum asset during the five years preceding the last day of the year of the report (whether recognized as an expense or as an asset in the financial statements):	Approx. $381,444 thousand[23].

7.2.2. The principal terms and conditions of the Leviathan Leases

(a) The terms and conditions of the Leviathan North and Leviathan South leases are principally identical. The description presented below relates to the main subjects in the Leviathan South lease (in this section: the "**Lease**"), and where there is a material difference in relation to the Leviathan North lease, it is stated.

(b) The operator's actions will be binding on the lease holder and notices from the Petroleum Commissioner or anyone on his behalf to the operator will be binding on the lease holder. Nothing in the provisions of this section shall derogate from the undertakings and liability of each of the Leviathan Partners to act in accordance with the provisions of the lease and the provisions of any law, jointly and severally.

(c) The lease holder will only replace the operator with approval in advance and in writing by the Petroleum Commissioner.

(d) Scope of the lease

1. The lease holder will have the exclusive right to explore and produce oil and natural gas in the lease area alone, throughout the entire term of the lease, as aforesaid, subject to the other provisions of the lease deed and to any law.

2. The lease holder, at its sole responsibility, will plan, finance, construct and operate the production system and will maintain it for the purpose of its ongoing operation, all through the operator, contractors, planners and consultants who have a high level of knowledge and vast experience in their fields, in such manner so as to enable the reliable, regular, proper and safe supply of oil and natural gas from the Leviathan field.

[23] The costs in the table do not include costs in respect of Leviathan's Participation (as specified in Section 7.26.6(d) below), the Combined Section (as specified in Section 7.13.2(b) below), the EMG Transaction (as specified in Section 7.26.6 below), and the construction of the Israeli transmission system up to the border between Israel and Jordan (as specified in Section 7.12.3(b) below).

(e) Term of the lease

If the term of the lease ends or if the lease is revoked under the provisions of the Petroleum Law, or by virtue of the regulations thereof, or under the provisions of the lease deed, the right of the lease holder to act by virtue of the lease deed will expire.

(f) Sale to consumers in Israel and export

1. The lease holder will not unreasonably refuse to supply oil and natural gas to consumers in Israel.

2. The export of natural gas from the lease will require written approval from the Petroleum Commissioner with the approval of the Minister of Energy (the "**Export Approval**"). The Export Approval will be granted in accordance with government resolution no. 422 of 23 June 2013 on export, and subject to the terms and conditions specified therein, including changes thereto and any resolution of the government that shall replace it, and subject to any law.[24] In addition, export will not be allowed in a manner that prejudices the leaseholder's ability to supply and transmit, from the Leviathan field to the national transmission system, an amount of at least 1.05 MCM of gas per hour (from the areas of the Leviathan Leases jointly). Despite the aforesaid, the Petroleum Commissioner may consider reducing the amount that the leaseholder is required to supply and transit from the Leviathan field to the national transmission system as aforesaid, if he believes, *inter alia*, that another leaseholder that receives a lease after 27 March 2014, is transmitting or is expected to transmit gas to the national transmission system, according to a reasonable timetable.

3. In case of a shortage of natural gas in Israel, the lease holder will give preference to the needs of the local economy, in relation to its supply capacity which is not subject to sale undertakings under a contract thereof, valid at the time. The quantity that will be supplied, as aforesaid, to the local economy will be considered part of the quantity designated for the local economy according to the foregoing government resolution, and will not diminish the quantity permitted for export according to the Export Approval, to the extent it is given.

(g) Construction of facilities and adjustment of the capacity to the needs of the local economy

1. The planning and set up of the production system and transmission system to the shore, in the framework of the development program, will be performed so as to allow the

[24] For details regarding the government resolutions on export, see Section 7.24.8 below.

supply and transmission of gas to the national transmission system in an amount of at least 1.4 MCM per hour (~12 BCM per year) from the areas of the Leviathan Leases jointly.

2. The lease holder may, subject to receiving written approval from the Petroleum Commissioner and the Director General of the Natural Gas Authority, as applicable, increase the capacity of the production system and the transmission system to the supplier, and add facilities and wells, in a manner that will allow for the transmission of quantities of gas exceeding those stated in Subsection 7.2.2(a) above to the national transmission system.

3. The Petroleum Commissioner may demand that the lease holder, if necessary due to special circumstances, adds facilities and wells, and another entrance point to the production system and transmission system, in a manner that allows for the safe, reliable, and effective transmission of quantities of gas, that exceed those aforementioned, to consumers in Israel; the demand, as aforesaid, will be made only if special circumstances exist, and while weighing and balancing all the relevant considerations, amongst them considerations of economic merit, and if the Petroleum Commissioner finds that the addition has no economic merit for the lease holder, only upon finding a solution thereto. If the Petroleum Commissioner demands, as aforesaid, the lease holder will prepare an addition to the development plan and submit it for his approval within the period determined by the Petroleum Commissioner in his demand.

(h) Commercial production

1. Commercial production from the lease area will be conducted under the following principles:

   a. Production will be carried out with proper diligence, without waste, without creating a risk, and in a manner that does not constitute any harm to the features of the gas reservoir situated in the Leviathan field.

   b. The production from each well will be performed in a manner so as not to exceed the maximum effective output; the Petroleum Commissioner may instruct the lease holder, from time to time, of the maximum output, taking into account the data from the gas reservoirs located on the Leviathan field, and the characteristics thereof.

   c. The lease holder will maintain the quality of the gas transmitted thereby to the national transmission system in accordance with the gas specification, as shall be determined.

2. The lease holder will perform commercial production in accordance with the provisions of the authorized authorities and any law, and in accordance with the provisions of any license, permit, approval etc. required as such according to any law.

3. The lease holder will only commence commercial production and will only commence natural gas flow into the transmission system to the supplier, after the submission of an application for approval of the operation to the Petroleum Commissioner, and the approval of the application by him.

4. At the end of every year (at least 30 days prior to the end of the calendar year), the lease holder will submit to the Petroleum Commissioner a detailed work program describing the work that he intends to perform in the following year with regards to the lease for the purpose of the production and compliance with the provisions of the lease deed, a projection of the costs for performing the activities in the aforementioned work program, and a forecast of the production rate in the following year.

5. The lease holder shall notify the Petroleum Commissioner of the dates on which it intends to begin construction of additional facilities in order to fulfill the provisions of the lease deed.

(i) <u>The supervision companies</u>

The planning of the production system, the production of its components, its construction and operation will be carried out under the supervision of supervision companies with training and experience in supervising planning, production, construction or operation, as applicable, of maritime production systems, subject to the approval of the Petroleum Commissioner.

(j) <u>The development plan</u>

1. The lease holder will prepare and submit the development plan that it proposes for the Leviathan field to the Petroleum Commissioner for approval.

2. The lease holder will include in the development plan a detailed timetable for executing the development plan regarding the production system for the local economy, according to which the commercial production and the transmission of gas to the transmission system will begin 48 months from the date of the provision of the lease deed.

3. The lease holder may submit to the Petroleum Commissioner a reasoned and detailed request to postpone or update the timetable determined in the development plan, as aforesaid. The Petroleum Commissioner will postpone or update the timetable, as requested or otherwise, as he sees fit under the circumstances, if convinced that the lease holder acted with appropriate diligence as required for keeping up with the timetable, and the delay in the timetable does not derive from an act or omission of the lease holder, or from an event the results of which the lease holder could, had he acted with the appropriate diligence, have prevented or limited or mitigated.

(k) Change of conditions in the lease deeds

If a layer is discovered on the area of the lease, from which crude oil can be produced in commercial quantities, the Petroleum Commissioner will add chapters to the lease deed that will include all that is necessary to adapt it to what is required for the production of crude oil, its processing and transmission; the lease holder will not produce oil from the leased territory, unless the aforesaid chapters are added, and in accordance with their provisions.

(l) Revocation or restriction of the lease

The lease will be terminated upon the end of the term of the lease, upon expiration thereof under Section 29 of the Petroleum Law, upon revocation thereof under Section 55 of the Petroleum Law, or upon the occurrence of either of the conditions specified below:

1. The lease holder shall have materially deviated from a material provision of the lease deed or from the instructions of the Petroleum Commissioner by virtue of the lease deed.

2. The guarantee (as detailed in Section 7.2.2(n) below) or a part thereof shall have been forfeited and the lease holder shall not have supplemented the amount of the guarantee as required under the provisions of the lease deed.

(m) Decommissioning plan

1. No later than the date on which the balance of the reserves (2P) in the Leviathan field, according to the updated and latest resource assessment report will be reduced to less than 125 BCM, the lease holder will submit a detailed plan for the decommissioning of the facilities, and an estimate of the decommissioning costs (the "**Decommissioning Plan**") to the Petroleum Commissioner for approval. If the lease holder does not submit the foregoing Decommissioning Plan on time, or the

Petroleum Commissioner finds that the Decommissioning Plan that was submitted is not suitable for approval, and the parties did not succeed in agreeing on a Decommissioning Plan, the Petroleum Commissioner will determine the Decommissioning Plan in accordance with the accepted international standards.

2. On the date of approval of the Decommissioning Plan by the Petroleum Commissioner, the Petroleum Commissioner will determine a plan for the lease holder according to which the lease holder will provide collateral or a deposit into an "abandonment fund", on the dates, in the format and according to the accrual method, as instructed by the Petroleum Commissioner, with the aim of ensuring that the lease holder will have the means required for executing the Decommissioning Plan.

3. The lease holder will provide notice of his intention to abandon a well, to the Petroleum Commissioner, at least 3 months prior to the date on which he requests to perform the act, and it will not be executed until after receiving written approval from the Petroleum Commissioner.

   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 below.

(n) Guarantees[25]

1. For the purpose of ensuring compliance with the provisions of the lease deed and any approval provided by the Petroleum Commissioner according to the lease deed (in this section: "**Letters of Approval**"), for ensuring the payments from the lease holders to the State according to any law, and as a condition for the provision of a lease deed, the lease holder will provide an autonomous, unconditional and irrevocable bank guarantee in favor of the State of Israel in the amount of $50 million for each of the Leviathan Leases (and in total $100 million, while the Partnership's share is approx. $45 million) in accordance with timetables determined in advance (in this section: the "**Guarantee**"). As of the report approval date, each one of the holders of the Leviathan Leases has provided its share in the said Guarantee.

2. The Guarantee will be valid throughout the lease period and will continue to remain valid also following the expiration of the lease so long as the Petroleum Commissioner shall not have

[25] Such a guarantee will be provided for each of the Leviathan Leases separately, but each one of them will be used for both leases, as aforesaid.

given notice that there is no need therefor, and subject to the provisions of the Petroleum Law.

3. The Guarantee will serve to ensure compliance with the provisions of the lease deed and the Letters of Approval by the lease holder, to ensure payments due according to any law by the lease holder to the State for compensation and indemnification of the State and any authority thereof, for any damage, payment, loss, or expense incurred thereby, directly or indirectly, following non-compliance with the provisions of the lease deed or Letters of Approval, on time and in full, or following the revocation of a condition in the lease, its limitation or its suspension or following any action or omission of the lease holder in connection with the lease and the compliance with the conditions of the lease deed, and ensuring the payment of pecuniary sanctions if imposed on the lease holder according to any law.

4. The Petroleum Commissioner may forfeit the Guarantee, in full or part, in any of the cases detailed below:

   (a) The lease holder did not carry out the development plan approved by the Petroleum Commissioner and according to the conditions determined in the approval, or did not set up the production system facilities, or did not begin the commercial production or the transmission to the transmission system to the supplier on the dates determined therefor according to the lease deed or Letters of Approval.

   (b) A safety or environmental malfunction occurred as a result of the lease holder's operations, and the lease holder did not repair the malfunction or its results according to the instructions of the Petroleum Commissioner and any law.

   (c) With regards to the Leviathan North lease alone – the lease holder violated a term set by the Petroleum Commissioner in connection with the abandonment of the "Leviathan 2" well or did not execute in the optimal manner, the Abandonment Plan related to the foregoing well.

   (d) The lease holder did not execute the abandonment in accordance with the Decommissioning Plan.

   (e) A claim or demand is filed against the State for payment of compensation for damage caused due to a violation of any condition of the lease deed or the Letters of Approval, due to the deficient performance of the provisions of the lease deed or the Letters of Approval, or due to the revocation of the lease deed, and also if the State incurs expenses as a result of such claim or demand. Forfeiture of the Guarantee for the purpose of covering the amount of such claim will only be made after a judgment on such claim (including an arbitrator's award) becomes final and conclusive, and according to amounts ruled against the State in such judgment (and in the event of a settlement – subject to approval thereof by the lease holder, which approval shall not be unreasonably withheld) and subject to the lease holder being given the opportunity to join as a party to the proceeding;

(f) The State incurs expenses or damage as a result of the revocation of the lease;

(g) The lease holder did not perform the tests required according to the lease deed, did not submit reports and documents as required according to the lease deed.

(h) The lease holder did not comply with one of the provisions relating to insurance as determined in the lease deed or imposed on him according to any law.

(i) The lease holder violated instructions given to him by a representation of the IDF on any security matter related to the production system.

(j) The lease holder did not comply with the provisions in the lease deed relating to the Guarantee.

(k) The lease holder materially breached another condition in the lease deed or the Letters of Approval or the instructions given thereto by the Petroleum Commissioner according thereto.

5. If the Petroleum Commissioner finds that *prima facie* grounds are established for forfeiture, the Petroleum Commissioner shall give the lease holder notice thereof and enable him to respond in relation to the prima facie grounds and the possibility of forfeiture, within 7 days of receiving the cease-and-desist letter, unless under the circumstances waiting is not possible; If the Petroleum Commissioner decided, after weighing the lease holders response, if any, that there is room for forfeiture, a notice will be sent to the lease holder detailing the breach, the explanations for the forfeiture, and the amount of the forfeiture. The Petroleum Commissioner may contact the bank and demand the forfeiture commencing from the end of the 7 days from the day the notice was delivered, unless prior to that, the lease holder paid the amount determined in the notice.

6. Notwithstanding the provisions in Section 7.2.2(n)5 above, if the *prima facie* grounds for forfeiture is an act or omission that may be remedied, the Petroleum Commissioner may notify the lease holder that his request to the bank will be made if within a determined period the lease holder does not remedy the act or omission, and the stated period will pass without the lease holder remedying the act or omission to the satisfaction of the Petroleum Commissioner.

7. If the Guarantee or any part thereof is forfeited, the lease holder will provide a new guarantee, or supplement the balance thereof up to the amount of the Guarantee, as it is intended to be at such time, immediately upon receipt of the Petroleum Commissioner's demand.

8. Neither the authority to forfeit nor the forfeiture derogates from the State's right to claim from the lease holder payment of damage which it owes according to the lease deed, or the right of the State or the Director General of the Natural Gas Authority to claim any remedy or other relief according to any law or the lease deed.

(o) The lease deeds include additional provisions, including on the following subjects: security arrangements, conditions for operation of the facilities and dealing with malfunctions, tests, reporting and supervision; provision of services to other lease holders, provisions relating to environment protection, safety; limitations on the transfer or pledge on the lease deed and assets of the production system; liability, indemnification and insurance.

7.2.3. <u>Compliance with the conditions of the work program in the Leviathan project</u>

Over and above the terms and conditions of Leviathan's lease deeds as specified in Section 7.2.2 above, no binding work program in the Leviathan project was determined.

7.2.4. <u>Actual and planned work program for the Leviathan project</u>

Below is a concise description of the main activities actually carried out in the Leviathan project between 1 January 2022 and the report approval date, as well as a concise description of planned activities in the aforesaid project:

Leviathan Leases			
Period	Concise Description of Activities Actually Performed for the Period or of the Planned Work Program	Total Estimated Budget for Activity at the Petroleum Asset Level ($ in thousands)[26,27]	Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)
2022	• Continued improvement of the systems and production processes, *inter alia*, by taking the necessary actions to reduce pressure drops in the process, as well as improvement of the monitoring and detection systems in environmental and safety aspects, in accordance with operational and regulatory requirements.	Approx. 23,185	Approx. 10,512
	• Completion of engineering actions related to the development of Phase 1A.	Approx. 11,056	Approx. 5,014
	• Performance of maintenance work and improvements in the subsea electricity and control systems.	Approx. 6,482	Approx. 2,939
	• Drilling the Leviathan 8 development and production well and performance of subsea work as preparation for connection of the well to the production system.	Approx. 121,026	Approx. 54,873
	• Continued update of the geological model and the flow model, *inter alia* according to the production and well data, and planning and preparations for drilling wells and additional supplementations, insofar as required.	Approx. 102	Approx. 46
	• Continued examination of the development of Phase 1B and/or additional development options, insofar as required, including an	Approx. 13,472	Approx. 6,108

[26] The amounts for the years 2022-2024 are amounts actually expended and audited in the framework of the financial statements.

[27] The costs, budgets and actions specified in the table do not include approved costs and budgets for: (a) the addition of the additional compressor (as specified in Section 7.13.2(b)(1) below, in the sum of approx. $39.9 million (100%; the Leviathan Partners' share – approx. $27.6 million, the Partnership's share – approx. $12.5 million); (b) the construction of the Combined Section (as specified in Section 7.13.2(b) below) in the sum of approx. $155.6 million (100%; the Leviathan Partners' share – approx. $112 million, the Partnership's share – approx. $50.8 million); (c) the construction of the Nitzana Pipeline (as specified in Section 7.13.2(b)(5) below) in the sum of approx. $222.2 million (100%; the Leviathan Partners' share – approx. $111.1 million, the Partnership's share – approx. $50.3 million); (d) conversion of the PEI pipeline for the transmission of condensate (as specified in Section 7.12.4(c) below) in the sum of approx. $26.6 million (100%; the Partnership's share – approx. $12 million); (e) the project specified in Section 7.13.2(b)(3) below in the sum of approx. $343 million (100%; the Leviathan Partners' share – approx. $171.4 million, the Partnership's share – $77.8 million); and (f) costs of decommissioning of the reservoir and insurance and management costs.

Leviathan Leases			
Period	Concise Description of Activities Actually Performed for the Period or of the Planned Work Program	Total Estimated Budget for Activity at the Petroleum Asset Level ($ in thousands)[26,27]	Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)
	alternative to the export of natural gas via a subsea pipeline and/or liquefaction (including via an FLNG), *inter alia* through preparations for the performance of FEED and preparations for execution.		
	• Examination of options for increasing the volumes of natural gas export to Egypt through onshore transmission systems. For further details, see Section 7.13.2(b) below.	Approx. 2,667	Approx. 1,209
	• Various additional actions, including: Continued production from the Leviathan reservoir, ongoing operation and maintenance[28], performance of monitoring actions, surveys, tests and review of options for specification, drilling and development of the deep exploration targets.	Approx. 102	Approx. 46
2023	• Continued improvement of the production system on the Leviathan platform and the onshore facilities, and improvement of support systems and environmental systems, in accordance with operational and regulatory requirements.	Approx. 23,530	Approx. 10,665
	• Continued performance of maintenance work and improvements in the subsea electricity and control systems.	Approx. 6,412	Approx. 2,907
	• Completion of the Leviathan-8 well and connection thereof to the existing production system.	Approx. 54,983	Approx. 24,929
	• Performance of pre-FEED in a competitive process between international groups specializing in the design and construction of FLNG facilities, in the context of promoting the options for development of Phase 1B.	Approx. 36,165	Approx. 16,397

[28] For details regarding operating costs in the Leviathan project which are attributed to the Partnership, see data on discounted cash flow attributed to the Partnership's share, as specified in the report on the resources in the Leviathan project, as defined in Section 7.2.10(a) below.

Leviathan Leases			
Period	Concise Description of Activities Actually Performed for the Period or of the Planned Work Program	Total Estimated Budget for Activity at the Petroleum Asset Level ($ in thousands)[26,27]	Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)
	• Performance and completion of pre-FEED for expansion of the production system of the Leviathan reservoir, including the construction of subsea infrastructures and incorporation of the required changes into the platform, in the context of promoting the options for the development of Phase 1B.	Approx. 21,981	Approx. 9,966
	• Conduct of surveys, design and procurement for the Third Pipeline Project (as defined in Section 7.2.5(b) below), including changes and adjustments on the platform.	Approx. 144,706	Approx. 65,610
	• Various additional actions, including: Continued production from the Leviathan reservoir, ongoing operation and maintenance[29], performance of monitoring actions, surveys, tests and review of options for specification, drilling and development of the deep exploration targets.	Approx. 102	Approx. 46
2024[30]	• Continued improvement of the production system on the Leviathan platform and the onshore facilities, and improvement of support systems and environmental systems, in accordance with operational and regulatory requirements.	Approx. 1,574	Approx. 714
	• Completion of the preparations for performance of a baseline gravity survey above the area of the reservoir to optimize production forecasts and assist in the making of development decisions in the project.	Approx. 1,087	Approx. 493
	• Completion of pre-FEED for FLNG facility.	Approx. 3,371	Approx. 1,528

[29] For details regarding operating costs in the Leviathan project which are attributed to the Partnership, see data on discounted cash flow attributed to the Partnership's share, as specified in the report on the resources in the Leviathan project, as defined in Section 7.2.10(a) below.

[30] The costs specified for 2024 do not include a budget update (reduction) of $14,434 thousand (100%; the Partnership's share – approx. $6,544 thousand) for investment in the drilling and completion of the Leviathan-8 well.

Leviathan Leases			
Period	Concise Description of Activities Actually Performed for the Period or of the Planned Work Program	Total Estimated Budget for Activity at the Petroleum Asset Level ($ in thousands)[26,27]	Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)
	• Continued performance of the Third Pipeline Project (as defined in Section 7.2.5(b) below).	Approx. 164,049	Approx. 74,380
	• Completion of pre-FEED and commencement of FEED for expansion of the production system of the Leviathan reservoir in the context of promoting development of Phase 1B, including the construction of subsea infrastructures and incorporation of the required changes and additions into the platform, as well as early commitments for receipt of services and for procurement of long-lead items.	Approx. 55,186	Approx. 25,021
	• Various additional actions, including: Continued production from the Leviathan reservoir, ongoing operation and maintenance[31], performance of monitoring actions, surveys, tests and review of options for specification, drilling and development of the deep exploration targets.	Approx. 114	Approx. 52
2025 forth	• Continued improvement of the production system on the Leviathan platform and the onshore facilities, and improvement of support systems and environmental systems, in accordance with operational and regulatory requirements.	Approx. 2,503	Approx. 1,135
	• Completion of the Third Pipeline Project (as defined in Section 7.2.5(b) below).	Approx. 259,079	Approx. 117,446
	• Completion of the FEED in the context of promotion of development of Phase 1B, and early commitments for receipt of services and procurement of long-lead items.	Approx. 400,200	Approx. 181,450

[31] For details regarding operating costs in the Leviathan project which are attributed to the Partnership, see data on discounted cash flow attributed to the Partnership's share, as specified in the report on the resources in the Leviathan project, as defined in Section 7.2.10(a) below.

Leviathan Leases			
Period	Concise Description of Activities Actually Performed for the Period or of the Planned Work Program	Total Estimated Budget for Activity at the Petroleum Asset Level ($ in thousands)[26,27]	Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)
	• Adoption of a final investment decision (FID) by the Leviathan Partners for the development of Phase 1B[32] and performance thereof.	Approx. 2,028,000[33]	Approx. 919,495
	• Exploration of possibilities for expansion of the Leviathan reservoir's production system beyond stage one of Phase 1B, including the possibility of laying a fourth pipeline between the field and the platform and expanding the subsea system above the reservoir (stage two of Phase 1B).	Approx. 529,500[34]	Approx. 240,075
	• Continued actions to improve systems for filtration and MEG recovery and produced water treatment.	Approx. 13,520	Approx. 6,130
	• Various additional actions, including continued production from the Leviathan reservoir, ongoing operation and maintenance[35], performance of monitoring actions, surveys and tests.	Approx. 144	Approx. 65
	• Review of options for specification, drilling and development of the deep exploration targets, including performance of a seismic survey.	Approx. 84,775[36]	Approx. 38,437
	• Continued performance of gravity surveys above the area of the reservoir to optimize production forecasts and assist in the making of development decisions in the project.	Approx. 11,028[37]	Approx. 5,000

7.2.5. Plan for development of the Leviathan reservoir

[32] For further details, see Section 7.2.5 below.

[33] As of the report approval date, this budget has not yet been approved by the Leviathan Partners.

[34] As of the report approval date, this budget has not yet been approved by the Leviathan Partners.

[35] For details regarding operating costs in the Leviathan project which are attributed to the Partnership, see data on discounted cash flow attributed to the Partnership's share, as specified in the report on the resources in the Leviathan project, as defined in Section 7.2.10(a) below.

[36] As of the report approval date, the Leviathan Partners have approved approx. $3,799 thousand (100%; the Partnership's share – approx. $1,722 thousand) out of this budget.

[37] As of the report approval date, the Leviathan Partners have approved approx. $5,083 thousand (100%; the Partnership's share - $2,305 thousand) out of this budget.

(a) On 2 June 2016, the Leviathan field development plan was approved by the Petroleum Commissioner. This plan, which is divided into two phases (Phase 1A and Phase 1B), includes the supply of natural gas to the domestic market and for export of a total volume of up to ~21 BCM per year, and the supply of condensate to the domestic market (in this section: the "**Development Plan**" or the "**Plan**"). According to the Plan, a production system will be built that includes up to 8 first wells that will be connected by a subsea pipeline to a permanent platform (in this section: the "**Platform**"), which is located in the territorial waters of Israel in accordance with the provisions of NOP 37/H and on which the gas and condensate processing systems will be installed. Gas will be transmitted from the Platform to the shore to the northern entry point of the national transmission system of INGL as defined in NOP 37/H (the "**INGL Connection Point**"). The condensate will be transmitted to the shore via a separate pipeline, parallel to the gas pipeline, and will be connected to a refinery via an existing fuel pipeline. The condensate was first transmitted via a pipeline of Europe Asia Pipeline Co. ("**EAPC**"), which leads to the container site of Energy Infrastructures Ltd. ("**PEI**") in Kiryat Haim, and from there to Oil Refineries Ltd. ("**ORL**"). In March 2024, the condensate began being transmitted via a pipeline of PEI directly to Ashdod Refinery Ltd. ("**ARF**"). The Development Plan also includes the construction of a site for temporary storage and unloading of condensate, near the Hagit power plant (the "**Hagit Site**"), for the purpose of providing backup in the event that the transmission of condensate to a refinery is not possible. For further details, see Section 7.12.4(c) below. For details regarding the approval of NOP 37/H and the provisions thereof as aforesaid, see Section 7.24.12 below. For further details regarding the production system of the Leviathan project and the Hagit Site, see Section 7.17.1 below.

(b) The Development Plan may be implemented fully or in two main phases, according to the maturity of the relevant markets, as specified below:

1. <u>Phase 1A</u> – the current stage, in which 5 first subsea production wells were drilled, a subsea production system was built, which connects the production wells with the platform, and a transmission system to the shore and related onshore facilities were built. According to the Development Plan, at this point the gas production capacity is ~12 BCM per year, and in certain operating conditions a higher production capacity may even be attained.

   On 23 February 2017, the Leviathan Partners adopted a final investment decision (FID) for the development of Phase 1A, with a budget of approx. $3.75 billion (100%). The total cost invested in the development of Phase 1A, as of 31 December 2024, is approx. $4.2 billion (100%).

After a preliminary running-in period, on 31 December 2019, the transmission of natural gas from the Leviathan reservoir commenced. On 1 January 2020, the sale of natural gas from the Leviathan reservoir to Jordan began, under the agreement with NEPCO (as specified in Section 7.12.3(b)1 below). On 15 January 2020, the transmission of natural gas from the Leviathan reservoir to Egypt began under the agreement with Blue Ocean (as specified in Section 7.12.3(c) below).

To increase the gas production capacity to ~14 BCM per year, the Leviathan Partners adopted a final investment decision (FID) on 29 June 2023 to carry out a project in which a third subsea transmission pipeline will be laid from the field to the platform and systems on the platform will be upgraded (the "**Third Pipeline Project**") with a total budget of approx. $568 million (100%, the Partnership's share – approx. $258 million).

On 6 October 2024, the operator in the Leviathan project announced that due to escalation of the security situation, work on the laying of the offshore pipeline in the framework of the Third Pipeline Project had been suspended, and that completion of this project (which was planned for mid-2025) would be postponed by at least 6 months, depending on the timetables and the backlog of the construction contractor. As of the report approval date, in the operator's estimation, the Third Pipeline Project is expected to be completed at the beginning of 2026, depending on various factors that are beyond the Leviathan Partners' control, including the security situation in the region.

2. Phase 1B – on 23 February 2025, the Leviathan Partners submitted, for the approval of the Petroleum Commissioner, an updated plan for development of the Leviathan reservoir, which mainly includes updates in connection with Phase 1B (the "**Updated Development Plan for the Leviathan Reservoir**"), including with respect to the processing facilities on the platform, the location and timing of well drillings, and the possibility of performing stage two of Phase 1B, as specified below.

According to the Updated Development Plan for the Leviathan Reservoir, Phase 1B may be implemented fully or in stages, as follows:

(a) Stage one – includes the drilling of 3 additional production wells, the addition of related subsea systems and expansion of the processing facilities on the platform, which is expected to increase the total gas production capacity of the system to ~21 BCM per year.

(b) Stage two – mainly includes the drilling of additional production wells and related subsea systems, including, insofar as required, the laying of a fourth pipeline between the field and the platform (the "**Fourth Pipeline**"), which is expected to increase the maximum daily production capacity by an additional ~2 BCM per year, i.e. to a total quantity of ~23 BCM per year.

As of the report approval date, the Leviathan Partners are promoting the receipt of the required regulatory approvals and the signing of the agreements for the sale of natural gas to the domestic market and for export, in the context of Phase 1B, in a total volume of over 100 BCM, in accordance with the Petroleum Commissioner's letter, as specified in Paragraph (d) below, in order to adopt a final investment decision (FID) for performance of stage one of Phase 1B in the coming months. For further details, see Section 7.17.2 below.

It is clarified that as of the report approval date, the Petroleum Commissioner's approval has not yet been received for the Updated Development Plan for the Leviathan Reservoir.

(c) As specified in Section 7.24.8 below, engagements for the export of natural gas require the Petroleum Commissioner's approval, in accordance with government resolutions. The Commissioner's approval for the export of gas from the Leviathan reservoir was determined, *inter alia*, based on estimates made by the Commissioner from time to time with the assistance of international professional consultants with respect to the estimated total recoverable quantity of natural gas in the reservoir. On 18 April 2024, the Petroleum Commissioner informed the Leviathan Partners that based on the existing data and given the quantity of natural gas that was produced from the reservoir, the Ministry of Energy's estimates regarding the said recoverable quantity of natural gas is within a range of 413-478 BCM (14.6-16.9 TCF), compared with NSAI's estimate whereby, in the best estimate, the recoverable quantity of natural gas (which includes the reserves, the contingent resources and the total gas produced from the reservoir) is ~632 BCM (~22.3 TCF) as of 31 December 2024.

(d) On 21 June 2023 and 21 December 2023, the Leviathan Partners submitted an in-principle application to the Petroleum Commissioner for approval of expansion of the volume of export of natural gas produced from the Leviathan project, according to the government resolution applicable to the export of gas from the Leviathan reservoir (as specified below), via an existing and future regional pipeline or via an FLNG facility, alongside expansion of the volumes of natural gas to be transmitted from the Leviathan project to the domestic market.

On 25 June 2024, the Commissioner's response to the said applications was received, whereby the position of the professionals at the Ministry of Energy allows, as of the present time, the export of additional natural gas from the Leviathan reservoir in a total quantity of up to 118 BCM, which may increase to up to 145 BCM, upon the fulfillment of certain conditions (the "**Commissioner's Letter**"). The Commissioner's Letter further stated that from 2044, the export of natural gas from the Leviathan reservoir may be performed only on an interruptible basis, subject to guaranteeing the supply to the domestic market, and that export on a firm basis, from such year, will only be possible following a reexamination of the needs of the domestic market. The Commissioner's Letter clarified, *inter alia*, that this professional position is according to the forecast of supply and demand in the market, according to the professionals' estimate as of the present time, and does not constitute approval of export or an undertaking to grant export approval, which insofar as is granted is expected to include further restrictions and conditions, and that the content of the Commissioner's Letter shall not require the Commissioner to make a future decision on the issue. It is clarified that, in the Partnership's estimation, the government resolutions on the export of natural gas and the Commissioner's Letter allow the Leviathan Partners to promote the signing of agreements for the sale of natural gas in the context of Phase 1B in the volume required in order to adopt a final investment decision (FID) for performance of stage one of Phase 1B in the coming months.

(e) In the context of promotion of Phase 1B, the Leviathan Partners approved, in 2023 and 2024, in accordance with the Joint Operating Agreement, budgets in the sum total of approx. $75 million (100%) for the performance and completion of pre-FEED and preparations for the performance of FEED for expansion of the Leviathan reservoir's production system, including the construction of subsea infrastructures, connection of additional production wells, and performance of the required changes on the platform. As of the report approval date, the pre-FEED stage has been completed, and on 31 July 2024, the Leviathan Partners adopted a decision regarding the performance of FEED and advance procurement of long-lead items, with an additional budget of approx. $429 million (100%, the Partnership's share is approx. $194.5 million). The Leviathan Partners intend to complete performance of the FEED with the aim of adopting a final investment decision (FID) for the development of Phase 1B in the coming months, and to this end, the Leviathan Partners are promoting, *inter alia*, negotiations at various stages with potential customers, both in the domestic market and for export, for the signing of agreements for the sale of natural gas in the context of Phase 1B, in a total volume of more than another 100 BCM, according to the Commissioner's Letter.

In the estimation of the operator in the Leviathan project, prior to completion of the FEED, the estimated cost of stage one of Phase 1B (i.e., exclusive of the costs of the Fourth Pipeline) is approx. $2.4 billion (100%)[38]. Insofar as a final investment decision (FID) is adopted for development of stage one of Phase 1B during 2025 as aforesaid, the estimated timetable for the production of first gas is expected to be in H2/2029.

Additional production wells will be required during the years of operation of the project to enable preservation of a production capacity in the required volume and in accordance with the level of redundancy of the production system and the wells in the field, which is defined, from time to time, by the Leviathan Partners.

Caution concerning forward-looking information – The above estimates in relation to the expected production capacity of the Leviathan reservoir, the amount of the budget and the timetables for additional development phases of the Leviathan reservoir and the updated development plan and the potential date for adoption of a final investment decision (FID) for the performance of stage one of Phase 1B and the dates of completion of the engineering design phases, the estimated cost of the actions in Phase 1B, and the potential date of operation of stage one of Phase 1B, constitute forward-looking information within the meaning thereof in the Securities Law. Such information is based on assessments and estimates of the Partnership and the operator in the Leviathan reservoir, based on a range of factors which are beyond the Partnership's control or which may change, including the Third Pipeline Project, in respect of the costs and the timetables for performance of the said project, the Development Plan and the timetables for implementation thereof, the possibility of receipt of regulatory approvals, estimated data of availability of equipment, services and costs, past experience and geological, geophysical, technical-engineering and other information accumulated, *inter alia*, from the scope of production from the Leviathan reservoir and from the seismic survey conducted in the area of the Leviathan Leases. In addition, the Partnership's estimation in respect of the FID adoption date is based on information received from the other Leviathan Partners and depends, *inter alia*, on the Leviathan Partners making the suitable decisions. The estimates in this report may not materialize or may materialize in a materially different manner due to factors beyond the Partnership's control, *inter alia*, if changes and/or delays occur in the range of factors as specified above, and if the estimates and assessments received change, *inter alia*, as a result of geological conditions and/or operational and technical conditions and/or regulatory changes the market conditions change and/or due to a gamut of regulatory and/or

[38] Out of the said amount, the partners have approved a budget of approx. $505 million (100%).

geopolitical changes and/or due to operating and technical conditions in the Leviathan reservoir and/or due to unexpected factors relating to the exploration, production and marketing of oil and natural gas and/or as a result of the progress of development of the Leviathan reservoir until completion thereof and/or due to materialization of one or more of the risk factors entailed by the Partnership's operations, including as specified in Section 7.30 below.

7.2.6. The actual participation rate in the expenses and revenues under the Leviathan Leases

Participation Rate	Percentage Pre Investment-Recovery	Percentage Post Investment-Recovery	Rate grossed-up to 100% Pre Investment-Recovery	Rate grossed-up to 100% Post Investment-Recovery	Explanations
The rate actually attributed to the holders of the equity interests of the Partnership in the petroleum asset	45.34%	45.34%	100%	100%	See description of chain of holdings in Section 7.2.1 above.
The rate actually attributed to the holders of the equity interests of the Partnership in the revenues from the petroleum asset	37.63%	35.37%	83.00%	78.00%	See calculation in Section 7.2.7 below.
The actual participation rate of the holders of the equity interests of the Partnership in the expenses involved in the exploration, development and production activity at the petroleum asset.	45.79%-47.15%	45.79%-47.15%	101%-104%	101%-104%	See calculation in Section 7.2.8 below.

7.2.7. Participation rate of the holders of the equity interests of the Partnership in the revenues from the Leviathan Leases

Item	Percentage Pre Investment-Recovery	Percentage Post Investment-Recovery	Concise Explanation as to How Royalties or Payments are Calculated
Projected annual revenues of petroleum asset	100%	100%	
Specification of the royalties or payment (deriving from revenues post-finding) at the petroleum asset level:			
The State	(12.50%)	(12.50%)	As prescribed by the Petroleum Law, royalties are calculated according to market value at the wellhead. The actual royalty rate may be lower, as a result of the deduction of expenses in respect of the systems of gas processing and transmission up to the onshore gas delivery point. For further details, including with respect to the publication of directives on the method of calculation of

Item	Percentage Pre Investment-Recovery	Percentage Post Investment-Recovery	Concise Explanation as to How Royalties or Payments are Calculated
			the royalty value at the wellhead with respect to offshore petroleum interests, see Section 7.24.7(c) below.
Adjusted revenues at the petroleum asset level	87.5%	87.5%	
Share in the adjusted revenues deriving from the petroleum asset attributable to the holders of the equity interests of the Partnership (indirect holdings)	45.34%	45.34%	
Total rate of the holders of the equity interests of the Partnership in the actual amount of revenues, at the petroleum asset level (and before other payments at the Partnership level)	39.67%	39.67%	
Specification of royalties or payments (deriving from revenues post-finding) in connection with the petroleum asset at the Partnership level (the following percentage will be calculated according to the rate of the holders of the equity interests of the Partnership in the petroleum asset)			
The rate of the holders of the equity interests of the Partnership in payment to related and third parties	(2.04%)	(4.30%)	Overriding royalty in respect of the Partnership's share at a 4.5% rate Pre Investment-Recovery and at a 9.5% rate Post Investment-Recovery calculated according to market value at the wellhead[39]. The said rate was calculated according to the principles under which the State's royalties in respect of the project are calculated, and therefore such rate may change, insofar as the method of calculation of the State's royalties changes. For further details with respect to the method of calculation of the royalty rate, see Section 7.26.9(b) below.
Actual rate in revenues from the petroleum asset attributable to the holders of the equity interests of the Partnership	37.63%	35.37%	

7.2.8. Participation rate of the holders of the equity interests of the Partnership in the exploration, development and production expenses in the Leviathan Leases

Item	Percentage	Summary explanation of how the royalties or payments are calculated
Theoretical expenses within the framework of a petroleum asset (without the said royalties)	100%	

[39] The parties entitled to royalties are a wholly-owned subsidiary of Delek Energy and others which are not related parties.

Item	Percentage	Summary explanation of how the royalties or payments are calculated
Specification of the payments (derived from the expenses) at the petroleum asset level:		
The operator	1%-4%	Including a rate of 1% for the indirect expenses of the operator out of the total direct expenses in relation to development and production activities, subject to certain exclusions, such as marketing activity. A rate of 1%-4% for exploration expenses, with the rate of payment to the operator decreasing upon an increase in the exploration expenses. Such sums are for payment of the operator's indirect expenses and are in addition to the reimbursement of direct expenses paid thereto.
Total actual expense rate on the petroleum asset level	101%-104%	
The share of the holders of equity interests of the Partnership in the petroleum asset expenses (indirect holdings)	45.34%	
Total actual share of the holders of the equity interests of the Partnership, in the expenses, on the petroleum asset level (and prior to other payments on the Partnership level)	45.79%-47.15%	
Specification of payments (derived from the expenses) in respect of the petroleum asset and at the Partnership level (the following percentage will be calculated according to the share of the holders of the equity interests of the Partnership in the petroleum asset):		
The rate actually attributed to the holders of the equity interests of the Partnership in expenses involved in the exploration, development and production activity at the petroleum asset.	45.79%-47.15%	

7.2.9. Fees and payments paid during exploration, development and production activity in the petroleum asset ($ in thousands)

Item	Total share of the holders of the equity interests of the Partnership in the investment in the petroleum asset in this period (including costs for which no payments are made to the Operator)	Out of which, the share of the holders of the equity interests of the Partnership in payments to the General Partner	Out of which, the share of the holders of the equity interests of the Partnership in payments to the Operator (in addition to the reimbursement of its direct expenses)
Budget actually invested in 2022	Approx. 179,458	-	Approx. 1,273
Budget actually invested in 2023	Approx. 248,111	-	Approx. 1,744
Budget actually invested in 2024	Approx. 244,948	-	Approx. 1,715

7.2.10 Reserves, contingent resources and prospective resources in the Leviathan Leases

(a) For details regarding reserves and contingent resources in the area of the Leviathan Leases and the discounted cash flow that derives from the reserves and from part of the contingent resources in the Leviathan Leases as of 31 December 2024, see current reserves, contingent resources and DCF figures report for the Leviathan Leases attached as **Annex B** to this chapter (the "**Leviathan Project Resource Report**"). Attached as **Annex D** to this report is NSAI's consent to the inclusion of the said report herein by way of reference, and a letter of lack of material changes from NSAI in the Leviathan Leases.

(b) Prospective resources in the Leviathan Leases

Following an analysis of reprocessing of seismic surveys carried out in 2019, and on the basis thereof, NSAI prepared for the Partnership a report on prospective resources in the Leviathan Leases, according to SPE-PRMS guidelines (in this section: the "**Resource Report**"), the details of which are specified below.

(1) Quantity data

According to the Resource Report, as of 31 December 2024, the prospective resources attributed to the Leviathan Leases are as specified below:

Target	Probability	Total (100%) in the Petroleum Asset (Gross)		The Partnership's Total Share (Gross)[40]	
		Gas (BCF)	Oil (MMBBL)	Gas (BCF)	Oil (MMBBL)
Carbonate buildup	Low Estimate	25.4	26.6	11.5	12.1
	Best Estimate	161.0	155.3	73.0	70.4
	High Estimate	826.8	766.6	374.9	347.6
Clastic channel	Low Estimate	45.2	47.3	20.5	21.5
	Best Estimate	229.2	223.9	103.9	101.5
	High Estimate	886.8	813.7	402.1	368.9

(2) In the Resource Report, NSAI stated, *inter alia*, several assumptions and reservations, including that: (1) NSAI did not visit the petroleum field; (2) NSAI did not examine exposure deriving from environmental matters. However, it was noted that as of the date of the Resource Report, it was not aware of any potential liability regarding environmental matters which may materially affect the quantity of the resources estimated in the prospective resources report or the commerciality thereof. NSAI also stated that the Resource Report includes

[40] Before payment of royalties.

no economic analysis of the reservoir, and that based on the development of similar reservoirs, and assuming that there will be a finding in the petroleum asset, the prospective resources in the best estimate category have a reasonable chance of being economically recoverable.

(3) The Resource Report was prepared based on 3D seismic surveys carried out in 2009 and 2010 by Petroleum Geo-Services, which were reprocessed in 2017-2019 by WesternGeco, and based on data collected in the Leviathan-1 well and information from similar and/or nearby oil and gas fields and wells (including the Zohr reservoir that was discovered in Egypt).

(4) Below are the basic parameters used to calculate the various scenarios:

Parameter	Carbonate buildup			Clastic channel		
	Low Estimate	Best Estimate[41]	High Estimate	Low Estimate	Best Estimate[41]Error! Bookmark not defined.	High Estimate
Gross Rock Volume (Acre-feet) [42]	370,734		16,051,915	660,818		17,297,896
Net-to-Gross Ratio (Decimal)	0.20	0.50	0.80	0.20	0.50	0.80
Porosity (Decimal)	0.10	0.15	0.25	0.12	0.17	0.22
Oil Saturation (Decimal)	0.45	0.65	0.85	0.55	0.65	0.75
Average Producing Gas-Oil Ratio (SCF/STB)	200		2,200	200		2,200
Initial Oil Formation Volume Factor (RB/STB)	2.20		1.10	2.20		1.10
Oil Recovery Factor (Decimal)	0.15		0.45	0.15		0.45
Average Gross Thickness (feet)	257		818	143		773
Area (Acres)	1,443		19,619	4,628		22,380

(5) The significant risks entailed by the process:

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[41] The parameters for which no "best estimate" value is stated in the table are also not stated in the resource evaluator's report, since the estimate of the resources is based on statistical methods in which, for parameters with a log-normal, uniform or normal distribution, "best estimate" is of no significance

[42] Acre-foot is a unit of volume equal to ~1,233.48 m^3.

The significant risks entailed by drilling to the deep targets in the Leviathan Leases are mainly technical, operating and geological risks, including difficulties in reaching the target layers and in drilling the well, *inter alia* during the running of logs and performance of production tests, if any. Even in a case where the technical operating actions are completed without any issues and the drilling reaches the planned depth and hydrocarbons are found in the target layers, there are risks later in the process required to reach a finding, including that the size and/or qualities of the reservoir are not good enough to justify economic recoverability and development into a project for production of the resources, if found, the sum of the development costs, the duration of the development, and other risks entailed by development of the finding. The estimate of the prospective resources and the probability of the presence of hydrocarbons, as specified below, is not the only consideration when making a decision to drill in the area of the leases, and it is accompanied by other considerations such as the depth of the target, its location relative to the gas field which is located at shallower depths, the prospect of developing it in the event of a finding according to the estimated size and economic recoverability, etc. For a discussion on the risk factors entailed by exploration activity, see Section 7.30 below.

(6) The estimated probability of success in terms of each one of the geological risk factors entailed by the process of exploration in the said well, and the estimated probability of the presence of hydrocarbons (oil and/or natural gas) are as follows:

Parameter	Carbonate buildup(%)	Clastic channel(%)
Trap Integrity	40	45
Reservoir Quality	70	70
Source Evaluation	80	80
Timing / Migration	80	75
Probability of Geologic Success	18	19

(*) It is emphasized that in the Resource Report, each target was evaluated separately, and the targets are not interdependent.

(7) <u>Estimated probability of development for commercial production:</u>

As of the date of the Resource Report, the Partnership is unable to provide a statistical estimate for the probability of development of the targets for commercial production. However, it is possible to estimate that the potential markets for the said resources are the domestic, the regional and the international markets. Therefore, the Partnership is exploring various alternatives for commercialization of the hydrocarbons (if discovered and produced), including the possibility of exporting the oil and/or natural gas, if discovered, and the sale thereof on the domestic, regional and international markets. It is further noted that if relatively low quantities of natural gas and/or oil are discovered in all or any of the said targets, economic development may require joint development of several findings using regional infrastructures.

(8) The Partnership's reasoning regarding the basis for the basic parameters used to calculate the scenarios:

The parameters used to calculate the various estimates are mainly based on the results of 3D seismic surveys, on data collected in wells in the region, and specifically in the Leviathan-1 well, and on general knowledge in relation to similar reservoirs and layers.

(9) Agreement between the report data and data of previous reports pertaining to the petroleum asset:

The previous resource report[43] was updated following findings that arose from an analysis of reprocessing of the data carried out in 2019, and following the Zohr discovery and other discoveries in the region which changed the geological perception of the structures in the area of the lease. Based on these findings, two new targets were defined: (1) an isolated carbonate buildup target; (2) a clastic subsea channel target, which was defined in lieu of the two deep targets that appeared in the previous resource report (deep-sea sand fans deposited on the slope of a seamount). The volume of prospective resources for the isolated carbonate buildup target in the best estimate (2U-P50) is ~155 million barrels of oil and ~161 BCF of natural gas, with prospects of geological success of 18%. The volume of prospective resources for the clastic channel target in the best estimate (2U-P50) is ~224 million barrels of oil and ~229 BCF of natural gas, with prospects of geological success of 19%, as aforesaid in lieu of the two deep targets, as specified in the previous resource report (Middle Cretaceous and Lower Cretaceous).

[43] The previous prospective resource report was included in the Partnership's periodic report as of 31 December 2019, as released on 30 March 2020 (Ref.: 2020-01-032010).

In the current Resource Report, the resources in all of the estimates in the two targets were updated by negligible quantities, except quantities in the high estimate in the clastic channel target. It is clarified that in the best estimate (2U), which includes both targets, the quantities were reduced by a negligible rate of around 3%. It is further clarified that there was no change in the estimated prospects of success of the two targets.

Caution – There is no certainty that any of the potential resources stated will indeed be discovered; if discovered, there is no certainty that any of the resources will be commercially recoverable; the prospective information is not an estimate of reserves and contingent resources, which it will only be possible to evaluate after the exploration drilling, if at all.

Caution regarding forward-looking information – NSAI's estimates regarding the prospective resources in the deep targets is forward-looking information, within the meaning thereof in the Securities Law. The said estimates are based, *inter alia*, on geological, geophysical and other information received from the wells and from the operator, and constitute professional estimates and assumptions of NSAI only, in respect of which there is no certainty. The natural gas and oil quantities that shall be discovered (if any) and actually produced (if any) may be materially different to the said 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 market and/or the actual performance of the reservoir. The said 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. Moreover, there is no certainty that upon completion of the examinations being carried out by the Partnership as stated above, a decision will be made to perform another seismic survey and/or to drill a well and/or to bring in another strategic partner.

(10) Opinion of the evaluator

Attached hereto as **Annex C** is a report on prospective resources in the Leviathan Leases prepared by NSAI as of 31 December 2024, and NSAI's consent to the said report's inclusion herein is attached hereto as **Annex D**.

(11) Management declaration

(a) Date of the declaration: 9 March 2025;

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

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

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

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

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

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

(h) We confirm that no change has been made to the identity of the evaluator who performed the last prospective resource disclosure released by the Partnership;

(i) We agree to the inclusion of the foregoing declaration herein.

____

Gabi Last,
Chairman of the Board

7.3 Interests in Cyprus

7.3.1 Background

On 11 February 2013 the authorities in Cyprus approved transfer to the Partnership of 30% of the rights of Chevron Cyprus in a production sharing contract dated 24 October 2008 (the "**PSC**") conferring gas and/or oil exploration, evaluation, development and production rights in the EEZ of the Republic of Cyprus in an area known as Block 12 ("**Block 12**") and in an exploration license according to the PSC (in this section: the "**Exploration License**").

On 7 November 2019, the right holders in the PSC and the Cypriot government signed an amendment to the PSC (the "**First Amendment to the PSC**"), and at the same time, the right holders were given a production and exploitation license (in this section: the "**License**" or the "**Production License**" or the "**Block 12 License**"), and a production and development plan for the reservoir was approved (in this section: the "**Original Development Plan**"), as specified in Section 7.3.11 below. In the First Amendment to the PSC, additional modifications and updates were made, *inter alia* with respect to the transfer of rights by the parties, approval of work programs and annual budgets, the method of approval of changes to plans and budgets, the method of calculation of the various expenses, changes in connection with grounds for termination of the PSC, arrangements with respect to ensuring the plugging, decommissioning and disposal of wells and facilities at the end of the term of the PSC, and more.

Further thereto, on 9 November 2022, another amendment to the PSC was signed, deferring the date of the commitment of the Aphrodite reservoir partners to drill another appraisal/development well A-3 (Aphrodite 3) (the "**A-3 Well**") and to complete it by August 2023. For details regarding the drilling of the A-3 Well, which was completed in July 2023, see Section 7.3.3(b) below.

Further to the aforesaid, on 14 February 2025, the Cypriot government approved an updated development plan for the reservoir which is based on the Original Development Plan (the "**Updated Development Plan**"), and at the same time another amendment to the PSC was signed regulating updated milestones for development of the reservoir and canceling the notice of breach that was issued to the partners in the reservoir, as specified in Section 7.3.3 below.

The PSC and the amendments to the PSC as aforesaid shall hereinafter be referred to jointly as the: "**PSC**".

7.3.2 General details

General details about the petroleum asset	
Name of petroleum asset:	Block 12.
Location:	An offshore area at the EEZ of Cyprus, located approx. 35 km north-west of the Leviathan reservoir[44].

[44] The vast majority of the Aphrodite reservoir is located in the area of the EEZ of Cyprus, and a few percent of its area is in the area of the 370/Ishai license (the "**Ishai License**"), which is located in the area of the EEZ of Israel. It is further noted that the partners in the Aphrodite reservoir were previously contacted by the partners in the Ishai License, the Ministry of Energy of the State of Israel and the Ministry of Energy of Cyprus, with respect to the need to regulate the rights of the parties as aforesaid prior to the adoption of a decision on development of the Aphrodite reservoir. The position of the partners in the Aphrodite reservoir, as of the report approval date, is that the matter is subject to the governments' authority, and that they will act in accordance with such mechanism for regulation of the parties' rights as shall be determined by the governments and in accordance with international law and standard practice in the industry. On 11 April 2022, the Israeli Ministry of Energy announced that the Israeli and Cypriot Ministers of Energy had agreed on the appointment of an outside expert to examine the quantity of natural gas in the reservoir and determine the division between the EEZs of Israel and Cyprus. See: https://www.gov.il/he/departments/news/press_110422. To the best of the Partnership's knowledge,

General details about the petroleum asset	
Area	Approx. 386 km^2.
Type of petroleum asset and description of actions permitted according to this type:	Exploitation license granted subject to the PSC.
Original grant date of the petroleum asset:	7 November 2019.
Original expiration date of the petroleum asset:	7 November 2044.
Dates on which an extension of the term of the petroleum asset was decided:	-
Current date for expiration of the petroleum asset:	7 November 2044 (25 years from the date on which the license was granted).
Is there an additional option to extend the term of the petroleum asset; if so – what is the possible extension period:	Extendable by 10 more years.
The operator's name:	Chevron Cyprus
The names of the direct partners in the petroleum asset, and their direct share in the petroleum asset, and, to the best of the Partnership's knowledge, the names of the control holders of such partners:	▪ Chevron Cyprus (35%) ▪ BG Cyprus (35%). To the best of the Partnership's knowledge, BG Cyprus is a subsidiary (indirect holdings) of Royal Dutch Shell Plc. ("**Shell**"), an energy company engaged in all fields of activity of the gas and oil industry, which is active in more than 70 countries worldwide[45]. ▪ The Partnership (30%).

General details regarding the Partnership's share in the petroleum asset	
For a holding in a purchased petroleum asset – the purchase date:	22 January 2009. On 11 February 2013, the approval of the authorities in Cyprus was granted for the transfer of the rights in the Production Sharing Agreement and in the exploration license to the Partnership.
Description of the nature and manner of holding of the petroleum asset by the Partnership:	The Partnership holds directly 30% of the license.
The actual share attributed to the holders of the equity interests of the Partnership in the revenues from the petroleum asset:	For details see Section 7.3.8 below.
The total share of the holders of the equity interests of the Partnership in the aggregate investment in the petroleum asset during the five years preceding the last day of the report year (whether recognized as an expense or as an asset in the financial statements):	Approx. $48,118 thousand.

7.3.3 Further details regarding the license in Block 12 and the PSC

on 29 January 2024, talks were held between the Israeli and Cypriot Ministers of Energy, in which it was agreed to boost the inter-government efforts to resolve the issue as soon as possible. As of the report approval date, to the best of the Partnership's knowledge, as it has been informed by the operator, the President of Cyprus recently expressed a commitment to reach agreements with the State of Israel in connection with the appointment of an independent outside expert to resolve the issue. Moreover, there is a dispute between Cyprus and Turkey regarding the interests in the EEZ of Cyprus which may affect the Partnership's activity in the license. However, according to its official reports, the Turkish government is not claiming ownership of the areas in which Block 12 is located.

[45] Further details regarding Shell are available on the website: https://www.shell.com/about-us/who-we-are.html.

(a) In the PSC, as amended on 14 February 2025 concurrently with the approval of the Updated Development Plan (the "**Plan Approval Date**"), the partners undertook, *inter alia*, to comply with the key milestones for promotion of the reservoir's development, as follows:

1. Completion of pre-FEED within 9 months from the Plan Approval Date;

2. Commencement of FEED within 11 months from the Plan Approval Date;

3. Completion of FEED within 23 months from the Plan Approval Date;

4. Adoption of a final investment decision (FID) for development of the reservoir within 28 months from the Plan Approval Date.

Failure to comply with the milestones defined in the PSC will be grounds for termination of the PSC, unless resulting from "*force majeure*" (as defined in the PSC).

(b) <u>The A-3 Well</u>

In accordance with the terms and conditions of the PSC, on 15 September 2022, the partners approved a budget for the drilling of the A-3 Well in the sum of $130 million (100%). The A-3 Well is an appraisal well whose purpose was to corroborate the estimates of the operator and the Partnership regarding the nature and scope of the reservoir, and which is designed to be used in the future as a production well. For further details regarding the decision to drill the well, see the Partnership's immediate report of 18 September 2022 (Ref.: 2022-01-118267), the information appearing in which is incorporated herein by reference. The drilling of the A-3 Well began in May 2023 and was completed in July 2023, on schedule and on budget. For details regarding an updated report on the resources attributed to the Aphrodite reservoir, which was released after completion of the A-3 Well, see Section 7.3.12 below.

(c) <u>Payments to the Republic of Cyprus</u>

1. The Republic of Cyprus is entitled to receive one-time bonuses from the holders of rights in Block 12 upon the fulfillment of milestones regarding the average daily production rate for a consecutive period of 30 days which can amount to a sum total of $9 million (100%).

2. The PSC specifies mechanisms for the distribution of natural gas and oil output, as specified below. The Republic of Cyprus is entitled to receive its share of the produced natural gas or oil, in whole or in part, in kind.

(d) Oil sharing

The holders of the rights in Block 12 will share the oil produced (after setting off expenses as specified below) with the Republic of Cyprus according to the daily average production rate of oil, to the extent it shall be produced, as follows[46]:

Average daily production (in barrels)[47]	Price per barrel ($)		
	Up to 50	From 50.1 to 100	Above 100
	The share of the Republic of Cyprus (including corporate tax in Cyprus)		
For the share in the average daily production lower than 50,000 (inclusive)	60%	63%	65%
For the share in the average daily production from 50,001 to 100,000 (inclusive)	63%	67%	72%
For the share in the average daily production from 100,001 to 150,000 (inclusive)	70%	75%	80%
For the share in the average daily production between 150,001 and 200,000 (inclusive)	77%	80%	83%
For the share in the average daily production higher than 200,000	83%	85%	85%

(e) Natural gas sharing

The PSC determines a mechanism for distribution of the natural gas output, based on an R-Factor coefficient. According to the said mechanism, the partners will be entitled to 55% of the annual revenues generated from the natural gas output, up to coverage of all of their recognized capital and current expenditures (the "**Expenditure Coverage Output**"), while the balance (the "**Distributable Output**") will be distributed between the partners and the Cypriot government according to an R-factor coefficient, the numerator of which consists of the total Net Accrued Revenues and the denominator of which consists of the total Accrued Capital Investments. Under the mechanism, the share of the Cypriot government in the Distributable Output increases linearly as a function of the coefficient and will reach the maximum rate when the R-factor coefficient is equal to 2.5. For this purpose:

- "**Net Accrued Revenues**" means: The partners' share in revenues actually received from the gas output (including the

[46] The oil sharing mechanism was not amended in the amendments to the PSC.
[47] The calculation is made progressively according to the brackets specified in the table.

Expenditure Coverage Output), net of the operating expenses borne by the partners in the area of the PSC, from the date of signing of the PSC (28 October 2008) to the end of the quarter preceding the day of the calculation (the "**Calculation Period**").

- "**Accrued Capital Investments**" means: The development expenses, production expenses of a capital nature (excluding operating expenses) and all exploration expenses, in respect of the area to which the PSC pertains, which were actually expended during the Calculation Period.

  For details regarding the participation rate of the holders of equity interests in the Partnership according to 4 theoretical scenarios only, according to which the R-factor coefficient has been determined, see Section 7.3.8 below.

(f) The calculation of the share of the Republic of Cyprus in the natural gas and/or oil produced will be performed every year from the revenues from the sale of natural gas and/or oil which will remain after setting off the expenses of the holders of rights in the Block 12 project in respect of exploration, evaluation, development, production and operation ("**Block 12 Expenses**")[48] at a rate of up to 55% of the total revenues from the gas produced and up to 49% of the total revenues from the oil produced ("**Output Designated for Expense Reimbursement Coverage**"). In the event that the expenses are higher than the Output Designated for Expense Reimbursement Coverage, any surplus will be carried forward to the following year until full coverage of the expenses or until termination of the PSC. Any expense not covered on the PSC termination date will not be recovered.

(g) The expenses recognized within the Output Designated for Expense Reimbursement Coverage according to the PSC as aforesaid, are subject to the approval of the Republic of Cyprus and include, *inter alia*, direct expenses in respect of exploration and evaluation, expenses in respect of the employment of workers and subcontractors, leasing offices, costs related to statutory requirements pertaining to environmental quality, material costs, insurance expenses, legal expenses, costs related to employee training, general and administrative costs of the Operator related to the project and any other reasonable expense which is required for reasonable and effective exploration activity. It shall be stated that expenses related to the construction and operation of an export facility are not recognized within the Output Designated for Expense Reimbursement Coverage.

[48] The Block 12 Expenses are recognized every year according to reports filed by the operator of the project and is limited to a budget submitted to the Republic of Cyprus for its approval as part of the process of approval of the annual work program under the PSC.

(h) The bonuses as specified in Section 7.3.3(c) above are not included in the expenses which may be offset as aforesaid.

(i) The payment of the share of the Republic of Cyprus in the gas and/or oil produced engrosses also the payments of corporate tax which the holders of the rights should have paid the Republic of Cyprus.

(j) In addition, the Republic of Cyprus may, upon provision of a prior written notice, obligate the holders of rights in Block 12 to sell gas thereto from the production which is not designated for coverage of expense reimbursement subject to the compliance of the holders of rights in Block 12 with their commitments according to agreements for the supply of natural gas, if such will be executed.

(k) According to the PSC, any change in control of the Delek Group or the Partnership, directly or indirectly, is subject to the advance approval of the Republic of Cyprus.

(l) Termination of the PSC

Subject to specific conditions which include, *inter alia*, circumstances of force majeure, the Republic of Cyprus may terminate the PSC (and with it also the license) upon the occurrence of one of the following causes for termination: (1) Violation of the provisions of the Cypriot law and regulations promulgated thereunder; (2) Arrearage in payment to the Republic of Cyprus for 3 consecutive months; (3) after the FID milestone is reached, cessation of the development work for 6 consecutive months; (4) After production commences, cessation of production for two consecutive months or a disruption of production for 6 consecutive months due to a reason which was not approved by the Republic of Cyprus; (5) The PSC contractor does not fulfill an arbitration decision or an expert determination issued pursuant to the provisions of the PSC; (6) An event of bankruptcy, composition with creditors, receivership of any of the partners or its parent company or any other event which will result in harm to the financial or technical abilities of any of the partners to fulfill its undertakings pursuant to the PSC; (7) Any and all other events not included in paragraph (6) above which materially derogate from the financial or technical abilities of the PSC contractor in comparison to the abilities it had on the PSC grant date and expected to result in the PSC contractor no longer having the technical of financial abilities to fulfill its undertakings pursuant to the PSC; (8) Failure to meet a milestone determined in the terms and conditions of the PSC; and (9) Non-compliance with the duty to provide the guarantees required under the terms and conditions of the PSC.

According to the PSC, upon the occurrence of one of the aforesaid causes for termination, the Cypriot government may give the PSC contractor notice of termination of the PSC, provided that the PSC contractor was given formal notice and the PSC contractor failed to remedy the breach within a 3- or 6-month remedial period in respect of causes (3) and (4) above, or seven days in respect of cause (9) above, from the notice receipt date, and other than termination pursuant to cause (6) which will take effect immediately on the notice receipt date.

The PSC sets provisions regarding the PSC contractor's right to give the Cypriot government notice with regard to disagreements pertaining to the PSC, and provisions regulating the method of settlement of disagreements in the framework of an international arbitration proceeding or, in specific cases, by way of appointment of an expert who will decide. It further sets forth that disagreements with regard to the establishment of a cause for termination of the PSC announced by the Cypriot government will be decided in the arbitration proceeding and in such case, the PSC will remain valid until a decision is issued in the arbitration proceeding.

(m) Until the date of adoption of a final investment decision, and subject to their compliance with their undertakings under the PSC, the holders of the interests in the project will be entitled to waive their interests in the reservoir, and the Cypriot government shall have no right to compensation or any other remedy.

(n) Grant of a performance guarantee to the Republic of Cyprus

For details regarding a performance guarantee in an unlimited amount provided by Delek Group in favor of the Republic of Cyprus to secure fulfillment of all of the undertakings of the Partnership under the PSC, see Regulation 22(c) of Chapter D of this report.

7.3.4 Activities within Block 12 which were performed before the Partnership held the petroleum asset

Performing Entity	Period in which the action was performed	Summary description of the action	Summary description of the action results
Chevron Cyprus	2011-2012	Preparation for drilling of the test well "Aphrodite A-1", drilling of the said well and an analysis of the well results and preparation for drilling of an appraisal well[49].	-

[49] On 2 October 2013, the Aphrodite A-2 appraisal well, which was started on 7 June 2013, was completed.

7.3.5 Compliance with the binding work program for Block 12

Up to the report approval date, the binding work program for Block 12, as updated on 14 February 2025 in the context of the last amendment to the PSC, was fulfilled in full. For details regarding the partners' non-compliance in connection with the FEED execution milestone, which was determined in the PSC before it was amended as aforesaid and before cancelation of the notice of breach that was issued to the partners in the reservoir by the Cypriot government, see Section 7.3.11 below.

7.3.6 Actual and planned work program for Block 12

Below is a concise description of the main activities actually carried out in the petroleum asset between 1 January 2022 and the report approval date, as well as a concise description of planned activities:

Block 12 Project			
Period	Concise Description of Activities Actually Performed for the Period or of the Planned Work Program	Total Estimated Budget for Activity at the Petroleum Asset Level ($ in thousands)[50]	Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)
2022	• Preparations for the drilling of the A-3 Well.	Approx. 11,722	Approx. 3,517
	• Examination of the possibility of adopting an investment decision in relation to alternatives for the development of the Aphrodite reservoir.	Approx. 7,076	Approx. 2,123
	• Various additional actions, including: Geological analysis of data and update of the geological model, technical and economic analysis of the prospects in the license area and alternatives for commercialization of the natural gas produced from the reservoir.	Approx. 195	Approx. 58
2023	• Drilling of the A-3 Well.	Approx. 85,871	Approx. 25,761
	• Update of the development plan and promotion of actions for receipt of approval from the Cypriot government.	Approx. 11,042	Approx. 3,313
	• Various additional actions, including: Geological analysis of data and update of the geological model, technical and economic analysis of the prospects in the license area and alternatives for commercialization of the natural	Approx. 200	Approx. 60

[50] The amounts for the years 2022-2024 are amounts actually expended and audited in the framework of the financial statements.

Block 12 Project			
Period	Concise Description of Activities Actually Performed for the Period or of the Planned Work Program	Total Estimated Budget for Activity at the Petroleum Asset Level ($ in thousands)[50]	Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)
	gas produced from the reservoir.		
2024	• Update of the development plan and promotion of actions for receipt of approval from the Cypriot government .	Approx.11,497	Approx. 3,449
	• Various additional actions, including: Geological analysis of data and update of the geological model, technical and economic analysis of the prospects in the license area.	-	-
	• Completion of analysis of the findings of the A-3 Well.	Approx. 1,525	Approx. 458
2025 forth[51]	• Update and approval of the development plan, performance of pre-FEED and FEED ahead of adoption of a final investment decision (FID).	Approx. 378,840	Approx. 113,652
	• Various additional actions, including: Geological analysis of data and update of the geological model, performance of surveys and technical and economic analysis of the prospects in the license area.	Approx. 30,500	Approx. 9,150
	• Development of the Aphrodite reservoir.	Approx. 4,000,000	Approx. 1,200,000

Caution concerning forward-looking information – The Partnership's evaluation regarding the activities planned at Block 12 (including development of the Aphrodite reservoir) including in respect of costs, timetables and the actual performance thereof, is forward-looking information within the meaning thereof in the Securities Law, based on estimates of the General Partner regarding the components of the work program, which are all based on evaluations received by the Partnership from the operator. The actual performance of the work program, including timetables and costs, is subject to the partners' approval and might be materially different from the aforesaid evaluations and it is contingent upon, *inter alia*, the applicable regulation, technical ability and economic merit.

7.3.7 Actual participation rate in the expenses and revenues at Block 12

[51] The amounts for 2025 forth have not yet been approved by the Aphrodite partners.

Participation Rate	Percentage Pre Investment-Recovery	Percentage Post Investment-Recovery	Rate grossed-up to 100% Pre Investment-Recovery	Rate grossed-up to 100% Post Investment-Recovery	Explanations
The rate actually attributed to the holders of the equity interests of the Partnership in the petroleum asset	30%	30%	100%	100%	See description of the chain of holdings in Section 7.3.2 above.
The rate actually attributed to the holders of the equity interests of the Partnership in the revenues from the petroleum asset	For details see Section 7.3.8 below.				
The actual participation rate of the holders of the equity interests of the Partnership in the expenses involved in the exploration, development and production activity at the petroleum asset	30.3%-31.2%	30.3%-31.2%	101%-104%	101%-104%	For details see Section 7.3.9 below.

7.3.8 Participation rate of holders of the equity interests of the Partnership in the revenues from Block 12

The table below presents details with respect to the participation rate of the holders of equity interests in the Partnership out of revenues that will derive in respect of natural gas to be produced from the petroleum asset, if any, in accordance with the new distribution mechanism, according to 4 theoretical scenarios only, according to which the R-Factor has been set at 1, 1.5, 2 and 2.5. It is emphasized that the data in the following table are based on calculations made under various work assumptions and assessments, *inter alia*, with respect to the rate of production of the natural gas from the reservoir and sale thereof, the costs of development of the reservoir and the facilities, according to information received from the operator, the current production costs, and more, which may in practice materially differ from the assumptions and assessments that have been taken into account. The figures provided below are based on various assumptions in relation to the Updated Development Plan as of the report approval date, as specified in Section 7.3.11 below.

	R-factor 1	R-factor 1.5	R-factor 2	R-factor 2.5	Notes
Total revenues from natural gas production	100%	100%	100%	100%	
Cypriot Republic's share of the revenues from natural gas production	15.75%	37.11%	54.81%	65.89%	The figures specified in the table are based on calculations that were made based on various working hypotheses, *inter alia*, with regard to the development and operating costs of the project, rate of the production and sale, gas prices, etc.
The partners' share of the revenues from natural gas production	84.25%	62.89%	45.19%	34.11%	
The Partnership's rate of holding of the oil asset	30.00%	30.00%	30.00%	30.00%	
The Partnership's share of the revenues from natural gas production, before payment of overriding royalties	25.28%	18.87%	13.56%	10.23%	
Payment of overriding royalties to various entities	1.14%	1.79%	1.29%	0.97%	The parties entitled to royalties are Delek Energy, Delek Group and others that are not related parties. For further details see Section 7.26.9 below. Assuming that the calculation of the R-factor and the investment recovery for purposes of the overriding royalty are the same. The figures specified in this table were calculated according to the Partnership's position, whereby the overriding royalties in

	R-factor 1	R-factor 1.5	R-factor 2	R-factor 2.5	Notes
					respect of Block 12 apply to the Partnership's share in the natural gas output, i.e., after deduction of the State's share in the output (as opposed to the overriding royalties in respect of petroleum assets in Israel, which apply to the Partnership's share in the output before payment of the State's royalties under the Petroleum Law).
Rate of the effective participation of the holders of the equity interests in the Partnership, in the revenues from natural gas production	24.14%	17.08%	12.27%	9.26%	

Caution concerning forward-looking information – The aforesaid figures with respect to the rate of participation of the holders of the equity interests in the Partnership in the revenues that will derive from the petroleum asset, if any, constitute forward-looking information within the meaning thereof in the Securities Law. The aforesaid figures are largely based on various estimations and working hypotheses, *inter alia*, with regard to the rate of production of the natural gas from the reservoir, quantities and prices of sale of the natural gas, costs of development of the reservoir and the facilities, current production costs, etc. It is emphasized that such figures may materially differ from the aforesaid estimations and hypotheses, and are *inter alia*, affected by and contingent on completion of the detailed planning of the Updated Development Plan, actual performance of the project, and a gamut of additional factors over which the Partnership does not have full control or which it is unable to estimate in an adequate level of certainty.

7.3.9 Participation rate of the holders of the equity interests of the Partnership in the exploration, development and production expenses in Block 12

Item	Percentage	Summary explanation of how the royalties or payments are calculated
Theoretical expenses within the framework of a petroleum	100%	

Item	Percentage	Summary explanation of how the royalties or payments are calculated
asset (without the said royalties)		
Specification of the payments (derived from the expenses) on the petroleum asset level:		
The operator	1%-4%	A rate of 1.5% in respect of the indirect expenses of the operator out of all of the direct expenses in connection with development actions,[52] subject to certain exclusions, such as marketing activity. The 1%-4% rate pertains to exploration expenses. Such sums are for payment of the operator's indirect expenses and are in addition to the reimbursement of direct expenses paid thereto. The rate of payment to the operator decreases as exploration expenses increase.
Total actual expense rate on the petroleum asset level	101%-104%	
The share of the holders of equity interests of the Partnership in the petroleum asset expenses (indirect holdings)	30%	
Total actual share of the holders of the equity interests of the Partnership, in the expenses, on the petroleum asset level (and prior to other payments on the Partnership level)	30.3%-31.2%	
Specification of payments (derived from the expenses) in respect of the petroleum asset and on the Partnership level (the following percentage will be calculated according to the share of the holders of the equity interests of the Partnership in the petroleum asset):		
The rate actually attributed to the holders of the equity interests of the Partnership in expenses involved in the exploration, development or production activity at the petroleum asset.	30.3%-31.2%	

[52] As of the report approval date, such rate has not yet been agreed in connection with the production actions.

7.3.10 Fees and payments paid during exploration and development activity at Block 12 ($ in thousands)

Item	Total share of the holders of the equity interests of the Partnership in the investment in the petroleum asset in this period[53]	Out of which, the share of the holders of the equity interests of the Partnership in payments to the General Partner	Out of which, the share of the holders of the equity interests of the Partnership in payments to the Operator (beyond the reimbursement of its direct expenses)
Budget actually invested in 2022	Approx. 6,597	-	Approx. 100
Budget actually invested in 2023	Approx. 30,370	-	Approx. 448
Budget actually invested in 2024	Approx. 3,579	-	Approx. 78

7.3.11 The plan for development of the Aphrodite reservoir

The Original Development Plan for the Aphrodite reservoir, which was approved as aforesaid by the Cypriot government on 7 November 2019, included the construction of a floating production and processing facility above the reservoir in the area of the license (the "**Floating Production Facility**") and a subsea system for transmission to the Egyptian market. In 2023-2024, the partners applied to the Cypriot government for authorization to make changes to the outline of the original production plan, but these applications were not approved, and during this period the partners failed to meet the FEED execution milestone as determined in the PSC at that time. Against this backdrop, on 25 August 2024, the operator in the Aphrodite reservoir received a notice of breach from the Minister of Energy in the Cypriot government, according to which the partners in the reservoir had 3 months to remedy the alleged breach (the "**Remediation Period**"). Consequently, meetings and conversations were held between representatives of the parties, and on 17 September 2024, an agreement was signed between the partners in the reservoir and the Cypriot government, in which a standstill was agreed on with the aim of continuing to hold discussions in order to obtain approval for an updated development plan prepared by the partners based on the original plan.

Further to the aforesaid, on 14 February 2025, the Cypriot government approved, as aforesaid, the Updated Development Plan, which is based on the Original Development Plan, and according to which the Floating Production Facility will be built, with a maximum daily production capacity of ~800 MMCF, through 4 production wells at the initial stage,

[53] Including costs in respect of which no payments are made to the operator.

and from which the natural gas will be transmitted via a subsea pipeline to the Egyptian transmission system.

According to a current estimate of the operator in the reservoir, before completion of technical-economic feasibility studies, including execution of the pre-FEED and the FEED, the estimated cost of the Updated Development Plan is approx. $4 billion (100%). It is emphasized that execution of the Updated Development Plan and reaching adoption of a final investment decision (FID) are contingent, *inter alia*, on the execution of pre-FEED and FEED and the results thereof, finalization of commercial arrangements for development and construction of the export pipeline, the signing of agreements for the supply of natural gas and fulfillment of the closing conditions of such agreements, obtaining regulatory approvals and finalization of financing arrangements. Insofar as the foregoing closing conditions are fulfilled, the supply of natural gas from the reservoir is expected to begin in 2031.

Caution concerning forward-looking information – The information specified above, including regarding the potential date for adoption of a final investment decision (FID) for development of the Aphrodite reservoir, the estimated cost of the Updated Development Plan, the potential date for commencement of the supply of natural gas from the reservoir and the anticipated production volume, as well as the information regarding the possibility of engagement in agreements for the export of natural gas from the reservoir based on the MOU, are forward-looking information within the meaning thereof in the Securities Law. This information is based on working assumptions and assessments of the Partnership and of the operator in the reservoir, Chevron Cyprus Limited (the "Operator"), which there is no certainty will materialize, in whole or in part, and which may materialize in a materially different manner to the aforesaid, due to various factors, including: adoption of an investment decision (FID) by the partners; regulatory and other difficulties in obtaining the approvals required for construction of the cross-border transmission infrastructure, including approvals of the authorities in Cyprus and in Egypt; changes in the local and global market conditions, including changes in energy prices and in demand; geopolitical changes or changes in the security situation in the region; operating or technical difficulties with development of the reservoir and construction of the infrastructures; changes in the volume or pace of consumption of natural gas in the target markets; failure to reach binding commercial agreements with EGAS or with other required third parties; and materialization of any of the risk factors entailed by natural gas exploration, development and production activity. There is therefore no certainty that the information specified above will materialize, and it may materialize in a materially different manner to the aforesaid. It is clarified that the said assessments and estimates may be updated and even change substantially in the future or as a result of a gamut of factors

relating to natural gas and oil exploration, development and production projects, including as a result of operating conditions or market conditions or regulatory conditions or the materialization of any of the risk factors specified in Section 7.30 below.

7.3.12 Further to approval of the Updated Development Plan and amendment of the PSC on 14 February 2025, on 17 February 2025, the partners in the reservoir, together with the Cypriot government, the Cyprus Hydrocarbons Company (CHC), the Egyptian government and the Egyptian national gas company EGAS, signed a non-binding MOU that outlines the framework for continued negotiations in connection with the export of natural gas from the reservoir to Egypt, including the construction of the required transmission infrastructure and the sale arrangements. According to the MOU, EGAS shall serve as the sole buyer of the natural gas produced from the reservoir, while the partners shall be granted an option to purchase specific quantities of the gas that is sold to EGAS as liquefied natural gas (LNG). The MOU also includes principles regarding the construction of the required transmission infrastructure and the sale arrangements, which shall be established in detailed agreements intended to be signed between the parties in due course.

7.3.13 <u>Contingent and prospective resources attributed to the Block 12 petroleum asset in Cyprus</u>

Following completion of the drilling of the A-3 appraisal well, on 5 September 2023, the Partnership released (Ref.: 2023-01-102990) a contingent and prospective resources evaluation report, which was prepared by NSAI in accordance with the rules of the Petroleum Resources Management System (SPE-PRMS) (in this section: the "**Resource Report**"). The Resource Report relates to resources located in the area of the EEZ of Cyprus only. According to the Resource Report, as of 31 August 2023, most of the natural gas and condensate resources attributed to the Aphrodite reservoir in the area of Block 12 were proven by the A-3 Well and previous wells in the reservoir , and were therefore classified as development-pending contingent resources, while a small part of the natural gas and condensate resources attributed to the petroleum asset were not proven and were therefore classified as prospective resources. For details regarding the resources attributed to the Block 12 petroleum asset, see the Resource Report, the information appearing in which is incorporated herein by reference. Attached to this chapter as **<u>Annex D</u>** is NSAI's consent to the inclusion of the said report herein, including by way of reference, and a letter from NSAI on the absence of material changes in the said resources.

7.4 The Yam Tethys project

7.4.1 Background

The Yam Tethys project includes the Noa Lease, in the area of which the Noa natural gas reservoir was discovered in 1999, and the Ashkelon Lease, in the area of which the Mari B and Pinnacles reservoirs were discovered in 2000 and 2012 respectively. The production of natural gas in the Yam Tethys project began in March 2004 and was discontinued in May 2019 due to a depletion of the reservoirs.

As of the report approval date, the project's assets serve mainly for the provision of infrastructure services to the Tamar Reservoir, in accordance with an agreement signed on 23 July 2012 between the Partnership together with the other Yam Tethys Partners and the Tamar Partners. In the context of a usage agreement signed between the parties, the Yam Tethys Partners gave the Tamar Partners rights to use the project's facilities, in consideration for a total payment of $380 million (the "**Usage Agreement**"). The term of the Usage Agreement shall expire on the earlier of: (a) the expiration or termination of the Tamar Lease, and in case that the Dalit field is developed, such that use is made of the Yam Tethys Facilities, the expiration or termination of the Dalit Lease; (b) giving of notice by the Tamar Partners of permanent discontinuation of commercial production of gas from the Tamar project; and (c) the abandonment of the Tamar project. The Usage Agreement provides various provisions in relation to the term of use and in relation to the end of the term of use, including a mechanism for the settlement of accounts in respect of upgrades made to the facilities. [54]

In the context of the sale of the Partnership's remaining interests in the Tamar I/12 and Dalit I/13 leases (the "**Tamar and Dalit Leases**"), the Partnership assigned to the buyers its rights in the Usage Agreement as a partner in the Tamar project.

In view of the aforesaid, the Partnership deems the Yam Tethys project a negligible petroleum asset.

In 2021, the operator began performing decommissioning actions for the project's facilities, with the exception of the platform, two subsea gas pipelines (the "**Two Subsea Gas Pipelines**") and the Terminal, in accordance with a plan approved by the Petroleum Commissioner. In July 2024, the operator notified the partners that the said actions had been completed and that summary reports had been submitted to the Petroleum Commissioner. At the same time, a discussion is being held on possible future uses and/or the decommissioning of the Yam Tethys

[54] The Gas Framework determines that the holders of the interests in the Tamar lease will be entitled to use the Mari B platform for the entire term of the Tamar lease, for the purpose of export or supply of natural gas to the domestic market from the Tamar reservoir, subject to the conditions stipulated in the Gas Framework.

platform, considering the link that exists between the facilities of the Yam Tethys project and production from the Tamar project. The cost of the decommissioning actions for the Yam Tethys facilities, with the exception of the platform, the Two Subsea Gas Pipelines and the onshore terminal as aforesaid, totaled approx. $273 million (100%). In addition, per his request, the Petroleum Commissioner was presented with a comparative survey, which was prepared by an independent expert, which supports leaving the Two Subsea Gas Pipelines in place after they have been rinsed and plugged in accordance with the plan approved by the Petroleum Commissioner as aforesaid. According to the expert opinion, the cost entailed by removal of the Two Subsea Gas Pipelines is expected to total approx. $45 million (100%). As of the report approval date, the Petroleum Commissioner's confirmation is yet to be received regarding completion of the decommissioning actions for the Yam Tethys project, including in connection with the Two Subsea Gas Pipelines.

For details regarding a draft policy document regarding the decommissioning of offshore exploration and production infrastructures released by the Ministry of Energy for public comment, see Section 7.24.9 below.

In view of the project being classified as a negligible petroleum asset, a limited description thereof is presented below:

7.4.2 General details

General Details with respect to the Petroleum Asset	
Name of the petroleum assets:	Noa Lease. Ashkelon Lease.
Location:	Ashkelon Lease – approx. 25 km west of the shores of Ashkelon. Noa Lease – approx. 40 km west of the shores of Ashkelon.
Area:	The overall area of the leases is approx. 500 km^2.
Type of petroleum asset and description of the activities permitted for such type:	Lease; Permitted activities under the Petroleum Law – exploration and production.
Original grant date of the petroleum asset:	Ashkelon Lease – 11 June 2002. Noa Lease – 10 February 2000.
Original expiration date of the petroleum asset:	Ashkelon Lease – 10 June 2032. Noa Lease – 31 January 2030.
Dates on which an extension of the term of the petroleum asset was decided:	-
Current expiration date of the petroleum asset:	Ashkelon Lease – 10 June 2032. Noa Lease – 31 January 2030.
Is there an additional option to extend the term of the petroleum asset; if so – what is the possible extension period:	Subject to the Petroleum Law, by 20 additional years.
The name of the operator:	Chevron
The names of the direct partners in the petroleum asset and their direct share in the petroleum asset, and, to	▪ The Partnership (48.50%). ▪ Chevron (47.059%).

General Details with respect to the Petroleum Asset	
the best of the Partnership's knowledge, the names of the control holders of such partners:	▪ Delek Group (4.441%).

7.4.3 Work program for the Yam Tethys project – actual and planned

Below is a concise description of the main activities actually carried in the Noa Lease and the Ashkelon Lease between 1 January 2022 and the report approval date, as well as a concise description of planned activities:

Yam Tethys Project			
Period	Concise Description of Activities Actually Performed for the Period or of the Planned Work Program	Total Estimated Budget for Activity at the Petroleum Asset Level ($ in thousands)[55]	Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)
2022	• Continued plugging and abandonment of the project's production wells, and decommissioning of subsea facilities, in accordance with standards and the directives of the Petroleum Commissioner.	Approx. 106,550	Approx. 51,677
	• Various additional actions, including examination of possible uses of existing project infrastructures.		
2023	• Completion of plugging and abandonment of the project's production wells and continued decommissioning of subsea facilities, in accordance with standards and directives of the Petroleum Commissioner.	Approx. 15,906	Approx. 7,715
	• Various additional actions, including examination of possible uses of existing project infrastructures.		
2024	• Completion of decommissioning of subsea facilities, in accordance with standards and directives of the Petroleum Commissioner.	Approx. 3,460	Approx. 1,678
	• Conduct of asset integrity surveys in accordance with directives of the Petroleum Commissioner by 2029.	Approx. 1,500	Approx. 728
	• Various additional actions, including examination of possible uses of existing project infrastructures, including a comparative survey for reviewing alternatives for the decommissioning of the Two Subsea Gas Pipelines.		
2025	• Conduct of asset integrity surveys in accordance with directives of the Petroleum Commissioner by 2029		

[55] The amounts for the years 2022-2024 are amounts actually expended and audited in the framework of the financial statements.

Yam Tethys Project			
Period	Concise Description of Activities Actually Performed for the Period or of the Planned Work Program	Total Estimated Budget for Activity at the Petroleum Asset Level ($ in thousands)[55]	Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)
forth[56]			
	• Decommissioning of the platform and the subsea pipeline upon termination of use thereof, in accordance with standards and directives of the Petroleum Commissioner.	Approx. 109,002	Approx. 52,866
	• Decommissioning of the onshore terminal upon termination of use thereof, in accordance with standards and directives of the Petroleum Commissioner.	Approx. 8,843	Approx. 4,288
	• Various additional actions, including examination of possible uses of existing project infrastructures.		

Caution concerning forward-looking information – The information specified above with respect to the activities planned in the Yam Tethys project in 2025 forth, including as pertains to costs, timetables and the actual performance thereof, constitutes forward-looking information within the meaning thereof in the Securities Law, which is based on the estimations of the Partnership with respect to the components of the work program, which are all based on estimates received by the Partnership from the Operator. The actual performance of the work program, including timetables and costs, may materially differ from the aforesaid estimations due to factors beyond the Partnership's control which are dependent, *inter alia*, on applicable regulation, technical ability and economic merit.

7.5 Right to overriding royalties from the Tanin and Karish Leases

7.5.1 Background

As specified below, the Partnership has rights to receive overriding royalties from the Tanin and Karish Leases which are owned by Energean Israel Ltd. ("**Energean Israel**"). It is clarified that the description presented below in relation to the Tanin and Karish Leases is based mainly on public reports of Energean, a foreign public company whose shares are traded on the TASE and the London Stock Exchange, which is, to the best of the Partnership's knowledge, the controlling shareholder of Energean Israel. It is further clarified that the Partnership is unable to independently corroborate the veracity of the details presented in these reports.

[56] These budgets are estimates of the Partnership, and as of the report approval date have not yet been approved by the Yam Tethys partners.

7.5.2 General details

Following the Government's decision to ratify the Gas Framework, on 16 August 2016, an agreement was signed between the Partnership and Avner, and Energean Israel, for the sale of all of the interests of the Partnership, Avner and Chevron in the Tanin and Karish leases, in consideration for a payment, which constitutes reimbursement of past expenses invested in the leases by the Partnership, Avner and Chevron plus royalties in connection with natural gas and condensate that shall be produced from the leases. After fulfillment of all of the conditions precedent on 26 December 2016, the transaction was closed and all of the interests (except in relation to the export of natural gas from Israel) in the leases were transferred to Energean Israel. For details regarding the aforesaid agreement, see Section 7.26.10 below.

As of 31 December 2024, the Partnership deems the overriding royalty from the Tanin Lease and the overriding royalty from the Karish Lease as petroleum assets that are negligible to the results of the Partnership's operations and its business, after quantitative examination was conducted by the Partnership, whereby it transpires, *inter alia*, that: (a) the Partnership's share in reserves and contingent resources in the Karish Lease and the Tanin Lease constitutes, respectively, less than 1% and 2% of the total reserves and contingent resources attributed to all of the Partnership's petroleum assets; and (b) the current value of cash flows attributed to the overriding royalty in the Tanin Lease and the overriding royalty in the Karish Lease constitutes, respectively, less than 1% and 5% of the total net current value attributed to all of the Partnership's petroleum assets including reserves or contingent resources.[57] In addition, also in qualitative terms the asset should be deemed as negligible, in view of the fact that the Partnership's rights in the Tanin and Karish Leases are passive, and that it has no ability to influence the activity therein.

In view of the classification of the benefit in the leases as a negligible petroleum asset, a limited description of the Tanin and Karish Leases is presented below.

General details about the Petroleum Asset	
Name of petroleum asset:	Tanin Lease. Karish Lease.
Location:	Offshore assets located approx. 80-130 km west of the shores of Nahariya.
Area:	The total area of both leases collectively is approx. 500 km^2.
Type of petroleum asset and description of actions permitted according to this type:	Lease; Actions permitted under the Petroleum Law –

[57] For the purpose of calculating the net current value of the cash flows from the petroleum assets, the following cap rates (after tax) were taken into account: the Leviathan project – 10%; the Aphrodite project – 13.6%; overriding royalty from the Tanin and Karish Leases (before tax) – 11.4% (for details see Annex B to the Board of Directors' report (Chapter B of this report) and Note 8B to the financial statements (Chapter C of this report)).

General details about the Petroleum Asset	
	exploration and production.
Original grant date of the petroleum asset:	24 December 2015, valid since 11 August 2014 (amended on 25 April 2017)
Original expiration date of the petroleum asset:	10 August 2044
Dates on which an extension of the term of the petroleum asset was decided:	-
Current date for expiration of the petroleum asset:	10 August 2044
Is there an additional option to extend the term of the petroleum asset; if so – what is the possible extension period:	By 20 additional years, subject to the Petroleum Law.
The operator's name:	Energean Israel.
The names of the direct partners in the petroleum asset, and their direct share in the petroleum asset, and, to the best of the Partnership's knowledge, the names of the control holders of such partners :	Energean Israel (100%).

General details regarding the Partnership's share in the petroleum asset	
For a holding in a purchased petroleum asset – the purchase date:	-
Description of the nature and manner of holding of the petroleum asset by the Partnership:	The Partnership is entitled to royalties in connection with natural gas and condensate that shall be produced from the leases.
The actual share attributed to the holders of the equity interests of the Partnership in the revenues from the petroleum asset:	Approx. 5.12% before payment of a petroleum profit levy under the Taxation of Profits from Natural Resources Law (the "**Levy**") and before the Investment Recovery Date; Approx. 2.47% before payment of the Levy and after the Investment Recovery Date; and Approx. 3.22% upon commencement of payment of the Levy and after the Investment Recovery Date.
The total share of the holders of the equity interests of the Partnership in the aggregate investment in the petroleum asset during the five years preceding the last day of the report year (whether recognized as an expense or as an asset in the financial statements):	-

7.5.3 The development plans of the Tanin and Karish Leases and the resources attributed thereto

To the best of the Partnership's knowledge, the original development plan for the Tanin and Karish leases that was submitted to the Petroleum Commissioner by Energean Israel, was approved by the Ministry of Energy in August 2017 (in this section: the "**Original Development Plan**"), which specifies that the Karish reservoir will be developed first and the Tanin reservoir will be developed further down the line.[58]

[58] https://www.gov.il/he/Departments/news/spokesperson_development.

In 2018, Energean adopted a Final Investment Decision for development of the Karish reservoir through a floating production storage facility (FPSO). On 26 October 2022, Energean reported production of first gas from the Karish reservoir and on 28 October 2022 began to sell gas to its customers.

According to data released by the Ministry of Energy, in 2022, Energean marketed 0.29 BCM of natural gas produced from the Karish field. According to Energean's report of January 2024, in 2023, the Karish reservoir produced approx. 4.4 BCM. On 29 February 2024, Energean reported on the production of first gas from the Karish North reservoir.

Furthermore, to the best of the Partnership's knowledge, the current data on the resources attributed to the Tanin, Karish and Karish North reservoirs were reported by Energean in March 2024[59]. According to this report, the said reservoirs contain approx. 96.3 BCM of natural gas reserves (2P) and approx. 98.3 million barrels of hydrocarbon liquids.

For details with respect to a highly material valuation of the Partnership's royalty interest in the Tanin and Karish Leases, see Note 8B to the financial statements (Chapter C of this report) which are attached below, and Annex B of the Board of Directors' Report (Chapter B of this report).

It is emphasized that the Partnership, as the holder of a right to royalties, does not bear the development plan expenses of the Reservoirs.

7.5.4 Disputes with Energean

Several letters have been exchanged between Energean and the Partnership regarding claims raised by Energean with respect to the Partnership's rights to receive royalties from the Tanin and Karish Leases. Energean claimed that: (a) The Partnership's overriding royalty does not apply to the Karish North reservoir (as opposed to the Karish reservoir); and (b) not all hydrocarbon liquids to be produced from the Karish Lease are deemed as condensate according to the sale agreement which is subject to the duty to pay royalties. It is the Partnership's position, based on its legal counsel, that Energean's duty to pay royalties applies to all natural gas and condensate to be produced from the leases, including from the Karish North reservoir, and that any and all hydrocarbon liquids to be produced from the reservoirs in the area of the leases constitute condensate, as defined in the agreement, which is subject to royalties. Between the date of commencement of production and the report approval date, Energean paid the Partnership royalties for the condensate produced from the

[59] https://www.energean.com/media/5770/energean-israel-cpr.pdf.https://www.energean.com/media/5159/024343-energean-israel-2021ye-cpr.pdf

Karish Lease (including from the Karish North reservoir), "under protest".

Caution concerning forward-looking information – The above description regarding the activities planned in the Karish Lease, including the timetables for performance thereof, constitutes forward-looking information, within the meaning thereof in the Securities Law, and is based only on public releases by Energean. Actual performance of the work program, including the timetables, may materially differ from the foregoing and is contingent, *inter alia*, on applicable regulation, technical abilities and economic merit.

7.5.5 Below is a concise description of the main activities actually carried out in the Tanin and Karish Leases between 1 January 2022 and the report approval date, and a concise description of planned activities, according to Energean's reports and to the best of the Partnership's knowledge. Since the Partnership does not bear the development and production costs in the Tanin and Karish Leases, the table below does not present data regarding the budget for the activities and the actual scope of the participation of the holders of the equity interests of the Partnership in the budget:

Tanin and Karish Leases			
Period	Concise Description of Activities Actually Performed for the Period or of the Planned Work Program	Total Estimated Budget for Activity at the Petroleum Asset Level ($ in thousands)	Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)
2022	• Completion of installation and running-in of gas and condensate production and processing systems on the FPSO hull in Singapore.		
	• Departure of the FPSO, with its systems, to Israel.		
	• Completion of the connection and running-in of the production systems.		
	• Commencement of commercial production from the Karish Lease, ongoing operation and maintenance.		
	• Drilling of appraisal and development well in the Karish Lease and completion of the Karish North-1 well.		
2023	• Installation of a second export riser which connects the production facility to the export pipeline.		
	• Continued commercial production from the Karish Lease, ongoing operation and maintenance.		
	• Connection of the production well in Karish North to the FPSO.		

Tanin and Karish Leases			
Period	Concise Description of Activities Actually Performed for the Period or of the Planned Work Program	Total Estimated Budget for Activity at the Petroleum Asset Level ($ in thousands)	Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)
2024	• Commencement of production from the Karish North-1 well.		
	• Continued operating activities and production from the Karish Lease.		
	• Installation and commencement of running-in of a second fluid processing facility.		
2025 forth	• Continued operating activities and production from the Karish Lease.		
	• Completion of running-in of a second fluid processing facility.		
	• Drilling of additional production wells in the Karish Lease, insofar as required.		
	• Development of the Tanin Lease, including the drilling of production wells, manufacture and installation of a subsea system and connection thereof to the FPSO. In this context it is noted that according to Energean's reports, production from the Tanin Lease is expected to begin in 2029.		

7.6 The Boujdour Atlantique exploration license situated in the Atlantic Ocean off the Moroccan coast (the "Boujdour License")

7.6.1 Background

On 6 December 2022, the Partnership, jointly with Adarco Energy Limited[60] ("**Adarco**"), signed agreements concerning oil and natural gas exploration and production activities in the Boujdour Atlantique exploration license, which is situated in the Atlantic Ocean off the coast of Morocco (in this section: the "**Petroleum Asset**" or the "**License**"),[61] with the National Office of Hydrocarbons and Mines of Morocco (Office National des Hydrocarbures et des Mines, "**ONHYM**") (in this section: the "**Agreements**"). The Agreements confer, *inter alia*, on each of the Partnership and Adarco 37.5% of the interests in the License, with the remaining interests in the License, at a rate of 25%, being granted to ONHYM in accordance with the current regulation in Morocco. On 1 June 2023, NewMed Morocco signed the Agreements in lieu of the Partnership, and stepped into its shoes.

[60] As the Partnership has been informed by Adarco, Adarco is a company controlled by Mr. Yariv Elbaz (a Moroccan investor) and his family members.

[61] In practice, the License includes the areas of 17 different licenses.

The Agreements further grant the Partnership, Adarco and ONHYM the right to search for hydrocarbons in the area of the License for a term of 8 years, subject to compliance with a work program, which may be extended in the event of a discovery. NewMed Morocco is the operator in the License.

During the exploration period, the Partnership and Adarco shall bear, in addition to their relative share of the costs, the costs in respect of ONHYM's share, in accordance with existing regulation in Morocco. Furthermore, the Agreements with ONHYM include additional provisions, *inter alia*, with respect to bonuses that are paid to ONHYM according to accomplishment of milestones of output from the License, royalties to the State of Morocco, fines in the event of noncompliance with obligations under the agreements, guarantees, stability in respect of economic terms, obligations of professional training in the domestic market, as well as provisions pertaining to the joint operation of the License.

On 2 January 2023, the general meeting of the Unit holders approved the Partnership's engagement in the Agreements, which is also contingent on receipt of approval from the Ministry of Energy and Sustainable Development and the Ministry of Finance of Morocco.

In December 2022, the Partnership provided a bank guarantee in the sum of approx. $1.75 million (100%) in favor of ONHYM.

The License is situated off the coast of an area historically sometimes referred to as the "Western Sahara", whose sovereignty, according to the UN, is in dispute. In December 2020, a normalization agreement was signed between Israel and Morocco, under which, *inter alia*, Israel and the U.S. recognized Morocco's sovereignty over this area. According to the Partnership's Environment, Social and Governance ("**ESG**") strategy, the Partnership engaged with an international consulting firm to examine the implications of its operations in this region, and specifically to ensure that the Partnership is operating in accordance with the principles outlined by the UN for the welfare of the region's residents.

In July 2024, the partners in the License were informed that Morocco's Ministry of Energy Transition and Sustainable Development had granted them the interests therein.

As of the report approval date, the Partnership deems the License as a negligible petroleum asset relative to the Partnership's total operations and assets, and therefore a limited description thereof is presented below. The following details with respect to the Petroleum Asset relate to the rate of the Partnership's holdings in the Petroleum Asset through NewMed Morocco.

7.6.2 General Details

General Details with respect to the Petroleum Asset	
Name of the Petroleum Asset:	Boujdour Atlantique.
Location:	Offshore area in the south of the Moroccan EEZ (see a map of the Petroleum Asset in Section 2.9 above).
Area:	Approx. 33,812 km^2.
Type of the Petroleum Asset and description of the permitted activities according to such type:	Exploration and production license.
Original grant date of the Petroleum Asset:	1 June 2023.
Original expiration date of the Petroleum Asset:	30 November 2025.
Dates on which an extension of the term of the petroleum asset was decided:	-
Current expiration date of the Petroleum Asset:	The Agreements grant the right to conduct exploration for oil and/or natural gas in the area of the block for a term of 8 years in total – Initial term – 2.5 years (i.e., 30 November 2025); First extension (subject to the Partnership's decision and subject to commitment to the second term work program) – 2 years; Second extension (subject to the Partnership's decision and subject to commitment to the third term work program) – 3.5 years;
Is there an additional option to extend the term of the petroleum asset; if so – what is the possible extension period:	There is a possibility of applying for a special extension in a case where hydrocarbons are found and additional time is needed to examine economic viability.
The name of the operator:	NewMed Morocco.
The names of the direct partners in the Petroleum Asset and their direct shares in the Petroleum Asset, and also, to the best of the Partnership's knowledge, the names of the control holders of such partners:	NewMed Morocco – 37.5% (a private company wholly owned (100%) by the Partnership). Adarco – 37.5%. ONHYM – 25%.

General Details with respect to the Partnership's Share in the Petroleum Asset	
For a holding in a purchased petroleum asset – the purchase date:	-
Description of the nature and manner of holding of the Petroleum Asset by the Partnership:	The Partnership, through NewMed Morocco, holds 37.5% of the interests in the License.
The actual share of the revenues from the Petroleum Asset attributed to the holders of the Partnership's equity interests:[62]	Pre investment recovery date – 34.5%. Post investment recovery date – 32.63%.
Total share of the holders of the Partnership's equity interests in the aggregate investment in the Petroleum Asset during the five years preceding the last day of the reporting year (whether recognized as an expense or as an asset in the financial statements):	-

[62] The Partnership's interests in the petroleum asset are subject to royalties paid to Morocco. According to the local regulation in Morocco, the royalty amount depends on the water depth in the well and on the findings (gas or oil). Where the water depth in the well exceeds 200 meters, in the case of an oil discovery, royalties at the rate of 7% per annum will be paid. On the other hand, in the case of a **gas** discovery at the said depth or deeper, a royalty at the rate of 3.5% will be paid. The obligation to pay the royalty applies in relation to quantities exceeding 500,000 tons of oil or 0.5 BCM of natural gas. The figures in the table above were calculated assuming a gas discovery (i.e., a royalty at the rate of 3.5%). It is further noted that according to Moroccan regulation, an exemption from corporate tax applies for a period of 10 years after commencement of production, after which corporate tax is paid at the rate of 31% (in both gas discoveries and oil discoveries).

7.6.3 Actual and Planned Work Program for the Petroleum Asset

Following is a concise description of actual and planned activities, noting the estimated budget for the conduct of each activity and the share of the holders of the Partnership's equity interests in such budget:

Boujdour License			
Term	Concise Description of Activities Actually Carried Out for the Term or of the Planned Work Program	Estimated Total Budget for the Activity at the Petroleum Asset Level ($ in thousands)	Amount of Actual Participation in the Budget by the Holders of the Partnership's Equity Interests ($ in thousands)
30 months from the License grant date	• Geological and geophysical analysis in the License, including reprocessing of 2D+3D seismic data and ESG work.	Approx. 6,100[63]	Approx. 4,700
	• Adoption of a drill or drop decision for the area of the License		
First extension – 24 months from the lapse of the first term	• Drilling of first exploration well.	Approx. 25,000	Approx. 12,500
Second extension – 42 months from the lapse of the second term	• Drilling of exploration/appraisal well.	Approx. 25,000	Approx. 12,500

Caution regarding forward-looking information – The information about the planned activities in the Boujdour license, including with respect to the costs, timetables and mere performance thereof, constitutes forward-looking information within the meaning thereof in the Securities Law, which is based on the information held by the Partnership on the report approval date, and includes assessments and estimations by the Partnership as of the report approval date. The actual execution of the work program, including the timetables and the costs, may materially differ from the information specified above, and this is contingent, *inter alia*, on market conditions, regulation, numerous external circumstances, including technical needs, technical ability, new findings to be discovered and economic viability.

7.7 **Exploration licenses in Zone I in the area of Blocks 4, 5, 6, 7, 8 and 11 in the EEZ of the State of Israel (the "Zone I Licenses")**

7.7.1 Background

On 29 October 2023, the Petroleum Commissioner gave the Partnership, the State Oil Company of Azerbaijan Republic ("**SOCAR**"), and BP (in this section, collectively, the "**Partners**"), a notice of winning of the bid they

[63] As of the report approval date, the partners in the Boujdour license have approved approx. $4.7 million (100%; the Partnership's share – approx. $4 million) out of this budget for 2024-2025.

submitted in connection with the Zone I Licenses, as part of the fourth competitive process for natural gas exploration in the northwest area of Israel's EEZ, entitling them to receive 6 exploration licenses in blocks 4, 5, 6, 7, 8, and 11, located in the Mediterranean Sea, in the area of Israel's EEZ (in this section: the "**Licenses**").

The Partners are continuing to comply with the terms and conditions of an agreement which regulated, *inter alia*, the terms of the said bid and also determined principles for the joint operating agreement which is expected to be signed after the Licenses are granted.

On 18 December 2023, the general meeting of the Unit holders approved the Partnership's participation in oil and/or natural gas exploration and production in the area of the Licenses.

Accordingly, in December 2023, the Partners provided a guarantee in the sum of $5 million (100%) and paid the signature bonus to the Ministry of Energy in the sum of approx. $5 million (100%).

Due to the Swords of Iron War, which continued throughout 2024, the process of issuance of the Licenses has been delayed, and in the Partnership's estimation, the Licenses are expected to be granted by the end of March 2025.

Presented below are further details regarding the Licenses. As of the report approval date, the Partnership deems the Licenses as a negligible petroleum asset relative to all of the Partnership's operations and assets, and therefore a brief description of the Licenses is presented below, in accordance with the disclosure format required with respect to a negligible petroleum asset.

7.7.2 General Details

General Details with respect to the Petroleum Asset	
Name of the petroleum asset:	Zone I (Blocks 4, 5, 6, 7, 8, and 11).
Location:	The northwest area of Israel's EEZ in the Mediterranean Sea.
Area:	The total area of the License zone is 1,677 km^2.
Type of petroleum asset and description of the permitted activities according to such type:	The petroleum asset includes 6 licenses, in accordance with the provisions of the Petroleum Law. A license grants its holder, subject to the provisions of the Petroleum Law: (1) A right to explore for petroleum in the license area; (2) A right to conduct, to the extent and under the conditions determined by the Director, exploration activities outside of the license area, which establish the prospects of finding petroleum within the license area; and with regards to such right, the license holder will be deemed as a preliminary permit holder; (3) A unique right to drill exploration wells and development wells in the license area and to extract petroleum therefrom; and (4) A right to receive a lease after making a discovery in the license area.
Original grant date of the petroleum asset:	Not yet granted.
Original expiration date of the petroleum asset:	3 years from the grant date.
Dates on which an extension of the term of the petroleum asset was decided:	-

General Details with respect to the Petroleum Asset	
Current expiration date of the petroleum asset:	3 years from the grant date.
Is there an additional option to extend the term of the petroleum asset; if so – what is the possible extension period:	In accordance with the provisions of the Petroleum Law, the license may be extended up to 7 years from the original grant date, with the possibility of an extension of up to two additional years in the event of a discovery.
The name of the operator:	SOCAR.
The names of the direct partners in the petroleum asset and their direct shares in the petroleum asset, and also, to the best of the Partnership's knowledge, the names of the control holders of such partners:	▪ The Partnership – 33.33%; ▪ SOCAR – 33.34%, to the best of the Partnership's knowledge, the control holder of SOCAR is the government of the Republic of Azerbaijan; ▪ BP – 33.33%, to the best of the Partnership's knowledge, BP's indirect control holder is BP plc., which is a public company whose shares are traded on the London Stock Exchange as well as on the stock exchanges in Frankfurt and New York, and it has no controlling shareholder.

General Details with respect to the Partnership's Share in the Petroleum Asset	
For a holding in a purchased petroleum asset – the purchase date:	A proportionate share (33.33%) of the signature bonus which will be paid to the State in the sum total of approx. $5 million (100%).
Description of the nature and manner of holding of the petroleum asset by the Partnership:	The Partnership will directly hold 33.33% of the rights in the license.
The actual share of the revenues from the petroleum asset attributed to the holders of the Partnership's equity interests:	The interests of the Partnership in the petroleum asset are subject to the payment of royalties to the State of Israel and to royalty interest owners which include, *inter alia*, Delek Group, as specified in Section 7.26.9 below. Below is the actual share attributed to the holders of the Partnership's equity interests in the revenues from the petroleum asset, net of the royalties: Before the investment recovery date – 27.66%; After the investment recovery date – 26.00%.
Total share of the holders of the Partnership's equity interests in the aggregate investment in the petroleum asset during the five years preceding the last day of the reporting year (whether recognized as an expense or as an asset in the financial statements):	-

7.7.3 Actual and planned work program for the Licenses

Below are details regarding the planned actions in the petroleum asset and the costs in respect thereof (100%), as included in the bid submitted by the Partners in the competitive process. According to the terms and conditions of the said process, these actions constitute the binding work program for the petroleum asset:

The Licenses			
Period	Concise Description of Activities Actually Performed for the Period or of the Planned Work Program	Total Estimated Budget for Activity at the Petroleum Asset Level ($ in thousands)	Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)
2025-2026	• Purchase, performance and processing of seismic surveys and additional work.	Approx. 25,000	Approx. 8,333

Caution regarding forward-looking information – The Partnership's estimate regarding the planned actions, including regarding the estimated costs, the timetables and the mere performance thereof, constitutes forward-looking information within the meaning thereof in the Securities Law, which is based, *inter alia*, on estimations of the Partnership with respect to components of the work program, as agreed between the Partners prior to submission of the bid in the competitive process. The actual execution of the work program, including the timetables and the costs, may be materially different to the estimates specified above, and is contingent, *inter alia*, on market conditions, regulation, many external circumstances, technical needs, technical capability, and economic merit.

7.8 Block 1-21 Han Asparuh in the EEZ of the Republic of Bulgaria in the Black Sea (the "Bulgaria License" or the "Block")

7.8.1. Background

a. In November 2024, the Partnership entered into an agreement for the acquisition of interests comprising 50% of a license that was granted by the Bulgarian government in relation to the area of the Block, rights in an agreement for natural gas and oil exploration in the area of the Block which was signed with the Bulgarian government, and rights in the joint operating agreement (JOA) that will apply between the partners in the Block (in this section: the "**Interests Acquisition Agreement**" or the "**Agreement**"). The Agreement was signed between NewMed Balkan, (in this section: the "**Buyer**") and OMV Offshore Bulgaria GmbH (in this section: "**OMV Bulgaria**" or the "**Seller**"), a subsidiary of OMV Petrom, which, to the best of the Partnership's knowledge, is a public company listed on the Bucharest Stock Exchange in Romania and is considered the largest energy corporation in south-east Europe. As of the report approval date, OMV Bulgaria holds all of the interests (100%) in the Block.

It is clarified that the information specified in this section is based on the assumption that transfer of the interests to the Buyer will be completed in the coming days, such that the Buyer will hold 50% of the interests in the license and the remaining interests (50%) will be held by the Seller.

b. On 9 January 2025, the general meeting of the Unit holders approved the Partnership's engagement in the Agreement. The said meeting did not approve the proposed resolution to grant Mr. Abu, CEO of the Partnership, equity compensation at the rate of 5% of the issued share capital of NewMed Balkan, and to bear the financing of Mr. Abu's proportionate share in the investment costs of the Partnership in NewMed Balkan, up to the sum of $173 million (100%), designated for the financing of the first two wells to be drilled in the area of the Bulgaria License. For further details, see the Partnership's immediate reports of 2 January 2025 and 9 January 2025 (Ref. 2025-01-000782 and 2025-01-003240, respectively), the information in which is incorporated herein by reference.

c. Notwithstanding the objection of the general meeting of Unit holders as aforesaid, on 9 March 2025 the compensation committee and the board of directors of the General Partner unanimously decided to approve the granting of updated equity compensation to Mr. Abu, based on the conditions of the equity compensation and with certain changes that are favorable to the Partnership, primarily: (a) Reduction of the sum of participation in the funding of Mr. Abu's proportionate share in the cost of such investment to a maximum of $100 million (in lieu of $173 million as aforesaid) (the "**Initial Investment**"); (b) Addition of mechanisms to secure the Partnership's rights through a trustee and pledge of the shares; and (c) Addition of a right for the Partnership to purchase the shares from Mr. Abu in case of termination of his employment.

7.8.2. <u>The Interests Acquisition Agreement</u>

Below is a concise description of the main terms of the Agreement:

a. In consideration for transfer of the Interests in the Block, the Buyer has undertaken to fund the Seller's share of the costs of the next exploration well to be drilled in the Vinekh prospect in the area of the Block (out of a number of prospects and leads) (the "**First Well**"), up to a total amount that shall not exceed €50 million (approx. $52 million), and also fund the Seller's share of the costs of an additional well in the Block, which will be either an exploration well in another prospect in the area of the Block or an appraisal well in the Vinekh prospect (in the case of a commercial discovery therein), according to the recommendation of OMV Bulgaria as operator and approval by NewMed Balkan, after completion of the First Well, up to a total (additional) amount that shall not exceed €50 million (the "**Second Well**", and together with the First Well: the "**Two Wells**").

It is clarified that, under the terms of the Agreement, the Buyer does not have the right to be reimbursed by the Seller for the amounts provided in its favor by the Buyer, as specified in this section above, and that beyond such amounts, the Seller and the Buyer shall bear their *pro rata* share (50%-50%) in the expenses of the project.

The aforesaid amounts include €5 million (approx. $5.2 million) in operating expenses in connection with the License during the interim period between the Agreement signing date and the transaction closing date, as well as approx. €5 million in expenses incurred by the Seller in relation to preparations for the wells. It has been further agreed that the Buyer will bear the fees to be paid to the Bulgarian Government in respect of transfer of the Interests.

b. From the transaction closing date, the Buyer shall bear, according to its share of the license, all the expenses, payments, liabilities and obligations imposed in respect of the Block and pursuant to the provisions of any law, except as set out above in connection with the Two Wells and except for certain liabilities and obligations for which, as stipulated in the Agreement, the Seller shall remain responsible also after the transaction closing date, as relating to the period preceding the closing of the transaction, including payment demands issued in respect of the Block prior to the closing of the transaction, as well as liabilities and obligations pertaining to environmental protection or to compliance with provisions of law pertaining to environmental protection, insofar as existed prior to the transaction closing date or were known to the Seller prior to the transaction closing date.

c. On the transaction closing date, the parties shall enter into a joint operating agreement (JOA) in such form as agreed, which shall stipulate, among other things, that the Seller will continue to serve as the operator of the license.

d. The Agreement determined several closing conditions for the transaction, including the condition regarding the parties' engagement with the Bulgarian government in an agreement authorizing the transfer of the interests to the Buyer, which as of the report approval date has not yet been fulfilled.

e. The transaction will be closed on the date on which the parties and the Bulgarian government enter into an agreement authorizing the transfer of the interests to the Buyer, or on another date as shall be agreed between the parties.

f. The Agreement sets out provisions with respect to the parties' rights to terminate the Agreement prior to the transaction closing date in each of the following cases:

(a) Non-fulfillment of the Closing Conditions within 180 days of the Agreement signing date (or such later date as shall be agreed by the parties).

(b) An event of insolvency of the counterparty.

(c) Failure by the counterparty to comply with its obligations in relation to the period preceding the transaction closing date and failure to cure such breach within 14 days of receipt of written notice.

(d) The Buyer shall have the right to terminate the Agreement in the event of a "material adverse change" in relation to the transferred Interests, and, under certain stipulated conditions, in the event of breach of the Seller's representations.

g. The Agreement is governed by English law and any dispute that pertains to the Agreement will be resolved by arbitration in Paris, to be conducted under the rules of the International Court of Arbitration in Paris under the auspices of the International Chamber of Commerce.

h. The Agreement sets out such additional provisions as are standard in agreements of this type, including mutual indemnification undertakings in case of breach of representations and obligations.

7.8.3. General Details

The details presented in relation to the Block are primarily based on information provided to the Partnership by OMV Bulgaria, which, on the report approval date, holds all of the interests (100%) in the Block, and are to the best of the Partnership's knowledge. The description below of the Partnership's holdings in the Block is based, as aforesaid, on the assumption that the transaction will be closed.

General Details about the Block	
Name of Block:	Block 1-21 Han Asparuh
Location:	The EEZ of the Republic of Bulgaria in the Black Sea.
Area:	Approx. 13,712 square km.
Block type and description of the operations allowed for such type:	License to conduct natural gas and oil exploration operations in the area of the license, as part of a Prospecting and Exploration Agreement (PEA) with the Government of Bulgaria, which includes the right to receive a concession for production in case a discovery is recognized. Production rights are restricted to certain areas that will be determined according to and after the announcement of a discovery or discoveries. The term of the concession for production is 35 years with an option for extension by 15 additional years under certain conditions.
Original grant date of the Block, dates on which it was decided to extend the term of the Block, the original expiration date of the Block and options for extension of the term of the Block:	The Bulgarian Government granted the license in August 2012 to a consortium that consisted of (i) TotalEnergies, which also served as project operator; (ii) Repsol; and (iii) OMV Bulgaria. In 2019, Repsol relinquished its interests in the license, and in 2022, TotalEnergies relinquished its interests in the license,

General Details about the Block	
	such that ownership of all interests in the license was transferred to OMV Bulgaria, which, as of the date hereof, also serves as project operator. The original license was granted for a 5-year term, which was extended by 135 days from September 2017, by two additional years from January 2018, by 109 additional days from January 2020, by two more years from May 2020 and by another two-year period from May 2022. In June 2024, the Bulgarian Minister of Energy and OMV Bulgaria signed an appendix authorizing an additional extension of the term of the license by 23 months until 18 October 2026 following *force majeure* circumstances, in view of the war in Ukraine and TotalEnergies' withdrawal from the project. To the best of the Partnership's knowledge, further extension of the license beyond its said current expiration date in October 2026 is not legally available. It is clarified that the license expiration date is the last date on which exploration drilling may be executed in the area of the Block. However, in the event of discovery in the area of the license, extension by one more year, i.e., until October 2027, will be available for discovery appraisal purposes. To the best of the Partnership's knowledge, the term of the license, which has been extended on several occasions as noted, including following *force majeure* circumstances, exceeds the maximum term prescribed by Bulgarian law, and the Interests Acquisition Agreement includes no indemnification undertakings by OMV Bulgaria in respect of this issue.
Name of operator:	OMV Bulgaria.
Name of direct partners in the Block and their direct share of the Block, and, to the best of the Partnership's knowledge, the names of the control holders of such partners:	▪ OMV Bulgaria – 50%. To the best of the Partnership's knowledge, OMV Bulgaria is a wholly owned (100%) subsidiary of OMV Petrom S.A., a public company approx. 51% of the share capital of which are held by OMV AG and approx. 21% of the share capital of which are held by the Government of Romania[64]. OMV AG is a public company approx. 56% of the share capital of which are co-held by ADNOC (the national oil company of Abu Dhabi) and OBAG, a company owned by the Government of Austria[65]. ▪ NewMed Balkan – 50%.
General Details about the Partnership's Share of the Block	
Acquired Block holdings – indicate acquisition date:	As specified in the description of the Agreement above.
Describe the nature and form of the Partnership's holdings in the Block:	The Partnership shall hold 47.5% of the interests in the Block, through a holding of 95% of the share capital of NewMed Balkan.
The actual share of revenues from the Block attributable to the holders of the Partnership's equity interests:	See the table below.
Total share of the holders of the Partnership's equity interests in the aggregate investment in the Block over the 5 years preceding the date of the report (regardless of whether it was recognized as an expense or an asset in the financial statements):	Approx. $5.2 million[66].

[64] https://www.omvpetrom.com/en/investors/shares-and-dividends/shareholder-structure.
[65] https://www.omv.com/en/investor-relations/share/shareholder-structure.
[66] Expenses incurred by the Seller prior to the transaction in relation to preparation work ahead of drilling in the area of the license, *inter alia*, in engineering, operational, environmental, safety-related and regulatory aspects, including the procurement of long-lead items in the sum of approx. €5 million, as specified in Section 7.8.2a above, which shall be paid to the Seller shortly after the transaction closing date.

Item	Precentage Pre-Investment Recovery	Precentage Post-Investment Recovery	Precentage Post-Investment Recovery	Precentage Post-Investment Recovery	Precentage Post-Investment Recovery	Precentage Post-Investment Recovery	Precentage Post-Investment Recovery	Concise Explanation on the Royalty or Payment Calculation Method
Projected annual revenues from the Block	100%	100%	100%	100%	100%	100%	100%	
R-Factor	0-1.0	1.0-1.5	1.5-1.75	1.75-2.0	2.0-2.5	2.5-3.0	Over 3.0	Assuming that the calculation of the R-Factor and the investment recovery for overriding royalty purposes is identical. For further details, see Section 7.8.5(b) below.
		List of the Royalties or Payment (deriving from Post-Discovery Revenues) at Block Level:						
State	2.5%	2.5%	5%	10%	12.5%	22.5%	30.0%	For further details, see Section 7.8.5(b) below.
Discounted revenues at Block level	97.50%	97.50%	95.00%	90.00%	87.50%	77.50%	70.00%	
Share attributable to the holders of the Partnership's equity interests in the discounted revenues generated from the Block (indirectly)	47.50%	47.50%	47.50%	47.50%	47.50%	47.50%	47.50%	
Partnership's equity interest holders' total rate of the actual	46.31%	46.31%	45.13%	42.75%	41.56%	36.81%	33.25%	

Item	Precentage Pre-Investment Recovery	Precentage Post-Investment Recovery	Precentage Post-Investment Recovery	Precentage Post-Investment Recovery	Precentage Post-Investment Recovery	Precentage Post-Investment Recovery	Precentage Post-Investment Recovery	Concise Explanation on the Royalty or Payment Calculation Method
amount of revenues, at Block level (and before other payments at Partnership level)								
		List of the Royalties or Payments (deriving from Post-Discovery Revenues) in connection with the Block at Partnership Level (the following percentages will be calculated according to the share of the holders of the Partnership's equity interests in the Block):						
Partnership's equity interest holders' rate of payment to related parties and third parties	2.14%	4.51%	4.51%	4.51%	4.51%	4.51%	4.51%	Overriding royalty in respect of the Partnership's share at a rate of 4.5% pre-investment recovery and 9.5% post-investment recovery is calculated according to market value at the wellhead. Because the calculation method of such rate follows the market value at the wellhead as noted, such rate may vary.
Rate of revenues from the Block actually attributed to the Partnership's equity interest holders	44.18%	41.8%	40.61%	38.24%	37.05%	32.3%	28.74%	

7.8.4. As specified in Section 7.8.5(b)1 below, the Partnership is examining, via its outside legal counsel, whether the obligation to pay overriding royalties to Delek Group and a subsidiary thereof and to third parties also applies in relation to the license. Notwithstanding the aforesaid, the above table also presents overriding royalties calculated for 47.5% of the interests in the Bulgaria License.

7.8.5. Rate of actual participation in expenses for and revenues from the Block

(a) As relating to the expenses entailed by exploration, development and production operations in the Block ("**Project Expenses**"), it is noted as follows:

1. As noted above, according to the Agreement, the Partnership has undertaken to bear the funding of OMV Bulgaria's share (50%) in the Two Wells up to a cap (in each one of the Two Wells) of €50 million (approx. $52 million), and beyond the said amounts, the Partnership and OMV Bulgaria shall bear their *pro rata* shares (50%-50%) of the Project Expenses.

2. The Partnership shall finance Mr. Abu's proportionate share (2.5% indirectly) in the Initial Investment. Over and above such funding, Mr. Abu shall bear his proportionate share in any additional investment required of the shareholders in NewMed Balkan, according to NewMed Balkan's decision.

3. It is clarified that the calculation of the participation rate actually attributed to the holders of the Partnership's equity interests in the Project Expenses, as specified in the table below, refers to expenses incurred after the Two Wells (i.e., after exhaustion of the funding obligations imposed on the Partnership in relation to the costs of the Two Wells).

4. Under the JOA, the Partnership shall bear the expenses of the operator at certain rates of the Project Expenses, as specified in Section 7.8.8(b) below.

(b) As relating to the revenues from the Block, it is noted as follows:

1. As noted, as of the report approval date, the Partnership is examining, via its outside legal counsel, whether the obligation to pay overriding royalties to Delek Group and a subsidiary thereof and to third-party royalty interest owners, also applies to its interests in the Bulgaria License.

It is noted that in this context, the royalty interest owners clarified their position with regards to the obligation to pay overriding royalties in respect of the Partnership's interests in the Bulgaria License, and added that they would take action against any attempt to repudiate such payment obligation.

2. The revenues from the Block are subject to the payment of royalties to the Government of Bulgaria, which are calculated as a certain rate of gross production or of the total revenues from the concession for production per the Government's choice. Under the regulation in Bulgaria as applicable on the date hereof, annual royalties are determined according to the product of multiplication of the economic value of the annual production by the royalty rate payable to the Government, which is determined according to the R-Factor formula, pursuant to the following brackets:

R-Factor	Royalty Rate
< 1.5	2.5%
1.5 – 1.75	5%
1.75 – 2	10%
2 – 2.5	12.5%
2.5 – 3	22.5%
> 3	30%

To the best of the Partnership's knowledge, under the regulation in Bulgaria as applicable on the date hereof, besides the right to receive royalties on the output, as specified above, the Government of Bulgaria does not have the right to receive working interests in the Block or other substantial economic interests in the petroleum output.

To the best of the Partnership's knowledge, in July 2023, the Bulgarian Parliament decided to direct the Bulgarian Minister of Energy to negotiate the terms by which a Bulgarian government-owned company would acquire up to 20% of the interests in the Block. Further thereto, in October 2024, OMV Bulgaria received a letter from the Bulgarian Ministry of Energy, requesting information, *inter alia*, with respect to the work programs, technical data and technical-economic analyses in relation to the project. It is clarified that to the best of the Partnership's knowledge, as of the report approval date, discussions are being held on this issue between OMV Bulgaria and the Bulgarian government, and it is impossible to predict what the outcome thereof will be or whether the Bulgarian

Parliament or Ministry of Energy will make additional decisions in the future in relation to this issue and/or on other matters that may affect the project or the Partnership's interests in the project.

3. Under the presently applicable fiscal regime in Bulgaria, the corporate tax rate imposed on taxable income is 10%.

(c) The following tables present calculations of the rates actually attributed to the holders of the Partnership's equity interests in the Project Expenses and the revenues from the Block.

Participation Rate	Pre-Investment Recovery Percentage	Post-Investment Recovery Percentage	Pre-Investment Recovery Rate in 100% terms	Post-Investment Recovery Rate in 100% terms	Explanations
Rate of the Block actually attributed to the Partnership's equity interest holders	47.5%	47.5%	100%	100%	See the description in Section 7.8.3 above.
Rate of revenues from the Block with overriding royalties actually attributed to the Partnership's equity interest holders	44.18%	28.74%-41.8%	93%	60.5%-88%	See the calculation in Section 7.8.3 above.
Rate of revenues from the Block, excluding overriding royalties, actually attributed to the Partnership's equity interest holders	33.25%-46.31%		70%-97.5%		See the calculation in Section 7.8.3 above.
Actual rate of participation by the Partnership's equity interest holders in expenses entailed by the exploration, development and production operations in the Block	47.975%-48.45%	47.975%-48.45%	101%-102%	101%-102%	See the calculation in Section 7.8.3 above.

Item	Percentage	Concise Explanation on the Royalty or Payment Calculation Method
Theoretical expenses of the Block	100%	
List of Payments (deriving from Expenses) at Block level:		
Operator	1%-2%	See Section 7.8.8(b) below.
Total actual expense rate at Block level	101%-102%	
Partnership's equity interest holders' rate of Block expenses (indirectly)	47.5%	After funding the operator's share, as specified in Section 7.8.5(a)1 above.
Partnership's equity interest holders' total actual rate of the expenses, at Block level (and before other payments at Partnership level)	47.975%-48.45%	
List of Payments (deriving from Expenses) in connection with the Block and at Partnership level (the following percentages will be calculated according to the rate of the Block of the holders of the Partnership's equity interests):		
Rate actually attributed to the Partnership's equity interest holders in the expenses entailed by the exploration, development and production operations in the Block	47.975%-48.45%	

7.8.6. Material operations previously executed in the Block

To the best of the Partnership's knowledge, over the years, the partners in the Block conducted various exploration operations, the principal among which are listed in the following table.

Activity	Period of Execution of the Activity	Concise Description of the Activity	Concise Description of the Results of the Activity
Polshkov-1 Exploration Well	2016	Examine the existence of hydrocarbons in the Polshkov Structure	The amount of petroleum discovered did not merit development at the time
Rubin-1 Exploration Well	2017	Examine the existence of hydrocarbons in the Rubin Prospect	Dry well
Melnik-1 Exploration Well	2019	Examine the existence of hydrocarbons in the Melnik Prospect	Dry well
Acquire, process and interpret a 3D seismic survey	2020-2024	Conduct a 3D seismic survey by Shearwater, processing by DUG and interpretation by the license holders	Identification of prospects and leads in the area of the license, and, *inter alia*, the Vinekh prospect and other prospects and leads, including the Krum prospect

To the best of the Partnership's knowledge, according to data presented by OMV Bulgaria, aggregate investments in exploration operations in the Block since the license was granted in 2012 have totaled approx. €387 million

7.8.7. Actual and planned work program in the Block

To the best of the Partnership's knowledge, by the report approval date, the partners in the Block have complied with their obligations with respect to the work program specified in the terms of the license, and there is currently no further work program by which the partners are bound.

Under the Interests Acquisition Agreement, the parties plan to drill the First Well in the Vinekh prospect in Q4/2025, following which the partners will make a decision regarding the drilling of the Second Well in 2026 (prior to expiration of the license in October 2026), either as the first appraisal well in the Vinekh prospect in the event that the First Well proves successful, or as an exploration well in another prospect within the area of the Block. Of note, the Second Well may be an exploration well in a different prospect, even if the First Well in the Vinekh prospect proves successful and ends with a discovery.

The following table presents a concise description of the activities planned in the Block, noting the estimated budget for the conduct of every activity and the share of the holders of the Partnership's equity interests in such budget, assuming a successful scenario in the First Well.

Bulgaria License			
Period	Concise Description of Activities Actually Performed for the Period or of the Planned Work Program	Total Estimated Budget for Activity at the Block Level ($ in thousands)	Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)[67]
2025	• Identification and characterization of prospects and leads in the area of the license.	Approx. 1,100	Approx. 550
	• Drilling of the Vinekh-1 exploration well and performance of production tests (assuming a discovery).	Approx. 113,000	Approx. 80,000
	• Preparations for the Second Well.	Approx. 10,300	Approx. 10,300
	• Planning for future wells.	Approx. 4,100	Approx. 2,050
	• Preliminary engineering work related to possible development design of the discovery or discoveries, if any.	Approx. 3,100	Approx. 1,550

[67] Including participation in the operator's share, as specified in Section 7.8.2(a) above, and participation in Mr. Abu's share, as specified in Section 7.8.5(a)2 above.

Bulgaria License			
Period	Concise Description of Activities Actually Performed for the Period or of the Planned Work Program	Total Estimated Budget for Activity at the Block Level ($ in thousands)	Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)[67]
	• Operating expenses, *inter alia*, on environmental, regulatory and project management aspects.	Approx. 4,900	Approx. 2,450
2026	• Drilling of the Second Well.	Approx. 101,000	Approx. 71,300
	• Depending on the results of the wells, drilling of additional (exploration and/or appraisal) wells.	Approx. 137,500	Approx. 65,300
	• Continued identification and characterization of prospects and leads in the area of the license.	Approx. 2,700	Approx. 1,300
	• In the event of discovery of an economically viable reservoir, initial engineering design work prior to the adoption of a development decision.	Approx. 10,300	Approx. 4,900
	• Operating expenses, *inter alia*, on environmental, regulatory and project management aspects.	Approx. 4,900	Approx. 2,300
2027 forth	• Depending on the results of the wells, drilling of additional appraisal wells.		
	• Continued identification and characterization of prospects and leads in the area of the license.		
	• In the event of discovery of an economically viable reservoir, adoption of a development decision.		

Caution concerning forward-looking information – The information concerning the activities planned in the Block, including as relating to costs, timetables and mere execution thereof, constitutes "forward-looking information" within the meaning thereof in the Securities Law, which is based on information that has formed with the Partnership at the time hereof and which is primarily based on information and assessments of the Seller provided to the Partnership during the negotiations and the due diligence reviews. Actual execution of the planned activities, including the timetables and costs, may materially differ from the aforesaid information, and this is contingent, *inter alia*, upon market conditions, regulation, numerous external circumstances, technical needs, technical ability, new discoveries to be found and economic viability. Furthermore, closing the transaction is subject to satisfaction of the remaining Closing Conditions.

7.8.8. Joint Operating Agreement (JOA)

An agreed version of the JOA that is expected to be signed on the date of the transfer of the interests in the Block and to apply between the parties in relation to the management of the Block, was attached to the

Interests Acquisition Agreement, which JOA includes, *inter alia*, the following key provisions:

(a) OMV Bulgaria will continue to serve as the operator.

(b) The operator will be entitled to reimbursement of all direct expenses to be incurred thereby in relation to the performance of its function as operator and to reimbursement of indirect expenses that derive from the amount of expenditure of the joint venture according to the type of activity in the Block, as specified below (with the annual payment for indirect expenses being no less than €200,000 under any circumstances):

1. At the exploration stage, the rate of the indirect expenses shall be 2% of the direct expenses.

2. At the development stage, the rate of the indirect expenses shall be 1.5% of the direct expenses.

3. At the production stage, the rate of the indirect expenses shall be 1% of the direct expenses.

(c) Under the agreement, an operating committee composed of the partners' representatives will be appointed, which will be tasked with and have the power of approval and oversight of the joint operations. Unless otherwise stipulated, all decisions, approvals and other acts of the operating committee with respect to all the proposals presented thereto shall be decided by a positive vote of two or more (non-related) parties holding together, at the time of the vote, at least 65% of all working interests.

(d) The JOA lists matters that require a unanimous vote by all the partners, including extension of the term of the concession; decisions related to drilling activities, and *inter alia*, the deepening, review or completion of exploration wells (over and above the minimum commitments), appraisal wells or development wells; termination of the concession or waiver of any part of the concession area; and consolidation with the area of an adjacent petroleum asset.

(e) The JOA sets out a process for submission and approval of work programs, budgets and authorizations for expenditure (AFEs) for the conduct of activities in areas governed by the agreement. Under the JOA, the parties have agreed on an initial work program and budget until the end of 2026, as specified in Section 7.8.7 above.

(f) The JOA specifies additional provisions on additional matters as per the standard in agreements of this type, including provisions with respect to exclusive operations, sanctions on the parties and conditions for imposition thereof, certain restrictions on the transfer of rights, withdrawal from the agreement, production-related rights and obligations, provisions in case of change of control, etc. The JOA is governed by UK Law and any dispute pertaining thereto shall be resolved by arbitration under the rules of the ICC in Paris.

7.8.9. Prospective resources data

For details about prospective resources in relation to the Vinekh prospect, as of 30 November 2024, and about the planned exploration well in the Vinekh prospect, see the Partnership's immediate report of 28 November 2024 (Ref. 2024-01-620288), the information in which is hereby incorporated by reference. As of 31 December 2024, such details remain unchanged. NSAI's consent to the inclusion of the said report herein, including by way of reference, and a letter of no material changes in the Vinekh prospect from NSAI, are attached hereto as **Annex D**.

The resources specified in the resources report are located within the area of the Block. The reservoir, if discovered, may overflow into the EEZs of nearby countries. For details regarding the "reservoir overflow" risk factor, see Section 7.30.32 below.

7.9 Discontinued operations

Below are details regarding petroleum assets, the activity in which was discontinued in recent years:

7.9.1 Eran License

In the past, the Partnership held approx. 22.67% of the interests in the Eran License, which expired on 14 June 2013. Following the decision of the Petroleum Commissioner not to extend the Eran License, on 3 October 2013, the Partnership and the other interest holders in the Eran License submitted an appeal to the Minister of Energy from the decision of the Petroleum Commissioner as aforesaid. On 10 August 2014, the Minister of Energy denied the appeal. On 17 November 2014, the holders of the interests in the Eran License (including the Partnership) filed a petition on this decision with the High Court of Justice. On 2 June 2016, the High Court of Justice entered a decision on the parties' agreement to defer to a mediation proceeding as proposed thereby. With the parties' consent, (Ret.) Chief Justice of the Supreme Court, A. Grunis, was appointed as mediator. At the end of the mediation proceeding, the parties reached agreements that were established in a mediation arrangement. On 20 March 2019, this mediation arrangement was filed with the court, which was moved to enter a judgment on the arrangement. In the mediation arrangement, the parties to the mediation agreed (with the consent of the Tamar Partners) on the division of the Tamar SW reservoir between the area of the Tamar Lease (78%) and the area of the Eran License (22%). It was further agreed that the interest in the area of the Eran License would be divided at a ratio of 76% to the State and 24% to the holders of the interests in the Eran License prior to its expiration (proportionately to their holding rate in the license). On 11 April 2019, a judgment was entered on the mediation arrangement agreed to by the parties, as aforesaid. Negotiations are conducted between the Tamar Partners and the State of Israel and the holders of the interests in the Eran License, regarding the manner of regulation of the rights of the State and the holders of the interests in the Eran License on other related matters, but as of the report approval date, the parties have not yet reached agreements on how to implement the mediation arrangement, as specified above.

7.9.2 <u>Tamar project (Tamar Lease (I/12) and Dalit Lease (I/13))</u>

In accordance with the Gas Framework, on 9 December 2021, the transaction for the sale of the Partnership's remaining interests in the Tamar and Dalit Leases was closed, in accordance with the sale agreement, as specified in Section 7.24.13 of Chapter A of the Partnership's 2022 periodic report, which was released on 28 March 2023 (Ref.: 2023-01-033096) (the "**2022 Periodic Report**"). For further details regarding the closing of the transaction, see the Partnership's immediate reports of 6 December 2021 and 9 December 2021 (Ref.: 2021-01-176682 and 2021-01-178137, respectively), the information in which is incorporated herein by reference. See also Notes 7C1 and 10E to the financial statements, which were attached to the 2022 Periodic Report.

7.9.3 <u>New Ofek license</u>

In the past, the Partnership held 25% of the interests in the onshore 405/New Ofek license, which expired on 20 June 2022. On 7 November 2024, the partners in this license received a letter from the Petroleum Commissioner, according to which, *inter alia*, abandonment of the well must be completed by 31 March 2025. As of the report approval date, the operator in this license, S.O.A. Energy Israel Ltd. ("**SOA**"), has informed the Partnership that the preparation work ahead of the plugging and abandonment of the well has begun, and that it is in contact with the Petroleum Commissioner in connection with the timetables for completion of the said work.

7.10 <u>Renewable energies</u>

On 21 September 2022, the general meeting of the unitholders authorized the Partnership to make investments in renewable energy projects, up to an aggregate investment amount (the Partnership's share only) of $100 million (by way of capital and/or shareholder loan, including a capital note or by way of a guarantee for loans to be provided), as required by the TASE Rules, and in this context an outline was approved for the collaboration with Enlight as specified below, considering, *inter alia*, the personal interest in the transaction of Mr. Abu. For further details see the Partnership's immediate reports of 6 September 2022 and 21 September 2022 (Ref. 2022-01-092520 and 2022-01-120358, respectively), the information appearing in which is included herein by reference.

As of the report approval date, the Partnership's renewable energies operations are carried out in the framework of the collaboration with Enlight, as specified below:

7.10.1 On 13 March 2023, the Partnership engaged with Enlight in a detailed agreement regarding exclusive collaboration for a fixed term regarding the identification, initiation, development, financing, construction and operation of renewable energy projects, including in the following areas: solar projects, wind projects, energy storage, and other renewable energy segments, if they will be relevant in several target countries, including Egypt, Jordan, Morocco, the UAE, Bahrain, Oman and Saudi Arabia (in this section: the "**Collaboration Agreement**" and the "**Target Countries**", respectively).

According to the Collaboration Agreement, Enlight and the Partnership established Medlight, which is controlled by the Enlight Corporation, as specified in Section 1.7.9 above.

Concurrently with the signing of the Collaboration Agreement, Enlight and Mr. Abu signed an agreement under which Enlight allotted to Mr. Abu 30% of the Enlight Corporation's share capital. According to the agreement signed between the parties, Mr. Abu's share in the investments required in the Enlight Corporation will be provided for him by Enlight by way of provision of a non-recourse loan.

The Collaboration Agreement determined, *inter alia*, the following provisions:

(a) The parties will act together for the identification, initiation, development, financing, construction and operation of renewable energy projects in the Target Countries (in this section: the "**Joint Venture**"). For the purpose of the Joint Venture, the parties will form corporations that will engage in the promotion of the joint operations (the "**Co-Owned Corporations**").

(b) As part of the Joint Venture, the Partnership will utilize its business connections in the Target Countries to promote the Joint Venture, with Mr. Abu's active personal involvement. The Enlight Corporation, via Enlight, will provide the joint operations with professional design, development and management services in the interest of promoting the Joint Venture.

(c) Control during the projects' construction and operation stages will be held by Enlight. The agreement stipulates provisions with respect to the parties' rights to appoint board members of the Co-Owned Corporations based on their holding rates, and it also stipulates that Mr. Abu will serve as chairman of the board of the Co-Owned Corporations in the first 24 months.

(d) In the context of the Joint Venture, one of the Co-Owned Corporations will perform feasibility studies and due diligence for any project it deems suitable for the collaboration and thereafter, each party will notify the other party whether it wishes to participate and promote the proposed project in the context of the Joint Venture. If the Partnership does not approve its participation in a specific project or objects to its promotion, Enlight will be entitled to perform the project independently, without the Partnership, in which case the Partnership will be entitled to reimbursement of its expenses in the aforesaid project together with interest.

(e) In the Agreement it has been agreed that resolutions of the Co-Owned Corporations will be adopted by a majority vote, subject to the requirement of the Partnership's consent in certain resolutions, so long as the Partnership holds 15% or more of the capital of the Co-Owned Corporations. Provisions have also been specified with respect to the manner of financing of the operations of the Joint Venture and the investments in projects to be made thereunder, based on the relative share of each of the parties.

(f) The term of the parties' exclusive collaboration will be 3 years from the Agreement signing date, which, under certain circumstances, may be extended up to a term of five years from the Agreement signing date (the "**Term of Exclusivity**"). Following the expiration of the Term of Exclusivity, the collaboration will continue with respect to projects that shall have commenced prior to the expiration date, and Enlight may promote projects that are in advanced development stages without the Partnership's participation.

(g) The Agreement specifies additional provisions on other matters, as is standard in transactions of this type, *inter alia*, with respect to resolutions requiring the Partnership's consent, so long as the Partnership holds 15% or more of the equity of the Co-Owned Corporations, provisions on the restrictions that will apply to the transfer of interests in the Co-Owned Corporations to third parties, early termination of the Term of Exclusivity, provisions regarding the joining of third parties to the projects and provisions regarding the Co-Owned Corporations' profit distribution policy.

7.10.2 On 9 March 2025, MedLight engaged with a local partner in Morocco (a third party not affiliated with the Partnership or Enlight, in this section:

the "**Partner**") in a series of agreements for the establishment of two project companies for the development and construction of two renewable energy projects in Morocco (in this section: the "**Agreements**"): (a) A photovoltaic project for the production of power from solar energy with a capacity of approx. 300 MW; and (b) a project for the production of power from wind energy with a capacity of approx. 200 MW (in this section: the "**Projects**").

Under the Agreements, MedLight will be allotted 75% of the share capital of the project companies, and the rest of the shares (25%) will be held by the Partner. MedLight has undertaken to inject capital into the project companies through a shareholder loan, according to agreed milestones, in the aggregate amount (for both Projects) of approx. €25 million (subject to certain adjustments). Furthermore, MedLight has been given the option to acquire the remainder of the Partner's holdings by the date of commercial operation of the Projects, and the Partner has been given the option to sell its holdings to MedLight during the period beginning on the commercial operation date and ending at the lapse of five years from that date.

The Agreements stipulate additional provisions, *inter alia*, with respect to services the Partner will provide for the Projects until they reach the 'Commercial Operation Date', and provisions that determine the parties' rights as shareholders of the project companies, including refusal right, tag-along right, drag-along right and BMBY mechanisms, provisions pertaining to the appointment of board members and corporate governance, certain veto rights to be afforded to the Partner, restrictions on share transfers, and other matters, as is standard in transactions of this type.

According to the timetables agreed between the parties, financial closing of the Projects is scheduled for 2027-2028, and commercial operation is scheduled for 2029-2030. For the avoidance of doubt, it is clarified that as of the report approval date, at this preliminary stage, there is no certainty that the Projects will come to fruition or reach the commercial operation stage, *inter alia*, because development of the Projects requires approvals by third parties and local authorities, over which the Partnership has no control.

Caution concerning forward-looking information – The information specified above in connection with the potential renewable energy projects in Morocco, including their capacity and the possible timetables for their development and operation, constitutes forward-looking information, as defined in the Securities Law, the materialization of which is uncertain and beyond the Partnership's exclusive control. The said information is primarily based on the commercial agreements reached by the parties and assessments performed by or on behalf of MedLight in relation to the feasibility of the Projects, which may fail to materialize or materialize in a

materially different manner due to factors beyond the Partnership's control, including due to delays in obtaining the permits required for construction of the Projects and/or due to the materialization of any of the risk factors specified in this report.

7.10.3 As of the report approval date, MedLight is exploring and promoting other potential renewable energy projects.

7.11 **Products**

7.11.1 Natural Gas

The vast majority of the natural gas discovered in the reservoirs held by the Partnership is comprised of methane gas and is therefore defined as "dry", even though upon production and processing, small quantities of liquid separate therefrom. Therefore, the required treatment of the gas for the purpose of supply to customers is relatively minimal.

As a rule, natural gas is transportable in three main ways: (a) through pipelines; (b) through the liquefaction thereof (i.e., the turning thereof into liquid, LNG) by the cooling thereof to a temperature of 161 degrees Celsius below zero, which decreases its volume by a factor of 600 and allows the transportation and storage thereof in large quantities; and (c) through the compression thereof (CNG), which decreases its volume by a factor of 100-300, depending on the compression pressure.

LNG and CNG may be transported in large quantities over great distances by means of specifically-designated tankers.

For details regarding the domestic gas market, including developments and changes therein, see Section 6 above, and for details regarding the natural gas export and sale on the international market, see Section 7.13.2 below.

7.11.2 Condensate

The process of production and treatment of natural gas also produces condensate as a byproduct, which is a product of condensation of various hydrocarbon components of natural gas. Condensation is caused as a result of temperature and pressure differences between the reservoir and the gas processing systems. The condensate produced from the Leviathan project requires minimal treatment, and mainly stabilization, to enable transportation thereof to the customers, where it mainly serves as feedstock for the production of refined oil products. The amount of condensate produced compared with the quantity of gas produced from the Leviathan project is relatively small, and is a few barrels per million cubic feet of natural gas (MMCF). For details regarding the engagements of the Partnership, together with its partners, in agreements in relation to the supply of condensate from the Leviathan project, see Section 7.12.4 below.

7.12 Customers

7.12.1 General

As of the report approval date, the Partnership, together with its partners in the Leviathan project, supplies natural gas produced from the Leviathan reservoir, to independent power producers, marketing companies and industrial customers in the domestic market, and exports natural gas to its customers in Jordan and in Egypt. At the same time, the Partnership continues to conduct various stages of negotiations with other potential customers in the domestic market and in the export markets.

7.12.2 Key customers

In 2024, NEPCO in Jordan and Blue Ocean in Egypt were the largest customers of the Leviathan reservoir. The Partnership's revenues from the sale of gas from the Leviathan project in 2024 to NEPCO and Blue Ocean were approx. 26% and approx. 62%, respectively, of the Partnership's total revenues from the Leviathan project. The agreements signed between the Leviathan Partners and NEPCO and Blue Ocean are long-term agreements and termination or non-fulfilment thereof may materially affect the Partnership's business and future revenues. The Partnership's other revenues from the Leviathan reservoir in 2024 originated from sales in Israel to independent power producers, industrial customers and natural gas marketing companies.

7.12.3 Engagements for the supply of natural gas from the Leviathan project

Below are concise details regarding the agreements for the supply of natural gas from the Leviathan project which were signed by the Partnership, together with the other Leviathan Partners, that are valid as of the report approval date[68].

[68] The figures in the table do not include agreements for the supply of natural gas from the Leviathan project on an interruptible basis.

Customer	Supply commencement year	Agreement period[69]	Total maximum contract quantity for supply (100%) (BCM)	Total quantity supplied until 31 December 2024 (100%) (BCM)	Main linkage basis of the gas price
Independent power producers[70]	2020, or the date of commencement of the commercial operation of the purchasers' power plant (whichever is later).	The agreements are for a long term of 9 to 25 years. Some of the agreements grant each of the parties an option for extension of the agreement in the event that the total quantity determined in the agreement is not purchased.	Approx. 17.1	Approx. 3.3	In most of the agreements the linkage formula of the gas price is based on electricity prices (the Electricity Production Tariff and the TAOZ Index) and includes a "floor price". One of the agreements determines a fixed price without linkage.
Industrial customers	2020	The agreements are for a period of 2.5 to 15 years. In most of the agreements the parties are not granted an option to extend the agreement period.	Approx. 4.2	Approx. 1.1	The linkage formula in most of the agreements is based in part on linkage to the Brent prices and in part to the Electricity Production Tariff, and includes a "floor price". There is partial linkage also to the crack spread index and to the TAOZ Index. Several agreements determine a fixed price without linkage.
NEPCO export agreement (described in Section 7.12.3(b) below)	2020	15 years. The agreement stipulates that in the event that the purchaser does not buy the total contract quantity, the supply period will be extended by another two years.	Approx. 45	Approx. 12.7	The linkage formula is based on linkage to the Brent prices and includes a "floor price".
Blue Ocean export agreement (described in Section 7.12.3(c) below)	2020	15 years. The agreement stipulates that in the event that the purchaser does not buy the total contract quantity, the period of the supply will be extended by another two years.	Approx. 60	Approx. 23.5	The linkage formula is based on linkage to the Brent prices, and includes a "floor price". The agreement includes a mechanism for updating the price by up to 10% (up or down) after the fifth year and after the tenth year of the agreement, upon fulfillment of

[69] In most of the agreements, the gas supply period may end on the date of supply to the customers of the maximum contract quantity set forth in the agreement.
[70] Including engagement in an agreement that was signed on 23 May 2024 between the Leviathan Partners and Eshkol Power Energies Ltd. for the supply of an aggregate annual volume of ~0.5 BCM of natural gas, as specified in the Partnership's immediate report of 23 May 2024 (Ref.: 2024-01-050965), the information in which is included herein by reference.

Customer	Supply commencement year	Agreement period[69]	Total maximum contract quantity for supply (100%) (BCM)	Total quantity supplied until 31 December 2024 (100%) (BCM)	Main linkage basis of the gas price
					certain conditions determined in the agreement.
Total			Approx. 126	Approx. 40.5[71]	

Caution regarding forward-looking information – the information specified in the table above in relation to the overall financial scope of the supply agreements, natural gas quantities and supply periods, constitutes forward-looking information within the meaning thereof in the Securities Law, which there is no certainty will materialize, in whole or in part and which may materialize in a materially different manner, due to different factors that are beyond the Partnership's control, including changes in the scope, rate and timing of consumption of natural gas by the gas consumers, exercise of options granted to customers in the supply agreements and the date of exercise thereof, and additional factors that are beyond the control of the Leviathan Partners.

<u>The following table includes a breakdown of the Partnership's revenues from the Leviathan reservoir in 2023-2024</u>:

	Y2024		Y2023	
Name of Customer	Total Revenues ($ in million)	% of Total Revenues	Total Revenues ($ in million)	% of Total Revenues
Independent Power Producers				
Other	Approx. 97	Approx. 8	Approx. 125	Approx. 11
Industrial Customers and Marketing Companies				
Other	Approx. 45	Approx. 4	Approx. 43	Approx. 4
Natural Gas Export				
NEPCO	Approx. 291	Approx. 26	Approx. 296	Approx. 27
Blue Ocean	Approx. 703	Approx. 62	Approx. 630	Approx. 58

(a) <u>Further details regarding the agreements for the sale of natural gas from the Leviathan reservoir to independent power producers and industrial customers in the domestic market</u>

[71] The total quantity supplied from the Leviathan project until 31 December 2024 (100%) (under the agreements specified in the table, under spot agreements and under agreements that have expired) is ~51.5 BCM.

1. In 2024 and until the report approval date, the Partnership signed several agreements for the sale of natural gas from the Leviathan project with various customers in the Israeli market, both on a firm basis and on an interruptible (spot) basis.

2. In all of the natural gas sale agreements, with the exception of spot agreements (in this section: the "**Agreements**"), the customers have undertaken to buy or pay for ("Take or Pay") a minimal annual quantity of natural gas at the scope and according to the mechanism determined in the supply agreement (the "**Minimum Quantity**"). Provisions and mechanisms have been established in the Agreements to allow each of such buyers, after it pays for natural gas not consumed thereby under the Agreement by operation of the aforesaid Minimum Quantity mechanism, to receive gas for no additional payment, up to the unconsumed quantity of gas for which it paid, in the years following the year in which the payment was made, and subject to consumption of the minimum quantity in each one of the said subsequent years. The Agreements further establish a mechanism for accrual of a balance in respect of surplus quantities (over and above the "Take or Pay") consumed by the buyers in any given year and use thereof to reduce the buyers' obligation to purchase the Minimum Quantity as aforesaid for several years later.

3. The Agreements provide for additional provisions, *inter alia*, on the following issues: The right to terminate the Agreement in the case of breach of a material undertaking, the Leviathan Partners' right to supply gas to the said buyers from other natural gas sources, compensation mechanisms in the case of failure to supply the quantities set forth in the Agreement, limits on the liability of the parties in the Agreement, and in relation to the relationship between the sellers amongst themselves with respect to the supply of gas to the said buyers.

4. In accordance with the terms and conditions of the Gas Framework, each of the buyers under Agreements signed by 13 June 2017 for a term exceeding 8 years, was given an option to reduce the Minimum Quantity to a quantity equal to 50% of the average annual quantity that it actually consumed in the three years preceding the date of the option exercise notice, subject to adjustments as determined in the supply agreement. Upon reduction of the Minimum Quantity, the other quantities determined in the supply agreement will be reduced accordingly. Each of the said buyers may exercise such option by giving the sellers a notice during the 3-year period commencing 5 years after the date of first gas from the Leviathan project to the buyer. If the buyer gives such option

exercise notice, the quantity shall be reduced 12 months after the date of the giving of the notice.

(b) Agreements for the export of gas from the Leviathan reservoir to Jordan

1. On 26 September 2016, an agreement was signed for the supply of natural gas between NBL Jordan Marketing Limited (the "**Marketing Company**") and the national electric company of Jordan (NEPCO) (the "**Export to Jordan Agreement**"). The Marketing Company is a wholly owned subsidiary of the Leviathan Partners, including the Partnership, which hold it proportionately to the rate of their holdings in the Leviathan project.

   According to the Export to Jordan Agreement, the Marketing Company undertook to supply to NEPCO natural gas for a period of approx. 15 years from the date of commencement of the commercial supply or until the total supply volume would be approx. 45 BCM. The supply according to the Export to Jordan Agreement began on 1 January 2020.

   The gas delivery point according to the Export to Jordan Agreement is at the connection between the Israeli transmission system and the Jordanian transmission system at the border between Israel and Jordan. In December 2019, INGL completed the construction of the Israeli transmission system up to the border between Israel and Jordan at a cost of approx. $109 million (100%).

   NEPCO has undertaken to 'take or pay' for a minimum annual quantity of gas, at the scope and according to the mechanism as determined in the Export to Jordan Agreement. In addition, in connection with NEPCO's 'take or pay' undertaking, the agreement sets forth, *inter alia*, provisions and a mechanism that allow NEPCO, after it has consumed the minimum billable quantity for a certain year, to receive in such year, a supply of gas for no additional payment up to the remaining gas quantity not consumed in previous years and for which it paid consideration to the Marketing Company in the context of the 'take or pay' undertaking (makeup mechanism), as well as provisions and a mechanism that allow NEPCO to accumulate quantities purchased in any year over and above the minimum quantity, and to utilize the same to reduce its undertaking (carry forward mechanism).

   The gas price determined in the agreement is based on a price that is linked to the Brent oil barrel prices, and includes a "floor price" plus a marketing fee, a transmission fee and NEPCO's bearing the cost of the transmission payments to INGL. On the signing date, the Leviathan Partners estimated that the aggregate scope of the revenues from the sale of natural gas to NEPCO may amount to approx. $10 billion, assuming that NEPCO consumes the total contract quantity, and based on the Partnership's estimate with respect to the natural gas price during the term of the agreement.

2. On 9 November 2016, the Leviathan Partners and the Marketing Company signed a back-to-back GSPA (the "**Back-to-Back GSPA**"), whereby the amounts that shall be received, the liabilities, the risks and the costs relating to the Export to Jordan Agreement will be endorsed to the Leviathan Partners under the same terms (back-to-back), as if the Leviathan Partners were a party to the Export to Jordan Agreement instead of the Marketing Company.

3. On 14 April 2020, an Offtake Intercreditor and Security Trust Deed was signed between the Marketing Company, the Leviathan Partners and HSBC Corporate Trustee Company (UK) Limited ("**HSBC**"), which deed is intended to secure the Marketing Company's undertakings vis-à-vis the Leviathan Partners under the Back-to-Back GSPA, according to which HSBC was appointed as trustee for the collateral and undertakings by virtue of the Export to Jordan Agreement.

4. On 3 July 2023, the parties agreed to increase the natural gas quantities that would be supplied to NEPCO on a firm basis, temporarily and in relation to a number of months in 2023-2024, and that the minimum annual quantity that NEPCO had undertaken to take or pay for during 2023-2024 would increase accordingly. The aforesaid does not change the total supply volume under the Export to Jordan Agreement (approx. 45 BCM), as specified above.

5. In October 2024, an agreement was signed between the Marketing Company and FAJR for the supply of a total volume of ~2.5-3 BCM of natural gas for a period of 10 years. The gas price formula determined in this agreement is based on linkage to the Brent prices and includes a "floor price". The agreement is also contingent on obtaining the required regulatory approvals in Israel, including export approval from the Petroleum Commissioner, and in Jordan, the signing of a transmission agreement with INGL which will allow transmission of the quantities under the agreement, and obtaining a tax ruling. As of the report approval date, the export approval for this agreement has not yet been received and supply of the gas thereunder has not yet begun.

Caution regarding forward-looking information – the information specified above regarding the total financial scope of the engagement for supply of natural gas to NEPCO and the quantity of natural gas that may be purchased under such engagement, constitutes forward-looking information within the meaning thereof in the Securities Law, which there is no certainty will materialize, in whole or in part, in the manner specified above or in any other manner, and may materialize in a materially different manner than described above, due to various factors including changes in the scope, pace or timing of the natural gas consumption by NEPCO, a change in the gas price as a result of a change in the Brent oil barrel price, etc.

(c) Agreement for export of gas from the Leviathan reservoir to Blue Ocean in Egypt

1. Further to previous engagements with Blue Ocean, on 26 September 2019, an agreement for the supply of natural gas to Egypt was signed between the Leviathan Partners and Blue Ocean (the "**Export to Egypt Agreement**"), and at the same time, an agreement was signed between the Leviathan Partners and the Tamar Partners in connection with the allocation of the available capacity in the transmission system from Israel to Egypt and the bearing of the investments entailed by the purchase and refurbishment of this pipeline (for further details, see Section 7.26.6(d) below). The supply of natural gas to Egypt from the Leviathan reservoir according to the agreement began on 15 January 2020.

2. Below is a concise description of the main terms and conditions of the Export to Egypt Agreement:

   (a) The total contract gas quantity the Leviathan Partners undertook to supply the buyer, on a firm basis, is ~60 BCM (the "**Total Contract Quantity**").

   (b) The gas supply, which began on 15 January 2020, will continue until 31 December 2034 or until the supply of the full Total Contract Quantity, whichever is earlier (the "**Supply Period**"). In the event that the buyer does not purchase the Total Contract Quantity, each party will be entitled to extend the Supply Period by two additional years.

   (c) The Leviathan Partners undertook to supply the buyer with daily gas quantities as follows: (1) in the period commencing 15 January 2020 and ending 30 June 2020 – 200 MMCF per day (~2.1 BCM per year); (2) in the period commencing 1 July 2020 and ending 30 June 2022 – 350 MMCF per day (~3.6 BCM per year); and (3) in the period commencing 1 July 2022 and ending upon the conclusion of the Supply Period – 450 MMCF per day (~4.7 BCM per year). Furthermore, the agreement includes provisions with respect to the possibility of transmitting additional gas quantities, over and above the aforesaid daily quantities, on an interruptible (spot) basis. For details regarding the export of gas to Egypt via the EMG pipeline and through Jordan via the Jordan-North Export Pipeline and the Jordanian transmission system, see Section 7.13.2(b) below. The export agreement prescribes provisions whereby in cases of a shortfall in the supply of the daily gas quantities in a certain month, the buyer is entitled, under certain conditions, to compensation in the form of a discount on the gas that shall be supplied thereto in the following month, at a rate determined, *inter alia*, as a function of the rate of the supply shortfall in the current month.

The buyer undertook to buy or pay for (Take or Pay, TOP) quarterly and annual quantities, in accordance with the mechanisms set forth in the Export to Egypt Agreement, which, *inter alia*, allow the buyer to reduce the TOP quantity in a year in which the average daily Brent price (as defined in the agreement) shall have fallen below $50 per barrel, such that it will be 50% of the annual contract quantity. Insofar as the contract quantity is reduced in case of failure to agree on the gas price update, as stated in Subsection (e) below, the buyer's aforesaid right to reduce the TOP quantity will be revoked. The average Brent price in 2024, and the Brent barrel price shortly before the report approval date, were around $80, and approx. $70, respectively. In addition, in connection with the buyer's 'take or pay' undertaking, the agreement sets forth, *inter alia*, provisions and a mechanism that allow the buyer, after it has consumed the minimum billable quantity for a certain year, to receive in such year, a supply of gas for no additional payment up to the remaining gas quantity not consumed in previous years and for which it paid consideration to the sellers in the context of the 'take or pay' undertaking (makeup mechanism), as well as provisions and a mechanism that allow the buyer to accumulate quantities purchased in any year over and above the minimum quantity, and to utilize the same to reduce the buyer's undertaking (carry forward mechanism).

(d) The price of the gas that shall be supplied to the buyer will be determined according to a formula that is based on the Brent oil barrel price, and includes a "floor price". The Export to Egypt Agreement includes a mechanism for a price update of up to 10% (up or down) after the fifth year and after the tenth year of the agreement, upon fulfillment of certain conditions which were specified in the agreement. In a case where the parties fail to reach an agreement regarding the price update as described above, the Buyer will be entitled to reduce the contract quantity by up to 50% on the First Adjustment Date and by up to 30% on the Second Adjustment Date. The agreement includes an incentive mechanism that is quantity-contingent and subject to the oil barrel price.

(e) The Export to Egypt Agreement includes standard provisions pertaining to termination thereof, as well as provisions in case of termination of the export agreement signed between the Tamar Partners and Blue Ocean as a result of breach thereof, and the lack of consent of the Leviathan Partners to additionally supply the quantities under the aforesaid Tamar agreement, and also includes compensation mechanisms in such a case. For details regarding the engagement between the Tamar Partners and Blue Ocean for export of natural gas to Egypt, see Section 7.15.1(d) below.

3. Up to 31 December 2024, the Leviathan Partners supplied the buyer with ~23.5 BCM for total monetary consideration of approx. $5.1 billion. On the date of signing of the Export to Egypt Agreement, the Partnership estimated that the total amount of the contract (with respect to all of the Leviathan Partners) could total approx. $12.5 billion. This estimate was based, *inter alia*, on the assumption that the buyer will consume the Total Contract Quantity set forth in the agreement, as well as on various estimates regarding the prices of natural gas during the Supply Period. It is emphasized that the actual revenues will be derived from a gamut of factors, the majority of which are beyond the Partnership's control.

4. To facilitate an increase in the export quantities to Egypt, and in view of the delay in completion of the project for the new offshore transmission section between Ashdod and Ashkelon, as specified in Section 7.13.2 below, the Leviathan Partners and Blue Ocean signed an amendment to the Export to Egypt Agreement, in which it was agreed, *inter alia*, to define an additional gas delivery point in Aqaba, Jordan, under the Export to Egypt Agreement, in which a certain price discount was determined as compensation to Blue Ocean for the additional transmission expenses entailed by transmission of the gas from the additional delivery point, which are borne thereby. The transmission of gas to Egypt to the delivery point in Aqaba began in March 2022, and is performed through the Jordan-North Export Pipeline, as specified in Section 7.13.2 below.

As of the report approval date, the Leviathan Partners and Blue Ocean are conducting negotiations regarding additional gas quantities that shall be sold to Blue Ocean in a volume exceeding ~100 BCM.

Caution regarding forward-looking information – the above information regarding the amount of projected revenues under the Export to Egypt Agreement, and the natural gas quantities that may be sold to the Buyer, is based on various estimations, forecasts and assumptions made by the Partnership. These estimations constitute 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 that are beyond the Partnership's control, including due to changes in the scope, rate and timing of the natural gas consumption by the Buyer, changes in the gas price in accordance with the terms and conditions of the engagement and other factors that are not foreseeable on the report approval date and over which the Partnership has no control.

7.12.4 Agreements for the supply of condensate from the Leviathan reservoir

(a) General

As described in Section 7.11.2 above, condensate is a hydrocarbon liquid which is produced as a result of natural gas condensation. Since condensate is a byproduct of the production and processing of natural gas, the processes of production of the natural gas from the Leviathan reservoir require stabilization of the condensate and its transfer to a refinery.

(b) Agreement with ORL

On 15 December 2019, an agreement was signed whereby condensate produced from the Leviathan reservoir will be transmitted via EAPC's existing fuel pipeline to a container site of PEI in Kiryat Haim, and then transmitted from there to ORL's facilities, *inter alia*, according to regulatory directives.

The agreement signed with ORL is on an interruptible basis, up to a maximum quantity that was agreed between the parties, as shall be updated from time to time, in accordance with the terms and conditions determined by the authorities in this regard, for a term of 15 years from the date of commencement of flow in commercial quantities, with each party having the right to terminate the agreement by giving notice, no less than 360 days in advance, to the other party. In addition, each party may terminate the agreement on a shorter notice upon the occurrence of various events, including upon the occurrence of a breach event by the other party, and upon the occurrence of regulatory and other changes which will not allow the transmission of condensate according to the provisions of the agreement.

Pursuant to the agreement, the Leviathan Partners are not entitled to consideration for the supply of condensate to ORL, and the Leviathan Partners are obligated to bear any and all expenses, including the tax exposures, with respect to the condensate supply.

As specified in Paragraphs (c) and (d) below, on 7 March 2024, the Leviathan Partners began transmitting condensate via the pipeline to PEI and ARF, and consequently, from the said date, the quantities of condensate supplied to ORL under the said agreement have been significantly reduced.

In correspondence between the Leviathan Partners and ORL in Q1/2022, the Leviathan Partners communicated to ORL their claim that the absence of payment for the condensate supplied to ORL as noted above, constitutes prohibited abuse, in violation of the law, of ORL's power as a monopsony in the purchase of condensate. ORL responded in a letter rejecting the Leviathan Partners' claims. On 4 February 2024, the Leviathan Partners notified ORL that the transmission of the condensate to ARF was expected to commence in March 2024, and that from that date the quantities delivered to ORL would be significantly reduced. In response to this notice, ORL sent a letter to the Leviathan Partners, according to which the Leviathan Partners' said notice constitutes a breach of the agreement with ORL. It is the Partnership's position that ORL's said claims and demands are groundless, and accordingly the Leviathan Partners are exploring their next steps vis-à-vis ORL in this regard.

(c) Agreement with PEI

On 1 September 2022, Chevron (on behalf of the Leviathan Partners) and PEI signed an agreement designed to regulate an alternative mechanism for the transmission of condensate from the Leviathan project via an existing pipeline with a 6-inch diameter of PEI and the systems related thereto (in this section: the "**Pipeline**"). The agreement will be in effect for 20 years from the date of flow commencement, subject to provisions that confer on the parties the possibility of terminating it before the end of the term, under certain conditions. According to the agreement, PEI will be responsible for planning and carrying out the work for connection and adjustment of the Pipeline for the purpose of transmission of the condensate as aforesaid (the "**Connection Work**"), and for obtaining all the approvals for the transmission of condensate in the Pipeline and for the ongoing operation and maintenance of the Pipeline. Chevron (through the Leviathan Partners, according to their share in the

Leviathan Leases) has undertaken to bear the costs entailed by the Connection Work in accordance with the scope and the mechanism stipulated in the agreement, in amounts that shall be agreed by the parties in advance.

Each of the parties may terminate the agreement if the closing conditions are not met within 12 months from the date of signing or if the date of flow commencement is not within 12 months from the date the agreement takes effect.

During the transmission period, PEI will make the Pipeline available for Chevron's use (other than in emergencies, as defined in the agreement, in which the transmission of the condensate through the Pipeline will be temporarily halted), and reserve an agreed capacity in the Pipeline in exchange for fixed capacity fees as stated in the agreement. In addition, PEI will transmit the condensate through the Pipeline, in consideration for transmission fees as agreed in the agreement.

The connection work and the agreement took into account an increase in the quantity of the condensate that shall be transmitted in the pipeline deriving from operation of the third pipeline and from commencement of production in the context of Phase 1B.

The transmission of the condensate to PEI under the said agreement began on 7 March 2024.

(d) <u>Agreement with ARF</u>

On 18 January 2023, the Leviathan Partners, including the Partnership (in this section: the "**Sellers**"), engaged in an agreement with ARF for the sale of condensate to ARF (in this section: the "**Agreement**"). Below is a concise description of the main terms of the agreement:

1. According to the Agreement, the Sellers undertook to supply ARF with condensate produced from the Leviathan reservoir, to be transmitted through PEI's pipeline.

2. The Agreement determines, *inter alia*, provisions regarding restrictions on the maximum (daily and monthly) quantities of condensate to be supplied to ARF, fines in the event of a breach of the provisions of the Agreement, and additional provisions as is customary in agreements of this kind.

3. Transmission of the condensate to ARF will begin on the date of commencement of flow in PEI's pipeline (in this section: the "**Date of Flow Commencement**") and continue for a period of 4 years.

4. The price payable to the Sellers is determined according to the Brent oil barrel price, net of a staggered margin, as specified in the Agreement.

5. The Sellers estimate that the total revenues that the Sellers shall derive from the Agreement could total approx. $200-300 million (100%, the Partnership's share is approx. $90-135 million), based on the Brent price level on the report approval date. It is clarified that there is no certainty as to the amount of the revenues that the Partnership may derive from performance of the Agreement, and that the actual revenues will be derived from a gamut of factors, including the condensate quantities actually produced and sold to ARF, and the Brent prices.

The transmission of condensate to ARF under the said agreement began on 7 March 2024.

Caution regarding forward-looking information – the information provided above in relation to the agreement, including in respect of the amount of the revenues expected to derive from the Agreement, constitutes forward-looking information within its meaning in the Securities Law, and there is no certainty that it will materialize, in whole or in part, or it may materialize in a materially different manner due to various factors that are beyond the Partnership's control, including changes in the volume and rate of production of the condensate (as a derivative of the rate of gas production from the Leviathan reservoir), and the condensate price to be determined according to the Brent prices.

7.13 Marketing and Distribution

7.13.1 Supply to the domestic market

The Partnership, together with its partners in the Leviathan project, supplies natural gas and condensate to its customers in Israel, in accordance with the engagements described in Section 7.12.3 above. At the same time, the Leviathan Partners are conducting negotiations at various stages with other potential customers in the domestic market, including independent power producers and industrial consumers, subject, *inter alia*, to the supply capacity of the Leviathan project. Transmission of natural gas to some of the potential customers may also be contingent upon the continued development of the natural gas national transmission system by INGL, and the completion of the regional distribution systems.

As of the report approval date, the marketing of natural gas produced from the Leviathan reservoir to the customers is performed by way of joint marketing, in accordance with an exemption from certain provisions of the Economic Competition Law, 5748-1988 (the "**Economic Competition Law**"), which as signed on 17 December 2015 by the Prime

Minister in his then-capacity as Minister of the Economy, and according to supply agreements that were signed between the customers and all of the Leviathan Partners.

7.13.2 Export

(a) General

The Partnership, together with the Leviathan Partners exports natural gas to customers in Jordan and Egypt, in accordance with the engagements described in Section 7.12.3 above. At the same time, the Leviathan Partners are acting to identify additional potential customers and markets outside of Israel for the marketing of the natural gas. The Partnership estimates that the potential markets include the countries that are close to Israel (including the Palestinian market which currently purchases electricity from Israel, although, to the best of the Partnership's knowledge, there are also plans to build, on areas of the Palestinian Authority and in the Gaza Strip, power plants for the production of electricity), chiefly Egypt and Jordan, to which natural gas is exported via pipelines, and the more distant global markets to which it is possible to export natural gas via LNG and/or CNG. It is noted in this context that the Leviathan Partners are looking into the economic viability of potential projects for the export of natural gas via LNG (including liquefaction of natural gas via an FLNG facility), as specified above and below.

(b) Export via pipeline to Egypt and Jordan

As of the report approval date, the pipeline infrastructure for export to the Partnership's customers in Egypt and Jordan includes the main systems specified below. As specified below, the gas supply capacity for Egypt via the said systems is divided between the Tamar Partners and the Leviathan Partners.

(1) The EMG pipeline

The EMG pipeline connects between the Israeli transmission system in the Ashkelon area and the Egyptian transmission system in the el-Arīsh area, and has served as the main export pipeline to Egypt since commencement of production from the Leviathan reservoir. For details regarding the EMG Transaction which allows the transmission of natural gas to Egypt via the EMG pipeline, see Section 7.26.6 below.

In January 2025, another electricity connection to the compressor station was completed, allowing the simultaneous operation of the two compressors installed at the entrance to the EMG system in Ashkelon. Simultaneous operation of the two compressors as aforesaid allows, as of the report approval date, expansion of the transmission capacity in the EMG pipeline from

~600 MMCF per day (~6 BCM per year) to ~650 MMCF (~6.5 BCM). Maximum use of this capacity is contingent on the conditions of INGL's national transmission system, which may change from time to time.

To further increase the transmission capacity in the EMG pipeline to ~850 MMCF per day (~8.5 BCM per year), INGL is carrying out a project to build a new 46-km-long offshore section between Ashdod and Ashkelon (above and below: the "**Combined Section**"). The expected completion date of the project for construction of the Combined Section has been postponed several times.

For further details and for details on the transmission agreements signed with INGL, see paragraph (e) below.

For details regarding an agreement for allocation of capacity in the EMG pipeline between the Leviathan Partners and the Tamar Partners, see Section 7.26.6 below.

(2) The Jordan-North export pipeline

The Jordan-North export pipeline connects between the Israeli transmission system and the Jordanian transmission system near the Sheikh Hussein Bridge. The construction of this export pipeline was completed in December 2019, *inter alia* through the construction of a natural gas pipeline by INGL from the Tel Kashish station to the border with Jordan, including the construction of a station near the border whose purpose is to measure the gas exported to Jordan. The follow-on pipeline on the Jordanian side was built by FAJR, the Jordanian transmission company (which is Egyptian-owned) ("**FAJR**"), which connects the Israeli transmission system to the existing transmission pipeline in Jordan and the Arab Gas Pipeline, and connects to the Egyptian transmission system in the area of Aqaba (above and below: the "**Jordan-North Export Pipeline**"). As of the report approval date, the total maximum gas supply capacity in the Jordan-North Export Pipeline is approx. 7 BCM per year, of which around 3.5 BCM is allocated for the NEPCO agreement. The supply of gas to Egypt under the export agreement via the Jordan-North Export Pipeline began in March 2022. For further details in this regard, see paragraph (f) below.

(3) Agreements for participation in the funding of a project for upgrade of a system for the transmission of gas outside of Israel

On 19 September 2024, a set of agreements was signed which pertained to participation by the Leviathan Partners and the Tamar Partners in the funding of a project for construction of a compression terminal outside of Israel in the transmission system mentioned in paragraph (2) above for the local transmission company (in this section: the "**Project**", "**Transmission System**" and "**Transmission Company**", respectively), as specified below:

a. According to an agreement signed with the Transmission Company, Chevron undertook to contribute up to approx. $341 million to the funding of the Project (the "**Funding Contribution Agreement**"), which stipulates, *inter alia*, that the Transmission Company will be in charge of the building and operating the Project and Chevron will pay the Transmission Company an annual sum for operating and maintaining the compression terminal and for licensing fees. It is further provided that Chevron will be entitled to receive annual reimbursement payments from the Transmission Company for the contribution to the funding, and additional reimbursement for some of the operation and maintenance fees of the compression terminal, depending on the gas quantities to be transmitted via the Transmission System, including by third parties, over and above a certain amount and according to such mechanism and for such period as specified in the Funding Contribution Agreement.

   On 31 December 2024, Chevron notified the Leviathan Partners that the conditions precedent for entry of the Funding Contribution Agreement into effect had been satisfied.

b. The partners in the Leviathan and Tamar projects have entered into an agreement with Chevron, back-to-back with the Funding Contribution Agreement, whereby the Leviathan Partners and the Tamar Partners will bear, in equal shares, the funding contribution amount plus the costs of management of the Project by Chevron, in an aggregate amount not to exceed approx. $343 million (100% of the Project, the Partnership's share is up to approx. $78 million). Chevron shall exercise the rights, powers and discretion granted thereto under the Funding Contribution Agreement in accordance with the decision-making mechanisms specified in such agreement. The Leviathan Partners and the Tamar Partners shall be entitled to the aforementioned reimbursements, in equal shares, regardless of their respective shares in the transmission of gas through the Transmission System. In the event that a holder of interest in one of the reservoirs fails to discharge the payment imposed thereon under the Funding Contribution Agreement, the other interest holders in that reservoir will be required to bear the share of the defaulting party, and the defaulting party will be charged with the payment of interest and damages (as agreed under the said agreement) to the other paying interest holders. For details with respect to the manner of allocation of the additional capacity of the Transmission System to be provided by the Project (the "**Additional Capacity**"), see Paragraph (d) below.

c. An affiliate of Chevron (the "**Affiliate**") has entered into an agreement with the Transmission Company for the provision of transmission services for the Additional Capacity (the "**Additional Transmission Agreement**"). The payment of transmission fees under the Additional Transmission Agreement will be made based on the quantity of gas actually transmitted through the Transmission System. On 31 December 2024, Chevron notified the Leviathan Partners that the conditions precedent for entry of the Additional Transmission Agreement into effect had been satisfied.

   The Additional Transmission Agreement is effective until 25 January 2034, unless it is terminated at an earlier date in accordance with the provisions thereof.

d. Chevron and the other Leviathan Partners and Tamar Partners have signed an amendment to the existing service agreement (the "**Amendment to the Service Agreement**"), which stipulates, *inter alia*, that the Affiliate is engaging in the Additional Transmission Agreement for and on behalf of the Leviathan Partners and the Tamar Partners on a back-to-back basis, as if they were parties to such agreement. It is further provided, *inter alia*, that the Additional Capacity will be allocated between the Leviathan Partners and the Tamar Partners in equal shares. Chevron will exercise the rights, powers and discretion granted thereto under the Additional Transmission Agreement in accordance with the decision-making mechanisms specified in the Amendment to the Service Agreement.

As of the report approval date, estimated completion of the Project is expected to occur during H2/2026.

(4) The Jordan-south export pipeline, which connects the Israeli transmission system in the southern area of the Dead Sea to Jordanian industrial plants.

(5) As of the report approval date, the operator on behalf of the Leviathan Partners and the Tamar Partners is examining the possibility of participating in the construction of a project for a new onshore connection between the Israeli transmission system and the Egyptian transmission system in the area of Nitzana (the "**Nitzana Pipeline**" or "**Nitzana Project**"), which includes a pipeline and the construction of a compressor station in the area of Ramat Hovav. The Nitzana Pipeline (if built) will constitute part of INGL's transmission system and is expected to increase the transmission capacity to Egypt by at least ~6-7 BCM per year. For details regarding the Natural Gas Commission's decision of 9 August 2023 on the matter, see Section 7.24.5(f) below.

For promotion of the construction of the Nitzana Pipeline, the Leviathan Partners approved, by the report approval date, preliminary budgets prior to a commitment to participate in the funding of the Nitzana Pipeline, in accordance with the decision of the Natural Gas Commission on the matter, and prior to the adoption of a final investment decision (insofar as shall be adopted) in the sum total of approx. $111.1 million (100%). In the operator's estimation (based on the data provided by INGL), the Nitzana Pipeline project's budget is estimated at approx. $585 million (in equal shares between the gas exporters participating in the funding; the Partnership's share is approx. $133 million). As of the date of approval of the report, the Partnership, together with the other Leviathan partners, is examining all of the commercial conditions in this project in comparison with the alternatives of other projects to increase the capacity for export to Egypt, including the laying of a pipeline that shall connect the platform to the Egyptian transmission system, and accordingly, a decision will be made as to whether and how to participate in the Nitzana project.

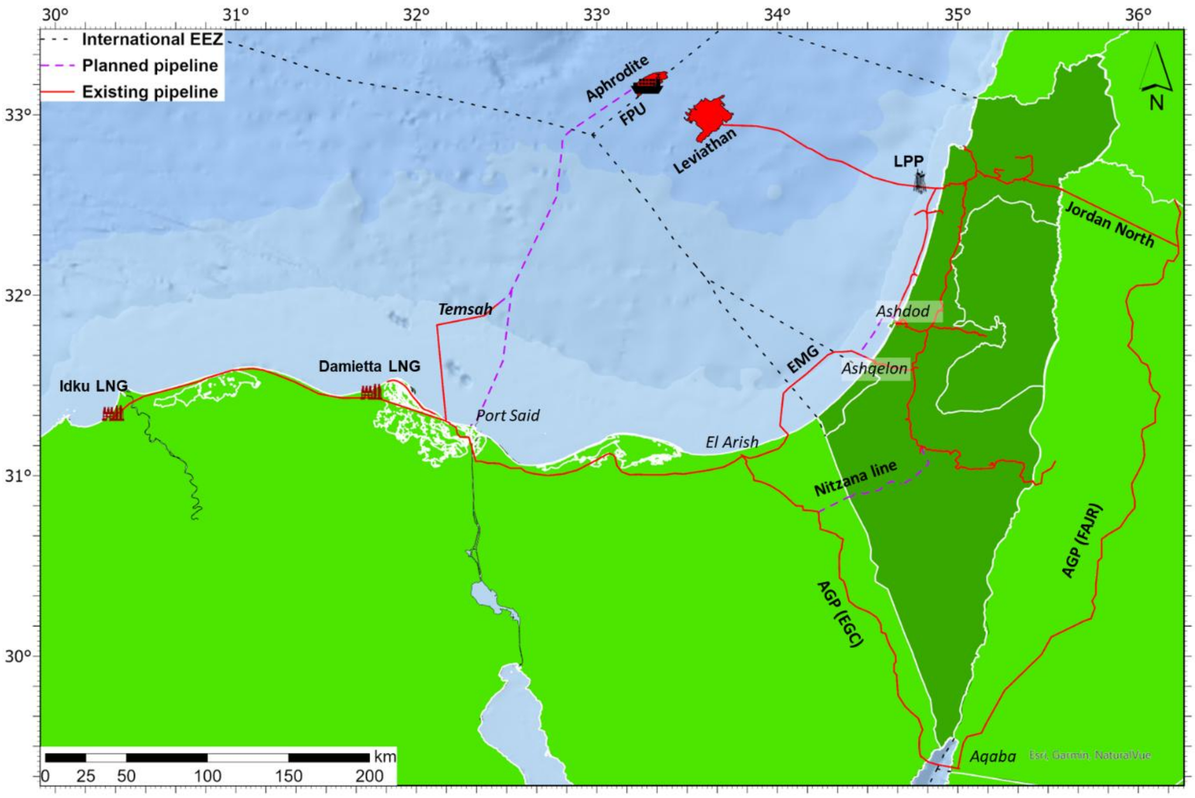
Below is a table summarizing the estimates of the current and possible transmission capacity of each of the transmission systems for the export of gas to Egypt and Jordan, and the total current and possible export capacity from the Leviathan reservoir, in BCM:

Infrastructure	Current transmission capacity	Possible additional transmission capacity[72]	Total possible transmission capacity	Total current and possible export capacity from the Leviathan reservoir	Additional transmission capacity is contingent on:

[72] The data specified in the table with respect to the transmission capacity are in the Partnership's estimation. The actual quantities may change according to the operating conditions prevailing in the regional transmission systems during the operation period. Assuming different conditions to those taken into account by the Partnership, the transmission capacity of the various systems may change.

EMG	Approx. 6.5	Approx. 2	Approx. 8.5	Approx. 6.5	Completion of the Combined Section
Jordan-North Export Pipeline	Approx. 7 (Approx. 3.5 to Egypt and 3.5 to Jordan)	Approx. 4 to Egypt	Approx. 11 (Approx. 7.5 to Egypt and 3.5 to Jordan)	Approx. 7.25 (Approx. 3.75 to Egypt and 3.5 to Jordan)[73]	Completion of the project (as defined in Section 7.13.2(b)(3) below)
Nitzana Pipeline	-	Approx. 7	Approx. 7	Approx. 3.5 (estimated)[74]	Completion of the Nitzana Pipeline project
Total	Approx. 13.5	Approx. 13	Approx. 26.5	Approx. 17.25	

The following map shows the system of existing and future export pipelines:



(c) <u>Engagement with INGL in transmission agreements in relation to the export to Egypt</u>

[73] The possible capacity for export from the Leviathan reservoir as stated above is in accordance with the Partnership's assessment of the estimated rate of allocation for the Leviathan project out of the potential export capacity of the Jordan-North Export Pipeline after completion of the Project (as defined in Section 7.13.2(b)(3) below).

[74] The possible capacity for export from the Leviathan reservoir as noted above is in accordance with the Partnership's assessment of the estimated rate of allocation for the Leviathan project out of the potential export capacity of the Nitzana Pipeline project, according to which the capacity shall be allocated equally between the Leviathan Partners and the Tamar Partners. See Sections 7.13.2(b)(4) and 7.24.5(f) below for details.

1. On 28 May 2019, an agreement was signed between Chevron and INGL with respect to the provision of interruptible transmission services in connection with the transmission of natural gas from the Leviathan reservoir and the Tamar reservoir to the EMG terminal in Ashkelon, for purposes of export to Egypt via the EMG pipeline (in this section: the "**2019 Agreement**"). The payment pursuant to the 2019 Agreement was determined based on the gas quantity actually transmitted in the transmission system, subject to Chevron's undertaking to pay for specific minimum quantities. For details regarding the capacity of the EMG system, see Paragraph (b)(1) above.

   On 26 December 2024, an addendum to the 2019 Agreement was signed between Chevron and INGL, according to which the agreement shall be extended until the earlier of: (a) the date of expiration of the agreement according to the terms and conditions thereof; (b) 1 January 2026; or (c) the date of first gas, as defined in the transmission agreement on a firm basis described below.

2. On 18 January 2021, Chevron engaged with INGL in an agreement for the provision of transmission services on a firm basis, which was intended to replace the 2019 Agreement, for the transmission of natural gas from the Leviathan and Tamar reservoirs to the EMG terminal in Ashkelon and for the transmission thereof to Egypt (the "**Transmission Agreement**" or, in this section: the "**Agreement**"). Below is a concise description of the main terms of the Agreement, as amended from time to time:

   (a) In the Transmission Agreement, INGL undertook to build the Combined Section in accordance with the Natural Gas Commission's decision on the financing of projects for export via the Israeli transmission system and division of the construction costs of the Combined Section, as described in Section 7.24.5(e) below (in this section: the "**Commission's Decision**"), in a manner which will enable the transmission of the full quantities under the Transmission Agreement, and to provide transmission services for the natural gas that shall be supplied from the Leviathan and Tamar reservoirs, including maintaining an annual base capacity in the transmission system of approx. 5.5 BCM (the "**Base Capacity**"). For the transmission services in relation to the Base Capacity, Chevron will pay capacity fees and a payment for the gas quantity that shall actually be transmitted (throughput), in accordance with the accepted transmission rates in Israel, as shall be updated from time to time.[75] In addition, INGL undertook to provide non-continuous transmission services, on an interruptible basis, of additional gas quantities over and above the Base Capacity, subject to the capacity that shall be available in the transmission system. For transmission of the additional quantities as aforesaid, Chevron will pay a transmission rate for non-continuous transmission services in relation to the quantities that shall actually be transmitted.

(b) In the Transmission Agreement, Chevron committed to payment for the transmission of a gas quantity that shall be no less than 44 BCM throughout the term of the Agreement. If the parties agree on an increase in the Base Capacity, the minimum quantity for transmission as aforesaid will be increased accordingly.

(c) The Transmission Agreement determined undertakings of INGL with respect to the date of completion of construction of the Combined Section and commencement of the transmission of the gas (in this section: the "**Date of First Gas**"), but from time to time INGL has given notice of delays and postponements in the performance of the construction work due to various constraints which have resulted in postponement of the Date of First Gas, *inter alia* due to technical problems that occurred during the course of the work and due to the foreign construction contractor leaving the region in view of the security situation.

(d) Against this backdrop, on 4 August 2024, an amendment to the Transmission Agreement was signed between Chevron and INGL according to which, *inter alia*, Chevron will bear, in respect of the share of the partners in the Leviathan and Tamar projects, an amount equal to 56.5% of the additional costs entailed by bringing the foreign contractor back to Israel and resuming the construction work on the project, insofar as is resumed, by October 2024. As of the report approval date, no notice has yet been received from INGL in connection with the date of the contractor's return and resumption of the work, and accordingly no estimate has yet been received regarding the additional costs entailed by the contractor's return and completion of the project.

In the operator's estimation, the Date of First Gas is not expected to be before Q1/2026.

[75] As of the report approval date, the capacity fee and the throughput fee that INGL charges its customers total approx. 58.7 and 10.7 Agorot per MMBTU, respectively, according to Decision no. 1/2024 of the Natural Gas Commission of 4 June 2024. The foregoing tariffs are linked to the CPI from the date of the said decision until the date of any relevant payment.

(e) The Transmission Agreement determined that it will end on the earliest of the following dates: (a) the date on which the total quantity that is transmitted is 44 BCM; (b) 8 years after the Date of First Gas; or (c) upon expiration of INGL's transmission license.

(f) In accordance with the principles determined in the Commission's Decision, the share of the partners in the Leviathan and Tamar projects (56.5%) in the total cost of construction of the Ashdod-Ashkelon Combined Section, with the Leviathan Partners and the Tamar Partners bearing such costs as well as provision of guarantees, as specified below, is 69% and 31%, respectively.

(g) As of the report approval date, the costs of construction of the Combined Section, including the costs for bringing forward the doubling of the Sorek-Nesher and Dor-Hagit sections, are estimated at a total sum of approx. $295 million (the Partnership's share is approx. $52 million), exclusive of additional costs that may apply for resumption of the work as stated in Section 7.13.2(c)2(d) above.

(h) In accordance with the Commission's Decision, the Leviathan Partners and the Tamar Partners provided a bank guarantee to secure INGL's share in the cost of construction of the foregoing infrastructure, and to cover Chevron's commitment to pay the capacity and transmission fees. Accordingly, in February 2025, the Partnership provided guarantees in respect of its interests in the Leviathan project, in the total sum, as of the report approval date, of approx. ILS 186.4 million.

(i) The Transmission Agreement stipulates that in the event of cessation of the export of natural gas from the Tamar and Leviathan projects to Egypt, Chevron will be entitled to terminate the Transmission Agreement subject to payment of compensation to INGL due to the early termination, in an amount equal to 120% of the costs of construction of the Ashdod-Ashkelon Combined Section, plus the costs of accelerating the doubling of the Sorek-Nesher and Dor-Hagit sections, net of the amounts Chevron paid until the date of the termination in respect of such construction and acceleration costs and in respect of the transmission of the gas under the Transmission Agreement. If, after the termination of the Transmission Agreement, export to Egypt resumes, the Transmission Agreement will be renewed subject to and in accordance with the capacity that shall be available in the transmission system at such time.

(j) In view of the delays in completion of the construction work and postponement of the Date of First Gas as aforesaid, Chevron raised claims of breach of the Transmission Agreement against INGL, following which the parties agreed to refer the matter to mediation and at the same time to act according to the arbitration mechanism in the Transmission Agreement.

3. Concurrently with the signing of the Transmission Agreement, Chevron, the Partnership and the other Leviathan Partners and Tamar Partners signed a back-to-back service agreement (in this section: the "**Service Agreement**"), which determined that the Leviathan Partners and Tamar Partners will be entitled to transmit natural gas (through Chevron) under the Transmission Agreement, and will be responsible for fulfillment of Chevron's undertakings under the Transmission Agreement (back-to-back), as if the Leviathan Partners and the Tamar Partners were a party to the Transmission Agreement in Chevron's stead, each according to its share, as determined in the Capacity Allocation Agreement between the Leviathan Partners and the Tamar Partners, as specified in Section 7.26.6(c) below. The Service Agreement further determined that the Base Capacity that is kept in the transmission system for Chevron will be allocated between the Leviathan Partners and the Tamar Partners according to the specified rates, and according to the order set forth in the Capacity Allocation Agreement. The Leviathan Partners and the Tamar Partners will bear capacity fees at a fixed ratio of 69% (the Leviathan Partners) and 31% (the Tamar Partners), except in a case where a party (the Leviathan Partners or the Tamar Partners, as the case may be) used the unutilized capacity of the other party.

For further details regarding the Combined Section project, see Section 7.13.2(b) above.

Caution regarding forward-looking information – The estimates specified above regarding the construction costs and the timetables for construction of the Combined Section, including the Partnership's share in the additional costs and the operator's estimate regarding the Date of First Gas, constitute 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, including delays in and problems with construction of the transmission system sections, actual construction costs that are different to the estimated costs, non-receipt of the required regulatory approvals, and other factors beyond the Partnership's

control, including prolongation of the Swords of Iron War or other geopolitical changes.

(d) Export of natural gas to Egypt via the Jordan-North Export Pipeline

In view of the delay in completion of the project for construction of the Ashdod-Ashkelon Combined Section, the Leviathan Partners have signed a set of agreements intended to allow the transmission of quantities of natural gas to Egypt under the Export to Egypt Agreement, through Jordan, using the Jordan-North Export Pipeline. In accordance with the said set of agreements, in March 2022, natural gas transmission to Egypt through Jordan began, which allows for maximizing the sale of the natural gas produced from the Leviathan reservoir and transmitting natural gas surpluses that are not consumed in Israel and Jordan and/or transmitted to Egypt via the EMG pipeline, to the Egyptian market, via the Jordanian transmission system, mainly until the Combined Section is completed by INGL as aforesaid. As of the report approval date, and as the Partnership was informed by the operator in the Leviathan project, using the existing transmission infrastructure and current operating conditions, natural gas can be flowed to Egypt, via Jordan, in an average daily amount of up to approx. 350 MMCF (approx. 3.5 BCM per year). It is noted in this context that the Ministry of Energy authorized the Leviathan Partners to add a point of delivery of natural gas to Egypt in Aqaba, Jordan. It is further noted that transmission of the gas to Egypt via the Jordan-North Export Pipeline entails additional transmission costs compared with transmission of the gas via the EMG pipeline.

The aforesaid set of agreements that was signed includes the agreements specified below:

1. An agreement between an affiliate of Chevron (the "**Affiliate**") and FAJR, the Jordanian transmission company, for supply of interruptible transmission services in relation to transmission of natural gas from the Leviathan and Tamar reservoirs through the transmission system in Jordan, from the point of entry at the border between Israel and Jordan to the delivery point at the border between Jordan and Egypt, near Aqaba (the "**FAJR Agreement**"). The payment pursuant to the FAJR Agreement will be made based on the gas quantity actually transmitted in the FAJR transmission system, net of own-use gas used for operation of the compressors in Aqaba. It was further determined that the term of the FAJR Agreement will be for 5 years from the transmission date, subject to earlier termination according to its provisions.

2. A back-to-back service agreement signed between the Affiliate, Chevron and the other Leviathan and Tamar partners, in which

it was determined, *inter alia*, that the Affiliate engaged in the FAJR Agreement for and for the benefit of the holders of the interests in the Tamar and Leviathan reservoirs for the export of natural gas to Egypt from the Tamar and Leviathan reservoirs, back to back, as if they were a party to the said agreement. It was further determined that use of the FAJR transmission system would be made in accordance with the mechanism, terms and conditions, and order of priority specified in the aforesaid agreement, which are based, *inter alia*, on the capacity of the EMG pipeline, the available capacity and the constraints of the FAJR transmission system, and the gas nominations that shall be made by virtue of the export to Egypt agreements between BOE and the holders of the interests in the Tamar and Leviathan reservoirs.

3. Agreement between Chevron and INGL for supply of interruptible transmission services in relation to the transmission of natural gas from the Leviathan reservoir via the Jordan-North Export Pipeline to the point of connection to the FAJR transmission system at the border between Israel and Jordan (the "**Jordan-North INGL Agreement**"). The payment pursuant to the Jordan-North INGL Agreement will be made based on the gas quantity actually transmitted through the INGL transmission system, subject to Chevron's undertaking to pay for a minimum quantity as specified in the agreement. The term of the Jordan-North INGL Agreement was extended until 1 January 2026, unless the parties consensually extend it, subject to the decisions of the Natural Gas Authority at such time. Concurrently with the signing of the Jordan-North INGL Agreement, Chevron and the other Leviathan Partners engaged in a back-to-back service agreement in connection with the Jordan-North INGL Agreement. In a letter of 22 December 2024, the Natural Gas Authority stated, *inter alia*, that the annual available transmission capacity for 2025 in the Jordan-North pipeline is 4.2 BCM. It was also clarified that the agreements for transmission in the Jordan-North pipeline will be signed on an interruptible basis only. Further to the aforesaid, the partners in the Leviathan project notified INGL that they are requesting that one half of the said transmission capacity be allocated for the transmission of gas from the Leviathan project.

4. An amendment to the Export to Egypt Agreement which was signed between the Leviathan Partners and Blue Ocean, as specified in Section 7.12.3(c)4 above.

According to the Export to Egypt Agreement, the Leviathan Partners have been obligated, since July 2022, to supply Blue Ocean with 450 MMCF of natural gas per day. The transmission of this full quantity via the EMG pipeline will only be possible after completion of the

Combined Section, whose construction, as aforesaid, is delayed. It is noted that despite the fact that until the report approval date the transmission of gas through Jordan has been conducted as planned, as the transmission agreements with INGL effective on the report approval date are for the provision of interruptible transmission services, it is not certain on the report approval date that it will be possible at all times to transmit via Jordan the full quantities that the Leviathan Partners are obligated as aforesaid to supply to Blue Ocean.

7.13.3 The natural gas markets in neighboring countries

(a) The natural gas market in Egypt

Natural gas plays a key role in the Egyptian energy market, with 57% of consumption being used for power production, and the remainder for energy-intensive industry, households and transport. In 2024, local consumption totaled ~62 BCM, down around 1% compared with 2023, which appears to have derived from increased use of fuel oil and from scheduled power outages lasting several hours a day, which have been carried out since the summer of 2023, and which were caused as a result of a natural gas shortage. To the best of the Partnership's knowledge, regular power supply was resumed in Egypt in August 2024.

(b) The natural gas market in Jordan[76]

In the Partnership's estimation, the domestic demand in Jordan in 2023-2024 totaled ~3.9 BCM per year, in 2025 is expected to total ~3.8 BCM per year, and in the following decade it is expected to total ~3-3.8 BCM per year. The demand for natural gas is affected by the demand for electricity and the production of electricity using gas substitutes, which include renewable energies and refined oil products. Natural gas represents approx. 80% of all of the power production sources of NEPCO, the Jordanian electric company. The decline in the anticipated demand for natural gas in Jordan as aforesaid, despite the forecasted growth in the demand for energy generally, and electricity specifically, is related to the accelerated penetration of renewable energies into the power production industry in Jordan as a result of government policy, and as a result of power production from the Attarat power plant. As of the report approval date, the Leviathan reservoir is the primary source of natural gas which is imported into Jordan for power production.

To the best of the Partnership's knowledge, Jordan has an operational LNG import facility in Aqaba capable of importing LNG

[76] The information regarding the natural gas market in Jordan and Egypt is based, *inter alia*, on reports published by external consulting firms.

by utilizing opportunities in the LNG spot markets. Despite Jordan's ability to import LNG, to the best of the Partnership's knowledge, no such import was carried out in 2024, *inter alia* due to the LNG prices.

(c) The natural gas market in the area of the Palestinian Authority and the Gaza Strip

Israel is the main source of electricity in the area of the Palestinian Authority and the Gaza Strip. In recent years, the Palestinian Authority has been developing the ability to independently generate electricity, *inter alia*, by promoting the construction of a new power plant for the generation of electricity in Jenin.

In the Partnership's estimation, the demand for natural gas for operation of the future power plant in Jenin is expected to total ~0.45 BCM per year, and the demand for natural gas for operation of the existing power plant in the Gaza Strip will total ~0.25 BCM per year.

As of the report approval date, due to the Swords of Iron War, the negotiations that were being held by the Partnership, together with its partners in the various projects, for the supply of natural gas to the power plant in the Gaza Strip have been suspended, and at this stage, there is no certainty as to whether and when they will resume, and under what conditions.

(d) The natural gas market in Cyprus

As of the report approval date, Cyprus does not consume natural gas at all, and 85% of the power production in Cyprus is based on oil-based imported products. Cyprus also experiences difficulties connecting to the energy infrastructures in Europe. Consequently, the Cypriot government and the Cypriot electric company are taking action to promote the use of natural gas and renewable energies for power production.

(e) The natural gas market in Morocco

According to reports in the media, natural gas production in Morocco presently totals ~0.1 BCM per year. In general, Morocco has gas resources of ~1.2 TCF in 3 different ventures that are operated by international companies. Electricity production in Morocco is currently mostly based on coal (approx. 68%), with only approx. 9% based on natural gas. However, Morocco strives to reduce greenhouse gas emissions, *inter alia*, by replacing coal with natural gas. As of the report approval date, domestic demand for natural gas in Morocco is approx. 1 BCM per year, most of which (approx. 90%) was previously supplied by gas import from Algeria via the GME pipeline. On 1 November 2021, gas transmission through the GME pipeline came to a stop following the expiration of the supply agreement between the countries, and to the best of the Partnership's knowledge, given the increasing political tensions between Morocco and Algeria, entry into a new agreement is not expected. Consequently, Morocco began to import natural gas through Spain. The gas arrives in Spain as LNG, it is re-gasified there and transmitted through the GME pipeline to Morocco. According to media reports, Morocco is expected to import LNG in this manner, in volumes of approx. 1.1 BCM, 1.7. BCM and 3.1 BCM in 2025, 2030 and 2040, respectively. As of the report approval date, there are no LNG regasification or production facilities in Morocco. In addition, to the best of the Partnership's knowledge, there are currently about 4 power plants in Morocco with the ability to produce electricity based on natural gas, which may create demands amounting up to approx. 150 MMCF per day, and there is a plan to build additional power plants that are expected to enable an increase in the natural gas-based electricity generation capacity.

7.13.4 Liquefied Natural Gas (LNG)

The Partnership is examining the possibility of liquefying natural gas and transporting it in a liquefied state (LNG) in designated tankers to various countries. The construction of a natural gas liquefaction facility is a highly complex project, *inter alia* due to the tremendous scope of the investment of liquefaction facilities whose liquefaction capacity is millions of tons of LNG per year, and due to design, engineering, environmental, regulatory and commercial challenges that are entailed by such a project.

Despite the Leviathan Partners' focus on the export of natural gas to the regional markets as the target markets for expansion of the Leviathan project, in 2024, the Leviathan Partners continued to explore the possibility of building an FLNG facility to be located offshore and used to produce and store LNG. The costs of building an FLNG facility are affected by a broad range of factors that are beyond the Partnership's control, which change from time to time, *inter alia* as a result of the supply and demand levels in the global market. Given the receipt of indications that point to a material change in the estimation of the costs of building an FLNG facility, the Leviathan Partners intend to consider in the course of 2025 additional options for the construction of an FLNG facility, *inter alia*, in view of the possibility of modular expansion of the Leviathan project.

7.14 **Backlog**

7.14.1 Following are data regarding the Partnership's backlog calculated on the basis of the minimum gas quantities (according to the Take or Pay quantity) determined in binding agreements (agreements on a firm basis in which all of the conditions precedent were fulfilled) for the supply of natural gas from the Leviathan project, which the customers have undertaken to consume or pay for. The backlog also includes revenues from the sale of condensate. The backlog was calculated based on the following main assumptions: (a) the possible reduction of the take or pay quantities due to the exercise of carry forward, was not taken into account; (b) the gas prices are based on the assumptions taken into account for the purpose of the discounted cash flows in the Leviathan project which were included in the resources report attached as **Annex B** to this chapter; and (c) no change shall occur in the minimal annual quantities in the Export to Egypt Agreement, as specified in Section 7.12 above.

Period	Backlog ($ in millions) as of 31 Dec. 2024[77]
Q1/2025*	Approx. 180
Q2/2025*	Approx. 180
Q3/2025*	Approx. 180
Q4/2025*	Approx. 180
2026	Approx. 704
2027	Approx. 735
2028	Approx. 739
2029	Approx. 727
2030	Approx. 708
2031	Approx. 713
2032	Approx. 692
2033	Approx. 684
2034	Approx. 696

* The division between the quarters was made in accordance with the terms and conditions of the gas sale agreements (insofar as determined) in relation to the gas quantities that shall be supplied and the Partnership's assumptions.

Caution regarding forward-looking information – the Partnership's estimations regarding the timing and amount of the revenues expected from the backlog constitute forward-looking information within the meaning thereof in the Securities Law, which are based on the minimum gas quantities specified in the binding agreements for natural gas supply from the Leviathan project, and based on various assumptions regarding natural gas quantities and prices, the materialization of which is completely uncertain, *inter alia*, due to the possible effect of the risk factors entailed by the Partnership's operations, as detailed in Section 7.30 below.

7.14.2 The backlog from the Leviathan project for 2024, as included in Chapter A of the 2023 Periodic Report, was approx. $810 million. The Partnership's actual revenues from the Leviathan project in 2024

[77] As of the report approval date, no material change has occurred in the backlog.

totaled approx. $1.14 billion. The difference between the backlog figures for 2024 and the actual revenues in this period primarily derived from the fact that the actual gas quantities supplied to customers exceeded the minimum gas quantities determined in the supply agreements and from sales to customers in accordance with spot-based supply agreements.

7.15 **Competition**

7.15.1 Natural gas discoveries in Israel

a. The supply of natural gas from the Leviathan project is currently performed via pipeline and is designated for the domestic market and the export markets in Egypt and Jordan. As of the report approval date, the Partnership's main competition in the domestic natural gas market is with the partners in the Tamar project and with Energean, the owner of the Tanin and Karish reservoirs, with owners of natural gas and oil assets that operate in neighboring countries, and with the import of LNG to the export markets.

   As of the report approval date, all of the natural gas currently supplied to the Israeli market originates from the Leviathan, Tamar and Karish reservoirs.

b. Production from the Karish reservoir began in October 2022. In addition, according to Energean's reports, on 31 May 2023, the Petroleum Commissioner granted Energean confirmation of a natural gas discovery in Block 12, in several reservoirs referred to jointly as the Katlan field, which is located between the Karish and Tanin leases, and contains ~31.9 BCM[78] of natural gas. In July 2024, a lease deed was granted for the Katlan field, a final investment decision (FID) was adopted for development thereof, and according to Energean's reports, first gas is expected from the field in H1/2027. In addition, in July 2024, the Petroleum Commissioner's confirmation was received of the making of a natural gas discovery in the Drakon reservoir in the area of license 31, situated south-east of the Tamar reservoir, which contains ~3-5 BCM[79]. Additionally, in December 2024, the Commissioner notified Energean of confirmation of a discovery in the Hercules natural gas reservoir estimated at ~4-5 BCM in the area of license 23. According to the provisions of the Gas Framework, the Energean-owned Tanin and Karish reservoirs are intended for the supply of gas to the domestic market only, but this restriction does not apply to new discoveries outside the Tanin and Karish Leases. Notwithstanding the aforesaid, to the best of the Partnership's knowledge, Energean is working on obtaining a permit

[78] Ministry of Energy, new Katlan natural gas discovery in Israel's waters, 31 May 2023: https://www.gov.il/he/departments/news/news-310523

[79] Link to 22 July 2024 announcement by the Communications and Spokespersons Office of the Ministry of Energy.

for the export of natural gas from the Karish North reservoir, despite provisions of the Gas Framework in connection with export as aforesaid, and contrary to the provisions of the agreement between the Partnership and Energean for the sale of the interests in Karish and Tanin, as specified in Section 7.26.10 above.

c. According to the reports of the Tamar Partners, as released up to the report approval date, the Tamar Partners have adopted a final investment decision (FID) for a development project for expansion of the production capacity from the Tamar reservoir to an annual quantity of approx. 16 BCM from 2027. Completion of the said expansion work may affect competition, in both the domestic and the export markets.

d. The Tamar Partners and Blue Ocean signed agreements for export of natural gas on a firm basis in the total volume of ~25 BCM (~200 MMCF per day, or ~2 BCM per year) until 31 December 2034, or until the entire contractual quantity is supplied (in this section below, the "**Original Agreement**"). The supply of gas by the Tamar Partners under the Original Agreement commenced in July 2020. On 16 February 2024, the Tamar Partners reported their engagement in an amendment to the Original Agreement, pursuant to which the Tamar Partners undertook to supply Blue Ocean with a total contract gas quantity of ~43 BCM, over and above the quantity that was set forth in the Original Agreement, until the end of the term of the Original Agreement. The annual quantity that the Tamar Partners undertook to supply to the buyer is ~4 BCM (a daily quantity varying between periods of the year, ranging between 350 and 450 MMCF), in addition to the contract quantity set forth in the Original Agreement.

e. According to agreements with the Competition Authority, an agreement was signed between the Tamar Partners which was intended to enable separate marketing of natural gas, which agreement took effect in May 2021. To the best of the Partnership's knowledge, as of the report approval date, no separate gas sale agreements were signed by any of the Tamar Partners. Implementation of this agreement by the Tamar Partners may increase competition. In addition, as of the report approval date, and according to the provisions of the exemption that was signed by the Prime Minister in his then role as Minister of the Economy on 17 December 2015, the gas produced from the Leviathan reservoir is marketed jointly by the Leviathan Partners, and no arrangements have been determined for separate marketing of the gas. According to the joint operating agreement in the Leviathan project, each partner is entitled, under certain conditions, to take its share of the gas and market it separately.

7.15.2 Oil and gas exploration in Israel in recent years

In 2016, the Ministry of Energy opened Israel's EEZ for oil and natural gas exploration, and it held competitive processes in 2016, 2018, 2020 and 2022.

In the competitive process announced on 13 December 2022, in which 4 zones of exploration licenses were offered, the Partnership submitted a bid together with the international companies BP and SOCAR, and on 29 October 2023, the Petroleum Commissioner notified the Partnership and BP and SOCAR that their bid had won in relation to the Zone I Licenses. For further details regarding the said licenses, see Section 7.7 above. In Zone G, which is located near the border of the EEZ with Egypt, the bid of Eni, Dana Petroleum and Ratio won.

It is noted in this context that, to the best of the Partnership's knowledge, two petitions have been filed with the High Court of Justice, *inter alia*, against the Ministry of Energy, in connection with the fourth competitive process, by which petitions the High Court of Justice is moved to order that such competitive process be revoked, suspended or amended.

Insofar as wells that shall be drilled in the areas of existing and/or new licenses, in which the Partnership holds no interests, lead to significant natural gas discoveries, and insofar as these discoveries, if any, are developed, these reservoirs shall constitute competition with the Partnership's field of business.

7.15.3 LNG import

From January 2013 until December 2022, LNG was imported on an interruptible basis into the domestic market via the offshore LNG buoy and the regasification vessel for the import of LNG off the shores of Hadera, which connected to an LNG tanker, that converts LNG into gas via the regasification vessel, in the volume of up to approx. 0.5 BCF per day. According to a report of the Ministry of Energy, upon the connection of the three natural gas reservoirs Leviathan, Tamar and Karish, it was decided at the end of 2022 that it was no longer viable to continue the permanent engagement with the regasification vessel, and there was no longer any need to continue operating it as a backup for the Israeli market in cases of natural gas shortages.

7.15.4 Coal and other alternative energy products

Coal and other alternative energy products also constitute competition for the natural gas suppliers. In relation to the consumption of natural gas by the IEC, the natural gas suppliers are in competition with the use of coal for electricity production, and therefore the level of the consumption and the price of the natural gas may be affected by the price of coal worldwide and by the tax policy thereon in Israel. For details about the Israeli Government Resolutions regarding the reduction of coal use, see Section 7.24.10(a) below.

In addition, the natural gas supplied by the Partnership to industrial customers, replaces the use of liquid fuels, such as diesel oil and mazut. The price of the liquid fuels is usually higher than the price of the natural gas supplied by the Partnership. However, despite their being polluting, a drop in the oil prices worldwide may render these fuels competitive relative to the natural gas which is supplied to these consumers. However, the Ministry of Environmental Protection institutes policy measures designed to ensure that plants with infrastructure for connection that enables usage of natural gas refrain from using polluting liquid fuels. For details on the decision regarding the imposition of carbon tax, see Section 7.23.2(d) below.

Moreover, it is expected that hydrogen will gradually enter the mix of energy sources, which may be used in electricity production, transportation and heavy industry (such as concrete, steel, chemicals, etc.). Hydrogen may be produced using various methods, some of which are polluting, such as cracking from natural gas without capture of the CO_2 that is emitted in the process (gray hydrogen), and some of which are "clean", such as blue hydrogen, which is produced from natural gas development and includes capture of the CO_2 and storage or sequestration thereof, and green hydrogen, which is produced from the electrolysis of water using electricity produced from renewable sources. In the context of the growing trend in the global energy market to reduce, insofar as possible, greenhouse gas emissions in general, and carbon dioxide emissions in particular, hydrogen itself does not leave a carbon footprint and use thereof for the production of energy does not produce greenhouse gas emissions, a clear advantage. To the best of the Partnership's knowledge, as of the report approval date, the main hydrogen producer in Israel is ORL, which produces gray hydrogen. However, several companies in Israel, including energy and technology companies, are exploring production and improvement of the processes for production of hydrogen using different methods.

According to reports of the Ministry of Energy, the Natural Gas Authority is the various implications of the developments in the hydrogen market, globally and in Israel, and their repercussions on the natural gas sector, and is promoting regulation, standards and safety rules for the future integration of hydrogen in the natural gas sector's infrastructures. In addition, the Natural Gas Authority has instructed INGL to move ahead with exploring entry into the field of low-emissions hydrogen transmission. At the end of 2023, the government approved an amendment to INGL's articles of association allowing it to transmit hydrogen in a pilot planned in the area of Yotvata for the production, transmission and use of green hydrogen produced from solar energy[80].

On 3 December 2023, the Ministry of Energy issued an international RFP to receive information regarding hydrogen valleys, aiming to formulate an outline for establishing a "hydrogen valley" in Israel, including information on the specification and proposed geographical location, production technologies, transmission and use by the end-users, all in accordance with the hydrogen value chain and regulatory and economic aspects in establishing the hydrogen valley. Further thereto, on 3 January 2024, INGL issued an RFP to explore collaborations in connection with the establishment of hydrogen valleys in Israel. The Partnership is exploring possibilities of collaboration in relation to these initiatives.

7.15.5 Renewable energy sources

(a) Like other developed countries, the Israeli government has adopted a policy that promotes the transition to a low-carbon economy, and in such context, significant incentives are presently being offered for the development of renewable energy sources, such as solar and wind energy, which compete with the natural gas sold by the Partnership for the production of electricity.

(b) According to a review report of February 2024, released by the Knesset Research and Information Center, in 2023, the breakdown of electricity production in Israel was as follows: renewable energies – 11.5%; coal – 17.2%; natural gas – 70.8%; and other fuels – 0.5%. According to a review report of July 2023 which was released by the Ministry of Energy[81], the breakdown of electricity production from renewable energy facilities in 2022, which totaled approx. 7,061 MWH and constituted approx. 10.1% of the total electricity consumption in that year, was as follows: photovoltaic facilities – around 83%; thermo-solar facilities – 11%; wind facilities – approx. 4%; and biogas, hydro, biomass and landfill facilities – approx. 2%. The electricity produced at these facilities in 2022 constituted approx. 10.1% of the total electricity consumed in that year. According to the report, in order to meet the target set by the Ministry of Energy for 2030, according to which 30% of electricity production in the market shall be from renewable energies, the installed production capacity as being at the end of 2022 will need to be increased x3.5.

(c) On 30 September 2024, the PUA-E released a summary report on the electricity sector for 2023, which presents, *inter alia*, trends in

[80] https://www.gov.il/he/pages/news-211223.

[81] For further details, see review report of July 2023: https://fs.knesset.gov.il/globaldocs/MMM/694b85d6-ab73-ed11-8155-005056aa4246/2_694b85d6-ab73-ed11-8155-005056aa4246_11_20199.pdf

2024[82]. The report states, *inter alia*, that the trend of decline in the use of coal for the production of electricity is continuing, and that in the coming years, the share of coal in the mix of fuels is expected to significantly decline as routine use of coal is phased out. In addition, according to the report, in 2030, the installed capacity of renewable energy is expected to total approx. 16 GW, while the installed capacity of natural gas-powered production facilities is expected to total approx. 7.9 GW.

(d) On 4 November 2024, the Ministry of Energy and the Ministry of Innovation released a report on energy with a focus on renewable energies and storage. The report makes several key recommendations, including promotion of applied research in the field of innovation, increased investments in renewable energy technologies, hydrogen and energy storage, improvement of regulation processes and promotion of an innovation-encouraging regulatory policy[83].

(e) On 29 January 2025, the Ministry of Energy released an update to the "Roadmap for Renewable Energies in 2030"[84], whereby meeting the target of 30% renewable energies in 2030 requires production of ~28 TWh per year of electricity from renewable energy, with an installed capacity of around 16,000 MW in renewable energy-powered production facilities. The update also states that as of October 2024, the installed capacity of renewable energies totals ~5,700 MW.

7.15.6 Natural gas discoveries and exploration activity in neighboring countries

Natural gas discoveries in neighboring countries, if developed, and exploration activity resulting in discoveries of new reservoirs, if developed, may also compete with the Leviathan reservoir. The Partnership is following up on activity and trends of exploration, development and production in the countries of the region, including Egypt, Cyprus, Lebanon and Jordan. Below are details regarding discoveries and exploration activity in Israel's neighboring countries[85].

(a) Egypt

Egypt is a regional natural gas hub, being the country with the highest demand, with the largest production capacity and with the

[82] https://www.gov.il/BlobFolder/generalpage/dochmeshek/he/Files_doch_meshek_hashmal_doch_meshek_2023_nnn.pdf
[83] https://www.gov.il/he/pages/energy-innovation-report.
[84] https://www.gov.il/BlobFolder/news/news-290125/he/re-2030-jan25.pdf.
[85] The Partnership is unable to independently corroborate the information in this section, which originates from various public reports.

most comprehensive network of facilities, including facilities that allow export of LNG.

1. Resources: Estimates of various consulting firms range between 12 TCF and 33 TCF (340 BCM-935 BCM).

2. Current gas production capacity: While domestic gas production in Egypt was ~50 BCM in 2024, the capacity of the natural gas system in the country (i.e., the general capacity to transmit natural gas from domestic and external production sources) is ~72 BCM per year.

3. Domestic demand: For details, see Section (a) above.

4. Key facilities: Egypt has a branched offshore and onshore network of facilities for the transmission and processing of natural gas, including two facilities for the production of LNG: (a) ELNG in Idku, which is primarily owned by Shell, with a production capacity of ~7.2 million tons of LNG per year; and (b) SEGAS in Damietta, which is primarily owned by Eni, with a production capacity of ~5 million tons of LNG per year. It is clarified that the joint capacity of the said two facilities is equivalent to ~19 BCM per year. As of the report approval date, the liquefaction facilities are not operating regularly and at full capacity, due to the shortage in natural gas for domestic demand. Therefore, the export of LNG from such facilities, according to the forecasts of independent consulting firms for the coming years, will be made possible through pipeline import of gas. At present, pipeline import of gas to Egypt is carried out only from Israel, but according to reports in the media, in 2027 Egypt is expected to commence import of gas also from Cyprus. For further details, see Section 7.15.6(a)7 below.

5. Production: In 2024, domestic gas production in Egypt totaled ~50 BCM, i.e., down around 15% compared with 2023. In addition, around 73% of the said gas was produced from the reservoirs in the Mediterranean Sea, with the most prominent reservoir in Egypt being Zohr, which supplies approx. 35% of the total domestic gas production. According to reports in the media, the decline in production in 2024 as aforesaid, beyond the forecasts, was caused as a result of the decline in production from significant gas fields in the Mediterranean Sea, and chiefly the Zohr field[86], as well as prioritization of the production of oil over gas from onshore fields, due to low gas prices. Production from producing fields and fields under development in 2025-2027 is expected to total ~43-49 BCM per year, such that the gap

[86] According to reports in the media, the Zohr reservoir is in significant decline, currently producing 1.5 BCF per day, and is not expected to return to the production rates of 2020-2022 (up to ~3.2 BCF per day).

between the forecasted demand and domestic production is expected to keep growing.

6. Exploration activity: In recent years, Egypt has offered exploration licenses of vast scope, *inter alia*, in tenders. Most of the licenses in the Mediterranean region have been granted to the majors, including Chevron, ExxonMobil, BP, Shell, Eni, QatarEnergy and ADNOC. In addition, in recent years, two significant discoveries were made that have not yet been developed, and in this context the Nargis discovery, which was made by Chevron in 2023, according to reports in the media contains ~2.8 TCF and is at future development planning stages, and the Nefertari discovery, which was made by ExxonMobil in early 2025, and according to reports in the media contains ~3-4 TCF. Several small and medium-sized discoveries were also made, containing up to ~500 BCF each, and in proximity to existing gas infrastructures, which are expected to slow the decline in the domestic production capacity. In addition, it is possible that as a result of the intensive exploration activity in Egypt, additional discoveries will be made in the coming years.

7. Import/export balance: Since the commencement of production from the Zohr reservoir in 2017, the domestic production capacity has modestly exceeded domestic demand. However, since May 2023, Egypt has reverted to being a gas importer. According to forecasts, domestic demand is expected to exceed the domestic production capacity, *inter alia* as a result of population growth and a decline in production capacity. Moreover, in order to feed the liquefaction facilities through which Egypt aspires to export natural gas, an additional amount of natural gas of up to ~19 BCM is required. Insofar as no additional significant discoveries are made in its territory, it will be difficult for Egypt to return to being a significant gas exporter. In 2024, the average gap between domestic production and domestic consumption totaled ~1.3 BCF per day (13 BCM per year). Egypt bridged the said gap through the import of natural gas from Israel at a volume of ~10 BCM, and import of LNG at a volume of ~4.4 BCM. In addition, since the domestic demand for natural gas exceeded actual consumption, Egypt used alternative sources, such as fuel oil and renewable energies, and implemented proactive power cuts for several hours on a daily basis. Total export of LNG from Egypt in 2024 amounted to ~1.4 BCM, and according to reports in the media, from April 2024 to the report approval date, there has been no export from the LNG facilities in Egypt.

   In addition, in order to address such gaps, the Government of Egypt is working to promote projects for the supply of natural gas from discoveries in Israel and in Cyprus, including the projects for expansion of the Leviathan and Tamar reservoirs in Israel, and the Aphrodite and Kronos reservoirs in Cyprus, the gas produced from which is expected to be transmitted to Egypt. For details on the MOU signed in this regard between the partners in the Aphrodite reservoir, together with the Government of Cyprus, the Cyprus Hydrocarbon Company (CHC), the Government of Egypt and the National Egyptian Gas Company (EGAS), see Section 7.3.12 above. In addition, according to reports in the media, the partners of Block 6 in Cyprus have signed with the governments of Cyprus and Egypt for the supply of gas from the Kronos field to the Egyptian market, using infrastructures of the Zohr field. Furthermore, according to reports in the media, some of the gas in the Kronos field is expected to be liquefied, for export through the LNG facility in Damietta. Furthermore, according to reports in the media, Egypt has reached agreements in connection with contracts for the import of ~60 LNG shipments (~7.5 BCM) in 2025.

(b) Cyprus

1. Resources: In the EEZ of Cyprus there are 3 main discovery zones, as follows: (a) Aphrodite in Block 12, as specified in Section 7.3 above; (b) Cronos, Zeus and Calypso in Block 6, which contain a total of ~6 TCF of resources, held by Eni and TotalEnergies; and (c) Glaucus in Block 10, which contains ~3-4.5 TCF of resources, held by ExxonMobil and QatarEnergy. The estimates of resources in connection with the discovery zones in Block 6 and Block 10, as specified above, are based on reports in the media and reports by foreign consultancy firms. In addition, the zone of discoveries in Block 6 is expected to be developed through Zohr infrastructures in Egypt, with the transmission of gas from the Kronos discovery expected to commence in 2027.

2. Current gas production capacity: None. First gas from the Kronos discovery is expected in 2027.

3. Domestic demand: See Section 7.13.3(d) above.

4. Key facilities: In January 2023, work began on the construction of a floating regasification facility (FSRU) for LNG import in Vasilikos in the south of Cyprus, by a consortium led by China Petroleum Pipeline Engineering Co. Ltd. According to reports in the media, although the said FSRU is ready for transportation to Cyprus, the gas infrastructures are not installed, and the project is experiencing significant delays. The supply of gas in this framework as aforesaid is not expected before 2026.

5. Production: None.

6. Exploration activity: Cyprus has granted licenses for most of its offshore territory to the majors, including Eni, Total Energies, and ExxonMobil. As of the report approval date, ExxonMobil is drilling a well in the Electra prospect in Block 5, which according to reports in the media is expected to contain up to ~30 TCF. Insofar as resources are discovered in the well as aforesaid, the effect on the gas industry in Cyprus and in the region generally may be significant. In addition, according to reports in the media, areas held by Eni and Total Energies are expected to return to Cyprus upon expiration of the licenses. The dispute between Cyprus and Turkey in relation to the rights in the EEZ of Cyprus is leading to delays in the work programs, and even preventing activity in the licenses situated within the disputed areas. In this context it is noted that, according to reports in the media, in the past the national Turkish oil company performed exploration activity, including drilling in the EEZ of Cyprus. For further details regarding the dispute, see Section 7.30.37 below.

7. Import/export balance: None.

(c) Lebanon

1. Resources: Yet undiscovered.

2. Current gas production capacity: None.

3. Domestic demand: As of the report approval date, the existing power production infrastructure in Lebanon totals ~2 GW (less than one tenth of that of Israel), of which approx. 25% MW may be produced using natural gas in the power plant in Dir Ammar in the north of the country.

4. Key facilities: None.

5. Production: None.

6. Exploration activity: As of the report approval date, only Block 9, which is located in the south of the EEZ of Lebanon, and which is held by a consortium headed by Total Energies, which includes Eni and QatarEnergy, is active. In 2023, the consortium drilled, as aforesaid, an exploration well in the block, which did not find significant volumes of gas. The consortium also previously held Block 4, and in 2020 drilled a well therein, which too did not find significant volumes of gas. The other areas in Lebanon's EEZ are presently offered in the third tender of the Lebanese government.

7. Import/export balance: As of the report approval date, Lebanon relies exclusively on the import of fuels, and is experiencing an energy crisis due to the absence of an active agreement for the import of gas.

(d) Jordan

1. Resources: Most of Jordan's gas resources are located in the Risha field, which is situated in the east of the country and was discovered in the 1980s. For years, production therefrom totaled ~30 MMCF per day, and in 2024 the estimate of the resources in the field was updated, such that according to reports in the media, it currently totals ~5 TCF. It was further reported in the media that Jordan is working to promote a technical plan for development of the field to a daily production capacity of ~150 MMCF by the end of the current decade, with potential expansion to daily production of ~500 MMCF in the next decade. However, to the best of the Partnership's knowledge, there are no substantial development plans, *inter alia* as a result of significant technical challenges with development of the field, which relate to the considerable distance between it and the consumption centers, and the quality of the reservoir. There is also oil shale production in the Attarat power plant project, used to fuel this power plant.

2. Current gas production capacity: The Risha field produces ~0.1 BCM per year, which is supplied to consumers near the field.

3. Domestic demand: For details, see Section 7.13.3(b) above.

4. Key facilities: Until recently, an FSRU for the import of LNG was anchored in the Gulf of Aqaba, but under an agreement between Egypt and Jordan, the said facility was redeployed to the Gulf of Suez. In 2024, Jordan did not import LNG at all, but at the end of 2026, upon completion of the work on the terminal in Aqaba, Jordan is expected to deploy an FSRU for the import of LNG.

5. Production: The Risha gas field is the only producing gas field.

6. Exploration activity: In recent years, Jordan appears to be undertaking efforts to promote exploration activity in its area, but has not yet awarded any licenses in practice. To the best of the Partnership's knowledge, there is no material exploration activity in Jordan.

7. Import/export balance: Jordan relies on the import of natural gas and energy, mostly from Israel and a little from Egypt.

(e) Morocco

As of the report approval date, exploration in Morocco has not yielded significant oil or gas discoveries, despite substantial activity by various companies, including Eni, Shell, BP, Chevron, Total Energies, Kosmos and Repsol, which held offshore and onshore licenses. The Anchois project, situated in the north of Morocco's EEZ in the Atlantic Ocean, was, until recently, a key natural gas project in Morocco, but a disappointing appraisal well drilled in 2024 by the operator in the license, Energean, has cast doubt, according to reports in the media, on implementation of the development plan as was published prior to the drilling.

In December 2020, a normalization agreement was signed between Israel and Morocco, under which, *inter alia*, Israel and the United States recognized Morocco's sovereignty over Western Sahara. For details on agreements signed by the Partnership with regard to oil and/or natural gas exploration and production activity in the Boujdour license in Morocco, see Section 7.6 above. As of the report approval date and to the best of the Partnership's knowledge, on 24 September 2021, Ratio Petroleum Energy – Limited Partnership signed an agreement for a research (reconnaissance) license known as Dakhla Atlantique.

7.16 Seasonality

7.16.1 In Israel, Egypt and Jordan, the consumption of natural gas for electricity production is affected, *inter alia*, by seasonal fluctuations in the demand for electricity and by the maintenance plans of the electricity producers. Accordingly, generally, in the first and third quarters of the year (the winter and summer months) electricity consumption will be highest. In addition, the gas consumption in Egypt is significantly affected by the demand for electricity and for energy for cooling purposes, and therefore the summer months are the peak months in demand for natural gas.

7.16.2 The table below presents data regarding the breakdown of natural gas sales (100%) from the Leviathan project in the past two years:[87]

Period	Q1 (in BCM)	Q2 (in BCM)	Q3 (in BCM)	Q4 (in BCM)
2023	Approx. 2.8	Approx. 2.5	Approx. 2.9	Approx. 2.8
2024	Approx. 2.6	Approx. 2.8	Approx. 3.1	Approx. 2.7

7.17 Facilities and production capacity in the Leviathan project

7.17.1 Phase 1A of the Leviathan project development plan

The production system of Phase 1A comprises 5 main segments, as follows:

(a) Production wells: As of the report approval date, the production system of the Leviathan project includes 5 subsea production wells designed for production of up to approx. 400 MMCF per day, including the Leviathan-8 production well, which was connected to the production system in June 2023. Natural gas and condensate from the Leviathan reservoir, which is at a depth of approx. 3 km below the seabed, is piped from the said production wells to the subsea production system.

(b) Subsea production system: Connects the production wells to the production platform and lies on the seabed. The subsea system comprises 14-inch infield pipes through which the natural gas, condensate and related fluids are transported from each well to the subsea manifold. Two 18-inch gathering lines that are about 120 km long, come out of the manifold, transmitting gas, condensate and related fluids to the production platform. A third 20 inch gathering line is expected to be laid in proximity to the existing two gathering lines, and operated in early 2026, as specified in Section 7.2.5(b)1 above. In addition, the subsea system includes two pipes, 6 inch in diameter and approx. 120 km long, for the transmission of MEG from

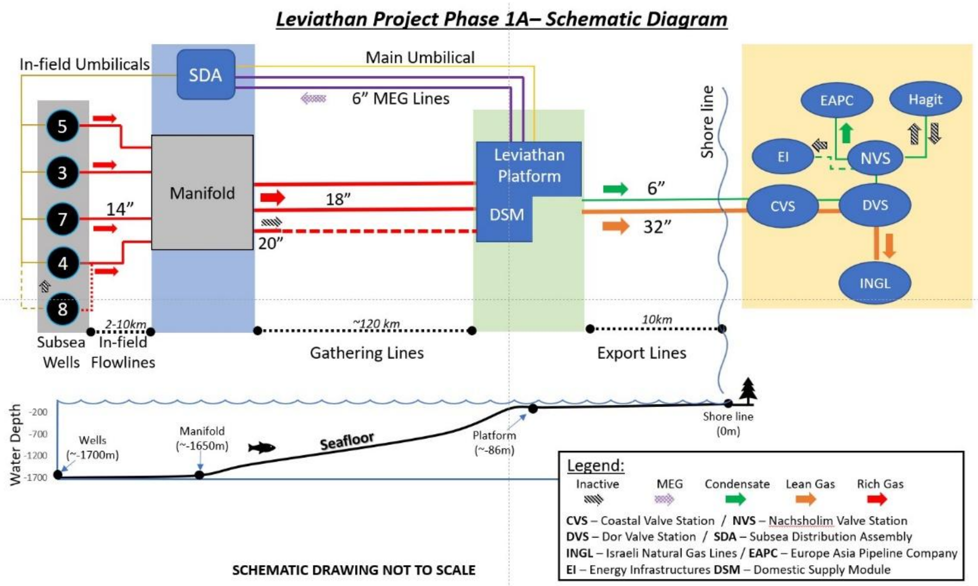
[87] The data relates to the total sales of natural gas produced from the Leviathan reservoir and are rounded off to one tenth of a BCM.

the production platform to the wells. Furthermore, a command and control (umbilical) cable, approx. 120 km long connects the production platform to the wells and manifold and enables the control and command of the production of the natural gas system on the seabed.

(c) Processing and production platform: The Leviathan platform is situated approx. 10 km from the shore. The entire gas and liquid treatment process is performed on the platform. The platform is attached to the seabed at a water depth of approx. 86 meters via a jacket. On the upper part of the topsides, which protrudes above sea level, the decks of the platform (which are referred to, as a single whole, as topsides) are assembled, which are divided at this stage into 2 main modules: (a) the domestic supply module (DSM) which contains, *inter alia*, the natural gas and condensate production and processing facilities, including facilities to separate out water from the gas, facilities for treatment of MEG, a facility for reduction of emissions (FGRU), generators, tanks, pumps, air compressors, a helipad, workers' living quarters, firefighting facilities, lifeboats, security facilities, gas dehydration facilities, auxiliary facilities and services, etc.; (b) the liquids supply module (LSM) which stores condensate and MEG. The capacity of the platform can handle approx. 1,200 MMCF of gas per day and approx. 5,400 barrels of condensate per day. However, under certain operating conditions, greater production may be attained.

(d) Transmission system to the shore: The pipeline that comes out of the Leviathan platform to the shore includes a 32-inch pipe for the transmission of natural gas[88] and a 6-inch pipe for the transmission of condensate. These pipes run under the shoreline, reach the coastal valve station and from there, the Dor valve station, which is situated near the INGL valve station, to which the natural gas is transferred. The condensate pipe connects at the Nahsholim Valve Station to the oil pipelines of EAPC and of PEI, as well as to the Hagit site.

[88] For details regarding a license for construction and operation of a transmission system, see Section 7.24.13(a) below.

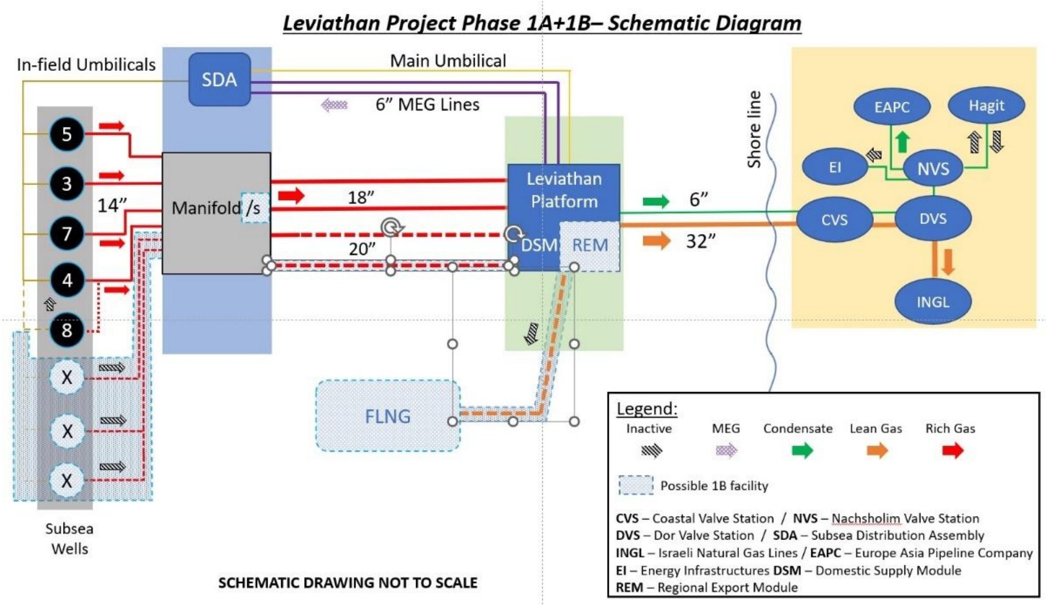


(e) Hagit site: The Hagit site includes a tank for temporary storage of condensate, and next to it is a tanker filling facility. The condensate is transported to the Hagit site via a 6-inch designated onshore pipe. The site is designated to allow for continued regular supply of natural gas also in situations where it is not possible to pipe condensate through a direct pipe from the Nahsholim Valve Station to the refinery. As of the report approval date, condensate cannot be stored at the Hagit site due to damage caused to the storage tank by weather conditions. The operator presented a plan to the Petroleum Commissioner for restoration of the storage tank to service, but according to its assessment, given the existence of 3 additional alternatives for the supply of the condensate, including one alternative through the PEI pipeline which is located southern to ARF, a second alternative through the EAPC pipeline which is located north of ORL, and a third alternative through tanks, the aforesaid is not expected to materially affect the operations of the Leviathan project. For details regarding the agreements with the condensate customers, see Sections 7.12.4(b) and 7.12.4(d) above.

7.17.2 Phase 1B of the Leviathan project development plan

Phase 1B of the development plan is intended to increase the daily production capacity of the Leviathan project to approx. 2.1 BCF, and under certain operating conditions even above that. The facilities planned in this context (as an addition to Phase 1A) include, *inter alia*, 3 additional production wells, each with a production capacity of up to approx. 400 MMCF per day, which shall be connected to the platform via a subsea pipeline and equipment which predominantly serves the existing production system, including the Third Pipeline Project. According to the plan, a 'Regional Export Module' (REM) that consists of additional natural gas and condensate processing systems will be added to the platform.

7.17.3 See Section 7.2.5 above for details about the possibilities for increasing the daily production capacity in the Leviathan project and the various alternatives explored by the Leviathan Partners in relation thereto, and about the updated development plan for the Leviathan reservoir, which was submitted by the Leviathan Partners to the Petroleum Commissioner, and mainly includes updates on Phase 1B, including the laying of a fourth pipeline, between the field and the platform, in a manner that is expected to increase the maximum daily production capacity to a total quantity of approx. 23 BCM per year.



7.18 Raw materials and suppliers

In general, engagements with suppliers or professional contractors, are made by the operator of the various projects. It is noted that, in Israel, there are currently no companies that can perform the main acts performed in the projects, such as the drilling of wells at deep sea, production and laying of subsea infrastructures, production and establishment of marine facilities such as processing and production platforms, etc. Therefore, a significant portion of the infrastructure and development work in the various projects in which the Partnership is a partner is performed through international suppliers, with whom the operator engages directly, on behalf of the partners in the project. However, it is noted that the international suppliers are instructed to integrate into their activity, insofar as possible, local services and consultants. It is emphasized that this situation, in which services are imported from various countries for the establishment and operation of the projects, is customary in the oil and gas industry, also when the project is located in a country with high capabilities in the field, such as the United States or England. In this context, designated tools and materials, such as drilling vessels and crane platforms as well as pipes and cement, are leased or purchased, and brought in from all over the world in accordance with their availability, the work type and the project requirements. Accordingly, the costs of each tool and material depend on global supply chains, and are sensitive, *inter alia*, to volatility in the prices of raw petroleum and to current and projected demand for natural gas. In this context, it is noted that due to the prolonged War in Israel, the availability of foreign contractors and suppliers required for the execution and advancement of various projects has been impacted, resulting in delays in the project timetables. For further details, see Section 6.8 above, and the risk factor in Section 7.30.1 below.

7.19 **Human capital**

7.19.1 In accordance with the provisions of the Partnerships Ordinance and the Partnership Agreement, the Partnership is managed by the board of directors of the General Partner. In general, the Partnership's workers are employed under personal employment agreements, and the officers and senior executives of the Partnership are employed according to terms and conditions that are agreed with each one of them in accordance with the Partnership's compensation policy. For further details see Regulations 21, 26 and 26A of Chapter D of this report.

7.19.2 According to the resolution of the general meeting of the unit holders, of 21 September 2022, the Partnership bears all of the management expenses of the Partnership and the General Partner, including the cost of employment of the Active Chairman of the Board, the CEO and all the other officers and employees of the Partnership, with the exception of the compensation of directors appointed by Delek Group, the control holder of the Partnership. For further details regarding the said resolution, see the Partnership's immediate reports of 6 September 2022 and 21 September 2022 (Ref.: 2022-01-092520 and 2022-01-120358, respectively), the information appearing in which is incorporated herein by reference.

7.19.3 As of 31 December 2023 and 31 December 2024, 23 employees were employed by the Partnership, 10 of whom are officers. As of the report approval date, the Partnership employs 24 employees, 10 of whom are officers.

7.19.4 In addition to the Partnerships' managers and workers above, the Partnership uses various consultants, including geological and professional consultants, lawyers and financial consultants) to the extent that such counsel is required. In addition, in the framework of operational agreements in various projects, the operator of the projects employs manpower for the purpose of management and operation of the projects.

7.20 **Working capital**

The Partnership's working capital comprises, on the assets side, primarily the cash balances, short-term investments and deposits, various receivables, and trade and other receivables deriving from the joint ventures, whereas, on the liabilities side, it primarily comprises payables deriving from the joint ventures, profits declared and not yet distributed, and short-term liabilities for retirement of oil and gas assets. For further details, see the statements of financial position in the financial statements (Chapter C of this report).

7.21 Financing

7.21.1 General

As of the report approval date, the Partnership finances its activity mainly from income from the sale of natural gas to customers of the Leviathan project and from the issue of bonds to the institutional market in Israel and overseas.

7.21.2 Bonds of Leviathan Bond

On 18 August 2020, Leviathan Bond, a special-purpose subsidiary (SPC) wholly (100%) owned by the Partnership, completed an issuance of bonds to foreign and Israeli institutional investors, in accordance with Rule 144A and Regulation S, in the overall amount of $2.25 billion, in 4 different bond series, as follows (in this section: the "**Bonds**" and the "**Leviathan Bond Issuance**", respectively):

(a) Bonds totaling $500 million in par value, which were paid by 30 June 2023, and bore fixed annual interest at the rate of 5.75%.

(b) Bonds totaling $600 million in par value, payable on 30 June 2025 (in one installment), bearing fixed annual interest at the rate of 6.125%.

(c) Bonds totaling $600 million in par value, payable on 30 June 2027 (in one installment), bearing fixed annual interest at the rate of 6.5%.

(d) Bonds totaling $550 million in par value, payable on 30 June 2030 (in one installment) bearing fixed annual interest at the rate of 6.75%.

The principal and interest of the Bonds are in dollars, with the interest on the Bonds of each series being paid twice a year, on June 30 and December 30. The Bonds were listed on TASE's "TACT-Institutional" system. For additional information on the Leviathan Bond Issuance see the Partnership's Immediate Report of 5 August 2020 (Ref. 2020-01-084006).

The issue proceeds were provided as a loan to the Partnership by the subsidiary, as noted, under terms and conditions that are identical to the terms and conditions of the Bonds (back-to-back). The balance of the bonds as of 31 December 2024 (net of capital raising and buyback costs, as specified below) was approx. $1.63 billion.

On 21 January 2023, the General Partner's board of directors approved the adoption of a plan for the purchase of bonds, in an aggregate sum of up to $100 million, for a period of two years, and accordingly, the Partnership made buybacks of the bonds, in the full sum of such plan.

On 15 October 2024, the board of directors of the General Partner approved the adoption of another plan for purchase of the bonds, in an aggregate amount of up to $100 million, for a period of two years (the "**Additional Purchase Plan**"). By the report approval date, the Partnership has carried out buybacks of the bonds, at a scope of approx. $44 million, in accordance with the Additional Purchase Plan.

It is clarified that the aforesaid decisions do not obligate the Partnership and/or Leviathan Bond to purchase the bonds in whole or in part, and that the Partnership's management may decide not to purchase bonds at all, and/or purchase bonds at a lower scope than the one approved.

For further details about the Additional Purchase Plan, see the Partnership's immediate report of 20 October 2024 (Ref. 2024-01-611345), the information appearing in which is incorporated herein by reference, as well as Section 3E in Part One of the Board of Directors' Report (Chapter B of this report).

For further details about the bonds, see Part Five of the Board of Directors' Report (Chapter B of this report) and Note 10C to the financial statements (Chapter C of this report).

7.21.3 Credit facility

On 8 October 2024, agreements were signed by the Partnership for the provision of credit facilities from two Israeli banks, each in the amount of $200 million (the "**Credit Facilities**"). It is noted that the Credit Facility from one of the banks replaces a $100 million credit facility that was provided to the Partnership by such bank on 14 March 2024 (for details, see Note 10E to the financial statements (Chapter C to this report). The Credit Facilities are designed to serve the Partnership in its operating activities, including in connection with Stage 1B of the development plan of the Leviathan reservoir. According to the terms and conditions of the Credit Facilities, over a term beginning on 8 October 2024 and ending on 8 October 2025, the Partnership will be able, from time to time, to draw down dollar loans up to a total amount of U.S. $200 million from each of the lenders (the "**Loans**"). The Loans that shall be drawn down as aforesaid, shall be partially repaid by 15 April 2027, and the balance of which, by 15 October 2027. As of the report approval date, the Partnership has drawn no amount of the Credit Facilities.

For further details regarding the Credit Facilities, see the Partnership's immediate report of 9 October 2024 (Ref.: 2024-01-608995), the information appearing in which is incorporated herein by reference, and Note 10D to the financial statements (Chapter C of this report).

7.21.4 Financial covenants

The Credit Facilities prescribe financial covenants which the Partnership is required to meet, the violation thereof gives the lender the right to acceleration, as specified below:

(a) The ratio between the value of the Partnership's assets and the net financial debt shall be no less than 1.5 on two consecutive review dates, with the covenant review being each quarter according to the Partnership's annual consolidated financial statements or according to the Partnership's quarterly consolidated financial statements, or each half-year insofar as the Partnership prepares only semi-annual reports.[89]

(b) The ratio between the surplus sources and the amount in the Credit Facility shall be no less than 1, and for the purpose of this calculation, an amount will be added to the sources which is equal to the balance of the Credit Facility not yet drawn down at such time, and it shall be deemed as part of the "surplus sources". A review of the coverage ratio shall be conducted every half-year according to the sources and uses report.[90] For further details, see Note 10D to the financial statements (Chapter C of this report).

The following table presents details regarding the financial covenants with which the Partnership is required to comply, and which give rise to the lender's right to acceleration, in accordance with the figures of

[89] For this purpose, the "**value of the Partnership's assets**" – the total capitalized cash flow (at a rate of 10%), after deduction of taxes of the probable and/or contingent reserves (2P and/or 2C) of the Partnership's share in all of the projects, on the basis of the latest discounted cash flow (DCF) announced to the Partnership public, plus the value of additional assets of the Partnership (which are not included in the definition of projects) on the basis of an independent external valuation by a valuator whose identity is acceptable to the Bank.
"**Projects**" – Gas and oil projects that are held by the Partnership and for which a DCF report was released to the public.
"**Financial debt**" – Duties and obligations of the Partnership to banks and other financial institutions and/or which derive from bonds of any type, including straight bonds and convertible bonds and/or which derive from loans which were received by the Partnership from affiliated companies or from any third parties (other than loans for which letter of subordination were signed vis-a-vis bank by the Partnership and the loan provider). For the avoidance of doubt, the term "financial debt" does not include guarantee facilities and bank guaranties issued thereunder at the Partnership's request.
"**Net financial debt**" – Financial debt net of: (1) cash and cash equivalents; and (2) deposits in banks and financial institutions; (3) fund and safety cushions which were given in order to secure a financial debt (insofar as such were not included in subsection (1) or (2)), and provided that none of the assets specified above is encumbered with a fixed charge and/or is the subject of an undertaking of non-withdrawal in favor of any entity which is not the bank other than due to the debt or liability included in the definition of the financial debt.
[90] For this purpose, "**surplus sources**" – the aggregate amount of sources by 31 December 2027 (as specified in an agreed form of sources and uses report) after deduction of the aggregate amount of uses (as defined in the sources and uses report) by 31 December 2027.

the Partnership's financial statements as of 31 December 2024 (Chapter C of this report):

Covenant	Value calculated as of 31 December 2024
The ratio between the value of the Partnership's assets and the net financial debt, shall be no less than 1.5 on two consecutive check dates	4.48
The Partnership's liquidity (on a standalone basis) shall be no less than $20 million	Approx. $451 million
Total financial debt, other than limited recourse loans, which are not the bonds of Leviathan Bond Ltd., shall not exceed $3 billion	Approx. $1.6 billion
The ratio of surplus of sources to credit facility amount in each bank separately shall be no less than 1	4.45

7.22 Taxation

7.22.1 General

In accordance with an amendment to the Income Tax Regulations (Rules for the Calculation of Tax for the Holding and Sale of Participation Units in Oil Exploration Partnerships), 5749-1988 (the "**Income Tax Regulations**"), which amendment was approved on 3 August 2021, as of the tax yea" 2022, the Partnership has been governed by the tax regime that governs companies. As a result of this change, from the tax year 2022, the holders of the Partnership's Participation Units are subject to a tax regime for profit distributions made by the Partnership, similarly to the tax regime applicable to shareholders of a company in respect of dividend distributions (i.e., according to the two-stage method).[91] For additional details in this regard, see Note 20A to the financial statements (Chapter C of this report).

7.22.2 Section 19 of the Taxation of Profits from Natural Resources Law

For details regarding a legal proceeding conducted by the Partnership with respect to Section 19 of the Taxation of Profits from Natural Resources Law, and regarding an originating application that was filed by the Partnership and the General Partner with the District Court in connection with application of the provisions of Section 19, see Note 19C to the financial statements (Chapter C of this report). It is noted that a summary report by the trustee, who was appointed by the court to execute the payment according to the judgment, was filed with the court on 30 April 2024 (the "**Summary Report**"). According to the Summary Report, the distribution of the money has been completed, with 99.7% of the total compensation amount distributed to the eligible holders in the Partnership and in Avner. In May 2024, the trustee returned the remaining amounts in the trust accounts to the

[91] See link to the Tax Regulations as published in the Official Gazette on 14 September 2021: https://www.nevo.co.il/law_word/law06/tak-9627.pdf.

Partnership. It is clarified that with the filing of the Summary Report, the legal proceeding on this matter was concluded.

7.22.3 Oil and gas profit levy

(a) The Taxation of Profits from Natural Resources Law (in this section: the "**Law**"), enacted by the Knesset in April 2011, determined, *inter alia*, provisions which apply to the Partnership regarding a duty to pay an oil and gas profit levy pursuant to an R-Factor mechanism (in this section: "**Petroleum Profit Levy**" or the "**Levy**"). For details regarding the Levy and its calculation mechanism, as well as regarding the legal proceedings conducted in connection with the Levy for the Leviathan and Tamar reservoirs, see Note 19C to the financial statements (Chapter C of this report), respectively.

(b) 2 December 2020 saw the publication of the Taxation of Profits from Natural Resources Regulations (Advance Payments toward the Petroleum Profit Levy), 5781-2020 (in this section: the "**Regulations**")[92] pursuant to Sections 10(b) and 51 of the Law, which are intended to regulate the issue of advance payments in respect of the Petroleum Profit Levy to be paid by holders of petroleum interests in a petroleum project, including the calculation method, payment dates and reporting of the advance payments. A summary of the principal provisions included in the Regulations follows.

1. The Regulations determine that a holder of a petroleum interest in a petroleum venture (in this section: the "**Petroleum Interest Holder**") shall pay advances on account of the Levy for that tax year, with payment starting from the tax year following the tax year in which the Levy coefficient is 1 or more, plus interest and linkage differentials from the set payment date until payment of the amount of the advance.

2. In addition, formulae were determined for the calculation of the advance payment's amount, rate, payment date and method of reporting of the amount paid. According to the Regulations, anyone who is a Petroleum Interest Holder shall be obligated to pay the advances out of the ongoing receipts of the venture according to their proportionate share of the petroleum interest (in the case of joint marketing), or the ongoing receipts of the Petroleum Interest Holder (in the case of separate oil sale). It is further determined that in the first 3 tax years, starting from the tax year following the tax year in which the Levy coefficient is 1 or more, or starting from the 2021 tax year, whichever is later, the rate of the advance shall be: in the first tax year – 21%; in the second tax year – 30%; and in the third tax year – 37%.

[92] https://www.gov.il/BlobFolder/legalinfo/law8957/he/LegalInformation_kesher_8957.pdf

3. Pursuant to Section 9(b)(1) of the Law, a "derivative payment" is a payment calculated as a rate of the petroleum produced in the area of the petroleum venture, from the receipts of the venture or from the oil profit of the venture, and the recipient of a derivative payment is liable for payment of a levy known as the "participation amount". The section determines that the participation amount shall be subtracted from the Levy owed by the Petroleum Interest Holder, and therefore, the Regulations determine that Petroleum Interest Holders are entitled to offset against their advance payments sums they withheld from derivative payment recipients, pursuant to the provisions of Section 9(b)(1) of the Law, provided that all of the following are satisfied: (a) The Petroleum Interest Holder transferred the amount of the Levy he has withheld to the Assessing Officer, no later than the date of payment of the advance for the effective month; (b) The transferred withheld amount has not been previously offset; and (c) The effective month due to which the setoff was required falls within the same tax year as that in which the derivative payment was received.

4. The Assessing Officer may decrease or increase the rate of the advance for a certain tax year if it shall have been proven to his satisfaction that the Levy for the tax year in which the advance is paid is higher or lower than the total advances calculated for that tax year.

(c) On 10 November 2021 the Knesset approved Amendment No. 3 to the Law, which includes, *inter alia*, an amendment whereby, pursuant to the decision of an **A**ssessing **O**fficer, payment of 75% of the balance of the amount of a Levy that has been appealed may be compelled (before the dispute is resolved), and other amendments designed to confer powers on the assessing office to streamline the collection of the Levy. For further details, see Note 19C to the financial statements (Chapter C of this report).

7.22.4 <u>The 2015-2016 tax years</u>

(a) On 3 December 2017, the Partnership released an immediate report, attached to which were temporary tax certificates for entitled holders in respect of holding participation units of the Partnership and of the Avner Partnership (in this section: "**Entitled Holders**") for the 2015 and 2016 tax years (Ref. 2017-01-116190).

(b) On 20 October 2021 the Partnership issued an immediate report, attached to which were final tax certificates for Entitled Holders for the 2015 tax year (Ref. 2021-1-158139), the information included in which is incorporated herein by reference.

(c) In view of the disputes that had arisen between the Partnership and the Tax Authority and the disagreements on the amount of the Partnerships' taxable income in 2016, assessments to the best of judgment were received from the Tax Authority on 22 November 2018, pursuant to Section 145(a)(2)(b) of the Income Tax Ordinance, 5721-1961 (the "**Income Tax Ordinance**" and, in this section: the "**Tax Assessment**").

The disputes primarily pertain to the manner of recognition of finance expenses and other expenses that have been actually borne by the Partnerships and the manner of calculation of the capital gain from the sale of the Karish and Tanin Leases.

Further to an administrative objection to the Tax Assessment that had been filed by the Partnership, the Partnerships were issued tax assessment orders pursuant to Section 152(b) of the Income Tax Ordinance (the "**Orders**").

According to the Orders, the taxable business income of the Partnership and of the Avner Partnership in 2016 was approx. \$125.1 million and approx. \$113.4 million, respectively (rather than approx. \$106.6 million and approx. \$94.9 million, respectively, as included in the Partnerships' tax reports as filed with the Tax Authority), and the capital gain of the Partnership and of the Avner Partnership in 2016 was approx. \$49.1 million and approx. \$66.8 million, respectively (rather than approx. \$7.5 million and approx. \$18.0 million, respectively, as included in the Partnerships' tax reports as filed with the Tax Authority). It is noted that the said amounts were converted from ILS to \$ according to the dollar exchange rate known as of 31 December 2024.

In the event that all of the Tax Authority's arguments are accepted, the Partnership shall be liable to pay additional tax (including interest and linkage differentials) on account of the tax owed by holders of participation units in the Partnerships of approx. U.S. \$54.5 million.

On 15 September 2020, the Partnership filed a notice of appeal from the Orders with the Tel Aviv District Court. The grounds for the tax assessment in the appeal were submitted by the Assessing Officer on 21 December 2020, according to the Court's decision. A notice of the grounds for the appeal on behalf of the Partnership was filed on 3 May 2021. A pretrial hearing on the appeal was held on 25 November 2021, and another pretrial hearing was scheduled for 17 March 2025.

It is noted that in view of the aforesaid, the issue of final tax certificates for Entitled Holders, in respect of the holding of a participation unit of the Partnership and the Avner Partnership for the tax year 2016, may be delayed until the completion of the proceeding required for the determination of a final assessment. In the Partnership's estimation, based on the opinion of its legal counsel and past experience, chances of acceptance of the Partnership's principal arguments are higher than 50%.

(d) Upon determination of the taxable income of an Entitled Holder for tax year 2016, a final certificate will be issued for purposes of calculating the taxable income of an Entitled Holder for tax year 2016, according to the Income Tax Regulations.

7.22.5 <u>The 2017 tax year</u>

(a) On 8 November 2018, the Partnership released an immediate report, attached to which was a temporary tax certificate for Entitled Holders in respect of holding of participation units of the Partnership for the 2017 tax year (Ref. 2018-01-101494).

(b) Against the backdrop of the disputes that arose between the Partnership and the Tax Authority and disagreements regarding the amount of the Partnership's taxable income of the Partnership in 2017, on 23 July 2020, a tax assessment to the best of judgment was received from the Tax Authority, pursuant to Section 145(a)(2)(b) of the Income Tax Ordinance (in this section: the "**Tax Assessment**").

The disputes mainly pertain to the interpretation of the manner of recognition of financial expenses and additional expenses actually borne by the Partnership, including attribution of financial income deriving from exchange rate differences to a property under construction, the manner of implementation of Section 20(b) of the Taxation of Profits from Natural Resources Law with regard to deduction of depreciation expenses and losses formed in respect thereof and the manner of calculation of the capital gain from the sale of 9.25% (of 100%) of the interests in the Tamar and Dalit leases.

On 10 December 2020, the Partnership filed an administrative objection to the Tax Assessment, and, accordingly, several discussions have been held at the offices of the Assessing Officer with respect to the administrative objection.

On 21 December 2022, the Assessing Officer issued an order for tax assessment for the 2017 tax year.

In accordance with the said order, the Partnership's taxable business income in 2017 was approx. $342.3 million (rather than approx. $204.3 million, as included in the Partnership's tax report as filed with the Tax Authority) and the Partnership's capital gain in 2017, including deferred capital gain, was approx. $726.3 million (rather than approx. $590.2 million, as included in the Partnership's tax report as filed with the Tax Authority). It is noted that the said amounts were converted from ILS to $ according to the dollar exchange rate known as of 31 December 2024.

It is further noted that on 22 January 2023, the Partnership filed a notice of appeal from the order with the Tel Aviv District Court. The grounds for the tax assessment were filed by the Assessing Officer on 30 May 2023. A notice of the grounds for the appeal on behalf of the Partnership was filed on 31 January 2024. A pretrial hearing on the appeal was scheduled for 17 March 2025.

As of the report approval date, according to the said order, and insofar as all of the claims of the Tax Authority are accepted, the Partnership will be required to pay additional tax (including linkage differentials and interest), at the expense of the participation unit holders of the Partnership, in the sum of approx. $120.8 million.

It is noted that, in view of the aforesaid, the issuance of a final tax certificate for an eligible holder due to the holding of a Participation Unit of the Partnership for the 2017 tax year may be delayed pending the completion of the proceedings which will be required for the determination of the final assessment.

In the Partnership's estimation, based on the opinion of its legal counsel, chances of acceptance of the Partnership's principal arguments are higher than 50%, and the Partnership therefore intends to exhaust the administrative and legal proceedings available thereto.

(c) Upon determination of the taxable income of an Entitled Holder for the 2017 tax year, a final certificate will be issued for purposes of calculating the taxable income of an Entitled Holder for tax year 2017, according to the Income Tax Regulations.

7.22.6 <u>The 2018 tax year</u>

(a) On 19 February 2020, the Partnership released an immediate report, attached to which was a temporary tax certificate for Entitled Holders in respect of the holding of a participation unit of the Partnership for the 2018 tax year (Ref. 2020-01-017376), the information appearing in which is incorporated herein by reference.

(b) Against the backdrop of the disputes which arose between the Partnership and the Tax Authority and disagreements regarding the amount of the taxable income of the Partnership for 2018, on 24 March 2021, a tax assessment other than in agreement was received from the Tax Authority, pursuant to Section 145(a)(2)(b) of the Income Tax Ordinance (in this section: the "**Tax Assessment**"), whereby the Partnership's taxable business income in 2018 was approx. $179.6 million (rather than approx. $137.1 million, as included in the Partnership's tax report as filed with the Tax Authority) and the Partnership's capital gain in 2018 was approx. $15.9 million, as stated in the report so filed thereby. It is noted that the said amounts were converted from ILS to $ according to the dollar exchange rate known as of 31 December 2024.

The disputes mainly pertain to the interpretation of the manner of recognition of financial expenses and additional expenses borne by the Partnership, similar to the disputes for which assessments to the best judgment were issued for 2016 and 2017, as specified in Sections 7.22.4(c) and 7.22.5(b) above, respectively.

As of the report approval date, pursuant to the Tax Assessment, and insofar as all the Tax Authority's arguments are accepted, the Partnership will be required to pay additional tax (including interest and linkage differentials), at the expense of the holders of Participation Units in the Partnership, in the amount of approx. $15 million.

On 10 June 2021, the Partnership filed a reasoned administrative objection to all of the Assessing Officer's determinations in the Tax Assessment. On 28 March 2024, an assessment order was received from the Tax Authority, pursuant to Section 152(b) of the Income Tax Ordinance. On 17 April 2024, the Partnership filed a notice of appeal on its behalf, with respect to such order and accordingly, a court file was opened. On 30 September 2024, a notice interpreting the reasons for the assessment of the Assessing Officer was filed, and according to the decision of the court, the Partnership filed the notice interpreting the reasons for the appeal on its behalf, on 17 February 2025.

It is noted that in view of the aforesaid, the issuance of a final tax certificate for an Eligible Holder due to the holding of a Participation Unit of the Partnership for tax year 2018 may be delayed pending the completion of the proceedings which will be required for the determination of the final assessment.

In the Partnership's estimation, based on the opinion of its legal counsel, chances of acceptance of the Partnership's principal arguments are higher than 50%, and the Partnership therefore intends to exhaust the administrative and legal proceedings available thereto.

(c) Upon determination of the taxable income of an Entitled Holder for the 2018 tax year, a final certificate will be issued for purposes of calculating the taxable income of an Entitled Holder for tax year 2018, according to the Income Tax Regulations.

7.22.7 The 2019 tax year

(a) On 14 July 2021, the Partnership released an immediate report, attached to which was a temporary tax certificate for Entitled Holder in respect of the holding of a participation unit of the Partnership for the 2019 tax year (Ref. 2021-01-116862), the information included in which is incorporated herein by reference.

(b) Upon determination of the taxable income of an Entitled Holder for tax year 2019, a final certificate will be issued for purposes of calculating the taxable income of an Entitled Holder for the 2019 tax year, according to the Income Tax Regulations.

7.22.8 The 2020 tax year

(a) On 12 April 2022, the Partnership released an immediate report, attached to which was a temporary tax certificate for Entitled Holders and participation unit sellers in respect of participation unit-holding for the 2020 tax year (Ref. 2022-01-047374), the information appearing in which is incorporated herein by reference.

(b) Upon determination of the taxable income of an Entitled Holder for 2020 tax year, a final certificate will be issued for purposes of calculating the taxable income of an Entitled Holder for the 2020 tax year, according to the Income Tax Regulations.

7.22.9 The 2021 tax year

(a) On 30 April 2023, the Partnership released an immediate report, attaching thereto a temporary tax certificate for Entitled Holders and participation unit sellers in respect of participation unit-holding for the 2021 tax year (Ref. 2023-01-046137), the information appearing in which is incorporated herein by reference.

(b) Upon determination of the taxable income of an Entitled Holder for the 2021 tax year, a final certificate will be issued for purposes of calculating the taxable income of an Entitled Holder for tax year 2021 tax year, according to the Income Tax Regulations.

7.22.10 Although under the amendment to the Income Tax Regulations, the Partnership is taxed as a company (i.e., according to the two-stage method) as of 2022, as noted in Section 7.22.1 above, according to a clarification received from the Tax Authority, the payments made in January 2022 (after the tax regulations had taken effect) will not be taxed as a dividend distribution by a company according to the regulations.

7.22.11 It is clarified for each of the tax years from 2016 to 2021, for which court proceedings or administrative objection proceedings against the **A**ssessing **O**fficer are still conducted or the Tax Authority's audit of the Partnership's tax reports is as yet uncompleted, that after a final decision on the disputes litigated in court or the conclusion of mutual agreements with the **A**ssessing **O**fficer or the completion of the Tax Authority's audit, it may transpire that there are assessment differences, such that the final tax assessment will higher than the tax payments made by the Partnership (net of refunds paid thereto), in which case the Partnership will be required to pay the Tax Authority, on account of the participation unit holders, the balance of the tax deriving from the assessment differences, according to the tax calculation under Section 19 of the Natural Resources Law . It is noted that according to the judgment of 28 June 2021, as specified in Note 19B to the financial statements (Chapter C of this report), balancing payments due to such assessment differences (if any) will not be made starting from 2017. Should it transpire in the future that advances were paid by the Partnership in amounts exceeding the amount required by law, the balance will be repaid to the Partnership.

7.22.12 It is further clarified that part of the unique tax issues related to the Partnership's activity have yet to be addressed in Israeli case law, and it is difficult to anticipate or to determine how the Court will rule if and when said legal issues are brought before them. In addition, with regard to certain of the legal issues, it is difficult to anticipate what the Tax Authority's position will be.

7.22.13 For further details see Note 19B to the financial statements (Chapter C of this report).

Every participation unit holder should examine its tax status through professional consultants, as well as the need for preparation according to the recommendations of its professional consultants as aforesaid. The Partnership is not responsible and shall not bear any responsibility in connection with the reports of the unit holders and/or amendment thereof and/or repercussions of amendment thereof.

7.23 <u>Environmental risks and management thereof</u>

7.23.1 By nature, the activity of exploration, development, production and decommissioning of natural gas and petroleum projects entails the risk of causing damage to the environment, that may occur, *inter alia*, from faults in equipment and/or implementation of work procedures, and/or unforeseen events. The nature and severity of the risks varies from one type of activity to another, and therefore the manner of management thereof is different.

Environmental and climate-related issues have the potential to cause significant damage to the Partnership's business, and the Partnership therefore undertakes risk management efforts in these areas, as specified in Section 7.23.5 below. The Partnership's environmental and climate risk management addresses specifically each one of the Partnership's assets, reflecting the nature of the activities and their maturity. Risk management, including an initial methodological mapping, is carried out by the Partnership's ESG Officer, with the assistance of external consultants. It is primarily based on the risk management systems of the operators in the various assets, which are audited by qualified third parties and include, *inter alia*, a process of identification, analysis, management, and monitoring.

The ESG Officer reports the main findings of his work to the Audit Committee, and these findings form a key part of the Partnership's ESG report, which is posted on the Partnership's website from time to time and prepared in accordance with the GRI reporting standards and in the spirit of the recommendations of TCFD (an international task force for financial disclosure related to climate, established in 2015).

In addition, the Partnership has developed and is implementing a procedure on Environment, Health and Safety ("**EHS**") by the ESG Officer with the assistance of external consultants. This procedure is updated from time to time and regulates the interface with the operator in terms of reporting. It also allows for monitoring the implementation of the operator's management plan and its performance in the EHS field.

7.23.2 <u>The Partnership is subject to the provisions of the law and/or instructions of competent authorities on environmental issues.</u>

(a) The Petroleum Law and its regulations provide, *inter alia*, that upon performing drilling cautionary measures will be taken, such that there will be no unchecked liquids or gases flowing into the earth or rising from it and that there be no penetration from one geological layer into another. In addition, it is forbidden to abandon a well without plugging it according to the instructions of the Petroleum Commissioner.

(b) In addition, the Partnership's activity via the operator is subject to the provisions of various environmental laws including the Prevention of Sea Pollution (Dumping of Waste) Law, 5743-1983 and the regulations promulgated thereunder; Prevention of Sea Pollution from Land-Based Sources Law, 5748-1988 (the "**Prevention of Sea Pollution Law**") and the regulations promulgated thereunder; Prevention of Sea Water Pollution by Oil Ordinance (New Version), 5740-1980; Hazardous Substances Law, 5753-1993 (the "**Hazardous Substances Law**") and the regulations promulgated thereunder; Maintenance of Cleanliness Law, 5744-1984 and the regulations promulgated thereunder; Liability for Compensation for Oil Pollution Damage Law, 5764-2004 and the regulations promulgated thereunder; Prevention of Environmental Nuisances (Civil Actions) Law, 5752-1992; Clean Air Law, 5768-2008 (the "**Clean Air Law**") and the regulations promulgated thereunder; Environmental Protection (Emissions and Transfers to the Environment – Reporting Duty and Register) Law, 5772-2012 and the regulations promulgated thereunder; Abatement of Nuisances Law, 5721-1961 and the regulations promulgated thereunder; Protection of the Coastal Environment Law, 5764-2004; Business Licensing Law, 5728-1968 ("**Business Licensing Law**"), the regulations and the orders promulgated thereunder.

(c) On 12 September 2023, the Ministerial Committee for Legislation authorized the Draft Climate Law, 5783-2023 (the "**Draft Climate Law**") toward a first reading in the Knesset. On 22 September 2023, Government Resolution No. 927 was adopted, whereby the Government authorized the Draft Climate Law, subject to certain modifications. On 3 December 2024, the Knesset's Interior and Environmental Protection Committee discussed the Climate bill and made several modifications thereto, which have not yet been finally approved. Accordingly, before the bill is approved in the Knesset plenum in its second and third readings, the bill shall be sent for further discussion in the Ministerial Committee for Legislation. The Draft Climate Law establishes a national target for the reduction of greenhouse gas emissions in 2030, a 27% reduction, such that it total 73% of the amount of greenhouse gas emissions measured in 2015 (the base year). As of the report approval date, it is impossible to estimate when, if ever, the legislation proceedings of the Draft Climate Law will be promoted and what changes will be made therein.

(d) The 2024 Arrangements Law included the proposal to impose a carbon tax on fossil fuels used for electricity production and industry as well as on waste disposal. The said proposal took effect on 1 January 2025, and according to the framework that has been released, tax is gradually imposed on coal, natural gas, fuel oil, LPG and petcoke, at variable rates, with the natural gas being the lowest, in order to encourage the transition to alternative energy sources. In November 2024, the Investment Authority at the Ministry of Economy and Industry, in collaboration with the Ministry of Energy and the Ministry of Environmental Protection, released CEO Directive 4.79, which includes directives regarding the assistance mechanism for fuel consuming plants. The goal of such mechanism is to help the local industry adapt to the carbon tax and create business certainty regarding the investments required in this matter. In addition, an assistance track was released, focusing on the capture and removal of greenhouse gas emissions, aimed at incentivizing plants to reduce carbon emissions from their operations. In the Partnership's estimation, carbon tax, in its proposed form, has no material effect on its operations.

(e) On 2 May 2023, a policy document was released regarding the decommissioning of offshore petroleum and natural gas exploration and production infrastructures (policy of the Ministry of Environmental Protection and the Ministry of Energy). Chevron submitted a position regarding such document, as part of the public comments.

(f) 16 April 2024 saw the release of the Environmental Protection Law (Efficiency of Environmental Licensing Proceedings)(Legislative Amendments), 5784-2024, which passed the third reading at the Knesset on 3 April 2024. The purpose of the law is to optimize and enhance the efficiency of the existing licensing schemes from both a regulatory perspective and an environmental perspective, by means of a comprehensive reform that is based on conformity to the standards generally accepted in the European Union. The provisions of the law shall take effect gradually by 1 January 2027, in order to allow plants and businesses to prepare for the required changes and adjust their operations to meet the new requirements. In addition, under the law, the licensing arrangements in the existing environmental legislation will be amended so that licensing proceedings will be consolidated, to the extent possible, based on the regulation principles in the European Union, such that a uniform environmental permit will be issued for operations with the potential to cause considerable environmental impact. In addition, the law extends the validity of the toxins permits to ten years, reclassifies the types of activities that require a toxins permit, and allows for an exemption from permit for part of the activities that previously required a permit.

(g) On 14 April 2022, a memorandum was released for a Bill on the Preparedness and Response to Incidents of Oil Pollution of the Sea and Coastal Environment, 5782-2022, which aims to implement the 1990 International Convention on Oil Pollution Preparedness, Response and Cooperation at Israeli-local level. According to the said bill, all entities that have a coastal strip within their scope or under their responsibility or that operate in the sea, including owners of facilities for the exploration and production of petroleum and natural gas, shall be prepared for incidents of oil pollution of the sea and the coastal environment. The bill includes the method of regulation of incidents of this type on several levels: preparedness – preparation of emergency plans, equipping and practicing. These entities are required to prepare plans to face incidents and be prepared to act on them if they occur; Response to the incident – reduction of damage in general and environmental in particular; Cleaning and restoration – cleaning what is polluted, returning the situation to its original state, and removing the waste that was created. As of the report approval date, such bill has been presented to the Knesset for an initial discussion (preliminary reading).

(h) Besides the regulation imposed by Israeli law, additional directives on environmental issues are also imposed by the terms of the lease deeds and licenses that have been granted to the Partnership, and by the various approvals required for the purpose of conducting the exploration and production activities and for the purpose of construction and operation of the production systems of the projects in which the Partnership is a partner. Upon exploration, drilling and/or in the framework of the production of oil and natural gas, the Partnership purchases, independently and/or through the operator, in accordance with directives for provision of collateral in connection with petroleum interests (for details, see Section 7.24.7(a) below), insurance to cover damage for expenses of environmental cleanup, removal of debris and bodily injury and/or property damage to third parties which derive from a sudden, unexpected and uncontrolled accidental eruption of oil and/or natural gas. The Partnership does not take out insurance for non-accidental pollution damage resulting from a gradual and ongoing process. In this context, it is noted that the Petroleum Regulations (Principles for Offshore Petroleum Exploration and Production), 5777-2016 (which revoked the regulations of 2006) include various provisions regarding offshore petroleum exploration and production activity, and *inter alia* conditions in relation to the identity of an operator, including with respect to its experience in maintaining safety and environmental protection in the framework of petroleum exploration and production.

(i) On 30 December 2024, the Marine Zones Bill, 5785-2024 was placed on the Knesset's table for preliminary discussion (first reading). The bill, which wad submitted as a private bill, aims to regulate the activity of the State of Israel in maritime areas, including coastal waters, domestic waters, adjacent areas, EEZ and the continental shelf. The bill defines the rights and powers of the State of Israel in these zones, and sets forth the acts of legislation that shall apply thereto and to the marine facilities located therein.[93]

[93] https://main.knesset.gov.il/activity/legislation/laws/pages/lawbill.aspx?t=lawsuggestionssearch&lawitemid=2223639

(j) Environmental directives for offshore exploration and production of oil and natural gas

In September 2016, the Ministry of Energy, jointly with the Ministry of Environmental Protection and other government ministries, published directives designated to regulate the environmental aspects of the operations of offshore oil and natural gas exploration, development and production. Furthermore, the Ministry of Energy and the Ministry of Environmental Protection, as well as other agencies on behalf of other governmental bodies, including the Israel Land Authority, release environmental directives to which the Partnership may be directly or indirectly subject. Such directives are updated from time to time, and they are intended to instruct the holders of offshore petroleum interests as to the actions and documents they are required to prepare in the context of their operation in the areas of their rights, in order to prevent, or minimize to the greatest extent possible, environmental hazards that might be created during the operations of offshore oil and natural gas exploration, development and production. Such directives constitute an integral part of the petroleum interest and the work plan therefor, and deviation therefrom might lead to the revocation of the right. These directives include, *inter alia*, directives for the performance of seismic surveys, directives on the drilling of exploration and appraisal wells and directives post-discovery and on leases, and specify the various tests, approvals and permits which are required from the interest holders in each of the aforesaid stages.

(k) In addition to the instructions of the Ministry of Energy and the Ministry of Environmental Protection, in the context of its activity the Partnership may, directly or indirectly, be subject to environmental directives of additional authorities that may be given from time to time, on behalf of other governmental bodies, including the Israel Land Authority.

7.23.3 In addition, the operating approval of the Leviathan platform determines the leaseholder's duty to act, on issues of environmental protection, pursuant to the law and instructions and permits that are given pursuant to law, and also determine provisions with respect to the discharge of emissions into the sea, emissions into the air, etc. The said operating approval further determined that on matters in respect of which there are no provisions in Israeli legislation, U.S. standards will apply, subject to law, in relation to issues of safety and environmental protection, as well as the provisions specified in some of the annexes to the MARPOL Convention (The International Convention for the Prevention of Pollution from Ships) which apply or shall apply with respect to (mobile) rigs or permanent rigs.

7.23.4 Events in connection with the environment

According to information provided to the Partnership by the operator of the Leviathan project, in 2024 there was no event or matter relating to the Partnership's operations in connection with the environment which had a material effect on the Partnership. For details regarding material legal or administrative proceedings related to the environment, see Section 7.23.7 below.

7.23.5 Environmental risk management policy

(a) The operator in the Leviathan project operates according to a strategic policy for the protection of the environment and for compliance with the provisions of the law in general, and the environmental laws in particular. This policy includes the operator taking care to act in accordance with an environmental risk management system, including training suitable manpower, and including a work plan for the reduction of environmental damage, for the support in biodiversity, for the prevention of incidents and accidents and for the constant improvement of the organizational culture and activity on issues of safety, environment and hygiene. In this framework the operator has a designated team both for all stages of the activity, which is responsible for implementation of and supervision over such policy, and for fulfillment of the procedures for ensuring fulfillment of and compliance with all of the requirements and standards, including various systems for the management of environmental risks, such as SEMS (Safety & Environmental Management System). In addition, the operator performs due diligence by a third party, in addition to current audits performed by the Ministry of Energy and the Ministry of Environmental Protection in the production facilities. The operator carries out current activities on issues of EHS to increase awareness, knowledge and preparedness, including training of and drills for its teams and the teams of the contractors that work on the facilities. Additionally, the operator is acting to obtain all of the environmental-regulation permits required for each one of the sites operated thereby, as applicable, including a business license under the Business Licensing Law, a toxic materials permit under the Hazardous Substances Law, a marine discharge permit under the Prevention of Sea Pollution Law and an emission permit under the Clean Air Law. The Partnership is acting to receive periodic and specific updates regarding the operator's activity regarding the aforesaid matters, as needed and in accordance with an internal procedure on the matter, adopted by the Partnership.

(b) Over the course of 2019, the operator in the Leviathan project received a preliminary business license, air discharge permit, marine discharge permit and toxins permit for the Leviathan platform, which are extended from time to time in accordance with the requirements of the law. As of the report approval date, the business license is valid until 31 December 2029, the air discharge permit is valid until 5 November 2026, the marine discharge permit is valid until 31 March 2029, and the toxins permit is valid until 1 January 2027. A business license and toxins permit have also been obtained for the Hagit site, and their term is extended similarly.

(c) As for all of the assets in which the Partnership is not the operator, the Partnership is working to ensure that the operator conducts its activities in accordance with a strategic policy for environmental protection and complies with the provisions of the law in general, and environmental law in particular. Such policy includes ensuring that the operator follows actions in accordance with an environmental risk management system, including training appropriate personnel, and includes a work plan to reduce environmental harm, support biodiversity, prevent malfunctions and accidents, and continuously improve operations and organizational culture on EHS matters. In this context, the operator has a dedicated team which is responsible for implementing such policy and overseeing it, as well as ensuring the procedures are followed to meet all requirements and standards, including various risk management systems. The risk management systems are comprehensive and undergo internal and external controls from time to time, in accordance with international standards and by qualified third parties.

(d) A risk assessment conducted prior to entering the Boujdour license in Morocco, which the Partnership (through NewMed Morocco) is its operator, revealed that the primary ESG exposure is related to geopolitical issues. It is emphasized that the Boujdour license is currently at the initial exploration phase, which does not require substantial work on-site. In view of the aforesaid, the Partnership engaged with an international consulting firm specializing in ESG, with the aim of supporting its efforts to assess and monitor the geopolitical and social situation in the region.

7.23.6 Environmental costs and investments

The projected costs of actions relating to environmental protection are included in the budgets of the various projects and are updated from time to time according to the approved work plans. As of the report approval date, no additional material costs are expected.

It is noted that, over and above the direct costs associated with EHS, *inter alia*, costs for the development, production, and installation of dedicated systems, and costs for dedicated staff members on behalf of the operator whose role is EHS-related, there are also significant indirect costs which are inseparable from the costs of the projects and ongoing operations. These costs arise from the fact that the identification, characterization, management, and monitoring of environmental and safety risks are integrated into the operator's operational procedure (Operations Management System), and dictate the manner in which operations are conducted throughout the entire value chain.

7.23.7 <u>Material legal or administrative proceedings in connection with the environment</u>

As of the report approval date and to the best of the Partnership's knowledge, no material legal and/or administrative proceeding is being conducted against the Partnership and/or any of the officers of the General Partner and/or of the Partnership in connection with environmental protection, which is expected to have a material effect on the Partnership.

(a) <u>Administrative monetary penalties</u>

On 20 May 2020, Chevron received a notice from the Ministry of Environmental Protection of the intention to impose an administrative monetary penalty, in an immaterial amount, due to alleged violations of the Leviathan project's air emission permit and the Clean Air Law, and the instruction of the Supervisor of the Emission Permit in the Ministry of Environmental Protection (in this section: the "**Supervisor**"), given by virtue thereof in connection with the continuous monitoring systems in the Leviathan platform. Chevron has informed the Partnership that it has submitted an information request to the Ministry of Environmental Protection under the Freedom of Information Law, 5758-1998 (the "**Freedom of Information Law**"), which directly addresses the claims raised in such notice and that the Ministry of Environmental Protection has agreed to postpone the date for submission of the arguments with respect to such administrative penalty and schedule such date for 30 days after the information is received. The requested information has not yet been received and therefore the count of days for responding to the aforesaid notice has not yet begun and on 5 January 2025, a decision was made by the Ministry of Environmental Protection not to impose the said administrative penalty on Chevron.

(b) <u>Hearings</u>

On 6 August 2023, Chevron received a letter of notice and summons to a hearing before the Ministry of Environmental Protection for alleged violation of the marine discharge permit and the toxins permit of the Leviathan project, and in accordance with the Prevention of Sea Pollution and the Hazardous Substances Law. The hearing took place on 7 January 2024, and on 21 January 2024, the hearing summary was received, whereby Chevron is required to take all actions to prevent deviations from the marine discharge permit, and that the Ministry of Environmental Protection is considering exercising its powers according to law.

It is not possible at this stage to estimate whether an administrative monetary penalty will be imposed for the violations and the amount of the administrative monetary penalty that will be imposed, if any.

(c) On 7 February 2024, a judgment was issued, denying the motion for class certification that was filed on 15 December 2020 with the Tel Aviv District Court against Chevron on behalf of "anyone who was exposed to the air, sea and coastal environment pollution, due to prohibited emissions from the gas platform of the Leviathan project, while charging the Petitioner with expenses. For further details, see Section 7.22.7(c) of Chapter A to the 2023 Periodic Report.

7.23.8 To the best of the Partnership's knowledge, under the Cypriot Environmental Effects Of Plans And Activities Law of 2005, (which is adapted to the European Directive), a strategic environmental evaluation is required in connection with a governmental decision to perform plans that may have environmental impact. The holder of a license in Cyprus for exploration or production activities is obligated to act in accordance with an environmental assessment report prepared for the Cypriot Ministry of Energy and to conduct an environmental survey prior to the conduct of such activities in the area of the license.

7.23.9 It is noted that the EMG pipeline, which connects between the Israeli transmission system in the area of Ashkelon and the Egyptian transmission system in the area of el-ʻArīsh, is subject to Israeli and Egyptian regulation.

7.23.10 As of the report approval date, and in accordance with information provided to the Partnership by the operator, the Partnership has no knowledge of non-compliance or deviation from environmental quality requirements in projects in which the Partnership holds rights, that is expected to have a material effect on the Partnership.

7.24 Restrictions and supervision over the Partnership's activity

7.24.1 The Gas Framework

On 16 August 2015, Government Resolution No. 476 (readopted with certain changes in a Government Resolution of 22 May 2016) was adopted with respect to a framework for the increase of the natural gas quantity produced from the "Tamar" natural gas field[94] and the

[94] In the exemption pursuant to Section 52 of the Restrictive Trade Practices Law, which was attached as Annex A to the Framework, Tamar was defined as "a natural gas reservoir situated in the area of the Tamar I/12 and Dalit I/13 leases, and the rights held by the entities that hold Tamar in the gas transmission infrastructure, including

expeditious development of the "Leviathan", "Karish" and "Tanin" natural gas fields and other natural gas fields (in this section: the "**Government Resolution**"), which took effect on 17 December 2015, upon the grant of an exemption from certain provisions of the Economic Competition Law, 5748-1988[95] to the Partnership, Avner, Ratio and Chevron (in this section: the "**Parties**") by the Prime Minister, in his then-capacity as Minister of Economic Affairs, pursuant to the provisions of Section 52 of the Economic Competition Law (in this section: the "**Exemption**" or the "**Exemption Pursuant to the Economic Competition Law**"). The Exemption applies to certain restrictive arrangements which ostensibly may have been attributed to the Parties, as specified in the Government Resolution (the "**Restrictive Arrangements**"). The Government Resolution and the Exemption as aforesaid shall hereinafter be referred to above and below as the "**Gas Framework**".

Below is a concise description of the main parts of the Gas Framework.

(a) The restrictive trade practices in relation to which the Exemption was granted are as follows:

1. The Restrictive Arrangement that was ostensibly created, according to the Competition Commissioner's position, as a result of the acquisition of the rights in the Ratio-Yam permit by the Partnership, Avner and Chevron; and the Restrictive Arrangement that was ostensibly created as a result of the Parties' coming together as joint holders of the Ratio-Yam permit and the Leviathan reservoir.

2. The Restrictive Arrangement that shall ostensibly be created in a case in which the Parties or some of them jointly market the gas that shall be extracted from the Leviathan reservoir to the domestic market until 1 January 2030.[96]

3. The Restrictive Arrangement that shall ostensibly be created in a case in which the Parties or some of them jointly market the gas that shall be extracted from the Leviathan reservoir for export only.

all of its components and parts, including the rights of the holders of Tamar to use the onshore gas reception and processing facility, from the Tamar reservoir to the national transmission system".

[95] On 1 January 2019, the Amendment to the Competition Law was approved, in the context of which the name of the law was changed from the "Antitrust Law" to the "Economic Competition Law".

[96] In accordance with the authority of the Minister of Energy to extend the Exemption until 1 January 2030 upon the fulfillment of certain conditions as prescribed in the Exemption, if the Minister of Energy finds that there are at least three natural gas reservoirs that are connected to the national transmission system, each of which has an obligation to supply at least 30 BCM to the domestic market at such time, and no entity holds more than 25% of any rights in more than one reservoir, then the Exemption will be extended until 1 January 2030. Based on the publications of the Ministry of Energy, as of the report approval date, the conditions for extending the Exemption have been met.

4. The Restrictive Arrangement which may be created as a result of a certain agreement for the purchase of natural gas from the Leviathan reservoir, provided that such agreement is signed by 1 January 2025. Due to the expiration of the exemption for such Restrictive Arrangement on 1 January 2025, from such date forward, the agreements for the purchase of natural gas from the Leviathan reservoir are subject to the provisions of Chapter B of the Competition Law concerning restrictive arrangements, and the provisions of Section 43(a)(1), Section 47(a)(1), and Section 50A with respect to Chapter B and Section 50D(a)(1) of the Competition Law.

5. With respect to their activity in the Leviathan and Tamar reservoirs only, the Partnership, Avner and Chevron being the holders of a monopoly according to the Competition Commissioner's declarations. For details, see Section 7.24.2(a) below.

(b) The Exemption from the aforesaid Restrictive Arrangements had been contingent upon the satisfaction of certain conditions, including the transfer of all the interests of the Partnership and Chevron in the Tanin and Karish Leases, the transfer of all the interests of the Partnership in the Tamar project and the transfer of some of the interests of Chevron (interests in excess of 25%) in the Tamar project, all of which were completed in accordance with the framework by December 2021.

(c) <u>Specific restrictions to apply to new agreements for the supply of natural gas</u>

The Gas Framework sets out specific restrictions that will apply to new agreements for the supply of gas from the Leviathan reservoir, that shall be signed with consumers from the date of the Government Resolution. Most of the restrictions are no longer relevant, other than:

1. The consumer shall be subject to no restriction with respect to the purchase of natural gas from any other natural gas supplier.

2. The consumer will have the possibility of selling natural gas that it purchased in a secondary sale, in accordance with the conditions and provisions set forth in the Exemption.

3. The parties shall not apply any restriction to the sale price at which the consumer shall sell the natural gas in a secondary sale.
4. The gas sales agreements shall not include a condition whereby the consumer's notification of shortening of the term of the agreement or reduction of the purchase amount will lead to any

change in the terms of the agreement that is detrimental to the consumer. In this context, no change detrimental to the consumer shall be made to the price and terms of payment, the terms, dates and quantities of supply, the addition of restrictions on resale of the gas, etc.

7.24.2 Economic competition laws

(a) The status of the Partnership as a monopoly

On 13 November 2012 the Partnership was declared a monopoly – together with its other partners in the Tamar project and separately – in the supply of natural gas in Israel commencing upon the date of the beginning of commercial supply from the Tamar project.

Even though in December 2021 the Partnership closed the sale of the balance of its interests in the Tamar and Dalit leases, as of the report approval date, the declaration of the monopoly in Tamar was not changed by the Competition Authority, and the Partnership still appears in the Register of Monopolists. In addition, since as of the report approval date, the Partnership is engaged in the joint marketing of the gas produced from the Leviathan project, it may also be considered a monopoly insofar as the Leviathan Partners are considered a monopoly in the natural gas supply in Israel.

A monopoly is subject to Chapter D of the Economic Competition Law, including a prohibition to unreasonably refuse to supply the asset or service in the monopoly and a prohibition on abuse of its position in the market in a manner that might reduce competition in business or harm the public.

(b) Natural gas price control

The Products and Services Price Control Order (Application of the Law to Natural Gas and Determination of Level of Control), 5773-2013 (the "**Products and Services Price Control Order**"), imposes control on the gas market at the level of profitability and price reporting. Such duty to report applies separately with respect to each project. Over and above the duty to report prices and profitability, as of the report approval date, no further sections have been implemented pursuant to the Products and Services Price Control Order in relation to the prices of gas marketed in Israel. For details regarding a risk factor pertaining to the possible impact of imposing control on natural gas prices in Israel, see Section 7.30.20 below.

(c) <u>The consent of the Competition Commissioner to the merger in connection with the acquisition of EMG shares</u>

In order to enable the export of gas from the Leviathan reservoir to Egypt, EMED acquired 39% of the share capital of EMG, according to an agreement signed in September 2018, specified in Section 7.26.6 below. The acquisition of EMG shares was subject, *inter alia*, to the receipt of approval for the merger, in accordance with Section 20(b) of the Economic Competition Law. On 31 July 2019, the decision of the Competition Commissioner approving the merger was given[97], under the conditions whose summary is described below:

1. The Partnership, Chevron, EMG and EMED and any party related thereto as defined in the Resolution (in this section jointly: the "**Parties**") shall not refuse a request for gas swap and shall supply natural gas to a customer in Israel who signed a natural gas supply contract with a natural gas supplier in Egypt, in the same quantity and at quality no lower than the quality undertaken by the natural gas supplier in Egypt to the customer in Israel (the "**Gas Swap Arrangement**"). In this context, they shall make every reasonable effort including by exercising their rights in the Leviathan and Tamar projects, in order to comply with such request.

2. The duty of the parties as stated in Section 7.24.2(c)1 above is up to the quantities of gas set forth in the Take or Pay clauses signed by the Leviathan Partners or any one of them and the Tamar Partners or any one of them in respect of which there are transmission agreements in the EMG pipeline.

3. In respect of natural gas to be swapped as part of the Gas Swap Arrangement, EMG shall not charge from an Egyptian supplier an amount that exceeds one half of the pipeline transmission fee.

4. The Parties shall not refuse to provide pipeline transmission services to another party wishing to receive pipeline transmission services up to the amount of the available capacity.

5. The aforesaid notwithstanding, the obligation to provide the transmission services shall not apply in any of the following cases: (a) the other party shall have refused to sign a transmission agreement with the Parties, despite the Director of the Natural Gas Authority having confirmed that the transmission agreement contains no conditions that are

[97] https://www.gov.il/BlobFolder/legalinfo/decisions037056/he/decisions_037056.pdf.

unnecessarily burdensome on the other party; (b) the other party shall have refused to meet conditions required by the Director of the Natural Gas Authority with respect to such transmission agreement.

6. EMED shall not exercise the option granted thereto to extend the capacity and operation agreement by 10 additional years (as specified in Section 7.26.6 below) without receiving prior permission from the Competition Commissioner.

On 8 September 2019, an appeal was filed with the Competition Court, challenging the merger approval decision issued by the Competition Commissioner. On 21 December 2022, the Competition Court handed down its judgment on the appeal, whereby it ruled that the appellants had failed to show that the merger gives rise to a reasonable concern of significant adverse effect on the competition and consequently denied the sought remedy of revocation of the approval granted to the merger transaction. However, the Competition Court ordered the Competition Commissioner to issue a supplemental decision with respect to the conditions imposed on the merger by the Commissioner, in view of the difficulties arising out of these conditions (in this section: "**Supplemental Decision**"). The judgment became peremptory on 5 February 2023. As a result of the aforesaid, the representatives of the Partnership, Chevron, EMG and EMED are discussing the Supplemental Decision with representatives of the Competition Authority. As of the report approval date, such decision has not yet been adopted. For this purpose, see also the clause "Applicable competition-related regulation" in Section 7.30.20 below.

(d) Information request from the Competition Authority in the natural gas sector

On 10 December 2024, Chevron notified the Partnership that on 9 December 2024, it received an information request from the Competition Authority, which included a request to transfer reports submitted to the Ministry of Energy, and gas supply agreements. Chevron responded to the information request in January 2025.

7.24.3 The Promotion of Competition and Reduction of Concentration Law, 5774-2013 (the "**Anti-Concentration Law**")

According to the Anti-Concentration Law, regulators have powers to make industry competitiveness considerations and economy-wide concentration considerations, as part of the allocation of public assets by the State, in order to ensure increased industry competitiveness and decentralization of economy-wide concentration. Accordingly, a regulator may choose not to allocate to an entity listed on the published list of dominant enterprises, determined on the basis of criteria set forth in the Anti- Concentration Law, a right, including a contract, in a business sector that uses critical infrastructure or a public resource, or in the framework of which a utility is provided to the public, listed in the Anti-Concentration Law (the "**Critical Infrastructure Sector**"), until having found that no actual damage will be caused to the sector in which the right is allocated and to the regulation of the said sector due to non-allocation, and after having taken into account considerations of prevention of the expansion of the operations of the dominant enterprise, bearing in mind the relevant business sectors and the link between them (the "**Economy-Wide Concentration Considerations**").

Therefore, prior to the allocation of a right in any Critical Infrastructure (including a business sector with respect to which a petroleum interest is granted or a business sector with respect to which a storage license or an LNG facility license is required under the Natural Gas Sector Law) to the Partnership, the regulator will have to weigh Economy-Wide Concentration Considerations.

Notwithstanding the foregoing, the aforementioned provisions with regard to Economy-Wide Concentration Considerations will not apply to the allocation of a petroleum interest to anyone having another petroleum interest in respect of the same area on the allocation date.

In addition, when allocating a right (within the above meaning thereof) including a license required for activity business sector that is not in an Critical Infrastructure Sector, the regulator is required to take into account considerations of promotion of the sectorial competition, in addition to any other consideration he is required to weigh under law for such purpose.

According to the provisions of the Anti-Concentration Law, the Committee for the Reduction of Concentration releases and updates from time to time a list of dominant enterprises in the economy, a list of significant financial entities and a list of significant non-financial corporations.

Delek Group, including the Partnership, was included in the list of dominant enterprises and in the list of significant non-financial corporations that was released on 10 August 2022.

On 28 March 2023, the Concentration Committee notified Delek Group that it would be taken off the list of significant non-financial corporations and the list of dominant enterprises when the lists would be updated in 2023. The Competition Authority further clarified that the Group's removal from the lists was subject to changes that may possibly occur in the infrastructure sectors or in the Group's financials.

As a result of changes that occurred since the last update to the lists on 10 August 2022, on 13 March 2024, the Concentration Committee released an updated list of dominant enterprises and an updated list of significant non-financial corporations.

Delek Group and the Partnership were removed both from the updated list of dominant enterprises and from the updated list of significant non-financial corporations, following the sale of the Partnership's holdings in the Tamar reservoir and because the credit amount taken by Delek Group was reduced and dropped below the effective threshold under the Anti-Concentration Law. Accordingly, Delek Group's controlling shareholder, Mr. Yitzhak Tshuva, was also removed from the said lists.

Therefore, as of the report approval date, the provisions of the Anti-Concentration Law no longer apply to Delek Group or the Partnership.

7.24.4 The Petroleum Law and the regulations promulgated thereunder

(a) The Petroleum Law

The exploration, development and production of oil and/or natural gas (in this section: "**Petroleum**") in Israel is regulated mainly under the Petroleum Law, including the amendments incorporated therein, and the regulations promulgated thereunder (in this section: the "**Law**") the principles of which are as follows:

1. The Law provides that a person shall not explore for Petroleum except under a "preliminary permit", "license" or "lease deed" (as defined therein) and a person will not produce petroleum except for under a license or lease deed.

2. Preliminary testing, that does not include test drilling, in any area, in order to ascertain the prospects for discovering Petroleum in such area, including the conducting of seismic surveys, is subject to the receipt of a preliminary license. The Law permits the granting of priority rights to the holder of the preliminary rights for petroleum interests in the area in which the preliminary permit was granted, if same will undertake to do preliminary tests and invest in the exploration for Petroleum as determined by the State's competent representatives to this matter.

3. A License grants the licensee, subject to the provisions of the Law and the terms and conditions of the License, mainly the right to explore for Petroleum in the area of the license in accordance with the plan submitted to the Petroleum Commissioner under the Law, and the exclusive right to conduct test and development drilling in the license area and to recover Petroleum therefrom. In general the License will be granted for an initial period of 3 years and is subject to extension, under conditions provided for by Law, for an additional term not to exceed 4 years.

4. If a leaseholder makes a Petroleum discovery, it is entitled to an extension of the license period for such time, not exceeding two years, as will give it sufficient time to define the borders of the Petroleum field, and the licensee is entitled to receive in a certain area within the license area (which shall not exceed 250 square kilometers), a "lease" which granting exclusivity to explore and to produce Petroleum in the leased area, for the term of the Lease. The lease is given for a period of up to 30 years from issuance, but if a lease is given pursuant to a license that was extended after a discovery in the license area, the license term will commence upon the original termination date of the license, prior to extension. A lease may be extended, under the provisions of the Law, for an additional period of up to 20 years. The Minister of Energy may expropriate the lease, if the license holder has not produced petroleum in commercial quantities during the first three years of receipt of the license. Furthermore, a lease may expire following a suitable prior notice given by the Minister of Energy, if the lease holder fails to produce or ceases to produce Petroleum in commercial quantities.

5. The Law provides that the lessee pay the State royalties of one eighth of the quantity of Petroleum produced from the leased area and utilized (excluding Petroleum used by the lease holder for operating the leased area), but in any event no less than the minimal royalty provided for by Law.

6. A lease might expire following a suitable prior notice given by the Minister of Energy if the lease holder fails to produce or ceases to produce Petroleum in commercial quantities.

7. The Law provides that the Petroleum Commissioner may cancel a petroleum interest or a priority right if the rights holder thereof has not complied with the provisions of the Law or fails to comply with any condition of its petroleum interest or preliminary permit, or has not performed in accordance with the work plan submitted by it or is late in its performance or fails to invest in Petroleum exploration the sums undertaken to invest, notwithstanding written notice given to the petroleum interest holder or preliminary permit holder sixty days previously.

8. The Petroleum Commissioner will maintain a Petroleum register which will be open to the public for review (the "**Petroleum Register**"). The Petroleum Register will list all requests, grants, extensions, revisions or expirations and transfers, pledges of petroleum interests or benefits therein or grant of a lease deed. No such transaction shall be in force until it is registered therein.

9. The Law provides that no one person shall have more than 12 licenses, and that it will not have licenses for a total area exceeding 4 million thousand sqm, except upon prior approval of the Petroleum Council.

10. The Minister of Energy, after consulting with the Petroleum Council, may require the lease holders to first supply, at market price, from the petroleum that is produced in Israel and also from the petroleum products which were produced therefrom, the same amount of petroleum and petroleum products which are required, in the opinion of the Minister of Energy, for domestic consumption. However, note that a lease holder shall not be required (a) to produce from a well more than its maximum effective rate of output; (b) to supply a percentage of its output which is greater than the percentage of output required of another lease holder, unless the Minister of Energy sees fit to deviate from the rule, if so required in his opinion, for reasons of State security or prevention of waste or unfairness towards another lease holder.

11. Section 54 of the Petroleum Law stipulates that if a petroleum interest holder has not paid fees or royalties on time and it has been notified thereof in writing, and after 30 days it has not been paid thereby, the Minister may impose an attachment the entire petroleum inventory, facilities, and the other rights which belong to the petroleum right holder, and it may seize all of the attached property until payment is received in full.

12. Section 76 of the Petroleum Law determines that a preliminary permit, license and lease are personal and neither they nor any benefit therein may be pledged or transferred in any manner – other than through inheritance – other than with the Petroleum Commissioner's permission, and the Petroleum Commissioner will not permit the pledge or transfer of a license or of a lease other than after consulting with the Petroleum Council.

13. A lease holder may build pipelines for the transport of oil and oil products. A leaseholder shall not build an oil pipeline, other than collection pipelines which lead to tanks in or around the areas of the lease wells, other than according to a line approved by the Petroleum Commissioner. An oil pipeline will be constructed according to detailed drawings in accordance with the law, which will first require the approval of the Petroleum Commissioner, which shall not be unreasonably withheld. The Petroleum Commissioner may, after consulting with the Petroleum Council, require a pipeline owner who is approved as aforesaid to transport the petroleum of a certain person, in the event that the owner of the pipe does not need it to transport

its own petroleum and under acceptable conditions which the Petroleum Commissioner shall determine.

(b) The Petroleum Regulations (Principles for Offshore Petroleum Exploration and Production), 5777-2017 (the "**Offshore Regulations**")

On 15 November 2016, the Offshore Regulations, which replaced the Petroleum Regulations (Principles for Offshore Petroleum Exploration and Production), 5766-2006, came into effect. The Offshore Regulations prescribe, *inter alia*, proof of qualification of the applicant seeking operator certification.

Below is a description of the principles of the Offshore Regulations:

1. The Petroleum Commissioner will not certify an applicant as operator unless the following principal conditions are fulfilled:

   (a) The operator will be the lease holder with at least 25% of the rights in the Petroleum asset.

   (b) The operator or control holder therein (subject to the conditions in the Offshore Regulations) will have at least 5 years of experience in the 10 year period preceding the filing of the application, in the performance of the functions of an operator, including (a) experience in offshore oil or natural gas exploration; (b) experience in offshore drilling; (c) experience in offshore development and production of oil and natural gas; and (d) experience in activities for preservation of health, safety, and environmental protection relating to activities in petroleum interests.

   (c) Furthermore, the Petroleum Commissioner will not certify a corporation as operator, unless it directly employs employees that have qualification and at least 5 years of experience in the offshore oil or natural gas exploration sector, and in the offshore oil or natural gas development and production sector, unless he decides to certify a corporation as an operator despite its noncompliance with the requirement of experience in offshore oil or natural gas development and production, as described below.

   (d) The Petroleum Commissioner may, according to the stage and characteristics of the right and according to the scope of the demand for receipt of the right in that area or according to the composition of the entire group, certify a corporation as an operator even if it fails to comply with the above requirement of necessary experience in offshore oil or natural gas development and production.

(e) The Petroleum Commissioner may require a certain corporation, for certification thereof as operator, greater experience than the one prescribed, if it finds it necessary according to the stage and characteristics of the right, and considering the work plan, its complexity and environmental and safety aspects.

(f) The Petroleum Commissioner will not certify a corporation as an operator unless it has sufficient financial capacity and financial strength. For this purpose, an operator or the control holder thereof (subject to the conditions in the Offshore Regulations) is financially sound (as defined in the Offshore Regulations) and has financial capacity that is deemed sufficient if the total assets in the balance sheet are at least $200 million and the total equity in the balance sheet is $50 million.

2. An applicant for a petroleum interest must prove appropriate financial capacity by fulfillment of both of the following:

   (a) The total assets in the balance sheet of the applicant (or of all holders of the petroleum interest jointly, including a member of the group approved as the operator with respect to the petroleum interest) are at least $400 million.

   (b) The total equity in the balance sheet of the applicant (or of all holders of the petroleum interest jointly, including a member of the group approved as the operator with respect to the petroleum interest) is at least $100 million.

   An applicant for a petroleum interest may rely on the control holder thereof in order to prove financial capacity, subject to the conditions prescribed by the Offshore Regulations.

   The aforesaid financial capacity, financial strength, total assets and total equity will be examined according to the data in the audited financial statement as of December 31 of the year preceding the submission of the application, or according to an average of the data in the audited financial statements as of December 31 of the two years preceding the submission of the application, according to the discretion of the Petroleum Commissioner.

3. The Petroleum Commissioner may, with approval from the Minister of Energy, withhold approval from an application to receive a petroleum interest or an application to serve as an operator, even if all the aforesaid conditions are fulfilled, if he is convinced that reasons of national security, foreign relations and international trade relations so justify, or if there are special

circumstances due to which approval of the application is not in the best interests of the public or the energy sector in Israel.

4. Notwithstanding the foregoing, it is possible to approve an operator or grant a petroleum interest even if not all of the details which appear above are fulfilled, provided that under the circumstances the non-fulfillment of the conditions is immaterial and the Petroleum Commissioner was convinced that there are special grounds which justify so doing.

5. The Offshore Regulations include additional provisions on the details to be included in the application for approval of an operator and reports which an operator and a holder of a petroleum interest are required to submit to the Petroleum Commissioner.

7.24.5 The Natural Gas Sector Law and the regulations promulgated thereunder

(a) The Natural Gas Sector Law and the regulations promulgated thereunder set forth provisions with regard to the construction of the transmission system, marketing and supply of natural gas. The Natural Gas Sector Law provides, *inter alia*, that:

1. The following activities may not be undertaken other than pursuant to a license issued by the Minister of Energy (in this section: the "**Minister**") and in accordance with its terms:

   (a) Construction and operation of a transmission system or part thereof.

   (b) Construction and operation of a distribution network or part thereof.

   (c) Construction and operation of an LNG facility.

   (d) Construction and operation of a storage facility.

   (e) Construction and operation of an export pipe by a person who is not a lease holder.

2. A transmission license will only be granted to a company incorporated in Israel under the Companies Law, 5759-1999 (the "**Companies Law**").

3. The holder of the transmission license, an electricity provider, or anyone who is a control holder or stakeholder thereof may not engage in the sale and marketing of natural gas.

4. The occupation of selling and marketing of natural gas does not require a license, however the Minister has the discretion under certain conditions set forth in the Natural Gas Sector Law, to determine, upon agreement with the Minister of Finance and upon approval of the Knesset's Economic Affairs Committee, that for a certain determined term, natural gas marketing activity will be subject to a license.

The Gas Sector Law establishes additional provisions that include, *inter alia*, conditions for granting licenses, granting powers to the Minister, the Natural Gas Sector Authority (appointed under Section 63 of the Natural Gas Sector Law) and the Director of the Authority regarding the granting of licenses and determining various conditions and restrictions that will apply with respect to the licenses or license holder, and grants them powers to determine provisions with respect to natural gas suppliers; provisions regarding revocation of licenses, guarantees required from a license holder, etc.

It is noted that in accordance with the provisions of the Natural Gas Sector Law, a transmission license was granted to Leviathan Transmission System, for the gas flow from the production platform of the Leviathan project to the northern entry point of the national transmission system of INGL.

The definition of the term "Rates" in the Natural Gas Sector Law includes not only payments paid by consumers for services they receive, but rather any payment that will be imposed on any one of the functions operating in the natural gas sector, including natural gas suppliers, for the benefit of another license holder and for any purpose, including purposes of gas sector development, backup and redundancies. The aforesaid applies whether or not such player on whom the Rate is imposed, receives any service from the license holder. This definition may allow for the imposition of charges under the law on natural gas suppliers as well.

28 December 2023 saw the publication of Amendment No. 13 to the Natural Gas Sector Law, 5784-2023, under which the Minister of Energy may extend the term of INGL's transmission license by an additional period of 15 years. It is further prescribed that the Minister of Energy may grant INGL a distribution license, including construction and operation of a distribution network, taking into account the considerations and the restrictions specified in the Amendment.

(b) The Natural Gas Sector Regulations (Management of the Natural Gas Sector in a State of Emergency), 5777-2017 (the "**Emergency Regulations**")

The Emergency Regulations were promulgated under Section 91 of the Natural Gas Sector Law, which authorizes the Minister of Energy, with approval from the Government, to announce a state of emergency in the natural gas sector and promulgate regulations applicable to the operation of the natural gas sector in a state of emergency. During 2024 and Q1/2025, the government renewed from time to time its authorization to the Minister of Energy and Infrastructure to announce a state of emergency in the natural gas sector, also without the approval of the Government plenum, to the extent that there is need to exercise the powers specified in the Emergency Regulations. Most recently, the authorization was renewed on 19 March 2025, and is valid until 16 May 2025.

In the event that the Minister of Energy announces a state of emergency in the natural gas sector, the Emergency Regulations determine that if the demand at any time exceeds the maximum quantity that a natural gas supplier can supply from the field for which the declaration was given (the "**Defaulting Gas Supplier**"), then the gas supplier and the transmission license holder are obligated to make allocations of natural gas and LNG to consumers in accordance with the provisions specified in the Regulations. Furthermore, the Regulations authorize the Minister of Energy, under certain conditions, to deviate from the provisions of the Regulations and order a different allocation of the quantities of gas and LNG, provided that the deviation does not exceed what is required.

The Regulations determine that they do not derogate from the remedies and relief available to anyone that signed an agreement with the Defaulting Gas Supplier and in accordance with the said agreement.

As of the report approval date, the conditions requiring that the Minister of Energy announce a state of emergency in the natural gas sector, have not been satisfied, and in accordance with Section 8 of the Emergency Regulations, in the event of announcement of a state of emergency in the natural gas sector, the Minister is authorized, *inter alia*, to order a different allocation of the natural gas quantities for supply. Therefore, in such a case, the Minister may order the Leviathan project partners to allocate natural gas quantities for the benefit of the domestic market at the expense of the gas supply to the customers in the export markets.

(c) The Natural Gas Sector Regulations (Duty to Provide Information of a Natural Gas Seller and Marketer), 5782-2022 (in this section: the "**Regulations**")

On 6 April 2022, the Regulations took effect, according to which all those engaged in the sale or marketing of natural gas will be required to submit to the Director of the Natural Gas Authority quarterly reports that include details on the quantities of natural gas sold or marketed each month, the prices agreed upon in each natural gas supply agreement, the total income of the seller or marketer from natural gas sales to consumers in the Israeli market, copies of signed agreements and other details.

(d) Regulation of criteria and rates for the purpose of operation of the transmission system

1. From time to time, the Natural Gas Commission adopts resolutions that update the rates of the various transmission services.

2. According to the Natural Gas Commission's resolution of 3 January 2021 on criteria and rates for the purpose of operation of the transmission system in a flow control regime , the Commission determined that the costs in respect of unaccounted for gas (UFG) in the transmission system that derives from reasons that cannot be attributed to deficient operation of the transmission system, but rather to factors that can be neither prevented nor controlled, such as measurement timing, pressure differences and temperature differences, will be borne by the gas suppliers. The resolution further stipulates that UFG within the range of 0% and 0.5% (either positive or negative) is deemed to be within the reasonable range (Unaccounted for Gas Target, UFG-T). The costs in respect of UFG-T will be allocated equally between the gas suppliers and the gas consumers.

3. On 11 April 2024, the Natural Gas Commission released a hearing for public response, on the reduction of the natural gas transmission tariff (in this section: the "**Hearing**"). As part of the Hearing, it was proposed to reduce the tariff of the capacity for natural gas transmission on a firm basis by 12.9% and the natural gas flow tariff by approx. 7.6% per MMBTU unit, starting from May 2024. On 16 May 2024, Chevron, on behalf of the Leviathan Partners, filed its response to the Hearing and on 4 June 2024, the Natural Gas Commission issued Decision No. 1/2024 on the annual update of continuous transmission tariffs[98], which included a reduction of the natural gas transmission capacity

[98] https://www.gov.il/BlobFolder/reports/ng-board-decision-2024/he/board-decision-1-2024.pdf

tariff by 12.9% and the natural gas flow tariff by approx. 7.6% per MMBTU unit, starting from July 2024.

(e) Resolutions of the Natural Gas Commission regarding the financing of export projects via the national transmission system

The Natural Gas Commission has adopted several resolutions regarding the transmission rates that will apply to the export of natural gas via the national transmission system, and regarding the financing of the construction of those segments of the transmission system designated for purposes of export of natural gas as aforesaid, by the gas exporters.

According to the Commission's resolutions, on 23 June 2020 the Director General of the Natural Gas Authority announced his determination that the cost of the combined section designated for the piping of natural gas from the Leviathan and Tamar reservoirs to EMG's terminal in Ashkelon for purposes of piping gas to Egypt according to the export agreements is estimated (as of the date of signing of the Transmission Agreement) at a sum total of ILS 738 million which will be updated according to an update and accounting mechanism between the parties as set forth in the Transmission Agreement with INGL. On 2 May 2022, INGL updated the project's budget to approx. ILS 796 million.

According to the announcement of the Director General of the Gas Authority, 43.5% of the section's cost, as shall be determined in accordance with the aforesaid, will be financed by the holder of the transmission license (INGL) and 56.5% of the section's cost shall be financed by the exporter in accordance with the milestones that shall be determined in the Transmission Agreement. In addition thereto, the exporter shall pay the holder of the transmission license ILS 27 million for its share in the cost deriving from the bringing forward of the doubling of the Dor-Hagit and Sorek-Nesher sections (which is estimated at approx. ILS 48 million) and that the exporter will provide the holder of the transmission license with an independent financial guarantee on behalf of an Israeli bank, in the sum of 110% of the aggregate amount of the cost stated above (the share of the holder of the transmission license in the cost of construction of the Combined Section plus 10%), and in the sum of ILS 21 million, which will decrease in accordance with the provisions of the addendum to the Decision.

The announcement of the Director General of the Authority further determines that as long as the exporter exports to Egypt, the quantity of natural gas determined in the Transmission Agreement will be transported via the transmission system of the holder of the transmission license and not via a section outside of the Israeli transmission system and that insofar as the exporter shall have ceased to export to Egypt, it will be required to pay the holder of the transmission license the difference, if any, between 110% of the aggregate total cost of the section plus ILS 48 million (the cost derives from the bringing forward of the doubling of the Dor-Hagit and Sorek-Nesher sections), and the aggregate capacity and piping fees that the exporter paid the holder of the transmission license from the date of completion of the Combined Section and of the payments that the exporter paid the license holder in accordance with the aforesaid.

For details on a transmission agreement signed between Chevron and INGL in connection with the export of natural gas to Egypt, see Section 7.13.2(c) above.

(f) 9 August 2023 saw the release of Resolution No. 3/2023 by the Natural Gas Commission on financing and allocation of capacity in all export lines (in this section: the "**Natural Gas Commission Resolution**"), the key points of which are as follows:

1. Every exporter shall be allocated capacity according to a percentage to be calculated according to certain parameters, such as the annual production capacity of the exporter and the existing and potential export volumes of that exporter. According to the initial allocation, 54% of the total export capacity will be allocated to the Leviathan reservoir, 33% will be allocated to the Tamar reservoir and 13% will be allocated to the Karish reservoir. For the avoidance of doubt, it is clarified that preexisting transmission agreements will not be adversely affected.

2. In the event of construction of export infrastructure other than by the transmission license holder, the share of each exporter in that infrastructure shall be taken into account as part of its export allocation.

3. The Commission shall reexamine and redetermine the allocation upon the occurrence of a significant event in the natural gas sector, the discovery of additional significant reserves, the entry of a new exporter, the construction of additional natural gas export infrastructure or another material change in the natural gas sector as shall be determined by the Commission.

4. The Commission may determine that use shall be made of all or part of the export lines for the purpose of importing natural gas in case it determines that there is need to supply the demand in the domestic market.

5. As relating to the Ramat Hovav-Nitzana line, the following provisions have been determined:

a. The allocation of capacity between the existing exporters shall be conducted on an equal basis, such that every existing exporter may request a third of the line's capacity and choose whether to use its allocation. The remaining capacity of an exporter that chooses not to use its allocation, or part thereof, shall be divided between the other exporters on an equal basis, subject to their respective total allocation limits.

b. An exporter that has financed the line shall be entitled to a refund proportionate to its allocation in respect of use of the line by another entity during the term of the transmission agreement.

c. An exporter that does not sign a transmission agreement within two months of receipt of the line allocation or fails to make up its share of the financing in accordance with the provisions of the transmission agreement shall be deemed to have waived its allocation. Accordingly, the allocation will be transferred to another exporter, and it shall receive reimbursement for the costs paid thereby.

d. The costs of construction of the line (CAPEX) include the costs of the compressor and are estimated at approx. ILS 2 billion. The period of construction thereof is estimated at approx. 36 months. It is noted that operation of the compressor is expected to entail high annual operating costs in relation to the operation of the rest of the national transmission system, which are estimated at approx. ILS 20 million per annum, excluding electricity costs associated with operating the compressors, which are borne by the exporters. For details regarding the Nitzana line, see Section 7.13.2(b)(5) above.

6. As relating to the Jordan North line, it has been determined that after the transfer of payment to the parties that financed its construction (NBL Jordan Marketing Limited and INGL), an exporter may sign a transmission agreement for use thereof, according to the available capacity over and above preexisting uninterruptible transmission agreements as of 1 August 2023.

7. The uninterruptible transmission agreements of each exporter with respect to the Ramat Hovav-Nitzana line and the Jordan North line shall not exceed 70% of the exporter's allocation of that line, with the remaining capacity reserved for interruptible transmission.

8. The actual line financing cost, and consequently the cost of use per MMBTU, shall be determined by the Director of the Natural Gas Authority after construction of the export line is completed.

9. In the event of discovery of a new natural gas reservoir from which natural gas export is intended, the new exporter shall receive its full allocation of the Ramat Hovav-Nitzana line and its remaining allocation in the Jordan North line, provided that its allocation does not exceed 20% of the capacity of each line. Such allocation shall be made at the expense of the interruptible transmission agreements and subject to the signing of a transmission agreement within 24 months prior to the commencement of piping through the line.

10. An export mechanism by way of re-trade shall be allowed through interruptible transmission agreements, in a volume of up to 5% of the capacity of every export line.

In June 2024 and November 2024, the Leviathan Partners approved additional preliminary budgets for the Nitzana project, of approx. $4.2 million and approx. $1.3 million (100%), respectively, such that until the report approval date a preliminary budget totaling approx. $20 million (100%) has been approved, prior to undertaking participation in the funding of the project, pursuant to the decision of the Natural Gas Commission and prior to the Leviathan Partners signing the transmission and construction agreement with INGL in relation to the Nitzana project. As of the report approval date, the Leviathan Partners are negotiating such an agreement with INGL, which negotiation has yet to evolve into an agreement due to the parties' differences. It is noted in this context that according to INGL's updated estimates, as confirmed by the Natural Gas Authority, the total cost of the Nitzana project is estimated at approx. $585 million (100%, the share of the Leviathan Partners is approx. $292.5 million (50% of the project), the share of the Partnership is approx. $133 million)[99]. In addition, and following the delays in the completion of negotiations with INGL as noted, the Leviathan Partners have begun an initial examination of alternative projects for construction of a transmission infrastructure for export to Egypt.

Following previous letters from the Natural Gas Authority, in its letter of 15 January 2025 regarding capacity allocation in the Ramat Hovav-Nitzana line, the Natural Gas Authority informed the Leviathan Partners once again, that their capacity allocation in the Ramat Hovav-Nitzana export line is 33.33%. The letter further states that according to the Decision, the Leviathan Partners are required to sign a transmission

[99] The allocation rate of the Leviathan project out of the possible export capacity of the Nitzana line, is based on the assumption that the capacity will be allocated equally between the Leviathan Partners and the Tamar partners.

agreement with INGL by 14 March 2025, under the terms and conditions set by the Natural Gas Authority in its said letter, and that exporters that will not sign a transmission agreement with INGL until such date shall be deemed as having waived their capacity in such pipeline and the vacated capacity will be offered to other exporters, as set forth in the Decision.

Further thereto, on 5 March 2025, INGL sent the Leviathan Partners an updated draft agreement, but due to the aforementioned differences, particularly as relating to the overall budget framework for the project, the Partnership estimates that it will not be possible to sign this agreement on such date.

To clarify, as of the report approval date, there is no certainty regarding the participation of the Leviathan Partners in the Nitzana project or an alternative project as aforesaid.

Caution concerning forward-looking information – The information specified above regarding the estimated overall cost of the Nitzana project constitutes forward-looking information, as defined in the Securities Law, which is based, inter alia, on estimations by INGL. To emphasize, there is no certainty that such estimations will be materialized, in whole or in part, and they may materialize in a substantially different manner, due to various factors which are beyond the Partnership's control.

7.24.6 Regulation of Security in Public Entities Law, 5758-1998 (in this section: the "**Law**")

(a) The Law imposes various duties on a "public entity" (as defined in the Law), including: (1) Appointment of a security officer who will report directly to the director of the entity, in order to ensure the security level required for the activity of the public entity; (2) Appointment of an officer in charge of the security of essential computerized systems; and (3) Appointment of a security guard in accordance with the requirements of an authorized officer.

(b) According to the Sixth Schedule to the Law, a license holder under the Gas Sector Law that owns an offshore facility or operates an offshore facility is deemed a public entity for the purpose of imposition of the duties listed in the Law, including the performance of maritime security activities required for the protection of a person's safety or the protection of property, in a building or on the premises of a public entity located in the maritime zone, as well as actions for the prevention of harm thereto. The definition of an offshore facility in the Law includes, *inter alia*, any facility or vessel used for the performance of a petroleum discovery survey or for a production well, for transmission, for liquefaction or for gasification of petroleum, or for the processing, storage or transportation of petroleum and therefore apply to the offshore production facilities of the Leviathan project. Accordingly, the provisions of the Sixth Schedule to the Law apply to Leviathan Transmission System, which holds the license for transmission from the Leviathan project.

(c) Other than offshore facilities the provisions of the Law also apply to an operator of an onshore facility for the processing of natural gas received by pipeline from the sea or from a foreign country, by virtue of a license or by law and therefore the provisions of the Law apply to the facilities of the Hagit site. An operator of an onshore facility as aforesaid is obligated to perform physical security activities and information security activities.

(d) In accordance with the Law, the Partnership and the other Leviathan Partners are responsible, *inter alia*, for the security of vital automated systems that exist in the facilities of the reservoirs, in accordance with the instructions of the Israel National Cyber Directorate (the "**INCD**"). Since it is the operator that is responsible for the operation of the production system of the reservoir, it is the one that actually implements the instructions of the INCD on the matter. As the Partnership has been informed, and to the best of its knowledge, in February 2024, the operator received renewal of confirmation from the INCD with respect to the Leviathan reservoir's compliance with the information security requirements. It is noted that the term of this confirmation is until February 2026.

(e) As of the report approval date, and as the Partnership has been informed by the operator, in connection with operation of the Leviathan reservoir, the operator meets the provisions of the Regulation of Security in Public Entities Law and the sections concerning regulation of security in the lease deed, including the directives on security matters issued thereto by the professional functions in the navy pursuant to law.

7.24.7 Directives of the Petroleum Commissioner

(a) Provision of collateral in connection with petroleum interests

In accordance with Section 57 of the Petroleum Law, the Petroleum Commissioner published directives for the provision of collateral in connection with petroleum interests, which are updated from time to time (in this section: the "**Directives**"). The Directives determine, *inter alia*, provisions regarding guarantees required to be provided by new license applicants when submitting the application and prior to drilling wells, and confer vast discretion on the Petroleum Commissioner in relation thereto. The Directives also determine that the guarantees will be in force even after the right for which they were given terminates, until the Commissioner advises otherwise, but no more than 7 years after expiration of the right for which they had been provided.

The Directives further set forth that the Petroleum Commissioner may order forfeiture of all or part of the guarantees if he deems that a petroleum interest holder did not act with due diligence in respect of the petroleum interest or caused damage in his actions due to the petroleum interest or did not incur expenses or failed to fulfill obligations that he was due to incur or fulfill under the Petroleum Law, and according to the instructions of the Petroleum Commissioner, during the period of the right.

Moreover, the Directives obligate a petroleum interest holder to take out at its expense and maintain throughout the entire term of the petroleum interest, all of such insurances, which are customary among international companies for exploration or production of oil or gas and to give instructions in connection therewith.

In the event of non-compliance with the Directives, the Petroleum Commissioner may deem the same as non-compliance with the work plan and with the provisions of the interest and act in accordance with the provisions of the Petroleum Law.

As of the report approval date, in accordance with the Directives and the terms and conditions of the Partnership's petroleum assets, the Partnership, together with its partners in the various projects, deposited autonomous bank guarantees for the Ashkelon, Noa, Leviathan North, Leviathan South leases, the Zone I Licenses and the New Ofek license.[100] The Partnership's total share in the said guarantees totals approx. $54.5 million.

(b) Directives regarding the report of safety events in offshore facilities

On 1 January 2023, the Petroleum Commissioner released, for public comments, the draft directives regarding report of safety events in offshore facilities (in this section: the "**Directives**"). The draft Directives refers to irregular events that derive from exploration and production of oil at sea. As of the report approval date, the Directives have not yet been published.[101]

[100] For details regarding additional guarantees the Partnership has provided together with its partners in the Leviathan project in accordance with the terms of the lease, see Section 7.2.2(n) above. For details regarding a guarantee the Partnership has provided in respect of the Boujdour license, see Section 7.6.1 above. For details regarding guaranties the Partnership has provided in favor of Customs in connection with the Leviathan project and Yam Tethys project, see Notes 12K5 and 12K6 to the financial statements (Chapter C of this report).

[101] See in the link: https://www.gov.il/he/departments/publications/Call_for_bids/reporting-jan-2023.

(c) Directives on the method of calculation of the royalty value at the wellhead

1. On 14 May 2020, the Director of Natural Resources at the Ministry of Energy released directives on the method of calculation of the royalty value at the wellhead according to Section 32(b) of the Petroleum Law (in this section: the "**Directives**").

   The Directives state that the value of the royalty at the wellhead shall be equal to 12.5% of the price of sale to customers at the point of sale, net of costs deemed essential for treatment, processing and transportation of the petroleum, actually incurred by the lease holder between the wellhead and the point of sale.

   The expenses to be recognized for purposes of calculation of the royalty value at the wellhead shall be expenses actually incurred by the lease holder between the wellhead and the point of sale specified above, provided that the Petroleum Commissioner deems them essential for the sale of the petroleum: (a) the following capital expenses (capex): (1) costs for the treatment and processing of the petroleum; and (2) costs of pipeline transportation of the petroleum up to the first point of connection to the national transmission system; and (b) operating expenses (opex) arising directly from the types of capital expenses.

   The Petroleum Commissioner shall from time to time determine, for each lease holder, specific directives for each lease, listing the deductible expenses for purposes of calculation of the royalty, according to the specific characteristics of the lease.

   The Directives determine additional provisions, including a specification of the types of expenses which will not be recognized, the method of recognition of abandonment costs and the method of treatment of transactions that are affected by the existence of special relations between the parties to the transaction.

2. On 24 July 2022, the specific directives of the Petroleum Commissioner at the Ministry of Energy were received, with respect to the method of calculation of the royalties to the State from the Leviathan reservoir, and on 1 September 2022, the Leviathan Partners' response to the said specific directives. For further details, see Note 12P3 to the financial statements (Chapter C of this report).

3. For details on the specific directives of the Petroleum Commissioner in the Ministry of Energy with respect to the method of calculation of the royalties to the State from the Tamar Reservoir, and on the final audit reports for the 2013-2018 royalties, as well as on the draft audit reports for the 2019-2020 royalties which were received from the Ministry of Energy in connection with the Tamar reservoir, see Notes 15B3 and 15B4 to the financial statements (Chapter C of this report), respectively. For details on the agreements reached between the Tamar Partners and the Ministry of Energy regarding the method of calculation of the royalty value at the wellhead, see Section 7.26.9(b) below.

(d) The transfer and pledge of a petroleum asset interest and benefit in a petroleum asset interest

On 28 December 2020 the Petroleum Commissioner published an updated version of directives for purposes of Section 76 of the Petroleum Law, which determine instructions and conditions for the transfer and pledge of a petroleum interest (preliminary permit, license and lease) and a benefit (including a right to contract royalties) in a petroleum interest (in this section: the "**Directives**"). These conditions are dependent, inter alia, on the question of whether commercial production has begun and the type of petroleum interest which is being transferred.

According to the Directives, the transfer and pledge of a petroleum interest is subject to receiving prior approval from the Petroleum Commissioner.

According to the Directives, the requirement to obtain the approval of the Petroleum Commissioner for a transfer and pledge of a petroleum interest and a benefit applies in certain cases also to a transfer or allocation of means of control in a corporation (as such terms are defined in the Directives).

The Directives specify conditions for the provision of the Petroleum Commissioner's approval for a transfer of interests, while distinguishing between a transfer of interests in a license and lease and other actions, including conditions regarding the financial capacity of the applicant and regarding the fulfillment of conditions required of an operator in accordance with the Petroleum Law and the Petroleum Commissioner's directives. The Directives further determine specific conditions pertaining to a transfer of royalty interests, a pledge of petroleum interests and other particular cases.

With respect to the pledge of petroleum rights the Directives clarify that permission for a pledge does not constitute permission to transfer the pledged right, and if the conditions for realizing the pledge are fulfilled, the license or lease or any part thereof or benefit in the license or lease, as the case may be, will not be transferred to the pledge holder or any other body, unless the Petroleum Commissioner allows the transfer to the transferee in advance and in writing, pursuant to the Directives. Furthermore, the appointment of a receiver for the pledged rights will not be subject to the rules applicable to the transfer thereof, provided that the Petroleum Commissioner agreed in advance and in writing to the identity of the receiver and the powers provided to him.

The Petroleum Commissioner may not approve a transfer, even if all the conditions for providing the approval which are detailed in the Directives are fulfilled, if he is convinced that reasons of public security, national security, foreign relations or international trade relations so justify, and in this context, in the case the transferee is a corporation controlled by a foreign country or there are other special circumstance with respect to which the transfer is not in the best interests of the public or the energy sector in Israel.

7.24.8 **<u>Regulatory restrictions and government decisions in respect of the export of natural gas</u>**

(a) Section 33 of the Petroleum Law states, inter alia, that the Minister may, after consultation with the Commission, obligate lease holders to supply first, at the market price, out of the petroleum produced by them in Israel and the petroleum products produced therefrom, such quantity of petroleum and petroleum products that are required, in the Minister's opinion, for Israeli consumption, refine it in Israel, if they have refining facilities, and sell it in Israel; for this purpose, he may require lease holders to produce petroleum from their existing wells at a rate sufficient for the said purposes.

Accordingly, and in accordance with the terms and conditions of the Leviathan leases, as specified in Section 7.2.2(f)2 above, and pursuant to the decisions of the Israeli government and the instructions of the Petroleum Commissioner, agreements for the export of natural gas outside of Israel are to be approved in advance by the Petroleum Commissioner. The Commissioner's instructions set forth, inter alia, the time and manner for filing such applications. As of the report approval date, export approvals were obtained for all the export agreements that were have been signed by the Partnership as specified in Section 7.12.3 above, with the exception of the agreement for the supply of gas to FAJR, which has yet to be approved, as specified in the said section.

(b) The policy of the Israeli government regarding the scopes of natural gas import is updated from time to time in accordance with new discoveries and other developments. Further to the conclusions of the committee for examination of the Government's policy on the natural gas sector in Israel headed by Mr. Shaul Tzemach, adopted by the Israeli Government in June 2013 (the "**Tzemach Committee**"), regarding a periodic review of the Government's policy on the matter, on 6 January 2019, by Resolution No. 4442, the Israeli Government adopted the principal recommendations of the interministerial professional team headed by the Director General of the Ministry of Energy, Mr. Udi Adiri, which reexamined the matter of natural gas supply and demand as of 2018 (in this section: "**Resolution 4442**"), the highlights of which are as follows:

1. According to Resolution 4442, the quantity of natural gas required to be secured for the domestic market shall be 500 BCM (the "**Minimum Quantity for the Domestic Market**"), which shall allow for the supply of natural gas for the market's needs over the next 25 years to the Government Resolution. In this context, the "natural gas quantity" means the quantity of natural gas in the 2P and 2C categories in the aggregate, according to PRMS, in the discoveries recognized by the Petroleum Commissioner, with respect to which leases have been granted and for which the connection of the leases to the shore has been completed according to a development plan in a manner allowing for the supply thereof to the Israeli market.

   The duty to supply the Minimum Quantity for the Domestic Market in respect of discoveries recognized prior to the Government Resolution will be as specified below:

Amount of Natural Gas in Reservoir	Rate of Minimum Supply to Domestic Market out of Natural Gas Amount in Reservoir
Exceeding 200 BCM (inclusive)	50%
Exceeding or equaling 100 BCM, but lower than 200 BCM	40%
Exceeding or equaling 25 BCM, but lower than 100 BCM	25%
Lower than 25 BCM	To be determined by the Petroleum Commissioner

2. The duty to supply the Minimum Quantity for the Domestic Market in respect of discoveries recognized after approval of Resolution 4442 will be as specified below:

Amount of Natural Gas in Reservoir	Rate of Minimum Supply to Domestic Market out of Natural Gas Amount in Reservoir
For every additional 1 BCM exceeding 200 BCM	55%

Amount of Natural Gas in Reservoir	Rate of Minimum Supply to Domestic Market out of Natural Gas Amount in Reservoir
For every additional 1 BCM from 50 BCM to 200 BCM	50%
Lower than 50 BCM	No duty to supply to the domestic market shall apply

Of note, for reservoirs shared by Israel and other countries, the Petroleum Commissioner shall determine specific arrangements and conditions.[102] In addition, it was determined that the export facilities will be located in an area that is controlled by Israel which is in its exclusive economic zone, unless determined otherwise in a bilateral agreement between Israel and another country.

3. The export of natural gas will require approval from the Petroleum Commissioner, and the amount of gas permitted for export will be in accordance with the relative part of quantities authorized for export in the reservoirs at that time, and subject to ensuring the minimum amount for the domestic market, as aforesaid.

4. Resolution 4442 further determines instructions regarding an obligation to connect reservoirs to the domestic market according to the size of the reservoir, instructions in relation to the sale of natural gas to consumers in the domestic market, which gas is designated for the production of follow-on products that are primarily designated for export, instructions regarding regulation of secondary trade in natural gas, which may be directed toward export, etc. On 28 January 2025, the draft of the Natural Gas Commission Regulations (Provision of Transmission Services for Natural Gas Export in Secondary Trade from Israel), 5785-2025, was released for public comment. As part of the draft regulations, it was determined, *inter alia*, that the sale of natural gas in secondary trade for export will be carried out through a trading platform, and that the holder of the transmission license (INGL) will provide transmission services to any consumer requesting to pipe natural gas through the transmission system to the connection point with the transmission system of a neighboring country.

5. It is determined within Resolution 4442 that it will be examined by the Government at the expiration of five years from the date of approval thereof for the purpose of incorporating changes, to the extent required, with respect to the policy on discoveries to be recognized by the Commissioner five years after the date of

[102] It is noted that the permitted export quota from the Tanin and Karish leases in the amount of 47 BCM was replaced, against the obligation to supply to the domestic market that applies to the holders of the Leviathan Leases, from the date of the Petroleum Commissioner's approval of the transfer of the interests in the Tanin and Karish leases. For details, see Section 7.24.1(b) above.

approval of the resolution, in accordance with the needs of the domestic market and considering the natural gas supply.

(c) Further to Resolution 4442, on 28 December 2023, it was reported that the Minister of Energy instructed the Director of the Ministry to set out to appoint the interministerial committee for periodic examination of the natural gas sector policy. Further thereto, on 14 February 2024, the committee launched its discussions. The committee is expected to review the natural gas export policy in relation to new natural gas reservoirs, rather than in relation to producing reservoirs, as well as all relevant aspects – energetic, economic, environmental and security-related. As of the report approval date, the committee has not yet released its recommendations.

(d) It is noted that in the months of August and December 2023, the Tamar Partners received authorization from the Petroleum Commissioner to export additional quantities from the Tamar project at a maximum volume of approx. 4 BCM a year, subject to execution of the expansion of the production capacity of the Tamar project.

7.24.9 <u>Draft policy document with respect to the decommissioning of offshore exploration and production infrastructures</u>

On 2 May 2023, the Ministry of Energy published for public comment a draft policy document that specifies general principles with respect to the decommissioning of offshore oil and natural gas exploration and production infrastructures, without derogating from the provisions of law applicable to this issue and from the provisions of the lease deeds and operation authorizations. The draft policy document specifies, *inter alia*, rules, criteria and timeframes for the decommissioning of wells and production facilities as well as the abandonment of no-longer used subsea infrastructures and pipelines, *inter alia*, according to the location of such installations in the deep sea, on the seabed or under the seabed.

According to the Partnership's preliminary assessment, to the extent approved, the stringent requirements under the draft policy document are expected to increase the costs of decommissioning of the Partnership's assets.

7.24.10 Resolutions and plans of the Israeli government and governmental authorities with respect to the reduction of greenhouse gas emissions and the promotion of renewable energies

(a) Cessation of use of coal for power production

On 3 June 2018, the government, in Resolution 3859, approved electricity sector reform and a restructuring of the IEC[103]. According to the resolution, the IEC will reduce its power production operations by selling 5 production sites with a total maximum capacity of approx. 4,500 MW, representing around 40% of its power production capacity, and the IEC will build two modern natural gas-fired production units in Orot Rabin, as part of the trend of reducing the use of coal in the power production process. According to the Minister of Energy's decision of 20 November 2019, two coal-fired production units at the Orot Rabin site in Hadera and the four coal-fired production units at the Rutenberg site in Ashkelon will be converted to natural gas by 2025, and no later than 2026, such that the era of coal use for power production in Israel will come to an end that year[104]. The aforesaid notwithstanding, based on IEC reports and as of the report approval date, there is uncertainty regarding the possibility for completion of the conversion project by no later than 2026 as stated in the Minister of Energy's decision. According to the 2023 review of the natural gas commission of 26 May 2024, in 2023, coal electricity production was 18%.[105]

(b) Government Resolution 1261 on the pricing of local pollutants and greenhouse gas emissions

14 January 2024 saw the adoption of Government Resolution No. 1261 ("**Resolution 1261**"), whereby the Minister of Finance was tasked with amendment of the Fuel Excise Tax Order, the Customs Tariff and Exemptions Order and the purchase tax on goods, in order to lead to the gradual internalization of the environmental externalities of carbon and local pollutant emissions. Natural gas-related taxation will be imposed gradually as of 2025, as follows: In 2025, the amount of the excise tax and purchase tax on natural gas shall be approx. ILS 33 per ton; in 2026, it shall be approx. ILS 54 per ton; in 2027, it shall be approx. ILS 80 per ton; in 2028, it shall be approx. ILS 114 per ton; in 2029, it shall be approx. ILS 149 per ton; in 2030 it shall be approx. ILS 192 per ton, and so on and so forth. As part of the resolution, it was decided: (1) To task the Ministry of Finance, the Ministry of Energy, the Ministry of Economy and Industry and the Ministry of Environmental Protection to set in place a procedure for budgetary support for fuel-consuming plants, which

[103] https://www.gov.il/he/departments/policies/dec3859_2018.
[104] https://www.gov.il/he/departments/policies/electricity_nov_2019.
[105] https://www.gov.il/BlobFolder/reports/ng-2023/he/ng-2023.pdf

support shall emulate the consideration that they would be entitled to receive in the context of emission quotas within the European Emissions Trading System (EU ETS) if they were subject to such mechanism, while retaining incentives for efficiency of the plants, and considering the changes required for the market features and the Israeli carbon tax structure and the principles determined in the Government's resolution; (2) For the purpose of reducing the use of polluting fuels, such as mazut and LPG, a plan will be implemented for acceleration of the natural gas network by the Natural Gas Authority; (3) To instruct the Ministry of Environmental Protection to request the Cleanliness Fund to allocate a budget for support of the conversion of fuels for waste use; (4) If, every year until the end of 2029, the average electricity price for household consumers at the date of update of the annual electricity tariff shall have increased over and above the Consumer Price Index (CPI) due to a change in the indicators: interest prices, fuel costs and exchange rates, the Minister of Finance shall present and order for suspension or reduction of the increase of the excise tax on natural gas for one year, so as to prevent an increase of electricity prices over and above the rate of increase of the CPI, and all subject to Sections 40 and 40A of the Budget Fundamentals Law; (5) The Ministry of Finance shall publish an outline for aid to the weaker demographics to assist them in dealing with the increase in energy prices, if any; (6) In the event of technological developments that allow for the reduction of carbon emissions from source fuels, the Ministry of Energy, Ministry of Finance and Ministry of Environmental Protection shall examine the implications of such technological developments; (7) Revocation of Government Resolution No. 286 of 1 August 2021 on the pricing of greenhouse gas emissions.

On 29 September 2024, the plenum of the Knesset approved the decision of the Finance Committee on the Customs Tariff and Exemptions and Sales Tax on Goods Order)Amendment no. 8 and Temporary Provision no. 10), 5784-2024, and the decision of the Finance Committee regarding the Fuel Excise Order (Imposition of Excise) (Amendment no. 2 and Temporary Provision no. 2). The said orders pertain to the pricing of local emissions of pollutants and greenhouse gases, as part of the regulation of the carbon tax, and gradually raise taxation on polluting fuels over a period of 6 years, such that the final bracket would take effect in 2030[106] . According to the Partnership's estimation, such decisions are not expected, in the coming years, to have a material effect on the price of natural gas and on the scope of the tax collected in respect of the use thereof.

[106] https://main.knesset.gov.il/news/pressreleases/pages/press29092024y.aspx

(c) National plan for prevention and reduction of air pollution in Israel

On 14 March 2022, Government Resolution No. 1282 was adopted, which presents a multi-annual national plan for the prevention and reduction of air pollution and greenhouse gas emissions in Israel (in this section - the "**Plan**").[107] The resolution stipulates that the Plan will constitute part of the State of Israel's response to the climate crisis and is intended, *inter alia*, to fulfill some of the obligations of the State of Israel under the Paris Agreement and the Glasgow Climate Change Conference. As part of the resolution, quantitative targets were set for reduction by 2030 of air pollutants and greenhouse gases from industry, power production, transport, agriculture and waste, as well as promotion of the environmental and health-related information pertaining to air pollutants and the promotion of environment- and climate-related technologies, including ratification of a national target for the introduction of renewable energy at the rate of 30% in 2030 and a 30% reduction by 2030 of greenhouse gas emissions from the electricity sector relative to the electricity sector emissions in 2015.

A report by the Knesset's Research and Information Center, dated February 2024[108] , indicates gaps between planning and reality in the transition of electricity production from coal to natural gas. In 2023, coal constituted approx. 17.2% of electricity production, versus previous forecasts of the Ministry of Energy that predicted a rate of 14%-15%. According to the report, delay in the conversion of the coal-based powerplants to natural gas results in a higher level of pollutant emissions, an increase in electricity prices, a loss of income to the State and a compromised GDP.

On 15 August 2024, the Ministry of Energy released for public comments an outline for net zero emissions in the energy sector by 2050. The outline presents three scenarios for net zero emissions by 2050, as well as various scenarios for the energy situation until 2050. In this outline, the Ministry addresses, for the first time, the option to produce electricity from nuclear energy in Israel, reviews the challenges and opportunities entailed thereby and details an outline that will enable examination of the applicability of a nuclear powerplant in Israel by 2050. The Ministry of Energy estimates that by 2050, greenhouse gas emissions will be reduced by approx. 94-96% relative to 2015, and that the remaining emissions will derive from the use of natural gas with carbon capture[109]. On 17 February 2025, the outline was released, in its final language[110].

[107] https://www.gov.il/he/departments/policies/dec1282_2022.

[108] Link to a review from the Knesset website on the transition from coal-based production of electricity to its production from natural gas and renewable energies, dated 5 February 2024.

[109] https://www.gov.il/BlobFolder/rfp/public-comments-2050/he/for-public-comments-2050.

[110] https://www.gov.il/he/pages/energy-2050

On 6 November 2024, the Ministry of Energy and Infrastructure released a document on "The Roadmap for Renewable Energy in 2030".[111] The document presents data regarding production and consumption from renewable energy as of today, as well as forecasts for 2030. For example, the document states that the total electricity capacity required from renewable energy in 2030 will be approx. 17,000 MW (DC), whereas the current capacity from renewable energy is 6,500 MW (DC) and that in order to meet the 2030 targets, installation of approx. 1,700 MW per year is required.

On 9 February 2025, the Ministry of Energy released an outline for (net) zero emissions in the energy sector by 2050. The outline presents three scenarios for (net) zero emissions by 2050, as well as various scenarios for the energy situation until 2050. In this outline, the Ministry addresses, *inter alia*, the option to produce electricity from nuclear energy in Israel, reviews the challenges and opportunities entailed thereby and details an outline that will enable examination of the applicability of a nuclear powerplant in Israel by 2050. According to such scenarios, by 2050, greenhouse gas emissions will be reduced by approx. 94-96% relative to 2015.[112]

(d) The Paris Agreement and the Powering Past Coal Alliance (PPCA)

In 2016, Israel joined the Paris Agreement, which was agreed in the course of the 2015 United Nations Climate Change Conference, and concerns reducing greenhouse gas emissions and coping with greenhouse gas emissions by the countries of the world. The principal undertaking of every country that signed the Paris Agreement is to submit a plan every 5 years which specifies the measures it will take to cope with climate changes.

Moreover, in December 2018, Israel joined the PPCA, the purpose of which is to encourage the reduction and discontinuation of use of coal. The parties to this initiative undertake to gradually reduce coal-fired power production and to support clean energy in government and corporate policies. The countries and the organizations that joined PPCA support the reduction of coal use in OECD countries by 2030 and worldwide by 2050.

(e) Background document for policy regarding subterranean use for net zero greenhouse emissions as part of storage or landfill of carbon dioxide

On 17 July 2024, the Ministry of Energy released a "Policy Background Document" regarding subterranean use for net zero greenhouse emissions as part of storage or landfill of carbon dioxide

[111] Link to the Ministry's publication of 7 November 2024.
[112] Link to the outline for (net) zero greenhouse gas emissions in the energy sector in Israel by 2050.

(CO2)[113]. Pursuant to such document, the Israeli energy sector is expected to use CO2 capture and burial as part of the production of blue hydrogen or as supplementation to the use of natural gas, as a complementary measure to reduce emissions of greenhouse gases and meeting the 2050 net zero target, and to that end, it is necessary to develop financial incentives and policy that will enable construction of the infrastructure required for the transport of CO2 in Israel, develop a governmental fiscal policy that is suitable for supporting overall reduction of emissions, and promote regulation and legislation in this area. As of the report approval date, it is impossible to estimate which fiscal and regulatory changes are expected to be implemented and how they will impact the Partnership's operations and business, if at all.

7.24.11 The incorporation of hydrogen into the Israeli energy sector

(a) On 15 May 2023, the Ministry of Energy released a strategy document for the incorporation of hydrogen into the Israeli energy sector. The document reviews the features of hydrogen production, transportation, storage and accumulation, and examines the hydrogen use manner, its incorporation around the world and the possibilities for its incorporation in Israel. In the document, it is proposed to formulate, by 2030, policy measures that would lay the initial groundwork for hydrogen use, including the mapping of areas that are suitable for hydrogen accumulation, promotion of experimentation areas, formation of hydrogen valleys, support of projects and pilots in the market, promotion of safety standardization and promotion of regulatory outlines for experimentation.

(b) On 3 May 2023, Government Resolution No. 482 was released, which determines that the 'Objectives' section in the articles of association of INGL would be amended to allow INGL to engage in the construction and operation of hydrogen gas pipelines including facilities related thereto as well as the construction and operation of a pipeline for the removal of carbon dioxide that is related to or created by the production of hydrogen, subject to the permit, insofar as granted, and the details specified therein and all in accordance with the provisions of Section 14(b) if the Natural Gas Sector, 5762-2002. On 21 December 2023, the Minister of Energy granted INGL an additional business permit for engagement in the hydrogen segment.

[113] https://www.gov.il/BlobFolder/reports/ccs-170724/he/ccs-july-2024.

7.24.12 National Outline Plan 37/H for the Reception and Processing of Natural Gas

In order to create the zoning infrastructure for the connection of the natural gas reservoirs to the national transmission system and construct the facilities required for such purpose, the National Planning & Building Council (in this section: the "**National Council**") and the Israeli Government approved the "detailed partial national outline plan on the reception and processing of natural gas from discoveries to the national transmission system" (in this section: the "**Plan**" or "**NOP 37/H**").

The Plan designates areas (onshore and offshore) for the construction of the facilities required in the process of production and transmission of natural gas, which include, *inter alia*, natural gas reception and processing terminals, pipelines for transmission of the gas etc. It is noted that the approved development plan of the Leviathan reservoir in the format specified in Section 7.2.2(j) above, is in keeping with NOP 37/H.

7.24.13 Permits and licenses for the facilities of the Yam Tethys project and the Leviathan project

(a) In the framework of the development of the Yam Tethys project, the Yam Tethys Partners received an approval to construct a permanent platform for the production of natural gas and oil and also an approval for the operation of a production system of natural gas under the Petroleum Law, and in addition the Minister of Energy granted Yam Tethys Ltd. (a company owned by the Yam Tethys Partners) a license to construct and operate a transmission system for the transfer of natural gas of the Yam Tethys Partners or other natural gas suppliers from the production platform to the Terminal, provided certain conditions are fulfilled and subject to the conditions of the license and the Natural Gas Sector Law .

(b) In Phase 1A, the Leviathan Partners received approval for the construction of a permanent platform for the production of natural gas and oil, as well as approval for the operation of a system for production of natural gas and condensate from the Leviathan project, according to which the Leviathan Partners were obligated, *inter alia*, to submit guaranties, as specified in Section 7.2.2(n) above.

7.24.14 On 21 February 2017, the Minister of Energy granted Leviathan Transmission System (a company owned by the Leviathan Partners, as specified in Section 1.7.1 above) a license for the construction and operation of a transmission system to be used for the transfer of natural gas of the Leviathan Partners originating from the Leviathan Leases, or of other natural gas suppliers, upon the fulfillment of certain conditions, and all subject to the conditions of the license.

7.24.15 Applicability of Cypriot, Bulgarian and Moroccan legislation to the Partnership's activity

The Partnership's gas and oil exploration activity in Cyprus, Bulgaria and Morocco is subject to legislation and regulation that applies to the operating sector in these countries, including instructions regarding the obligation to obtain permits and licenses for performance of acts, undertakings to execute work plans, provisions in relation to safety and environmental protection etc. It is noted that Cyprus and Bulgaria are full members of the European Union and is therefore subject to the European Community directive with regard to the granting and use of authorizations for exploration and production of hydrocarbons (Directive 94/22/EC) and other relevant European legislation which regulates the exploratory activity and the production of hydrocarbons onshore and within the EEZ of the these countries.

For details on the petroleum asset, Block 12 in Cyprus, and the agreements signed with the Cypriot government in relation thereto, and on the Bulgaria License, see Sections 7.3 and 7.8 above.

7.25 **Pledges**

For details regarding pledges the Partnership has given on its assets, see Notes 10 and 12K to the financial statements (Chapter C of this report).

7.26 **Material Agreements**

The Partnership has entered into material agreements that were in effect during the period from 1 January 2023 until the report approval date, as specified below:

7.26.1 The main agreements for the sale of natural gas from the Leviathan project to the domestic market and for export as specified in Section 7.12.3 above.

7.26.2 Financing documents of the bonds issued by Leviathan Bond, as specified in Section 7.21.2 above.

7.26.3 Production Sharing Contract in respect of Block 12 (as specified in Section 7.3.3 above).

7.26.4 Agreements with respect to entry into the renewable energy sector, in collaboration with Enlight and the CEO of the Partnership, as specified in Section 7.10 above.

7.26.5 Agreements with respect to the acquisition of rights in the Bulgaria license, as specified in Section 7.8 above.

7.26.6 Series of agreements for acquisition of EMG shares and regulation of the terms for export of gas to Egypt

(a) General

With the aim of enabling the consummation of the agreement for export of gas to Egypt that is described in Section 7.12.3(c) above, EMED purchased 39% of the share capital of EMG, a private company registered in Egypt which owns a submarine pipeline of a diameter of 26 inches and approx. 90 km long, which connects the Israeli transmission system in the Ashkelon area and the Egyptian transmission system in the el Arīsh area, and related facilities (hereinbefore and hereinafter, collectively: the "**EMG Pipeline**", and the "**EMG Transaction**", respectively).

The EMG Transaction was closed on 6 November 2019, and natural gas flow from the Leviathan reservoir to Egypt through the EMG Pipeline began on 15 January 2020, after additional related arrangements and agreements had been made, as specified below.

(b) The agreements for acquisition of EMG shares

On 26 September 2018, EMED signed 4 separate, mainly similar, agreements with 4 shareholders of EMG (in this section: the "**Sellers**") for acquisition of 37% of EMG's share capital held by the Sellers, and, at the same time, EMED signed an agreement with another shareholder ("**MGPC**"), which transferred to EMED, without consideration, 2% of the EMG shares held thereby, in the context of the resolution of disputes that had arisen between the Sellers and MGPC. Following the closing of the transaction, EMG's shareholders are as specified in Section 1.7.5 above.

In the context of the transaction, the Sellers, the shareholders of the Sellers and the companies affiliated with the Sellers have agreed to waive any claim, lawsuit, award, decision, order or remedy that are available to them against the Egyptian government and companies owned thereby in the framework of arbitration proceedings which were held between the parties in relation to discontinuation of piping of the gas from Egypt to Israel.

In consideration for the Purchased Shares, for waiver of their rights in the framework of the Arbitration Proceedings, and other rights in accordance with the Share Purchase Agreements, EMED paid the Sellers the sum total of approx. $527 million (in this section: the "**Consideration**"), out of which each one of the Partnership and Chevron paid a sum of approx. $188.5 million, and the balance was paid by the Egyptian Partner.

(c) Capacity Lease & Operatorship Agreement (CLOA)

In the CLOA signed on 30 June 2019 between EMED and EMG, EMG gave EMED the exclusive right to lease and operate the EMG Pipeline for the period expiring at the end of 2030, with an option to extend the agreement for 10 more years.

According to the agreement, the costs required for refurbishment of the EMG Pipeline, and the current operation costs of the pipeline, shall be borne by EMED (collectively in this section: the "**Operation Costs**"), while EMG will be entitled to receive the current transmission fees which Blue Ocean shall pay for use of the pipeline (in this section: the "**Transmission Fees**"), net of the Operation Costs. As of 31 December 2024, Chevron and the Partnership as well as the other partners in the Leviathan and Tamar projects, have invested in the refurbishment of the EMG Pipeline, through EMED, approx. $161 million, most of which will be repaid to Chevron and the Partnership and the other Leviathan and Tamar Partners, through EMG's revenues from transmission of the gas through the pipeline. As of the report approval date, out of the above amount, approx. $38.8 million were repaid (100%, the Partnership's share approx. $15.9 million).

(d) Agreement for allocation of capacity in the transmission to Egypt system

Concurrently with the signing of the Export to Egypt Agreement, on 26 September 2019 (as amended on 21 August 2023), an agreement was signed between the Partnership and Chevron and the Leviathan Partners and the Tamar Partners in connection with allocation of the capacity (in this section: the "**Capacity Allocation Agreement**") in the transmission from Israel to Egypt system. The capacity division in the transmission from Israel to Egypt system (the EMG Pipeline and the transmission in Israel pipeline) will be on a daily basis, according to the following order of priority:

1. First layer – up to 350 MMSCF per day will be allocated to the Leviathan Partners.

2. Second layer – the capacity above the first layer, up to 150 MMSCF per day until 30 June 2022 (the "**Capacity Increase Date**"), and up to 200 MMSCF per day after the Capacity Increase Date, will be allocated to the Tamar Partners.

3. Third layer – any additional capacity above the second layer will be allocated to the Leviathan Partners.

Pursuant to the Capacity Allocation Agreement, on the date of the closing the EMG Transaction, the Leviathan Partners and the Tamar Partners paid the Partnership and Chevron the sum of $250 million

(80% by the Leviathan Partners and 20% by the Tamar Partners), as participation fees, in consideration for the undertaking to allow the piping of natural gas from the Leviathan and Tamar reservoirs and guaranteeing capacity in the EMG Pipeline. Pursuant to the agreement, the amount of the aforesaid payments will be updated according to the formula determined in the agreement and the dates set therein, based on the actual use of the EMG Pipeline. In view thereof, for the period between 1 January 2022 and 30 June 2022, the payment division between the Leviathan Partners and the Tamar Partners was approx. 83% and approx. 17%, respectively. The Capacity Allocation Agreement determines further arrangements for bearing the additional costs and investments that will be required for refurbishment of the EMG Pipeline and maximum utilization of the pipeline capacity, which shall be paid by both the Leviathan Partners and the Tamar Partners. In this context it is noted that on 30 June 2022 and 30 June 2024, the parties updated the payment division between the Leviathan Partners and the Tamar Partners, and accordingly an accounting was performed in non-material amounts for purposes of adjusting the rates borne by the parties in the costs of the actual usage of the EMG pipeline's capacity in the said period.

The Capacity Allocation Agreement further determines that from 30 June 2020 until the Capacity Increase Date, insofar as the Tamar Partners shall be unable to supply the quantities which they undertook to supply to Blue Ocean, the Leviathan Partners shall supply the Tamar Partners with the required quantities.

The term of the Capacity Allocation Agreement is until the conclusion of the Export to Egypt Agreement, unless it shall have ended prior thereto in the following cases: a breach of a payment undertaking which was not remedied by the party in breach; or in a case where the Competition Authority shall not have approved the extension of the Capacity Lease and Operatorship Agreement according to the decision of the Competition Commissioner, as specified in Section 7.24.2 above. In addition, each party shall be entitled to end its part in the Capacity Allocation Agreement insofar as its export agreement shall have been terminated.

(e) EMED's shareholders' agreement

In proximity to the date of the signing of the agreements for the purchase of the shares of EMG, EMED's shareholders signed a shareholders' agreement which regulates the relationship between them as shareholders of EMED, including provisions regarding material resolutions that shall be adopted unanimously. In addition, right of first refusal arrangements were determined for the transfer of shares of EMED.

(f) Term sheet for use of additional infrastructures

Concurrently with the signing of the agreements for the purchase of the shares of EMG, as specified above, a term sheet was signed between the Partnership and Chevron and the Egyptian Partner (which holds the Arab Gas Pipeline in the segment between el Arish and Aqaba, and an affiliate of Blue Ocean, whereby the parties agreed that the Partnership and Chevron would receive access to additional capacity in the Egyptian transmission system, through the Arab Gas Pipeline, at the entry point to the Egyptian transmission system in the Aqaba area, allowing the flow of gas in additional quantities over and above the gas quantities that would flow via the EMG Pipeline, for the purpose of implementation of the Export to Egypt Agreement and other agreements for the sale of natural gas to Egypt. In addition, the parties agreed to look into other projects for the transmission of natural gas from Israel to potential customers and facilities in Egypt. For further details see Section 7.13.2(c) above.

(g) Agreement between EMG and EAPC and Eilat-Ashkelon Infrastructure Services Ltd.

On 1 July 2019, an agreement was signed between EMG and EAPC and Eilat-Ashkelon Infrastructure Services Ltd. (in this section: the "**EAPC Companies**" and "**EAPC Agreement**" or the "**Agreement**", respectively) for regulation of a sublease of areas in the EAPC site at the Ashkelon port, rights of way at the port and use by EMG and EMED of the natural gas facility situated on this site, for the purpose of the transport of the natural gas in the EMG Pipeline. In consideration for these rights, the EAPC Companies are entitled to payments as specified in the Agreement.

The EAPC Agreement took effect on 6 November 2019, together with the closing of the EMG Transaction, and will be in effect until 10 June 2030, unless terminated prior thereto, *inter alia* by EMG in the event that the Export to Egypt Agreements are terminated due to a breach by the buyer or due to *force majeure*, all in accordance with the provisions of the Agreement. According to the Agreement, and subject to the provisions thereof, including extension of the lease agreement between Eilat-Ashkelon Infrastructure Services Ltd. and the Israel Land Authority, EMG will be entitled to extend the term of the Agreement until 6 October 2043.

For the purpose of securing the payments to the EAPC Companies, EMG was required to provide a bank guaranty (renewable over the term of the Agreement) in the sum of $4 million (in this section: the "**Guaranty Amount**"). As of the report approval date, EMG has not provided the bank guaranty, and in its stead EMED provided a company guaranty up to the sum of the Guaranty Amount, which is backed by two bank guaranties in the sum of $2 million each, which were provided by the Partnership and Chevron (in this section: the "**Bank Guaranties**"). The guaranty provided by EMED shall expire and be null and void in the events that: (1) all of EMG's undertakings vis-à-vis the EAPC Companies shall have been cancelled; (2) the EAPC Companies shall have received payment in the sum of the Guaranty Amount due to enforcement of the Bank Guaranties; (3) the Bank Guaranties shall have been replaced with a bank guaranty provided by EMG; or (4) the Bank Guaranties shall have expired or been cancelled. It is further noted that according to the terms and conditions of the guaranty provided by EMED, the EAPC Companies will be obligated to first enforce the Bank Guaranties and only in the case of non-payment will they be entitled to use EMED's guaranty.

Alongside the signing of the Agreement, the Leviathan and Tamar Partners provided a release letter, according to which each one of the partners releases the EAPC Companies from any future lawsuit in respect of damage that shall be caused thereto (if any) due to an act or omission of the EAPC Companies or anyone on their behalf as parties to the EAPC Agreement or as the operators of the Ashkelon port (with the exception of damage caused with malicious intent). The EAPC Companies provided a similar letter to the Leviathan and Tamar Partners.

(h) For details regarding agreements signed between Chevron and INGL pertaining to transmission of natural gas at the EMG Pipeline through the INGL system, see Section 7.13.2(c)2 above.

7.26.7 <u>The Joint Operating Agreement in respect of the Leviathan Leases</u>[114]

(a) <u>General</u>

The activity in the framework of the Leviathan Leases is carried out under a joint operating agreement of 31 August 2008 (as amended from time to time), the present parties to which are the Partnership and the other partners in the Leviathan Leases as specified in Section 7.2.1 above (in this section: the "**Agreement**" or "**JOA**").

The purpose of the Agreement is to set forth the mutual rights and obligations of the parties in connection with activities in the areas of the Leviathan Leases (in this section: the "**Petroleum Asset**").

According to the aforesaid operating agreements, Chevron was appointed as the operator.

[114] It is noted that until 1 January 2012, the activity in the Leviathan Leases was carried out in the framework of a single joint operating agreement.

(b) Method of accounting

Unless otherwise provided for in the JOA, all the rights and interests in the Petroleum Asset, in the joint property and all the hydrocarbons produced from them, will be subject to the terms and conditions of the Petroleum Asset and the applicable rules, and in accordance with the participation rates of the parties therein. Furthermore, unless otherwise provided for in the JOA, the party's undertakings under the Petroleum Asset conditions and the JOA and all the liabilities and expenses incurred or undertaken by the operator in connection with the joint activity,[115] and all the credits to the joint account,[116] will be borne by the parties, amongst themselves, in accordance with their participation rate in the Petroleum Asset, and each party will pay, when due, in accordance with the Accounting Procedure instructions of the JOA (the "**Accounting Rules**") its share in accordance with its participation rate of all the expense of the joint account. It is noted that payment dates are of the essence of the JOA and payment by a party of another party's obligation under the JOA does not negate its right to dispute such liability at a later stage. According to the Accounting Rules, Chevron is entitled to be reimbursed for of all direct expenses paid in connection with it fulfilling its position as operator and to be reimbursed for the indirect costs derived from its shares of the expenses of the joint venture at the exploration state as follows:

Direct expenses (on an annual basis)	Rate of payment to operator (as a percentage of direct expenses
Up to $4 million	4%
$4-7 million	3%
$7-12 million	2%
Above $12 million	1%

The rate of indirect expenses for the development and production stage was not provided by the Agreement, and on 30 June 2016 an amendment to the JOA in the Leviathan project was signed, whereby the operator will be entitled to receive indirect expenses at the rate of 1% of all of the direct expenses in connection with development and production operations, subject to certain exceptions, such as marketing activity.

(c) Rights and obligations of the operator

Under the JOA the operator is exclusively responsible, for the management of the joint activity, which includes, *inter alia*,

[115] In accordance with the definitions in the JOA – the "joint activity" is the activity performed by the operator according to the provisions of the JOA and the costs for which each of the parties to the JOA may be billed.
[116] In accordance with the definitions in the JOA – the "joint account" are accounts held by the operator for the joint project in accordance with rules set forth in the JOA and the Accounting Rules.

preparation of work plans, budgets and payment authorizations, performance of the work plan according to the joint operating committee's approval, planning and obtaining all of the approvals and materials required for performance thereof, and provision of consulting services and technical services as required for the efficient performance of the joint operation. The operator may employ contractors and/or agents (which could be related companies/affiliates of the operator[117] or one of the parties to the JOA or a related party/affiliate to one of the parties to the JOA) to perform said joint activities.

In managing the joint activities the operator must, *inter alia*, perform the joint activities in accordance with the terms and conditions of the Petroleum Asset and the rules applicable thereto, the laws, the JOA and the instructions of the operating committee (which roles are specified below); and manage all the joint activity with diligence and in a safe and efficient manner in accordance with the acceptable principles in the international petroleum industry in similar situations. In addition, the operator is required to take out the insurances detailed in the JOA, in accordance with the instructions set forth therein.

In addition, the operator is required, after receipt of reasonable prior notice, to permit the representatives of all the parties at any reasonable time and at their expense and responsibility access to the joint activity including the right to observe the joint activity, to inspect the joint equipment and to conduct a financial audit in accordance with the provisions of the Accounting Rules set forth in the JOA.

Subject to the terms and conditions of the Petroleum Asset, the conditions applicable to it and the JOA, the operator will determine the number of workers, will select them and determine their hours of work and the consideration to be paid to them in connection with the joint activity. The operator will only employ the manpower reasonably required to perform the joint activity.

The operator will provide the other parties with information and data as detailed in the JOA and will enable them access at all reasonable times to all aforementioned information.

The operator, as shall be instructed by the operating committee, will immediately advise the parties of any significant actions and other actions that were filed as a result of the joint activity and/or related thereto. The operator will represent the parties and defend them from said actions. The operator may, at its sole discretion, settle any

[117] In this regard, "a related/associated party" is defined in the JOA as a legal entity that controls or is controlled by a party to the JOA (directly or indirectly); and "control" means the ownership (directly or indirectly) of more than 50% of the voting rights or the ability to control the decision-making at the said legal entity.

claim or series of claims for a sum that does not exceed $50,000 plus legal expenses, and will ask for permission from the operating committee for any sum(s) that exceed that. Each party will be entitled, at its own expense, to be represented by its own lawyer at any compromise arrangement or defense in said actions. No party will settle with regard to its proportionate share of any claim without first proving to the operating committee that this can be done without harming the interests of the joint activity.

Each party that is not an operator will immediately advise the other parties of any action against it by a third party that derives from the joint activity or may impact the joint activity, and the non-operator party will defend or compromise on the said claim, in accordance with instructions given by the operating committee. Costs and damages which will be caused in connection with the defense or compromise and that can be attributed to the joint activity will be charged to the joint account.

Unless otherwise provided for in this section: the operator (and in this regard – including the directors and officers therein, its related companies and the directors and officers therein, collectively: the "**Indemnified Parties**") will not bear (except as a party in the participation rate of a Petroleum Asset) any damage, loss, cost, expense or liability deriving from the joint activity, even if caused, in whole or in part, by a prior defect, negligence (sole, joint or parallel), gross negligence, strict liability or any other legal culpability of the operator or of any indemnified party as aforesaid.

Unless otherwise provided for in this section: the parties to the JOA in accordance with their participation rate in the Petroleum Asset will defend and indemnify the operator and the Indemnified Parties for all damages, losses, costs, expenses (including legal expenses and reasonable legal fees) and liability, deriving from actions demands or causes of action that were filed by any person or legal body and that are the result of or derive from the joint activity, even if caused in full or in part, by a prior defect, negligence (sole joint or parallel), gross negligence, strict liability or any other legal culpability of the operator or any other said Indemnified Party.

Notwithstanding the foregoing, if the operator's officers in senior supervisory positions or in its related parties is involved in gross negligence which proximately causes the parties damages, loss, cost, expense or other liability for actions, claims or claims of action as aforesaid, then in addition to its liability as a party in accordance with its participation rate, the operator will bear only the first $5,000,000 in aggregate of such damages, losses, expense, costs and debts.

Notwithstanding the foregoing, in no event will an Indemnified Party (except as a party with rights in the Petroleum Asset according to the percentage of its working interests therein) in the debt for damages or environmental or consequential losses.

(d) Operating committee

In the framework of the JOA the parties established an operating committee, which has the authority and responsibility to approve and supervise the joint activities required or necessary to meet the conditions of the Petroleum Asset and the JOA, for exploration and exploitation of Petroleum Asset areas in accordance with the JOA and in an appropriate manner according to the circumstances. The operating committee is made up of representatives of the parties (and their alternates) and each representative of a said party will have the right to an opinion equal to the working interest which it represents. The JOA determines the order of processes and proceedings for convening meetings of the operating committee and the discussion at them and includes processes and arrangements for making decisions in writing.

Unless otherwise provided for specifically in the JOA, all decisions, approvals and other activities of the operating committee with regard to the proposals presented before it, will be decided by the vote in favor of at least two parties or more (that are not related parties/affiliates, as defined above) jointly holding at the time of the vote at least 60% of all of the working interests in the area of the applicable Petroleum Asset.

It is further noted that in order to approve a decision to end the lease or waive any part of the area of the lease, a positive vote of all of the parties is required. A positive decision of any one party to the JOA is sufficient in order to approve any application for a license or renewal of a license or a lease.

(e) Work plans and budgets

The JOA sets forth procedures and processes to submit and approve work plans, budgets and authorizations for expenditure (AFE) for activities in the areas to which the JOA applies.

On or prior to the first day of October of each calendar year, the operator will present the parties with a proposed production work plan and budget, which will specify the joint activity that will be performed in the production area as well as the planned production timetables for the next calendar year, and the operating committee is required to make a decision, within 30 days of the submission of the proposal as aforesaid, about the production work plan and budget.

Engagement of the operator in contracts in the framework of the exploration and evaluation activity and also in the production activity, that the consideration thereof exceeds $2.5 million and also development activity that consideration thereof exceeds $5 million, will be subject to the approval of the operating committee.

Prior to expenditure or the giving of an undertaking in a sum that exceeds $500,000 for any item in the work plan and approved budget for exploration, evaluation and production activity, or in a sum that exceeds $1,000,000 for any item in the work plan and approved budget for development activity, the operator will send an authorization for expenditure request (AFE) which will include, *inter alia*, an evaluation of the sums and schedule required to perform said work, and all the additional information required to support the aforementioned application all of the other parties. Notwithstanding the foregoing, the operator will not be obliged to submit an AFE to parties prior to undertaking any expenditure with regard to operational expenditure, general and ongoing management activity, classified as separate items in the work plan and the approved budget.

The operator may deviate, without operating committee approval, at a rate that does not exceed 10% per item from the sum that was approved for such item and subject to the aggregate total deviations in calendar year not exceeding 5% of the work plan total and approved budget. Where the operator believes that the deviation shall exceed such aforementioned limits, it shall submit another AFE for the operating committee's approval for issuance of a permit. These limitations do not derogate from the right of the operator to deviate from the expenditure for urgent operational matters and emergencies as detailed in the JOA.

It is noted that the JOA permits the other parties who are not the operator to submit different work plans and budgets to those that were submitted by the operator, for the operating committee's approval. In the event that the work plans and the budgets that were submitted by the parties shall not be approved by the operating committee by an effective majority as aforesaid, the work plan that received the most assenting votes will be approved, insofar as it meets the obligations required by the minimum work terms determined in regards to the Petroleum Asset.

(f) <u>Sole Risk operations</u>

Activities in which not all the parties participate (defined in the agreement as "Exclusive Operations" and known in the oil exploration industry as "Sole Risk" operations) will not be performed if they contradict joint operations in which all the parties participate.

The agreement determines rules with respect to the framework of performance of such operations.

The JOA includes various provisions relating to Sole Risk operations, namely the drilling of wells, tests and development, other than with the consent of all of the parties and which, under certain conditions specified in the agreement, may be performed by some of the parties. Parties that did not join such activity were given a possibility, subject to conditions and payments determined in the agreement, to receive back their share in such activity and everything deriving therefrom. In addition, parties which did not join the Sole Risk operations but decided to join after the joining date will bear the penalties and interest set forth in the JOA.

(g) Resignation and removal of the operator

Subject to the provisions of the JOA, the operator may, at any time, resign from its position as operator, upon prior notice of at least 120 days.

Subject to the provisions of the JOA the operator will be removed from its position upon the occurrence of any one of the following events: (1) if it becomes insolvent, bankrupt or if it has made an arrangement with its creditors; (2) if a notice was provided by a party to an agreement in the event of a court order or valid decision for reorganization under the insolvency laws; (3) if a receiver is appointed to a significant portion of its assets; or (4) if the operator is liquidated or ceases to exist in another manner.

Furthermore, the operator may be removed from its position by a decision of other parties to the JOA (that are not the operator) if it materially breached the JOA and did not commence the remedy of said breach within 30 days from the date upon which it received notice detailing said breach, or if it did not act to complete the remedy of the breach. Any decision of other parties to the JOA (that are not the operator) to give a notice of breach to the operator or to remove the operator will require an affirmative vote in favor of the decision of one or more of the parties that are not the operator (or that are not a related party or an affiliate of the operator) that represent collectively at least 65% of the total working interests of the parties that are not an operator.

In case of such change in the identity of the operator, the operating committee will convene as soon as possible in order to appoint an operator, however no party to the JOA will be appointed as operator against its will. The operator that was removed from office against its will or the related party/affiliate will not be permitted to vote in favor of itself or to be a candidate for the position of operator.

(h) Sanctions applicable to the parties and the conditions for imposition thereof

A party that fails to timely pay its proportionate share in the joint expenses (including advances and interest) or that fails to obtain or maintain the collateral required thereof, will be deemed a party in breach (the "**Party in Breach**").

As of 5 days from the date a Party in Breach was provided with a notice of breach and the breach persists, the Party in Breach will not be entitled, *inter alia*, to participate in meetings of the operating committee or to vote at them, receive information regarding the joint activity and to transfer its working interests or any part thereof, except to parties in breach.

Any party that is not a Party in Breach (a "**Party Not in Breach**") must bear the proportionate share (its share relative to the share of the other Parties Not in Breach) of the sum that is in breach (excluding interest), and to pay this sum to the operator within 10 days from the date of receipt of a notice with regard to the breach, and if it does not do so will itself be deemed a Party in Breach.

As long as the breach is ongoing, the Party in Breach will not be entitled to receive its portion of the output, and this portion will be the property of the Parties Not in Breach and they will be entitled, while following the proceedings detailed in the JOA, to collect from it what is due to them until the full payment of the breached sum (including setting up a reserve fund). Any surplus sum will be paid to the Party in Breach and any shortage will remain as a debt of the Party in Breach to the Parties Not in Breach.

If the Party in Breach does not remedy the breach within 90 days from the date of the notice of the breach, then without derogating from any other rights the Parties Not in Breach may have under the JOA, each party that is not in breach will have the option (that can be exercised at any time until full remedy of the breach) to require the Party in Breach to resign completely from the JOA and the Petroleum Asset. If such option is realized on the date a notice of realization of the option was sent, the Party in Breach will be deemed as having assigned all of its working interests to the Parties Not in Breach, and it will be required to sign, without delay, any document and take any action required by law in order to give force and effect to the said transfer of shares, and to remove any attachment or pledge that apply to the said rights.

Rights and remedies of the Parties Not in Breach as a result of said breach are in addition to any right or other remedy at the disposal of the Parties Not in Breach, under law.

A fundamental principle of the JOA is that each party is required to pay its relative portion (according to its participation rate in the Petroleum Asset) of all sums it owes under the JOA when due. Therefore each party that becomes a Party in Breach waives any offset claims and will not be entitled to raise such vis-à-vis the Parties Not in Breach which instituted the proceedings set forth in the JOA against it, for non-payment of the sums owed by it on time.

(i) Transfer of rights

Transfer of working interests of a party to a Petroleum Asset, in whole or in part, will be in force if it meets all the conditions set forth in the JOA, including *inter alia* the following conditions:

1. Except for in the case where a party transfers all of its working interests in a Petroleum Asset, no transfer of rights will occur where as a result the transferor retains or the transferee has received a working interest in a Petroleum Asset and in the JOA of less than 10%.

2. Notwithstanding the transfer, the transferor will retain liability vis-à-vis the other parties to the JOA for all financial and other liabilities, that were vested, had matured or accrued under the Petroleum Asset and the JOA prior to the date of the transfer including any and all expenses approved by the operating committee prior to the transferor's notice with regard to the transfer of the offered rights to the other parties under the JOA.

3. The transferee will have no rights with regard to the Petroleum Asset or under the JOA, for as long as and until: (a) it receives the required government approval and provides the guarantees required by the government or according to the terms and conditions of the Petroleum Asset; (b) it specifically undertakes, in a written document, to the satisfaction of the other parties, to perform the transferor's undertakings under the terms and conditions of the Petroleum Asset and the JOA with regard to the working interest being transferred to him; and (c) all other parties have given their written consent to the transfer. It is noted that the parties may withhold their approval only if the transferee fails to demonstrate, to their reasonable satisfaction, that it has the ability to satisfy its payment obligations under the leases and the JOA and the technical ability to contribute to the planning and execution of the joint activity. However, in the event of transfer to a related party, the consent of the other parties is not required, subject to the transferor remaining responsible for the transferee's performance of all of its obligations.

4. The foregoing does not preclude a party to the JOA from pledging any or part of its working interests as collateral for financing, subject to such party remaining responsible for all undertakings relating to said interest. The said pledge or encumbrance will be subordinate to any government approval that will be required and will be done specifically as subordinate to the rights of the other parties under the JOA.

5. The transfer of a party's working interests in the petroleum assets, in whole or in part (with the exception of a transfer to a related party or encumbrance of the interests as specified above), shall be subject to the giving of a notice to the other parties, in which the transferor discloses to the other parties the final terms and conditions of the transaction and grants them the right of first refusal. Upon the delivery of such notice, each of the other parties shall have the right to acquire the working interests to which the transaction pertains from the transferor, on the same terms and conditions (and without any reservation), by giving a counter-notice within 30 days of the delivery of the notice. In the event that more than one party notifies of its intention to exercise the right of first refusal, the sale of the rights shall be conducted *pro rata* according to such parties' rate of working interests.

(j) <u>Change of control</u>

In the event of change of control of any of the partners, such party shall provide the other parties with: (1) all of the required governmental approvals, as well as the guarantees required by the government; and (2) collateral with respect to the financial ability to comply with the obligations under the agreement. In addition, the party undergoing such change, is required to give notice of the change of control to the other parties (in this section, the "**Notice**"). In this section, "change of control" means any direct or indirect change of control of a party (including by way of merger, sale of shares, other interests or otherwise), the value of the Leviathan Leases held by which constitutes more than 50% of the market value of all of the assets of such party. The Notice shall include, *inter alia*, the market value of the partner's rights according to the JOA, based on the amount that the entity acquiring the control is prepared to pay in an arm's length transaction. Upon delivery of the Notice as aforesaid, each one of the other parties shall be entitled to purchase all of the rights of the partner at which the change of control is performed, within a period of 30 days from delivery of the Notice, and the purchase will be according to the conditions and the sum of the purchase amount stated. It is also noted that according to the terms and conditions determined in the JOA, the other parties may challenge the value stated in the Notice of the change of control.

In a case where more than one party gives notice of its desire to exercise its right to purchase the rights as aforesaid, the division will be made proportionately to the share of the parties' working interests.

(k) Withdrawal from the JOA

The JOA includes provision regulating the matter of withdrawal, full or in part, of a party from any Petroleum Asset in which it is a participant (and from the JOA applicable) and determines the cases when withdrawal is possible, and the rights and obligations of the withdrawing party vis-à-vis the other partners for the Petroleum Asset and the JOA.

A party that wishes to withdraw from a Petroleum Asset, must provide notice of its decision to the other parties (in this section: "**Withdrawal Notice**"). The Withdrawal Notice will not be unconditional and irrevocable upon delivery, subject to the conditions set forth in the JOA. Within 30 days from the day of delivery of the Withdrawal Notice the other parties to the JOA will be entitled to also present a Withdrawal Notice. In the event that all the parties present a Withdrawal Notice, they will act to terminate the JOA and the remaining undertaking connected to the Petroleum Asset and the JOA. In the event that not all the parties will decide to withdraw, all the withdrawing parties will act in order to assign as soon as possible the said rights to the partner/partners that chose not to withdraw. Transfer of said rights will be without consideration, with each of the withdrawing partners bears all expenses with regard to its withdrawal, unless otherwise resolved. The transfer of the rights to the remaining partners will be in proportion to their relative holdings.

(l) Rights and obligations with respect to production

Each party has the right and obligation to take its share in the hydrocarbons produced from the leases, unless it is agreed otherwise.

(m) Governing law and dispute settlement

The JOA is subject to the laws of England and Wales. A dispute shall be decided in an arbitration proceeding in accordance with the arbitration rules of the London Court of International Arbitration (LCIA).

7.26.8 Joint operating agreement in Block 12

The joint operating agreement in Block 12 covers the same issues as, and is in a format similar to the joint operating agreement in the Leviathan project, as specified in Section 7.26.7 above, with decisions made by an "effective majority", which is affirmative votes in favor of the decision by at least two participants that are not related parties and collectively hold at least 65% of the total rights in the license. Chevron Cyprus serves as operator in Block 12. However, it is noted that in the joint operating agreement that applies to Block 12, the parties do not have a right of first refusal in the case of transfer of rights in the petroleum asset.

7.26.9 Payment of royalties to the State and royalty payment undertakings to related and third parties

(a) General

The Petroleum Law prescribes that a lease holder must pay the State royalties at the rate of one-eighth (12.5%) of the quantity of oil and natural gas produced from the area of the lease and utilized, according to the market value of the royalty at the wellhead (the "**State Royalties**").

In addition to State Royalties, the Partnership pays royalties, according to the market value of the royalties at the wellhead, to related and third parties (the "**Royalty Interest Owners**") according to undertakings originating from the agreement for the transfer of rights in petroleum assets to the Partnership, as specified in Section 7.26.9(c)2 below, and undertakings originating from Avner's Limited Partnership Agreement as specified in Section 7.26.9(c)3 below.

(b) Calculation of the market value of the royalties at the wellhead

1. General

Pursuant to the Petroleum Law, the leaseholder will pay the State the "market value of the royalty at the wellhead". A determination of a method for calculating the market value of the royalty at the wellhead is required, since natural gas sales are priced at the onshore gas delivery point, and therefore, the contractual price stipulated in the gas sale agreements is higher than the price that would have been determined, had the gas been delivered at the wellhead. Consequently, the effective rate of the State Royalties is actually lower than one-eighth (the "**Effective Rate**").

2. The Effective Rate of the royalties in the Tamar project.

Since commencement of production in 2013, a dispute has arisen between the Tamar Partners and the Ministry of Energy regarding the method of calculation of the Effective Rate of the royalties. According to the Tamar Partners, the payments made thereby, at the State's request, are payments in excess that were unlawfully collected, and therefore the Tamar Partners, through Chevron, took action to resolve this dispute vis-à-vis the Ministry of Energy. It is noted in this context that, according to the terms and conditions of the transaction for the sale of the remaining interests of the Partnership in the Tamar and Dalit Leases, which was closed in December 2021, the Partnership is entitled to receive amounts for excess payments made to the State in respect of the Tamar project, if the arguments of the Tamar Partners on this issue are accepted.

Further to the draft royalty audit reports for 2013-2018 that were received from the Ministry of Energy, and based on the understandings that were finalized vis-à-vis the Ministry of Energy following discussions that were held in connection with the draft audit reports as aforesaid, in July 2024, final audit reports for years 2018-2013 were transferred from the Ministry of Energy to the operator of the Tamar project. Accordingly, the Partnership has updated non-material gaps in the aggregate amounts carried to the Statement of Comprehensive Income in the "expenses of royalties to the State" item (in 2013-2018). Based on such final audit reports, the Partnership received from the State (by way of setoff against royalty payments in 2024) a sum of approx. $17.2 million for the years 2013-2018. The Partnership also received from the royalty interest owners a total sum of approx. $8.2 million in respect of the said years. For further details, see Note 15B4 to the financial statements (Chapter C of this report). In February 2025, the draft royalty audit reports for years 2019-2020 were transferred from the Ministry of Energy to the operator of the Tamar project.

3. The Effective Rate of the royalties in the Leviathan project

According to demand letters received from the Ministry of Energy in October 2023, January 2024 and January 2025, the Leviathan Partners are required to make advance payments to the State on account of the State Royalties in respect of the revenues from the Leviathan project in 2023-2025 at the rate of 11.06%, *in lieu* of 11.26% as paid by the Leviathan Partners since the date of commencement of the gas supply from the Leviathan reservoir in accordance with a demand letter received from the Ministry of Energy in January 2020. Such Effective Rate is higher than the calculation performed by the Partnership and Chevron, such that in accordance with the 2020 royalty reports submitted by Chevron to the Ministry of Energy, and for 2021, the rate of the State Royalties in the Leviathan project should be approx. 9.58% and approx. 10.17% respectively. Accordingly, the rate of the royalties on which the Partnership relied was approx. 10.73% in its financial statements for 2023, and approx. 10.57% in its financial statements for 2024.[118] The difference between the royalties actually paid to the State by the Partnership in the Leviathan project and the Effective Rate of royalties on which the Partnership based its financial statements for the years 2019 to 2024 is approx. $20.6 million. For further details see Note 15 to the financial statements (Chapter C of this report).

It is noted that the method of calculation of the market value at the wellhead of the royalties in respect of the Leviathan project, which the Partnership is paying to the Royalty Interest Owners is in accordance with the Effective Rate of the royalties paid by the Partnership to the State.

(c) Royalty payment obligations to the Royalty Interest Owners[119]

1. General

In addition to the State royalties, the Partnership pays, as aforesaid, royalties to the Royalty Interest Owners, which include related and third parties, in accordance with undertakings that the Partnership and Avner assumed in the past, as specified below.

2. Delek Group Royalties

(a) In the context of an interest transfer agreement of 1993 (the "**Interest Transfer Agreement**") signed between Delek Energy and Israeli Fuel Company Ltd.[120] ("**Delek Israel**" and jointly in this section: the "**Transferors**") and the General Partner, the Transferors transferred to the Partnership interests in several oil licenses, in consideration for the Partnership's undertaking to pay the Transferors (Delek Energy – 75% and Delek Israel – 25%) overriding royalties at the rates specified below from the entire share of the Partnership in oil and/or gas and/or other valuable substances that shall be produced and used from the petroleum assets, in which the Partnership has or shall have

[118] It is noted that in the discounted cash flow figures for the Leviathan project, the Partnership assumed that the Effective Rate of the State Royalties was 11.06%.

[119] Note that following the merger of the partnerships, all of the undertakings to pay royalties to the royalty interest owners now apply with respect to all of the Partnership's (existing and future) petroleum assets, however, on the merger date, such royalty rate was reduced by 50% relative to the royalty rate on the eve of the merger, since the Partnership and Avner held the said petroleum assets in equal shares, apart from the Ashkelon and Noa leases, in which the Partnership held 25.5% and Avner 23%, and in respect of which the royalty rate was reduced by 47.42% relative to the royalties that were paid by the Partnership prior to the merger of the partnerships to Delek Group and Delek Energy, and by 52.58% relative to the royalties that were paid by Avner prior to the merger of the partnerships.

[120] Following the reorganization that was carried out in the past, the royalty right as aforesaid of Delek Israel was transferred to Delek Group.

any right (prior to deduction of any kind of royalties, but after deduction of the petroleum used for the production itself) (the "**Delek Group Royalties**").

(b) The royalty rates of the Delek Group Royalties as set forth in the Interest Transfer Agreement (after an adjustment following the merger of the partnerships), are as follows: until the Partnership's Investment Recovery Date (as defined below), royalties shall be paid at a rate of 2.5% from onshore petroleum assets and 1.5% from offshore petroleum assets, and after the Partnership's Investment Recovery Date, royalties shall be paid at a rate of 7.5% from onshore petroleum assets and 6.5% from offshore petroleum assets.

With respect to determining the Investment Recovery Date, the following provisions were determined in conditions of the royalties:

1. The term "**Investment Recovery Date**" means – The date after the signing of the Interest Transfer Agreement in which the (Net) Revenues Value (as defined below) that the Partnership received or is entitled to receive in respect of petroleum and/or gas and/or other valuable materials produced and used from the Petroleum Asset (i.e. – license or lease) where the finding is located, calculated in dollars (according to the representative exchange rate published by the Bank of Israel) will reach an amount equal to the full Value of All of the Partnership's Expenses in such Petroleum Asset (as defined below), calculated in dollars (according to such representative exchange rate).

2. The term "(Net) Revenues Value" means – The value of all revenues as shall be approved by the Partnership's accountants in respect of petroleum and/or gas and/or other valuable materials produced and used from the Petroleum Asset (i.e. - license or lease) (the "**(Gross) Revenues Value**") after deduction of all expenses for production thereof and royalties paid therefor.

3. The term "Value of All of the Partnership's Expenses" means – any and all expenses that the Partnership incurred in the Petroleum Asset (i.e. – license or lease) where the petroleum and/or gas and/or other valuable materials are extracted, but with the exception of expenses (up to the (Net) Revenues Value) deducted from the (Gross) Revenues Value for the purpose of determining the sum of all of the (Net) Revenues Value and as approved by the Partnership's accountants.

For details about a legal proceeding the was conducted in connection with the calculation of the date of recovery of the investment in the Tamar project, see Section 7.26.5 of Chapter A of the 2023 Periodic Report. Of note, in the context of understandings reached between the parties to such legal proceeding, the royalty interest owners and the Partnership confirmed that the principles by which the Tamar project investment recovery date was calculated would apply (after certain adjustments as specified under such understandings) also to the calculation of the date of recovery of the investment in the Leviathan project.

(c) As of the report approval date, the holder of the right to the Delek Group Royalties in the Leviathan project is Delek Overriding Royalty Leviathan Ltd., a wholly owned subsidiary of Delek Energy (the "**Delek Overriding Royalty**").[121] Delek Group and Delek Energy are entitled to Delek Group Royalties with respect to all the remaining petroleum assets of the Partnership that exist on the report approval date, and with respect to the petroleum assets in which the Partnership will have interests in the future.

3. <u>Avner Partnership Royalties</u>

In the context of the closing of the merger of the partnerships the Partnership assumed the undertakings of Avner Partnership to pay royalties, as the same are set forth in the Avner Partnership Agreement[122] (the "**Avner Royalties**), at the rate of 3% of the Partnership's entire share of the oil and/or gas and/or other valuable substances which shall be produced and utilized from the petroleum assets in which the Partnership has or shall in the future have an interest (before deduction of royalties of any kind but after reduction of the petroleum which shall serve for the purpose of the production itself). As of the report approval date, all of the parties entitled to Avner Royalties are third parties.

[121] To the best of the Partnership's knowledge and in accordance with the reports of Delek Group, in October 2020, Delek Group and Delek Energy transferred their right to receive Delek Group royalties from the Partnership's share (45.34%) in oil and/or gas and/or other valuable substances to be produced and utilized from the Leviathan Leases, to Delek Overriding Royalty.

[122] The partnership agreement of August 6, 1991 (as amended from time to time) which was signed between Avner Oil & Gas Ltd., as the general partner of Avner of the first part, and Avner Trusts Ltd., as limited partner of Avner of the second part (the "**Avner Partnership Agreement**").

4. Terms and conditions of the royalties

The following terms and conditions apply to all of the royalties paid by the Partnership (Delek Group Royalties and Avner Royalties) (in this section jointly: the "**Royalties**"):

(a) The Royalty Interest Owners or any of them shall be entitled to receive all or part of the Royalties in kind, i.e. to receive in kind a part of the oil and/or gas and/or other valuable substances that will be produced and used from the petroleum assets, in which the Partnership has an interest (up to the amount of the aforesaid rate). If any of the Royalty Interest Owners shall have chosen to receive the royalties in kind, the parties shall regulate the manner of and dates on which the Royalty Interest Owners shall receive the royalties. Should either of the Royalty Interest Owners not choose to receive the royalties in kind, the Partnership shall pay such Royalty Interest Owner the market value, in Dollars or (if payment under law may not be made but in Israeli currency) in Israeli currency, calculated according to the Dollar's representative rate upon the actual payment, at wellhead price, of the royalties due to the Royalty Interest Owner. Such payment shall be made once every month. The measurement of the quantities of oil and/or gas and/or other valuable substances that shall be produced and exploited from the petroleum assets, for the purpose of calculating the royalties due to the Royalty Interest Owners, shall be made in accordance with accepted principles in the petroleum industry.

(b) The Partnership shall keep full and accurate records concerning its share in the oil and/or gas and/or other valuable substances that shall be produced and exploited from the petroleum assets in which it has an interest. Each of the Royalty Interest Owners shall be entitled to appoint an accountant who shall be entitled to inspect, examine and copy, during normal work hours, the Partnership's books and other documents and records regarding the Transferors' right to the royalties under the Interest Transfer Agreement.

(c) The aforesaid right to royalties shall be linked to the Partnership's share in each of the petroleum assets in which it has an interest. Should the Partnership transfer its rights in a petroleum asset in which it has an interest, the Partnership shall ensure that the transferee assume all of the undertakings to pay the royalties as aforesaid. The aforesaid shall not apply at the event of asset forfeiture due to the Partnership being behind on payments. Regarding the Royalties by Virtue of the Avner Partnership Agreement, the

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aforesaid shall also not apply in the event of a transfer to partners who are continuing operations by some of the participants (sole risk).

5. In view of the dispute that has emerged between the Tamar Partners and the State regarding the method of calculation of the royalty value at the wellhead in the Tamar Project, as described in Section 7.26.9(b) above (in this section: the "**Tamar Dispute**"), and the dispute that has arisen regarding royalties paid to the State for gas that was marketed from the Tamar reservoir to customers of the Yam Tethys project as described in Section 7.27.1 below (in this section: the "**Yam Tethys Dispute**"), in November 2020, the Partnership reached agreements with all of the parties to which it had paid royalties from the Tamar Project over the years and until the date of the said agreements (including Delek Group and its affiliated corporations) (in this section: the "**Royalty Interest Owners**"), whereby:

   (a) In reference to the Tamar Dispute, it was agreed that after said dispute with the State shall be decided, and should it be found that the Royalty Interest Holders received Overpayments from the Partnership, then the Royalty Interest Owners shall be required to return said Overpayments to the Partnership, as shall be determined regarding the Overpayments made by the Partnership in respect of the State Royalties, plus linkage differentials and interest according to the Adjudication of Interest and Linkage Law, 5721-1961. It was further clarified that should it be found, after the determination of a binding method of calculation, that the Royalty Interest Holders received underpayments, then the Partnership shall be required to return said underpayments to the Royalty Interest Owners, plus linkage differentials and interest as aforesaid. It was further agreed that until the expiration of 18 months from the date of determination of the binding method of calculation, none of the parties shall raise claims relating to the lapse of time. For details about the final audit reports for 2013-2018, and the draft audit reports for 2019-2020 that the operator received from the Ministry of Energy for the Tamar project, see Section 7.26.9(b)2 above.

   (b) In reference to the Yam Tethys Dispute, it was agreed that the ruling in the claim conducted in such regard by the Partnership and Chevron against the State shall apply, *mutatis mutandis*, also to the Royalty Interest Holders, and that should it be found that the Partnership underpaid royalties, then it shall be required to pay the Royalty Interest Owners the underpaid royalties plus linkage differentials and interest and should it be found, after a binding method of calculation is determined, that the Partnership overpaid royalties, then the Royalty Interest Owners shall be required to return such overpaid royalties, plus linkage differentials and interest as aforesaid. It was further agreed that until the expiration of 18 months from the date the claim against the State shall be decided, none of the parties shall raise claims relating to the lapse of time. For details about the legal proceeding that the Partnership is conducting vis-à-vis the State regarding the Yam Tethys Dispute, see Section 7.27.1 below.

7.26.10 <u>Agreement for the sale of the Partnership's interests in the Tanin and Karish Leases</u>

Following the Government decision to approve the Gas Framework, on 16 August 2016, an agreement was signed between the Partnership and Avner (in this section: the "**Sellers**") and Energean Israel (in this section: the "**Buyer**"), whereby the Buyer purchased all of the Sellers' and Chevron's interests in the Tanin and Karish leases.

For further details regarding the said agreement, see Section 7.24.10 of Chapter A to the 2021 periodic report. For details regarding the very material valuation regarding the Partnership's royalties from the sale of the leases, see Note 8B to the financial statements (Chapter C of this report) and Section 8B of Chapter D of this report. For details regarding disputes that arose between the Partnership and Energean, see Section 7.5.4 above.

7.26.11 <u>The agreement for the sale of 9.25% of the interests in the Tamar and Dalit Leases to Tamar Petroleum</u>

In accordance with the provisions of the Gas Framework, which, *inter alia*, obligated the Partnership to sell its full holdings in the Tamar and Dalit leases, on 2 July 2017, a sale agreement was signed between the Partnership as the seller of the first part and Tamar Petroleum as the buyer of the second part, according to which Tamar Petroleum purchased from the Partnership, 9.25% rights (out of 100%) in the Tamar and Dalit leases.

For further details regarding the agreement, see Section 7.24.11 of Chapter A of the periodic report for 2021.

7.26.12 <u>Agreement for the sale of the Partnership's remaining interests (22%) in the Tamar and Dalit leases</u>

In accordance with the provisions of the Gas Framework which, *inter alia*, obligated the Partnership to sell all of its holdings in the Tamar and Dalit leases, on 2 September 2021 the Partnership engaged in an agreement for the sale of the Partnership's remaining interests (22%) in the Tamar and Dalit Leases to Tamar Investment 1 RSC Limited and Tamar Investment 2 RSC Limited.[123]

For further details regarding the agreement, see Section 7.24.12 of Chapter A to the 2021 periodic report.

7.27 **Legal proceedings**

Below are details regarding material pending legal proceedings, to which the Partnership is a party, or material proceedings as aforesaid, which have ended in the report year:

7.27.1 On 12 March 2015, the Partnership and Chevron (jointly in this section: the "**Plaintiffs**") filed a complaint with the District Court in Jerusalem against the State of Israel through its representatives from the Ministry of Energy, which primarily includes a demand for the restitution of royalties paid by the Plaintiffs to the State in excess and under protest, for the Plaintiffs' revenues from gas supply agreements signed between consumers of natural gas and the Yam Tethys Partners, some of which was actually supplied from the Tamar Project, according to the accounting mechanism designed to maintain a balance of the gas quantities in the Tamar Project between the partners therein according to their share. The restitution remedy claimed from the State is, as of 31 December 2024, approx. $28 million, the Partnership's share being approx. $13 million.

Alternatively, the Plaintiffs' argument is that they are at least entitled to a partial restitution amount that is, as of 31 December 2024, approx. $19.4 million, the Partnership's share being approx. $9 million.

On 14 November 2022, the court handed down a judgement dismissing the claim, except as related to the Plaintiffs' position regarding the restitution of interest amounts the defendant had collected from the Plaintiffs in an insignificant amount.

On 6 February 2023, the Plaintiffs filed an appeal from the judgement with the Supreme Court. On 13 August 2023, the Defendant filed its response to the appeal, and a hearing on the appeal has been scheduled for 27 April 2025.

In the Partnership's estimation, based on the opinion of its legal counsel, the prospects of the Plaintiffs' success in the appeal are difficult to assess, further to the issuance of the judgment and since the a hearing on the appeal has not yet been held.

[123] To the best of the Partnership's knowledge, the buyers are SPCs that were established for the purpose of the transaction and are held (indirectly) by MDC Oil & Gas Holding Company LLC, a corporation from the Mubadala Investment Company PJDC group, which is owned by the Government of Abu Dhabi.

The decision on this matter, when it becomes final and conclusive, shall also apply, *mutatis mutandis*, with respect to the overriding royalties that the Partnership paid over the years for the Tamar Project, in accordance with the agreements described in Section 7.26.9(c)5 above. Accordingly, insofar as the court's said decision of 14 November 2022 stands, the Partnership shall bear an additional payment to the Royalty Interest Owners for the amounts of gas which were supplied by the Partnership to the customers of the Yam Tethys Project, for which a provision was recorded in the financial statements in the sum of approx. $6.7 million (including interest and linkage).

In accordance with the terms and conditions of the Agreements for the sale of the Partnership's rights in the Tamar and Dalit Leases, also after the closing of the transaction, the Partnership is responsible and entitled, as the case may be, with respect to the amounts in dispute vis-à-vis the State and the Royalty Interest Owners.

For further details, see Note 7C9 to the financial statements (Chapter C of this report).

7.27.2 On 25 December 2016, the participation unit holders in Avner prior to the merger of the partnerships (in this section: the "**Petitioners**"), filed a motion for class certification (in this section: the "**Certification Motion**") based on the argument that the Merger of the partnerships' transaction between the Partnership and Avner was approved in an unfair proceeding, and the consideration that was paid to the holders of the minority units in Avner, as determined in the Merger of the partnerships' agreement, is unfair. The motion was filed against Avner, the general partner of Avner and the members of the board of directors thereof, Delek Group as the holder of control in Avner (indirectly), and against PricewaterhouseCoopers Consulting Ltd. (PwC) as the economic consultants of an independent board committee that was established by Avner (in this section: the "**Respondents**"). The motion claims, *inter alia*, that the committee members, the board of Avner and the General Partner breached the duty of care vis-à-vis Avner, and Avner conducted itself in a manner that was oppressive to the minority.

The total damage was estimated by the petitioners to be in the amount of ILS 320 million.

On 13 February 2017 the court approved a stipulation whereby the Certification Motion will be amended by adding an argument of minority oppression by Delek Group, and on 6 July 2017, the court ordered to add the Partnership as a respondent in accordance with the Partnership's motion. On 7 May 2023 the court handed down its judgment, which denied the Certification Motion.

On 6 July 2023, the Petitioners filed an appeal from the judgment with the Supreme Court, requesting the Supreme Court to accept the appeal and order the grant of the Certification Motion.

On 27 December 2023, PWC filed a counter appeal from the judgment, which is litigated within the aforesaid appeal, arguing that the District Court erred in that it failed to order costs in its favor (in this section: the "**Counter Appeal**").

According to the court's decisions, on 22 August 2024, the parties filed their responses to the appeal and the Counter Appeal. A hearing on the appeal and the Counter Appeal has been scheduled for 11 September 2025.

In the Partnership's estimation, based on the opinion of its legal counsel, chances of the appeal being denied are greater than the chances of it being granted.

7.27.3 On 4 February 2019, a class action and a motion for certification thereof (in this section: the "**Certification Motion**") was filed with the Tel Aviv District Court (Economic Department) by a shareholder of Tamar Petroleum and the Public Representatives Association (in this section collectively: the "**Petitioners**"), against Tamar Petroleum, the Partnership, the CEO of the Partnership and the Chairman of the Board of Tamar Petroleum on the date of the offering, the CEO of Tamar Petroleum, the CFO of Tamar Petroleum and Leader Issues (1993) Ltd. (in this section: "**Leader**" and collectively: the "**Respondents**"), in connection with the issue of the shares of Tamar Petroleum in July 2017 (in this section: the "**IPO**").

According to the Petitioners, in essence, the Respondents misled the investing public in the IPO with respect to the ability of Tamar Petroleum to distribute a dividend to its shareholders, for the period commencing on the IPO date and ending at the end of 2021 (in this section: the "**Period**"), and breached duties under various laws, *inter alia* the duty of care of the said officers and the Partnership's duties as shareholder and holder of control of Tamar Petroleum before the IPO.

The remedies sought in the Certification Motion mainly included a financial remedy in the sum of at least $53 million which is, according to the Petitioners, the difference between the total dividend which Tamar Petroleum was expected to distribute for the Period, as stated in the offering to institutional investors document of 12 July 2017, and the total dividend which, according to an expert opinion that was attached to the Certification Motion, Tamar Petroleum is expected to distribute for the Period.

On 13 August 2019, the court ordered the Petitioners to deliver the pleadings in the file to the Attorney General in order that he give notice by 15 September 2019 of whether he wishes to be joined to the proceeding, and on 6 February 2020, the Attorney General gave notice that at this stage he does not deem fit to join the proceeding.

On 1 November 2020, the Petitioners filed a motion to amend the Certification Motion, in the context of which they sought to add to the Certification Motion an additional petitioner who participated in the IPO, unlike the current Petitioners who did not participate therein and they also sought to increase the amount of the alleged damage to $153 million. On 6 April 2021, the court granted the Petitioners' motion to amend the Certification Motion, and ruled that the Petitioners are entitled to file the amended Certification Motion in accordance with the language filed with the court subject to payment of expenses to the Respondents in the sum total of ILS 100,000. On 23 January 2022, an amended motion for class certification was filed, and on 21 August 2022 and 4 September 2022, the Respondents filed their response to such motion. On 20 December 2022, a pretrial hearing was conducted, and in accordance with the court's decision as part thereof, on 17 January 2023, the Petitioners filed an amended response to the Respondents' answers to the amended Certification Motion.

On 23 April 2023, the Petitioners filed a motion for a discovery order, and on 17 July 2023, the court denied the motion for discovery in relation to all the Respondents, except Leader, with respect to which the motion was partly granted. Furthermore, on 16 August 2023, the court approved an agreed procedural arrangement between the parties, whereby the cross-examination of witnesses in the context of the Certification Motion would be conducted in February-April 2024. Accordingly, in April 2024, the trial hearing stage has ended and according to the instructions of the court, the closing statements of the Petitioners were filed with the court in March 2025, and the closing statements of the respondents are to be filed with the court by October 2025.

In the Partnership's estimation, based on the opinion of its legal counsel, chances of the Certification Motion being granted are lower than 50%.

7.27.4 On 27 February 2020 the Partnership learned of the filing of a class action and a motion for class certification (in this section: the "**Certification Motion**"), which was filed with the Tel Aviv District Court by an electricity consumer (in this section: the "**Petitioner**") against the Partnership and Chevron and against the other holders in the Tamar Project and the Leviathan project (as parties against which no remedy is sought), in connection with the competitive process for the supply of natural gas conducted by the IEC and in connection with a possible amendment to the agreement for the supply of gas from the Tamar Project to the IEC, as agreed by Isramco, Tamar Petroleum, Dor and Everest Infrastructure – Limited Partnership (collectively in this section: the "**Other Holders in the Tamar Project**"), without involvement on the part of the Partnership and Chevron (in this section: the "**Amendment to the Tamar Agreement**").

The Petitioner's principal arguments are, that the bids made by the Other Holders in the Tamar Project and the holders in the Leviathan project in the competitive process amount to abuse of monopoly power and to a restrictive arrangement, as defined in the Economic Competition Law; the Partnership's and Chevron's not signing the Amendment to the Tamar Agreement also amounts to abuse of monopoly power; the price determined in the agreement for the supply of gas from the Leviathan project to the IEC further to the competitive process is an unfair price; and profits made and which shall be made by the Partnership and Chevron under this agreement, while harming competition, amount to unjust enrichment.

The Petitioner alleges that such actions of the Partnership and Chevron have caused and are expected to cause damage to the classes he seeks to represent in the sum of approx. ILS 1.16 billion, which he seeks for the classes he seeks to represent, and according to which the Court is moved to award compensation and fees. The main remedy that is sought in the Certification Motion is a ruling by the court that the Partnership and Chevron are not entitled to prevent the other holders in the Tamar Project from signing the Amendment to the Tamar Agreement.

On 22 December 2020 the other holders of the Tamar project filed a motion for summary omission thereof, and on 9 September 2021 the Court approved their omission. Furthermore, on 17 November 2021, the court approved Ratio's stipulation to be omitted from the Certification Motion.

On 9 December 2021, the Partnership and Chevron filed their response to the Certification Motion as well as a motion to remove the legal opinion that was attached to the Certification Motion, and on 27 February 2022, the Court decided that this motion will be heard at the pretrial hearing set for 24 April 2022. On 28 February 2022, the Petitioner filed a response to the Respondents' response to the Certification Motion.

On 24 April 2022, in the context of a pretrial hearing, the court ordered as follows: (a) the legal opinion which was attached to the Certification Motion will be removed, and the Petitioner will bear the expenses of the respondents to the Motion on this matter; (b) the Petitioner shall be given an opportunity until 24 May 2022 to file a motion to amend the Certification Motion; (c) until then, the parties shall be given an opportunity to file a list of questions with the court which will be directed to the regulator relevant to the Certification Motion; and (d) on 25 May 2022, or soon thereafter, the court shall allow the respondents to respond to the motion to amend the Certification Motion, insofar as such motion is filed, or alternately shall deliver the pleadings, with the questions filed by the parties attached, for the regulator's comments.

On 25 May 2022, the parties filed a list of questions which will be directed to the regulator, and on 31 May 2022 the court ordered the delivery of the pleadings to the Office of the Tel Aviv District Attorney (Civil) in order to obtain the position of the regulator on the dispute which is the subject of the Certification Motion. On 19 January 2023, the position of the regulator (the Competition Authority, with the consent of the Ministry of Finance and the Ministry of Energy and in coordination with the Attorney General) was filed. In summary, the position refrained from explicitly stating whether or not there is any truth in the claims made in the Certification Motion, but it reviewed the relevant factual and legal background in a way that is generally consistent with the claims of the Partnership and Chevron. On 6 February 2024, the court granted the Petitioner's motion, with the consent of the Respondents, to cancel the trial hearings scheduled for March-April 2024, and on 27 June 2024 the court entered a decision on the parties' agreement – reached pursuant to the court's recommendation – to hold a conciliation aiming to reach a withdrawal arrangement. According to the court's decision, a pretrial hearing was held at the court on 25 September 2024, wherein the court proposed that the parties engage in an attempt to agree on seeking mediation in this proceeding. On 15 January 2025, the parties filed a joint motion for a compensated withdrawal from the Certification Motion and on 18 February 2025, the judgment of the Tel Aviv District Court (Economic Department) was rendered, granting the joint motion for a compensated withdrawal from the Certification Motion, whereby, *inter alia*, the respondents are required to pay the Petitioner and his counsel compensation, legal fees, and reimbursement of expenses in the amount of ILS 400,000 (the Partnership's share being ILS 200,000), plus V.A.T. as required by law.

7.27.5 On 23 April 2020, a holder of participation units of the Partnership (in this section: the "**Petitioner**") filed a class action and motion for class certification against the Partnership, the General Partner, Delek Group, Yitzhak Sharon (Tshuva), the directors of the General Partner (including the former chairman of the board) and the CEO of the General Partner (in this section: the "**Certification Motion**" and the "**Respondents**", respectively), with the Economic Department of the Tel Aviv District Court.

The Certification Motion alleges that the Respondents refrained from disclosing, in the Partnership's reports, the existence of a clause in the agreements for the sale of natural gas from the Leviathan and Tamar reservoirs to Blue Ocean (formerly Dolphinus Holdings Limited) (in this section: the "**Sale Agreements**" and the "**Buyer**", respectively), according to which in a year in which the average daily Brent barrel price (as defined in the Sale Agreements) is lower than $50 per barrel, the Buyer is entitled to reduce the minimum annual quantity purchased under the Sale Agreements, to 50% of the annual contract quantity (the "**Reduction Clause**"). According to the Petitioner, the alleged non-disclosure in the Partnership's reports establishes causes of action by virtue of various sections of the Securities Law, by virtue of the tort of breach of statutory duty, and by virtue of the tort of negligence.

The main remedy sought in the Certification Motion is compensation of the class which the Petitioner intends to represent, for the alleged damage incurred thereby, which is assessed, according to the opinion attached to the Certification Motion, at approx. ILS 55.5 million. The Petitioner also moved for any other remedy in favor of the class, as the court deems fit under the circumstances.

On 17 January 2021, the Respondents filed their response to the Certification Motion, accompanied by an expert opinion that states, *inter alia*, that during the period relevant to the Certification Motion, the Reduction Clause was never material and therefore was not required to be disclosed to the public, and that there is no proximate cause between the disclosure of the Reduction Clause and the decrease observed in the prices of the Partnership's participation units. On 2 January 2022, the Attorney General, after being required to do so by the court, notified that at this stage, he did not deem it fit to take a position in the proceeding. Trial hearings were held in November 2022. On 10 December 2023, the Petitioner filed written statements on his behalf, and according to the court's decision, the Respondents and the Plaintiff are required to file written statements and responding summations by April 2025.

In the Partnership's estimation, based on an opinion of its legal counsel, chances of the motion being granted are lower than 50%.

7.27.6 On 3 May 2021, Haifa Port Company Ltd. (in this section: "**Haifa Port**") filed a claim against Chevron, Coral Maritime Services Ltd. (in this section: "**Coral**") and Gold-Line Shipping Ltd. (in this section: "**Gold-Line**"), in the amount of approx. ILS 77 million (in this section: the "**Primary Claim**"). According to Haifa Port's claim, the direct offloading of cargo onto the Leviathan platform, as done by Chevron, without first unloading such cargo in one of Israel's ports, is unlawful and was done to avoid making obligatory payments to the Port, thereby causing the Port a loss. As argued in the complaint, from July 2018 forward, Chevron engaged in such direct offloading, while declaring to the tax authorities that the Haifa Port was the "offloading port", although the offloaded cargoes did not actually go through the Haifa Port. The claim against the Coral and Gold-Line companies is that they acted, during the relevant times, as ship agents for Chevron, which, as argued by Haifa Port, gives rise to their duty to pay the handling fees on behalf of Chevron.

Chevron filed its answer on 31 August 2021, and on 1 December 2021, Haifa Port filed a reply. At the same time, Chevron filed a counter-complaint in the amount of ILS 4,405,842 against Haifa Port, seeking ILS 715,691 for handling fees and infrastructure fees actually charged by Haifa Port, in violation of the law, and seeking ILS 3,690,151 for mooring fees charged to Chevron without a 30%-reduction, in violation of the law, in cases of self-navigation by ships passing through the port area. Haifa Port filed a counter-answer on 1 December 2021.

On 11 September 2022, a pretrial hearing was held, in which it was determined that the parties will negotiate with the aim of reaching agreement on the completion of the preliminary proceeding, failing which they will file motions accordingly. Despite the attempt to reach agreements, the parties filed mutual motions regarding the preliminary proceedings and on 8 July 2023 and 18 July 2023, the court denied the said motions. On 4 June 2024 a pretrial hearing was held, in respect of several motions that were filed by the parties, excluding Haifa Port's motion to summon the custom representative for testimony, and on 28 July 2024 the court denied the motions filed by the Haifa Port and granted Chevron's motion to summon witnesses that are not under its control. On 13 October 2024, Haifa Port filed a motion for leave to appeal on the court's decision to deny the motions filed thereby, and a motion to postpone the filing date of the responding affidavits. The court granted the said motion for postponement and ordered that the responding affidavits shall be filed 30 days after the motion for leave to appeal is decided. On 20 November 2024, the court denied the said motion for leave to appeal, and responding affidavits on behalf of the parties in the claim and the counterclaim were filed on 21 January 2025. The final pretrial hearing and the hearing of Haifa Port's motion to summon the custom representative for testimony were scheduled for 10 March 2025.

It is also noted that on 3 April 2023, Haifa Port filed a motion for summary dismissal of the counterclaim, arguing lack of controversy between itself and Chevron, because the invoices and mooring fees had been paid by an agent. Such motion was denied on 21 June 2023 and the court issued an order for costs against Haifa Port.

In the Partnership's estimation, based on the opinion of its legal counsel, the Primary Claim is more likely to be dismissed than granted.

7.27.7 On 3 December 2023, a participation unit holder of the Partnership (in this section: the "**Petitioner**") filed a motion against the Partnership, in accordance with Section 65OO of the Partnerships Ordinance and Section 198A of the Companies Law, for the issuance of an order for the discovery and review of documents before filing a derivative claim against the General Partner; Mr. Abu, CEO of the General Partner; and the members of the General Partner's board of directors (including members of the compensation committee) in the relevant period (in this section: the "**Discovery Motion**"). In summary, the Discovery Motion is based on the claim that the approval of Mr. Abu's current terms of office and employment by the compensation committee and the board of directors, in the "overruling", against the position of the general meeting of the participation unit holders, was done in violation of the law, while breaching the duties of care and fiduciary duty applicable to the members of the board of directors and in violation of Mr. Abu's duty, as CEO of the General Partner, to act in the best interests of the Partnership. As part of the Discovery Motion, it was claimed that the approval of Mr. Abu's terms of office and employment in the overruling was done without the conditions required therefor being met pursuant to the Partnerships Ordinance; that there was no sufficient re-discussion of the terms of office and employment of Mr. Abu and that no reference was made therein to the general meeting's objection; and that the reasons detailed by the board of directors did not refer to the mere rejection by the general meeting of the approval of Mr. Abu's terms of office and employment.

It is noted that in proximity to the filing of the Discovery Motion, the Petitioner filed with the court, a notice regarding additional motions for discovery and inspection of documents before the filing of the derivative action, which were filed by him or by his counsel, based, as he alleges, on a "similar factual matrix"; against other respondents: Delek Group Ltd. (D.A. 58205-11-23); Electra Ltd. (D.A. 50050-11-23), Matrix I.T. Ltd. (D.A. 60805-11-23); and Scope Metals Ltd. (D.A. 47021-11-23) (the "**Additional Proceedings**").

On 6 December 2023, the court ordered that the parties to the Additional Proceedings consider consolidating their hearings by choosing a lead case ("**Locomotive Case**") which shall govern the decisions in all of the Additional Proceedings; or in any other way (the "**Consolidation of the Hearing**"). On 8 January 2024, the Petitioner informed the court of his consent to the Consolidation of the Hearing, and on that date the Partnership filed its objection with the court to the Consolidation of the Hearing, since, *inter alia*, these are different and distinct proceedings, which concern other decisions, made by other entities, in relation to the terms of office of other officers and in other corporations; and that under these circumstances the consolidation of the proceedings is not expected to simplify and streamline the hearing thereof, and there is no concern of conflicting decisions between them, as required by law in order to consolidate the hearing in parallel proceedings. To the best of the Partnership's knowledge, the respondents in the Additional Proceedings also opposed the proposal for Consolidation of the Hearing. On 17 July 2024, the court ruled that no Consolidation of Hearing shall take place.

On 18 April 2024, the Partnership filed its response to the Discovery Motion with the court, and on 4 June 2024, the Petitioner filed the reply to the Partnership's response to the Discovery Motion.

Pursuant to the court's decisions of 31 October 2024 and 7 November 2024, the Partnership's participation unit holders may give notice, until 5 December 2024, whether they support the Discovery Motion, and give reason for their position. To that end, the court ordered the Petitioner to deliver the proceeding's judicial documents to the Partnership's participation unit holders, until 7 November 2024, and on 6 November 2024 the Petitioner filed a motion to extend the said date until 14 November 2024. The court did not respond to that extension request. To clarify, the said court decisions apply, mutatis mutandis, also to the Additional Proceedings.

On 23 June 2024, a motion was filed on behalf of the Association of Publicly Traded Companies (the "**Association**") to join the proceeding as amicus curiae, and according to the court's decision, following the filing of the parties' replications to such motion, on 18 August 2024 the Association's answer to the Petitioner's objection to its request to join the proceeding as amicus curiae was filed. On 19 September 2024 the court granted the Association's said motion to join the proceeding.

On 5 December 2024, the position of the Attorney General was filed in respect of this proceeding and the Additional Proceedings, and according to the court's decision, a complementary position thereto may be filed by the Attorney General until 25 February 2025.

On 20 January 2025, a trial hearing was held and according to the court's decision, the Petitioner and the Partnership are to file summations and responding summations by September 2025, and the Association is required to file summations on its behalf, with respect to this proceeding and the Additional Proceedings, by June 2025.

In the Partnership's estimation, based on an opinion of its legal counsel, chances of the Discovery Motion being granted are lower than 50%.

7.27.8 Against the backdrop of the ongoing delays in the completion of construction work and the postponement of commencement of gas flow under the transmission agreement with INGL, of 18 January 2021, as detailed in Section 7.13.2(c)(2) above, on 24 November 2024, Chevron filed a statement of claim in arbitration against INGL regarding the breach of the said transmission agreement. As part of the statement of claim, Chevron sought, *inter alia*, the reimbursement of the difference that accumulated since 30 April 2023, between the actual SPOT rate paid and the regular transmission rate that should have been paid according to the binding transmission agreement of 18 January 2021. As of December 2024, the said difference totaled approx. ILS 102 million (100%, the Leviathan Partners' share being approx. ILS 67 million). The preliminary hearing in the proceeding is scheduled for 2 April 2025. It is noted that, concurrently with the said arbitration proceeding, the parties have referred to mediation with the aim of reaching agreements without an arbitration award, which mediation is still in progress.

7.28 Goals and business strategy

7.28.1 General

The Partnership's goals and accordingly also its business strategy, are exhaustion of the economic potential of the natural gas assets held thereby alongside examination of acquisition of additional natural gas assets, in and out of Israel, and examination of possibilities of using new technologies, including AI, designed to streamline the activity of natural gas production and utilization while protecting sustainability values. The said strategy is realized mainly through exhaustion of the production and sales potential of Phase 1A and promotion of the development of Phase 1B of the Leviathan Project, as specified in Section 7.2.5 above, promotion of the development of the Aphrodite reservoir, promotion of exploration activity in Israel, Morrocco and Bulgaria, including activity in connection with deep targets in the Leviathan leases, as well as promotion of possibilities for the use, ownership, development and expansion of infrastructure for natural gas transmission from the Partnership's petroleum assets to the domestic market and to the export markets including as LNG, in accordance with the ESG policy adopted by the Partnership, in order to generate optimal value for the Partnership's stakeholders.

For this purpose, the Partnership acts, *inter alia*, for the increase of the demands for natural gas, both by means of expansion and assimilation of the use of natural gas in the domestic market and by means of natural gas export through the pipelines and/or liquefaction and/or compression of the natural gas and the marketing thereof to the global markets and taking into account the Government's policy on the matter.

The Partnership is also examining business opportunities that are connected to its business sector, in and outside of Israel, including the possibility of joining as a partner in petroleum assets in various stages of exploration, development and production, and is also examining technological developments that are connected to its business sector.

Furthermore, in order to accomplish targets of reduction of greenhouse gas emissions from the Partnership's assets to zero, and in view of the changes occurring in the energy industry, government policy in Israel and in the developed countries to encourage the transition to electricity production from alternative energies, the Partnership is exploring possibilities for investment in the alternative energies sector. In this context, the Partnership has entered into an agreement with Enlight, as specified in Section 7.10 above. The Partnership is also exploring possibilities for production of hydrogen, *inter alia* blue hydrogen that is produced from natural gas, and in this context, it engaged with Airovation, as specified in Section 7.28.3(b) below.

7.28.2 **Natural Gas**

The Partnership will continue to act to exhaust the economic potential of the natural gas assets held thereby alongside examination of acquisition of additional assets, including:

(a) Leviathan Project

1. Ensuring natural gas and condensate supply from the Leviathan reservoir, in accordance with agreements that have been signed, and the conduct of negotiations and engagement in additional agreements for the sale of natural gas and condensate to various potential consumers in Israel and in counties in the region, chiefly Egypt and Jordan.

2. Promoting the development of Phase 1B through the receipt of the required approvals and the signing of agreements for natural gas sale to the domestic market and for export ahead of the adoption of a final investment decision (FID) for the performance of the first stage of Phase 1B, during the coming months, as specified in Sections 7.2.5(b)(2) and 7.13.2 above.

3. Promoting a seismic survey for the purpose of formulating deep target exploration prospects in the Leviathan Leases. In this context, the Partnership contacted major international seismic survey providers in order to obtain detailed offers for the conduct of a 3D seismic survey in the course of this year for the purpose of imaging and specification of the deep targets in the Leviathan Leases. As of the report approval date, initial offers have been obtained and are examined by the Partnership with the assistance of its outside consultants.

(b) Block 12 in Cyprus

Promotion of the development of the Aphrodite reservoir in Cyprus, as specified in Section 7.3.6 above.

(c) Optimization of infrastructures

The Partnership is examining, jointly with its partners in the various petroleum assets and other owners of infrastructures, the possibilities for optimization of existing infrastructures in the various projects, including the joint transmission infrastructure for export of natural gas to the various target markets and *inter alia* for the purpose of reducing construction and transmission costs and increasing the feasibility of advancing various projects.

(d) Oil and gas exploration

Continued natural gas and oil exploration activity in the Partnership's assets and identification of business opportunities in new assets. In this context, the Partnership won the Zone I Licenses, in the area of Blocks 4, 5, 6, 7, 8 and 11 in the Mediterranean Sea, within Israel's exclusive economic zone (EEZ), and engaged in an agreement for the acquisition of the rights in the Bulgaria license. For further details, see Sections 7.6, 7.7 and 7.8 above.

(e) Increasing the demand for natural gas

The Partnership is working to increase demand for natural gas, *inter alia*, in the following methods:

1. Transportation: In the Partnership's estimation, in the upcoming decade, transportation conversion volumes are expected to grow by approx. 3.7 BCM.

2. Conversion of coal-fired power plants to natural gas use: In the Partnership's estimation, the continuation of the Government's policy to reduce the use of polluting coal for the production of electricity, including the termination of all coal-fired electricity generation in the interest of switching to power generation by natural gas, may increase the use of natural gas in Israel in significant quantities, estimated at up to approx. 2.6 BCM per year.

3. Additional industries: To the best of the Partnership's knowledge, projects are being examined and promoted in the State of Israel by various entrepreneurs, both in industries in which natural gas is used as a raw material, such as the production of ammonia, hydrogen and methanol, and in energy-intensive industries. In the Partnership's estimation, the establishment in Israel of plants in these areas, if established, may lead to a significant increase in the domestic use of natural gas.

7.28.3 **Alternative energies**

(a) Renewable energies

The Partnership is exploring possibilities for investing in projects in the field of renewable energy as part of a collaboration with Enlight, as specified in Section 7.10 above.

(b) Hydrogen production

The Partnership is examining a blue hydrogen venture, in which natural gas is split into hydrogen and carbon dioxide (CO_2), with the carbon dioxide being collected and stored in designated subsurface storage sites, or connected in various ways to rocks underground or in seawater or used for the manufacture of various products. It is noted that hydrogen is considered one of the main staples of a sustainable and prosperous low-carbon economy and constitutes a key strategy for dealing with the climate crisis. For further details, see Section 7.15.4 above.

In this context, on 9 September 2024, the Partnership entered into agreements with Airovation for a multiple-stage investment of a total sum of up to $3 million, in a pilot project to examine the use of carbon sequestration technology developed by this company, which may, if proven to be effective and economically feasible, under certain circumstances, among other things, become a part of the production of clean blue hydrogen from the natural gas produced from the Leviathan project.

7.28.4 ESG

The Partnership strives to realize the potential of its primary assets and also expand its activity to additional assets, responsibly and efficiently, in order to maximize value for its stakeholders while protecting its sustainability values and being in line with its ESG strategy.

Although natural gas is a fossil fuel and perishable resource, it serves as an important transition fuel that enables electricity generation with a carbon and pollution footprint much lower than that based on coal or diesel. The demand for natural gas is expected to grow in the coming decades, particularly in the Middle East, as part of the transition to low-carbon energy sources.

In order to balance the greenhouse gas emissions attributed to the Partnership, and to ensure its prosperity also in the coming decades, the Partnership is working to expand its renewable energy operations, as specified in Section 7.10 above, and its use of carbon dioxide for the production of value-added products, including in combination with hydrogen production, as specified in Section 7.28.3(b) above.

7.28.5 The scope and range of the Partnership's operations require the investment of significant financial resources, *inter alia*, for the purpose of establishing and deepening the commercial, technical, financial, legal, regulatory and other capabilities and knowledge. Therefore, the Partnership intends to consider using the variety of resources available thereto for purposes of raising money, by way of debt and/or equity, in addition to using the future surplus income from the Leviathan project, and the surplus cash in its possession.

It is clarified that the Partnership's goals and strategy as specified above constitute general intentions and goals and therefore there is no certainty that they will be realized, *inter alia*, due to changes in the market conditions, geopolitical changes, changes in regulation and in tax laws, changes in priorities resulting from the results of the activity in the Partnership's projects as well as other developments, unpredicted events, and the risk factors, as specified in Section 7.30 below. It is further clarified that realization of the goals and strategy specified above is subject to approvals by the Partnership's competent organs, some of which have not yet been obtained, including the general meeting of the unit holders, as well as third-party approvals.

7.29 <u>Insurance coverage</u>

From time to time, the Partnership takes out the insurance policies generally accepted for the energy sector for natural gas exploration, development and production, *mutatis mutandis* to the requirements of the law, the regulation (in Israel and overseas), the conditions of the licenses and the leases, the requirements of the financing entities and the scopes of the Partnership's operations and its exposures in Israel and overseas.

Some of the insurance policies are taken out in group insurance policies that cover several insured, which cover the assets and liabilities in the Partnership's various activities, only against some of the possible risks, as is the common practice in the industry of exploration, development and production of natural gas and products thereof, and all subject to the provisions of this section. The insurance system covers, *inter alia*, expenses for loss of control of well, certain coverage for political risks, property damage and certain consequential damage related to the insured property damage at the production phase, risks to construction work in the development of the assets (including during the maintenance period pertaining to the development of the Leviathan reservoir) as well as liabilities for third party bodily and property damage due to the activity of drilling, construction and production, including pollution damage resulting from accidental events (except for gradual pollution damage).

It is noted that the Partnership and Chevron have taken out insurance coverage for physical damage to EMG's property in an 'all risks' policy, as well as in a policy for insurance of war and terror risks. In addition, the Leviathan Partners have taken out insurance coverage for interruptions in the supply of gas, caused by physical damage to the Egyptian transmission network in Sinai, due to acts of war and/or terror. It is noted that the insurance policies do not cover loss of revenues due to a halt in production as a result of receiving a binding regulatory instruction, such as the one received by the Tamar partners after the outbreak of the Swords of Iron war.

The aforesaid insurance policies have been taken out partly independently and partly in the framework of the operator's insurance system. Some of the insurance policies are subject to agreements of pledge and assignment of rights, in accordance with financing agreements that are signed from time to time.

Furthermore, the Partnership monitors, from time to time, changes in the value of the insured property, and the amounts of the consequential damage that is entailed by damage to the insured property and/or to the property of a customer and/or of a supplier, in order to adjust the scope of the purchased insurance according to the exposure subject to the insurance costs and the global supply of insurance for the energy sector. Consequently, the Partnership can decide on a modification and/or decrease of the purchased coverage and/or a reduction of the sum of the purchased insurance and/or decide not to purchase any insurance at all for this risk or another.

It is further noted that the Partnership engaged with Delek Group (in this section: the "**Guarantor**") in an agreement, whereby the Guarantor granted a performance guarantee in favor of the Republic of Cyprus with respect to the Partnership's activity in Block 12 as specified in Section 7.3.3(n) above. For further details, see Section (c) of Regulation 22 to Chapter D of this report. As a condition for granting the aforesaid guarantee, the Partnership was required to take out additional insurance to the Guarantor's satisfaction, at the stage of performing the drilling work, with respect to the insurance of liabilities to third parties as well as expenses for regaining control over an out-of-control well, including coverage of bodily and property damage and cleaning expenses resulting from the risks of accidental pollution.

For details with respect to the risk in the absence of sufficient insurance coverage, see Section 7.30.12 below.

7.30 Risk factors

Below is a concise summary of the threats, weaknesses and other risk factors of the Partnership, which derive from the general environment ("**Macro Risks**"), the business sector ("**Sectoral Risks**") and the unique characteristics of the Partnership's operations ("**Special Risks**"). It is clarified that the following risk factors are not an exhaustive list of the risks related to the Partnership and its operations, and that the Partnership has other risks that derive from the Partnership's business and assets, as specified in this chapter, as well as risks which, as of the date of approval of the report, are not yet known to the Partnership.

7.30.1 The Swords of Iron War

As specified in Section 6.8 above, as of the report approval date, the Swords of Iron War has not yet ended, and there is considerable uncertainty as to the possible developments of the war and the security situation in general in the various fronts. Accordingly, it is impossible to assess the impact of these developments on the Partnership's operations, and primarily on continued regular production from the Leviathan reservoir and on the marketing of gas to export customers and the domestic market.

Natural gas platforms, the offshore and onshore production and transmission facilities, facilities for treatment and transmission of natural gas and condensate and other essential infrastructure systems in Israel and in the export countries may constitute targets for missile firing and acts of sabotage, and impact they suffer, if any, may cause extremely significant damage and disrupt or shut down the production and/or transmission activities for such amount of time and to such extent that may prove to be considerable. In such cases, the insurance policies that Chevron and the Partnership have acquired may possibly prove insufficient to cover the damage and loss suffered by the Partnership. In the case of escalation of the war, the risk of imposition by the Government of restrictions on the regular production operations of the Leviathan reserve and/or the Tamar or Karish reservoirs may increase as well. Restriction or discontinuation of the production from the Tamar and/or Karish reservoirs is expected to compel the Leviathan Partners to increase the quantities of supply to the domestic market, predominantly at the expense of the export to Egypt.

Moreover, against the backdrop of the ongoing war, there is an increase in the geopolitical risk related to the export of natural gas from the Leviathan reserve pursuant to the export agreements, which accounts for most of the Partnership's revenues.

7.30.2 <u>Pandemic outbreaks</u>

The Covid crisis, which started in 2020, impacted the global economy in general and the energy sector in particular. As of the report approval date, Covid morbidity rates are relatively low, but it is possible that a renewed outbreak of Covid or an outbreak of other pandemics will occur, which may have a significant effect on the financial markets, interest margins, currency exchange rates and the prices of commodities in the energy sector, thereby adversely affecting many industries, including the energy sector in which the Partnership operates, with the effects being similar to or even harsher than the effects of the Covid pandemic outbreak. As of the report approval date, it is impossible to assess the probability for materialization of risks of this type.

7.30.3 <u>Fluctuations in the linkage components in the natural gas price formulas in the supply contracts</u>

The gas price is determined in the natural gas supply agreements according to price formulas which include various linkage components, including mainly linkage to the Brent barrel price, to the Electricity Production Tariff, to the ILS/$ exchange rate, to the TAOZ index, and in one of the agreements also to the refining margin index. All of the natural gas supply agreements in which the Partnership engaged, other than agreements that include a non-linked fixed price, also specify, along with the price formulas, price floors that limit, to a certain extent, the exposure to fluctuations in the linkage components. However, there is no certainty that the Partnership will also be able to determine such price floors in new agreements to be signed thereby in the future.

Moreover, a decrease in Brent prices and/or a decrease in electricity tariffs and/or a change in the ILS/$ exchange rate may adversely affect the Partnership's income from the existing and future gas sale agreements.

It is noted that the frequent methodological changes made by the Electricity Authority in the method of calculation of the Electricity Production Tariff render it difficult to predict, and may lead to between the gas suppliers and the customers disputes in relation to the method of calculation thereof. It is noted in this context that, for some of the private power plants (including plants sold by the IEC), the Electricity Authority has applied regulation referred to as SMP (System Marginal Price), whereby, the wholesale electricity price is determined every 30 minutes according to the marginal cost of production of an additional KW/-hour in the sector, based on half-hour tenders conducted by the Electricity System Manager between the various electricity producers, every day. Such pricing method may have an effect on the prices of natural gas to be sold by the Partnership to electricity producers in the domestic market, in the event that the gas prices in future contracts are linked to such pricing.

7.30.4 Changes in demand and in the prices of the energy products

The demand for natural gas from the Partnership's customers and the price thereof are affected, *inter alia*, by significant changes in the prices of oil, natural gas, LNG, and the prices of other sources of energy, including coal, sources of renewable energy and other alternatives to the produced natural gas marketed by the Partnership, both in the domestic market and in the global markets. Thus, for example, low LNG prices in the global markets may lead to increased import of LNG to Israel and/or to the regional markets, reduce the demand for natural gas in the markets relevant to the Partnership, and harm the Partnership's revenues from the Leviathan reservoir.

An increase in supply, a decrease in demand or a decrease in the prices of energy sources alternative to natural gas, including coal, sources of renewable energy and other products, in the domestic market or in the global markets, may reduce demand on the part of existing and potential customers and lead to a decrease in the price of the natural gas sold by the Partnership, which may adversely affect the Partnership, its financial position and results of operations.

Moreover, reforms and decisions relating to the electricity sector and in the energy sector, including changes in the environmental laws, may also reduce the demand for the natural gas sold by the Partnership and/or affect its price.

In addition, major events in the global economy, such as wars, hostilities and local or regional armed conflicts, an economic slowdown, recession, inflation, irregular volatility in foreign exchange rates, trade wars, impairment of the efficient functioning of the global manufacturing and supply chains in general, and in the segments of engineering, manufacture and supply of components for the oil and gas industry in particular, as well as weather conditions, including global warming, the outbreak of pandemics, such as the Covid pandemic and natural disasters, may also reduce the demand for the natural gas sold by the Partnership and/or affect its price and/or adversely affect the Partnership's revenues from the existing and future gas sale agreements, as well as the making of decisions on investment in new natural gas projects and/or expansion of existing projects.

7.30.5 Global macroeconomic factors

The Partnership's ability to sell natural gas from its assets, and to sign new long-term agreements for the sale of natural gas, and to adopt investment decisions with respect to new projects for the production of natural gas or expansion of existing projects, is impacted, *inter alia*, by various global macroeconomic factors or on major events in the large economies, such as the U.S., China and the European Union. Among the macroeconomic factors that may have a significant impact on the Partnership's business are, *inter alia*, wars, hostilities and local or regional armed conflicts, changes in the growth rate or a global economic slowdown, a global recession, global inflation, irregular volatility in foreign exchange rates, the global trade situation, a rise in interest margins, efficient functioning of the global manufacturing and supply chains in general, and in the segments of engineering, manufacture and supply of components for the oil and gas industry in particular, attacks on shipping lanes, including ships on their way to Israel, climate and weather changes – including global warming, trade wars, such as the US-China trade war, which has led to a slowdown in economic activity; natural disasters, the outbreak of pandemics such as the Covid pandemic, and global political and social processes that may destabilize regimes. Global macroeconomic factors of this type, which in the majority of cases are unforeseeable, may significantly harm the global economy, increase uncertainty in the markets, damage the confidence of investors, the business community and consumers, result in a decline in global consumption of energy products, including oil and natural gas, and make it difficult to refinance.

Accordingly, in 2024, the Partnership's operations and results were influenced by various factors, including the changes in energy prices due to the Russia-Ukraine war, and the rise of global inflation, and the consequent rises of interest rates by central banks globally. For the impact of such events on the Partnership's operations, see Section 7.1.4 above.

Naturally, the Partnership is unable to influence factors of this type, and it is difficult to assess and estimate how factors of this type may evolve and affect the Partnership's business.

7.30.6 Geopolitics

The general security, economic and political situation in the Middle East, and specifically in Israel, Egypt, Jordan and Cyprus, may affect the willingness of foreign entities and countries, including in the Middle East, to enter into business relationships with Israeli bodies, including the Partnership, together with its partners in the different projects. Therefore, any deterioration in the geopolitical situation in the Middle East and/or deterioration in the relations between Israel and its neighbors in the relevant target markets, for security and/or political and/or economic reasons, may materially impair the Partnership's revenues from agreements of export of gas to Egypt and to Jordan, i.e. to Blue Ocean and to NEPCO, which are key customers of the Partnership, as well as its ability to promote its business with countries and additional entities in the neighboring countries.

7.30.7 Difficulties in obtaining financing

For the promotion of additional development phases in the development plan of the Leviathan reservoir or the development of additional reservoirs in the future, such as the Aphrodite reservoir, and the reservoir in the area of the Bulgaria license, if it is decided to drill the same, the Partnership will need additional significant financial sources, and the Partnership may be required to raise capital or additional financing, including through a future raising of bank debt or a private or public bond offering.

Raising of additional financing or withdrawal of credit from the Credit Facilities as specified in Section 7.21.3 above, may be difficult, particularly in times of a crisis that is expressed in a reduction of the available credit sources, the tightening of requirements of the finance providers for provision of the financing, and the increase in the interest rates by the central banks in the world, which may affect the Partnership's financing expenses and in exceptional cases, may prevent the ability to raise the financing required.

7.30.8 Competition over gas supply

The Partnership is exposed to competition over the supply of natural gas to the domestic market and to export markets, including competition with existing competing has reservoirs, or new reservoirs that may be discovered in the future in Israel or in neighboring countries, and competition posed by alternative energy sources such as coal, liquid fuels (such as diesel oil and fuel oil) and renewable energy sources (such as solar energy and wind energy). The intensification in competition may lead to a drop in demand and in natural gas prices that will be determined in new supply agreements, which may lead to a material negative effect on the Partnership's revenues and business.

In Egypt and in Jordan, to which the Partnership exports natural gas under the Blue Ocean and NEPCO supply agreements, the Partnership is exposed to competition that may intensify in the future by reservoirs that have been discovered (In Israel and in the region) or new reservoirs to be discovered in the future, and also by suppliers of alternative energy products.

On the report approval date, the Tamar reservoir and the partners therein are competitors of the Partnership in the domestic and regional market, and the Karish lease and Energean that holds it, are competitors of the Partnership in the domestic market.

As of the report approval date, the gas from the Leviathan reservoir is jointly marketed by all of the Leviathan Partners. However, under the JOA each partner is entitled, subject to certain conditions, to take its share of the gas produced from the reservoir and market the same separately from the other partners, which, if and to the extent it occurs, may hinder the continued development of the Leviathan reservoir.

In view of the limited scope of the demand for natural gas in the domestic market, the entry of additional competitors to the domestic gas market, the restrictions on the scope of exportable gas, and incentives granted to the development of new sources of renewable energy, the Partnership may face considerable competition in selling the gas reserves that are attributed to its petroleum assets.

For further details regarding the competition in the business sector, see Section 7.15 above.

7.30.9 <u>Restrictions on export</u>

The results of the Partnership's operations are highly dependent on the ability to export gas from the Leviathan reservoir and sell it in the regional and international market. The Government Resolutions with respect to export, as specified in Section 7.24.8 above, limit the quantity of gas that may be exported. Therefore, in the event that a decision is adopted regarding further restrictions in connection with the quantities of natural gas permitted for export, this may lead to significant damage to the Partnership's business.

It is noted that in the event of a decrease in the supply capacity of natural gas from the Tamar reservoir and/or the Karish lease, mainly in the peak months where demand for natural gas in the domestic and export markets exceeds the production capacity from the Leviathan, Tamar and Karish reservoirs, the Leviathan Partners may be required to supply the domestic demand at the expense of quantities designated for export. For details on the export agreements, see Section 7.12.3(c) above.

In addition, the possibility of exporting and selling the gas depends on many highly uncertain factors, such as the foreign relations between the State of Israel and countries in the region, and with countries that are potential target markets for gas export, construction of an export and transportation system and receipt of the relevant regulatory authorizations, the economic merit of constructing such a system, identifying potential customers in the international market, finding sources for financing the investments required for the development and construction of the export system, and competition with local and international suppliers in the relevant target markets.

7.30.10 Dependence on the development and functioning of the gas transmission systems

The Partnership's ability to supply the gas produced from its assets to the existing customers and to additional potential customers in and outside of Israel, is contingent, *inter alia*, on the development and functioning of the national transmission system for gas supply, the regional distribution networks, and transmission pipelines to consumers in neighboring countries (in this section: the "**Transmission Systems**"). Any significant malfunction, disruption or sabotage in the Transmission Systems that are and/or shall be used by the Partnership in the future may limit the Partnership's ability to supply gas to its customers, while exposing it to loss of revenues and legal proceedings which may have an adverse effect on the Partnership's business and operation results. In addition, the establishment, expansion, and operation of the transmission systems involve exposure to construction risks, dependency on contractors and suppliers of equipment and professional services, and operational risks of the types specified in Sections 7.30.11 and 7.30.13 below. For details regarding delays in the integrated segment project due to dependency on construction contractors, see Section 7.13.2(c)2(a) above.

In addition, a delay in implementation of the development and expansion plans for the gas transmission systems may impair the Partnership's ability to meet its undertakings to its customers and its forecasts in connection with natural gas sales.

7.30.11 Operational risks

Operations of exploration, development, production and decommissioning of oil and natural gas assets, particularly in deep water, entail considerable risks, including, *inter alia*, an uncontrolled outburst of liquids and gas from a well, explosion, collapse and combustion of a well, breakdowns, accidents and other events that may disrupt the functioning of the production and transmission systems. Performance below the expected or efficient level may also be caused, *inter alia*, as a consequence of the contractor or the operator errors, work disputes or disruptions, injuries, a delay or non-receipt of permits, approvals or licenses, a breach of requirements of the permits or the licenses, a shortage of manpower, equipment or spare parts, delays in the delivery of equipment or spare parts, security breaches, cyberattacks, acts of terrorism, and natural disasters. The occurrence of any one of the aforesaid events may significantly reduce or completely put a stop to the ability to produce or supply the natural gas, undermine the schedule and budget of the operations, damage the quality of the sold hydrocarbons, and consequently lead to the imposition of fines for failure to comply with contractual terms and conditions and even to the termination of existing gas sale agreements of the Partnership.

In addition, operations of drilling, completion and sealing of deep water well require use of specifically-designated technologies and equipment, and usually take longer and cost more than their onshore counterparts, due to the considerable complexity of such operations and due to the need to sustain and maintain long supply systems. In view thereof, these operations are exposed to significant risks and challenges.

7.30.12 <u>Lack of sufficient insurance coverage</u>

Although the Partnership is insured with coverage of various kinds of damage that may be caused in connection with its operations, not all of the possible risks are or can be fully covered by the various insurance policies that were taken out, and therefore, the insurance payments, if received, will not necessarily cover the entire scope of the damage and/or all of the possible losses, with respect to third party damage (including during the crossing of infrastructures), with respect to possible loss of income, with respect to the costs of the construction and restoration of the production system in the case of an event due to which damage is caused to the production system, including due to terrorism, war, cyber and loss of control of the well, and with respect to damage to any kind of property inside the well. The Partnership's insurance policies include, *inter alia*, specific coverage for the Partnership's holdings in the Leviathan project against physical damage and loss of profits related to physical damage, due to risks of political violence, including risks of war and terror. The policy covers property damage over and above the coverage to which the Partnership is entitled from the State under the Property Tax and Compensation Fund Law, 5721-1961, and specific coverage for loss of income for a certain period. The said coverage is renewed from time to time and is subject to its availability in the insurance market under reasonable terms and conditions. It is further noted that the insurance policies purchased by the Partnership do not cover an event of loss of income that results from the halting of production following receipt of a mandatory regulatory directive, as received by the Tamar Partners after the outbreak of the Swords of Iron War. For further details regarding the impact of the Swords of Iron War on the Partnership's insurance policies, see Section 7.30.1 above. In addition, there are certain insurance policies which the Partnership may decide not to purchase at all for various reasons, such as lack of economic merit, nor is there any certainty that it will be possible to purchase suitable insurance policies in the future with reasonable commercial terms or at all.

In addition, the Partnership's activity in the export of natural gas to Jordan and Egypt (as specified in Sections 7.13.2(c), 7.13.2(d) and 7.26.6 above, respectively) exposes the Partnership to risks that cannot be insured at all or can only by partially insured, including, *inter alia*, consequential damage associated with damage of any type to property and/or associated with damage to property of a supplier and/or a customer and/or a breach of agreements and termination of agreements for a reason that is not permitted by the agreement and/or modification of legislation and/or directives of competent authorities in Jordan and in Egypt, which may damage the Partnership's business and property.

Therefore, in the case of large-scale loss or damage, the insurance policies taken out may be insufficient for covering all of the damage to the Partnership and/or third parties, including during infrastructuring crossing and including with respect to environmental pollution damage. These risks, if they materialize, may cause postponements and delays in the Partnership's exploration, development and production activities, damage the Partnership's business or have a material adverse effect on the Partnership's business, financial position, results of operations or its forecasts, and in an extreme case may even lead the Partnership to insolvency.

It is noted that the decision on the type and scope of the insurance is usually made separately for each activity, taking into consideration, *inter alia*, the type of prospect in which the well is expected to be drilled, the insurance costs, type and scope of the offered coverage, the regulatory requirements, the ability to obtain suitable coverage in the insurance market, the capacity available to the Partnership and the project in the insurance market and the foreseeable risks.

7.30.13 Construction risks, dependence on contractors and on professional service and equipment suppliers

In Israel there are currently no contractors and suppliers who can perform the main actions performed in the Partnership's assets, such as drilling of wells in deep waters and production and laying of subsea infrastructure of natural gas, and therefore the Partnership engages through the operator with foreign contractors for such purpose. Moreover, the equipment required for the performance of the actions, such as drilling vessels or vessels for laying pipelines at sea or crane platforms for the construction of platforms, is limited and therefore there is no certainty that it will be available for performing the aforesaid actions on the dates scheduled therefor. As a result, various actions may entail costs that are higher than planned and/or significant delays may be caused to the timetables set for the performance of the work. In addition, following the limited availability of the designated equipment and manpower to operate the same, it is required to reserve the engagement therewith a considerable time in advance, which adds complexity to the project and may significantly increase the costs of the Partnership's activities, including the ability to engage with foreign contractors and the ability of such contractors to consummate the engagement therewith, may encounter difficulties also due to the political and security situation of the State of Israel, and specifically the Swords of Iron War. For details regarding delays in the combined section project, and the third pipeline project, due to dependance on executing contractors, see Section 6.8.5 above. It is noted that the price of the services and costs of exploration, development, production and decommissioning operations is determined according to supply and demand on the markets, which are affected, *inter alia*, by commodity prices, regulation changes, the supply of alternative products and the level of activity in the industry. These risks apply, at times, also to the establishment and operation of part of the transmission systems in Israel and neighboring countries. For details, see Section 7.30.10 above.

7.30.14 Risks of exploration activity and reliance on partial and estimated data

Operations of exploration for oil and gas reservoirs entail a high level of risk, mainly because the geological and geophysical means do not provide a precise picture of the location, form, characteristics or size of the subsurface, and therefore exploration operations may end in findings that do not allow for commercial development and production.

7.30.15 Reliance on assessments and estimates in resource evaluation

The estimation of the quantity of resources in the assets of the Partnership in general, and in the Leviathan Project in particular, is examined on a continuous basis, and is updated from time to time, based, *inter alia*, on production data and additional information accrued, through the operator, an independent reserve evaluator and the Ministry of Energy. The process for estimating the quantities of resources is subjective and based on various assumptions and estimates and on partial information, and therefore the estimates regarding the same reservoirs that are carried out by different experts may sometimes be materially different.

It is noted that, given the aforesaid, the information included in the report with respect to the quantities of resources that are attributed to the petroleum assets of the Partnership is an estimate only, and should not be deemed as information on exact quantities of natural gas that will be recoverable from the various reservoirs. It is further noted that an estimate of the quantity of natural gas resources is used to determine the rate of amortization of the producing assets in the Partnership's financial statements, and in view of the significance of the amortization of the assets, the above-described changes may have a material effect on the Partnership's results of operations and financial position.

In addition, the discounted cash flow figures that are attributed to the Leviathan project are based on various assumptions many of which are not fully controlled by the Partnership, *inter alia* in relation to the quantities of gas and condensate that shall be produced, the rate of production and sales and the sale prices, which there is no certainty will materialize. For details regarding the main assumptions underlying the Leviathan project cash flows, see the resources report attached hereto as **Annex B**.

7.30.16 Merely estimated costs and timetables and the eventuality of lack of means

Estimated costs of and estimated timetables for the execution of exploration, development, operation and maintenance activities, are based on past experience and general estimates, and may thus entail considerable deviations, including in consequence of events that are not within the Partnership's control. In addition, exploration and development plans may change considerably, *inter alia*, following findings arising from such activities, and cause considerable deviations in the estimated timetables and costs of such activities. In addition, faults caused during exploration, development, operation or maintenance activities may cause the timetable to be extended far beyond the plan, and the actual expenditure required for completion of the activities to be considerably higher than the costs planned therefor.

For details regarding delays in the execution of the combined section project and the third pipeline project, see Section 7.13.2 above.

7.30.17 Forfeiture of the Partnership's interests in its petroleum assets and the financial strength of the partners in the petroleum assets

The activities of exploration, development and expansion/maintenance of the capability to supply gas in the Partnership's petroleum assets, entail considerable financial expenses, which the Partnership may not have the means to cover. According to the joint operation agreements, failing to pay on time the Partnership's share in an approved budget for the performance of an approved work plan constitutes a breach that may lead to the loss of the Partnership's share in the petroleum asset/s to which the operation agreement and/or agreements applies and/or apply.

In addition, in a situation where other parties to the joint operating agreements shall not have paid amounts that they were supposed to pay, the Partnership may be required to pay amounts that considerably exceed its proportionate share in such petroleum assets. Due to the especially high cost of development expenses and offshore drillings, these additional costs may lead to the Partnership's being unable to meet its financial obligations and as a result, it will lose its rights in the petroleum assets.

In view of the aforesaid, the financial strength of the partners in the petroleum assets held by the Partnership may have repercussions, *inter alia*, on its cash flow.

7.30.18 Dependence on obtaining regulatory and other approvals

Exploration, development, production and decommissioning activities in the Partnership's petroleum assets requires receipt of many regulatory approvals are required in the Partnership's field of business in Israel, mainly from the entities authorized pursuant to the Petroleum Law and the Natural Gas Sector Law, as well as related approvals from the state authorities, including the Ministry of Energy, the Ministry of Environmental Protection, the Ministry of Defense, the tax authorities, the various planning authorities, the Ministry of Agriculture, the Ports Authority, and the Ministry of Transportation (in this section: the "**Approvals**"). The Approvals required for the activity of the partners in the petroleum assets prescribe validity conditions, a considerable number of which are not controlled by the partners. A breach of such conditions may lead, *inter alia*, to cessation of the production activity from producing reservoirs, imposition of restrictions on the various activities, and exposure of the partners in the petroleum assets to financial, administrative or criminal sanctions. The partners in the petroleum assets have no control over the new Approvals that shall be required in the future and the conditions to be determined therein, and therefore, there is no certainty that it will be possible to obtain them or comply with their conditions.

7.30.19 Regulatory changes

In general, the scope of regulation applying to the field of business of the Partnership is constantly growing. The tightening of the regulation applying, *inter alia*, to activities of exploration, development, production, marketing and decommissioning of gas and oil facilities and reservoirs, natural gas supply terms and conditions, natural gas export, taxation of oil and gas profits, rules for allocation of new petroleum interests, insurance and guaranties, transfer and pledge of petroleum interests, antitrust, control of gas prices, planning regulation and so forth, may adversely affect the Partnership's business. In addition, if additional changes occur in any relevant law, regulation according to the Gas Framework, or any relevant regulations or policy, or if there is a delay in the receipt of regulatory approvals, or the Partnership or its customers do not receive the regulatory approvals required or do not fulfill the terms and conditions thereof, they may cause the Partnership and/or its customers to be unable to comply with their obligations according to preexisting agreements.

For details regarding the main regulation that applies to the Partnership's operations as of the report approval date, see Sections 7.23.2 and 7.24 above.

7.30.20 Applicable competition-related regulation

As of the report approval date, the number of entities holding rights to natural gas reservoirs in Israel is still relatively low, and as a result, the Partnership faces regulatory risks under competition law and price supervision.

As provided in Section 7.24.2(a) above, the Partnership was declared a monopoly together with the other partners in Tamar and separately, and although it has closed the sale of the remainder of its interests in the Tamar and Dalit Leases, it may be considered a monopoly in the field of supply of natural gas in Israel in view of its inclusion in the monopoly register and in view of its being a partner in the Leviathan project. It is noted that a monopolist may be subjected to restrictions and prohibitions under the Economic Competition Law, and is subject, inter alia, to the prohibition on unreasonable refusal to supply natural gas to customers and the prohibition on abuse of its status in the market in a manner that may undermine business competition or damage the public (for example, by a determination of an unfair price level or by determining different engagement terms for similar transactions which may grant certain customers an unfair advantage over their competitors).

In addition, as provided in Section 7.24.2(c) above, the final supplemental decision of the Competition Commissioner regarding the purchase of EMG shares was not yet made. If and when it is made, it may include conditions that could restrict the use of the EMG

pipeline for the export of gas produced from the Leviathan reservoir to Egypt.
In addition, the Partnership is subject to the Control of Prices of Commodities and Services Order, which imposes control on the gas sector in terms of profitability and price reporting, as specified in Section 7.24.2(b) above. According to the said order, it is necessary to report semiannually on the prices and on the profit margins of the sold natural gas. In the event that price control is imposed and a maximum price is determined, which is lower than the prices set forth in the Partnership's natural gas sale agreements, and insofar as such determination withstands judicial review, this may have an adverse effect on the Partnership's business, the scope of which shall be derived from the maximum price to be determined.

7.30.21 Applicable environmental regulation

The Partnership's activity, performed mainly by the operator in the various petroleum assets, is subject to various laws, regulations and guidelines concerning environmental protection, relating to various issues, such as seepage or leakage of oil, natural gas or other pollutants into the marine environment, discharge into the sea of pollutants and waste of various types (wastewater, operating fluids, cement, etc.), chemical substances used in various stages of the work, emission of pollutants into the air, light and noise nuisances, construction of pipe infrastructure on the seabed and related facilities. In addition, the Partnership is required, through the operator in the various petroleum assets, to obtain approvals for the activity of the operator from the competent entities under the Petroleum Law, the Natural Gas Sector Law and other laws, such as environmental protection laws.

Non-compliance with the provisions of such environmental regulation may expose the operator, the Partnership and its partners in the various petroleum assets, as well as the officers therein, to various enforcement measures, which also include lawsuits, penalties and various sanctions, including criminal, as well as to delays and even the discontinuation of the Partnership's activity. In addition, the Partnership may be responsible for the acts of others such as the operator or third-party contractors that are affiliated with the operator, and for pollution relating to the Partnership's facilities or deriving from its activity.

In addition, activities of exploration, development, production and decommissioning of oil and natural gas assets in deep water entail various risks, all the more so due to activities in shallow water and onshore, including the discharge of hazardous waste and substances into the environment, and exposure of humans to such hazardous waste and substances. Consequently, the Partnership may be responsible for some or all of the repercussions deriving from the risks of exposure or emission of such hazardous waste and substances.

In September 2016, the Ministry of Energy, together with the Ministry of Environmental Protection and other government ministries, published directives that regulate the environmental aspects of the offshore oil and natural gas exploration, development and production activity, as specified in Section 7.23.2(i) above. Such directives may have an effect on the costs and manner of the Partnership's activity, the scope of which cannot be estimated as of the report approval date. In addition, there is no certainty that the costs that will be required from the Partnership in connection with the existing and foreseeable laws, regulations and guidelines in the field of environmental protection, and in connection with the repercussions deriving from the emission of substances into the environment, will not exceed the amounts allocated by the Partnership for these purposes, or that these costs will not have a material adverse effect on the financial position of the Partnership and its results of operations.

It is noted that the interpretation and enforcement of the environmental laws and regulation change from time to time and may be stricter in the future.

For details on the provisions of law and the instructions of competent authorities on environmental subjects which apply to the Partnership and about material administrative and legal proceedings in connection with environmental protection and on the monitoring and control proceedings implemented by the General Partner's board of directors regarding the management of environmental risks, see Section 7.23 above.

7.30.22 Climate changes

Climate changes that are also included in various risk factors specified in this section, are a gamut of phenomena that have been extensively documented and researched in recent decades, and which require mankind to prepare in terms of slowing down adverse changes (e.g., decreasing the temperature increase rate) and in terms of contending with the implications of such phenomena (e.g., dealing with the rising sea level). The Partnership recognizes and addresses the international preparation for climate changes, including the transition to a low-carbon economy. Such preparation addresses various risks, which are commonly classified as "physical risks" (risks related to exposure to climate and weather events, including extreme events such as droughts, floods, and storms), and "transition risks" (risks arising from the transition to a low-carbon economy, such as risks related to regulatory and/or technological changes). The gamut of such risks exposes the Partnership's business, directly and indirectly, to various damage, which was identified and assessed as part of the Partnership's climate risk management processes.

The increasing intensity and frequency of extreme climate events, whether occurring in the Partnership's assets or in areas through which the chain of supply to such assets runs, may, *inter alia*, disrupt and delay the operations in the assets and/or render them more expensive, cause significant harm to employees in the Partnership's assets, the Partnership's assets themselves and the operating processes. In addition, extreme events and their increasing frequency may have an impact on demand in the Partnership's target markets. Regulatory intervention whose purpose is to lead to a reduction in the emission of greenhouse gases and promote the use of renewable energies, in the context of a government policy on dealing with climate changes, may be expressed in the determination of targets for reduction of the use of fossil fuels, pursuing them is implemented, *inter alia*, by giving positive incentives to producers and consumers of renewable energy sources and determining negative incentives for producers and consumers of fossil energy (such as the imposition of carbon tax). Such intervention may, *inter alia*, adversely affect the demand for natural gas, which is the primary product sold by the Partnership. In addition, the increasing regulatory burden may manifest in increased requirements for monitoring, management and reporting of activities with environmental impact, leading to higher operational costs for the Partnership's assets. Furthermore, the deepening of regulatory obligations may include expanded investor disclosure requirements regarding risks, opportunities, and the impact of climate change on the Partnership. For details regarding decisions and plans released on this issue by the Israeli government and government authorities, see Section 7.24.10 above. The applicability of carbon tax in Israel and the effects of the EU's carbon border adjustment mechanism (CBAM) may lead to an increase in operational costs and a reduction in demand for fossil fuels.

Over and above the aforesaid, the activity of organizations and activists that oppose the production and use of fossil fuels may adversely affect the Partnership's reputation and increasing concern with the stakeholders. Such risk may lead to legal and other expenses that will be required in order to cope with such activity and its consequences. Damage to reputation may also lead to difficulties in raising capital and attracting investors, difficulties in the recruitment of employees, as well as an increase in litigation proceedings related to environmental and climate harm claims against the Partnership and the operator.

The acceleration and development of various technologies also pose a risk to the Partnership's business. In addition, technological developments that enable the production and supply of alternative fuels (such as hydrogen), the development of efficient storage technologies, or the diversion of resources to the development of alternative energies, may disrupt the Partnership's target markets and increase various capital expenditures.

These trends may lead to a shift in market and consumer preferences, which may also result in reduced demand for traditional oil and gas products, higher financing and capital costs, as well as pressures to diversify the business model. In view of the aforesaid, the Partnership's strategy is a combination of continued growth in the natural gas sector, which is considered a "transitional fuel," alongside the development and expansion of activity in the renewable energy and hydrogen sector, *inter alia* in the context of the collaboration with Enlight, as specified in Section 7.10 above, and in blue hydrogen projects, as specified in Section 7.28.3(b) above.

7.30.23 Dependence on weather and sea conditions

Offshore activity is exposed to a variety of operating risks that are unique to the marine environment such as capsize, collision and damage or loss that are caused by harsh weather conditions and the sea conditions. Such conditions may cause significant damage to the facilities and disrupt the activity.

Furthermore, stormy sea conditions and unusual weather conditions may cause damage to the production and transmission system and to the (existing or under construction) equipment as well as delays in the timetable planned for the work plan of the offshore projects and the prolongation of its execution period. Such delays may cause the increase of the projected costs and even non-compliance with timetables to which the Partnership is committed.

For details regarding the impact of weather on demand, see Section 7.1.4 above.

7.30.24 Cyber and information security risks

The partners in the Partnership's petroleum assets, including the Partnership and the operator thereof (directly and via subcontractors) (in this section: the "**Corporations**"), rely in their activity on IT equipment and systems. Thus, for example, in the context of the production from the Leviathan reservoir, use is made of industrial control systems, which are used for supervision, control, data collection and monitoring ("**ICS**"), which monitor and control large-scale processes which include, *inter alia*, monitoring of the natural gas and condensate transmission pipelines. These systems are exposed to cyberattack risks.

In addition, the Partnership and the operator rely on equipment and computer systems, including computers, information systems, and infrastructure, for ongoing operations. These systems are used for processing personal information (for example regarding the Partnership's employees and consultants) and financial and operational data (such as seismic, geological, and engineering data analysis, reserve estimates, and other activities related to the Partnership).

The Partnership's business partners, its suppliers, and customers also depend on equipment and computer systems, including computers, information systems, and infrastructure. The more the reliance thereon increases, so does the potential exposure to indirect cyber threats to the Partnership.

Faults and/or failures and/or human errors and/or security exposures in IT systems, including in ICS, information systems, infrastructure and information security systems, may allow logic and/or physical unauthorized access for the purpose of misuse of the Partnership's assets, and deliberate harm to such IT systems of the corporations. Such access may lead to damage to the administration and/or operational networks, the leak of information, disruption of the information and damage to the processes in connection with ICS.

In extreme cases, such access may also lead to disruption or cessation of natural gas supply. Damage to information or data, and to operational continuity, may also cause, either directly or indirectly, business damage and reputational harm to corporations.

The above becomes even more significant, as recently the number of attacks against organizations in Israel has intensified against the backdrop of the Swords of Iron war, and due to changes in labor markets (following the Covid crisis, where organizations partially shifted to remote work), the likelihood of cyberattacks has increased for most organizations.

In view of the aforesaid, the Partnership implements the directives of the Privacy Protection Authority and the principles for cyber protection methodology, at the National Cyber Directorate, for effective management of information security and cyber protection at the Partnership. To the understanding of the Partnership, regarding the operational aspect of the Leviathan platform and the facilities of natural gas and condensate production and transmission from the Leviathan reservoir, the operator implements the directives of the National Cyber Directorate as a critical State infrastructure.

The Partnership has established an information security and cyber protection policy (the "**Protection Policy**") which is approved once a year by the relevant organs of the Partnership, defines the key objectives of the Partnership, and its position with respect to aspects of information security and cyber protection. The Partnership acts to implement this position through the procurement of technological means, at the recommendation of the content experts with whom it consults, guiding all of the relevant employees and suppliers for adequate conduct vis-à-vis cyber risks.

A manager that reports to the CEO of the Partnership is in charge of implementing the defense policy, and the Partnership is assisted by the outsourced services of an information security manager and an IT company, and they act on an ongoing basis for constant reinforcement and improvement of the Partnership's defense scheme.

The Partnership is preparing to cope with a cyber and information security event, and to this end has adopted a procedure for the management of such events and a procedure for recovery of the technology scheme, conducted an event management drill for the Partnership's management and technology team, and purchased a cyber insurance policy.

However, it is clarified that despite the various measures taken by the Partnership and the operator as aforesaid, there remains a significant risk of damage and harm resulting from cyber activity, which in extreme cases may lead to disruption or cessation of natural gas supply or harm to human life, as specified above.

7.30.25 Changes in investment trends due to ESG considerations

In recent years, there has been a growing awareness among investors in Israel and around the world and among other stakeholders, *inter alia*, suppliers, consumers, employees and credit providers, of the climatic and environmental impacts of various activities, as well as the corporation's method of conduct in aspects of corporate governance. As part of this trend, existing and potential investors, as well as other stakeholders, are considering ESG aspects as part of their investment and business policies, including with regard to the provision of credit.

Simultaneously, a similar trend is emerging among regulators in Israel and around the world. For example, in December 2020, the Supervisor of Banks issued a notice stating that banks are expected to take adequate operative measures to identify, monitor and manage environmental risks; In April 2021, the ISA released a proposed outline for reporting corporations regarding, *inter alia*, voluntary disclosure of annual reports on corporate governance and ESG risks; and in July 2022 a circular published by the Capital Market, Insurance and Savings Authority took effect, stating, *inter alia*, that institutional bodies will be obligated to address ESG aspects upon making investments. In September 2024, the ISA's Audit Unit released a document titled "Consolidation of Audit Findings on Disclosure and Reporting of Environmental Risks in Reporting Corporations." Similar approaches are also included in documents of other supervision and regulation bodies in the world and particularly in Europe.

These trends may manifest in various ways, including public opposition to operations in the Partnership's oil and gas assets, diminishing of the Partnership's appeal to potential employees, pressure from financing banks and investors to adapt the Partnership's operations to the targets of the Paris Agreement of December 2015 which aims to reduce greenhouse gas emissions, and difficulty in access to capital, including in debt raising, for external investments and financing of projects. In addition, these trends may also adversely affect the business and financial condition of the Partnership, and may lead, inter alia, to a decrease in the value of its assets, an increase in the price of debt and an erosion of the price of the participation units.

In February 2022, the Partnership posted on its website, its first corporate responsibility report reviewing the years 2020-2021, which set initial targets for areas defined as material by stakeholders, according to the materiality test and in accordance with GRI standards. In June 2024, the Partnership posted on its website, an ESG report for 2022 and 2023. The Partnership intends to release in the coming months, an ESG report for 2024.

7.30.26 Tax risks

Tax issues related to the Partnership's operations, specifically with regards to the manner of calculation of the mandatory payment under the Taxation of Profits from Natural Resources Law, have not yet been discussed in the case law of the courts in Israel and it is impossible to foresee or determine how the courts will rule if and when the aforesaid legal issued are brought to their decision. In addition, with respect to some of the legal issues, it is impossible to foresee the position of the tax authorities.

Judicial decisions on these issues, as well as changes in the fiscal regime resulting from changes in legislation, case law, or shifts in the position of the Tax Authority, may have a material impact on the Partnership and the unit holders.

7.30.27 Financing-related obligations

The terms of the bonds issued by Leviathan Bond define events of default and various undertakings, some of which are beyond the Partnership's control, a breach of which may give the bondholders grounds for acceleration of the debt and enforcement of the pledges on the Partnership's rights in the Leviathan project that were created to guarantee the repayment of the bonds, as specified in Section 7.21 above. Furthermore, the Credit Facilities prescribe financial covenants with which the Partnership is required to comply in the event that it makes a drawdown therefrom and noncompliance with which entitles the lender to immediate repayment, as specified in Section 7.21.4 above. In this context, it is noted that a significant deterioration in the security situation, which would lead to the early termination of export agreements, or cause physical damage to the Leviathan Project, that is not remedied, or other events that are reasonably expected to have a material adverse effect, and subject to remediation periods, exceptions, and conditions, could in certain cases lead to a breach of the terms of the Leviathan Bond bonds, granting the bondholders cause for acceleration and enforcement of the collateral and/or adversely affect the Partnership's ability to raise additional debt and increase financing costs for raising such additional debt.

7.30.28 Dependence on customers

As of the report approval date, Blue Ocean and NEPCO are the key customers of the Leviathan project. Accordingly, the Partnership is exposed, in respect of these customers, to risks that are beyond its control, including changes in the economic, political and security conditions in Egypt and in Jordan and in their relations with the State of Israel, which may affect these customers or their ability to meet their obligations under the gas supply agreements. For details regarding the Partnership's revenues from these customers, see Section 7.12.3 above.

It is noted that, in the agreement signed with Blue Ocean, dates were determined on which each party to the agreement may request adjustment of the price. In the event that Blue Ocean requests an adjustment of the price of the gas purchased thereby in accordance with the mechanism set forth in the agreement therewith, this may have a negative effect on the Partnership's business and on the results of its operations.

Furthermore, the Partnership is exposed to risks that are not under its control pertaining to the financial strength of its customers and their ability to meet their obligations under the gas supply agreements. Insofar as its customers in general and its key customers in particular fail to meet their obligations under the supply agreements, and if the Partnership shall be unable to sell the contract quantity determined in the supply agreement to other customers, this will have a material adverse effect on the Partnership's revenues and on its financial results.

7.30.29 Reliance on the operator

The Partnership relies to a great extent on the operator of its assets, in accordance with the provisions of the joint operating agreements.

The operator's resignation and/or removal, for whatever reason as specified in the operating agreements, or any change in its status and/or rights, such that it ceases to be the operator of the project, may impair the Partnership's ability to fulfill its undertakings according to the work plans of the petroleum assets and/or according to the gas sale agreements. In such a case, the Partnership cannot guarantee that a substitute operator will be found under the current terms and conditions or at all. The Partnership's failure to find a substitute operator may adversely affect the operations in the various projects, and in particular on the Partnerships' undertakings to supply gas in accordance with the existing gas sale agreements and consequently the Partnership's revenues may be impacted. Furthermore, in the event that the operators in the Partnership's assets fail to comply with their obligations as operators under the joint operating agreements or under agreements with third parties with which they engage as operators, the Partnership may then bear expenses and losses that may derive from the operators' acts (or omissions).

It is noted that according to the expired New Ofek license, the rights holders in the license are required by law to carry out plug and abandon activities, and although according to the joint operation agreements, such obligations apply, in practice, to the operator, SOA, this does not derogate from the obligations of the Partnership in this respect.

7.30.30 Risk in development and production in the case of a discovery

The process of making a decision to make an investment in the development of a field for the purpose of commercial production therefrom, interim actions until commercial production, and to perform the development and commercial production (if it is decided that there is room therefor) may take long periods of time and require the Partnership to invest considerable amounts. Not in every discovery which was defined as a commercial discovery, the acts of development of the oil or gas field will be economic for the Partnership and financeable, *inter alia* due to the duty to pay royalties to third parties. This is especially true with respect to the development and production of assets in deep water, such as the waters in which the Partnership's key assets are located.

7.30.31 Revocation or expiration of petroleum interests and assets

Petroleum interests are granted under the Petroleum Law for a limited period of time and the validity thereof is contingent on fulfillment of obligations on dates set forth in the terms of the petroleum asset. In case of non-compliance with such terms, the petroleum interest may be revoked, subject to the Petroleum Law. Furthermore, non-compliance with the terms set forth in the Petroleum Law or with the terms and conditions of the PSC Agreement granted to the partners in the Aphrodite reservoir from the Government of Cyprus, or with respect to projects in Morocco or Bulgaria, may lead to loss of the interests and all the money invested in such interests may be lost.

7.30.32 Overflow of reservoirs

Oil or natural gas reservoirs discovered or to be discovered in areas in which the Partnership holds interests may overflow (in terms of the span of the geological structure of the reservoir) into other areas in which the Partnership does not hold rights, and vice versa. In the event that the reservoir overflows into areas in which other parties hold rights, there may possibly be a need to reach agreements regarding joint utilization and production from the reservoir or an alternative indemnification arrangement, in order to achieve efficient utilization of the oil or natural gas resources, which may cause delays in various activities that the Partnership is due to perform.

For details on the mediation arrangement in connection with the Eran License, see Section 7.9.1 above.

For details regarding a possible overflow of the Bulgaria license, see Section 7.8.9 above.

7.30.33 Security risks

INGL's gas transmission facilities, the EMG Pipeline and other infrastructures used for the supply of gas to Egypt are located partly offshore and relatively close to the border between Israel and the Gaza Strip at sea and on land, and to the gas terminal and distribution infrastructure in Egypt which is connected to the EMG Pipeline in the Sinai, in consequence of which they are exposed to security risks, including terrorist attacks and sabotage. Furthermore, the facilities of the Leviathan project, the pipeline, the infrastructures and the facilities used for the supply of gas to Jordan and Egypt are also exposed to the aforesaid security risks. For further details with respect to security risk factors regarding the Swords of Iron War, see Section 7.30.1 above.

Such security risks, if and insofar as they materialize, may, *inter alia*, disrupt the production of gas from the Leviathan reservoir and/or the supply of gas to customers in the domestic market and/or in the export markets, and in an extreme scenario, may also lead to the revocation of the gas supply agreements or the reduction of the sums the customers are required to pay due to a "*force majeure*" argument.

In addition, such risks may limit the ability of service and equipment providers to provide their services or the items required for the operation of the Leviathan project, and adversely affect the ability to recruit and retain the appropriate human capital.

The materialization of such security risks may lead to a significant negative effect on the Partnership's revenues and business, including its ability to execute activities that are contingent on prior coordination with the defense forces.

7.30.34 Fluctuations in the dollar exchange rate

Changes in the ILS/Dollar exchange rate may affect the Partnership's results in several ways, as follows: (a) The Partnership's functional currency is the Dollar. Since some of the Partnership's expenses are stated in ILS or affected by the ILS/Dollar exchange rate, a decrease in the ILS/Dollar exchange rate (a strengthening of the ILS against the Dollar) increases such expenses in Dollar terms; (b) Since the gas prices in the agreements for the sale of gas from the Leviathan reservoir are determined by price formulas that include various linkage components, and, *inter alia*, linkage to the ILS/Dollar exchange rate and linkage to the electricity production tariff, which is partly affected by the ILS/Dollar exchange rate, a weakening of the ILS against the Dollar may have an immaterial negative effect on the Partnership's revenues; and (c) Since the Partnership reports its taxable income in ILS and pays the tax advances in ILS, changes in the ILS/dollar exchange rate affect the amount of the Partnership's taxable income and the amount of the cash flow which is used for payment of such tax advances.

7.30.35 The Partnership's belonging to Delek Group and to the control holder thereof

The Partnership's belonging to Delek Group and to the controlling shareholder thereof, and the financial position thereof, may have an adverse effect on the Partnership and its business.

The Partnership's belonging to Delek Group affects the Partnership's ability to raise credit, *inter alia*, due to the "single borrower" limitation, as a result of which the Partnership's credit sources in Israel may be limited, and there are also other regulatory restrictions imposed on the banking system and on institutional bodies by the Ministry of Finance and the Bank of Israel. In addition, a deterioration in the financial position of Delek Group may make it difficult for the Partnership to raise credit and/or adversely affect the commercial conditions according to which the credit required by the Partnership is provided.

In addition, according to the Petroleum Commissioner's directives, a change in or transfer of control of the Partnership requires receipt of his approval.

It is further noted that according to the Production Sharing Contract that was signed with the Republic of Cyprus in the context of the

NEWMEDENERGY

Aphrodite project as specified in Section 7.3.3 above, a change of control of the Delek Group or the Partnership, directly or indirectly, requires prior approval of the Republic of Cyprus. In addition, according to the terms and conditions of the Production Sharing Contract and the requirement of the Republic of Cyprus, Delek Group has provided a performance guaranty for the Partnership's undertakings under the Production Sharing Contract.

7.30.36 "*Force majeure*" event clauses in the various agreements

As is standard, the various agreements signed by the Partnership include events of "force majeure" clauses. "Force majeure" events may exempt a party to the agreement from fulfilling its undertakings under the agreement. Therefore, the occurrence of a "force majeure" event to a party to any agreement signed by the Partnership, may have an impact on the various projects promoted by the Partnership, the expected timetables for completion thereof and the costs derived therefrom. Also, in some cases a "force majeure" event that lasts a long time may lead to grounds for cancellation of the agreements.

In addition, in all of the Partnership's natural gas sale agreements (hereinafter in this Section: the "**Gas Agreements**"), the customers are obligated to pay for a minimum annual quantity of natural gas (Take or Pay) in accordance with the mechanisms set forth in the Gas Agreements. However, the customers may be exempt from this obligation upon the occurrence of "*force majeure*" events, which prevent them from fulfilling their undertakings, as defined in the Gas Agreements. A "*force majeure*" event is defined as an event beyond the customer's control, which prevents it from fulfilling its undertakings under the Gas Agreement, and which could not reasonably have been prevented in the circumstances. The Gas Agreements specify a list of cases that shall not be deemed as a "*force majeure*" event, also where they are beyond the customer's control. It is noted that the Partnership may also be exempt from its obligations according to the Gas Agreements upon the occurrence of a "*force majeure*" event which prevents it from fulfilling its undertakings according to the Agreements.

If a "*force majeure*" event lasts for a prolonged period as determined in a Gas Agreement, it has a material effect on the ability of a party to the agreement to fulfill its undertakings as aforesaid, this may constitute grounds for termination of the agreement. Therefore, the occurrence of a "*force majeure*" event for a long period, which suspends a customer's undertakings to buy a significant quantity of natural gas, may have a material adverse effect on the Partnership's revenues.

7.30.37 Geopolitical conflicts in regions where the Partnership operates

In July 1974, Turkish military forces invaded Cyprus and occupied about one third of its territory (in this Section: the "**Occupied Territories**"). As of the report approval date, Turkey still maintains a large military force in the Occupied Territories.

The ceasefire line that was drawn in August 1974 turned into a buffer area supervised by the UN and named the "Green Line".

From 1975, attempted negotiations between the parties were facilitated by the UN, in order to settle the dispute. In this context, the UN Security Council adopted throughout the years a number of resolutions on the dispute over the Occupied Territories, and drafts of two agreements were forwarded in 1977 and 1979.

In 1983 the "Turkish Republic of Northern Cyprus" unilaterally declared its independence; however Turkey is the only country that acknowledged it and its rights to the Occupied Territories.

In view of the aforesaid, the relationship between Turkey and Cyprus may deteriorate, leading to political instability in the region or even a military conflict. Developments of this type may result in delays in the development of the Aphrodite Reservoir.

It is noted that following the declaration of independence of the Turkish Republic of Northern Cyprus, Turkey is performing natural gas exploration activities in vast regions in the East Mediterranean, including in the exclusive economic zones of Egypt and Cyprus. In this context, Turkey is performing various drilling and surveys in disputed offshore areas. Such acts may lead to regional instability or even a military conflict in the East Mediterranean, which may affect (directly or indirectly) the Partnership's operations, cause physical damage to the Partnership's facilities in Cyprus or lead to a reduction in the trade between Israel and Cyprus and their current trading partners. However, it is noted that in accordance with its official reports, the Government of Turkey is not claiming ownership on the areas in which Block 12 is located.

Furthermore, the dispute in respect of the sovereignty of Morocco over area referred to as "the Western Sahara" areas may affect receipt of regulatory approvals in connection with the Partnership's activity in the Boujdour license, operation of the license and promotion of additional actions in this region.

* * *

The following table presents the above-described risk factors according to their nature (macro-risks, industry risks and risks specific to the Partnership), which were rated based on the estimates of the Partnership's General Partner, according to the magnitude of the effect thereof on the Partnership:

	Degree of Risk Factor's Effect on Partnership's Business		
	Significant Effect	Medium Effect	Small Effect
Macro Risks			
Swords of Iron War	X		
Outbreak of pandemics			X
Fluctuations in linkage components in the natural gas price formulas in the supply contracts		X	
Changes in demand and in energy product prices		X	
Global macroeconomic factors	X		
Geopolitics	X		
Industry Risks			
Difficulties in obtaining financing		X	
Competition over gas supply		X	
Restrictions on export		X	
Dependence on the development and functioning of the gas transmission systems	X		
Operational risks		X	
Lack of adequate insurance coverage	X		
Construction risks, dependence on contractors and on professional service and equipment suppliers		X	
Risks of exploration activity and reliance on partial and estimated data		X	
Reliance on assessments and estimates in resource evaluation			
Merely estimated costs and timetables and the eventuality of lack of means		X	
Forfeiture of the Partnership's interests in its petroleum assets and the financial strength of the partners in the petroleum assets			X
Dependence on obtaining regulatory and other approvals		X	
Regulatory changes	X		
Applicable competition-related regulation		X	
Applicable environmental regulation	X		
Climate changes		X	
Dependence on weather and sea conditions			X
Cyber and information security risks		X	
Changes in investment trends due to ESG considerations		X	
Risks Specific to the Partnership			
Tax risks		X	
Financing-related obligations			X

	Degree of Risk Factor's Effect on Partnership's Business		
	Significant Effect	**Medium Effect**	**Small Effect**
Dependence on customers		X	
Reliance on the operator	X		
Risk in development and production in the case of discovery			X
Revocation or expiration of petroleum interests and assets	X		
Overflow of reservoirs			X
Security risks	X		
Fluctuations in the dollar rate		X	
The Partnership's belonging to Delek Group and the controlling shareholder thereof		X	
"*Force majeure*" events clauses in the various agreements		X	
Geo-Political conflicts in regions where the Partnership operates			X

It is noted that the extent of the effect of the aforesaid risk factors on the Partnership's operations is based on estimation only and the actual extent of the effect may be different.

Glossary of Professional Terms

Set forth below is a glossary of professional terminology, in alphabetical order. The explanations and interpretations are provided for readers' convenience. The official definitions may be found in the PRMS and in regulations of the Israel Securities Authority, as updated from time to time.

Appraisal/Confirmation well	A well that is designed to confirm the size, quality and continuity of a natural gas/oil field, that was discovered by a successful exploration well. Appraisal drilling is performed during the field evaluation stage, which formally culminates at FID for the field development. Depending on the size and complexity of the field, there may be more than one appraisal well in a field.
Blue hydrogen	A product of cracking natural gas in which the gas molecules are split by using steam into hydrogen and CO2. The hydrogen produced is taken for processing, transportation and marketing, while the CO2 is separated from the other products of the process and carried separately for processing, transportation and marketing or geological burial (a process known as carbon capture, utilization and storage (CCUS)).
Commercial	According to the PRMS, a project is considered commercial when there is evidence for firm intent to develop a reservoir within a reasonable timeframe, and firm evidence that all contingencies (including technical, environmental, economic, social, political, legal, contractual and regulatory) are met.
Compressed Natural Gas (CNG)	Natural gas compressed at high pressure by a factor of 100 to 300 of its original volume, depending on the compression pressure. Compressing the gas enables its storage and transportation. CNG is mainly used as a fuel for natural gas-powered vehicles.
Condensate	Hydrocarbon mixture that is found in a gas state at reservoir conditions, but condenses to a liquid on its way to the surface, as a consequence of the decrease in pressure and temperature.
Contingent resources	Defined by the PRMS as the quantities of hydrocarbons estimated, as of a given date, to be potentially recoverable from known accumulations, but which commerciality is contingent on one or more contingencies. Such contingencies may be, inter alia, technical, commercial and/or regulatory. Contingent resources are reported based on the certainty associated with the estimates, to low estimate (1C), best estimate (2C) and high estimate (3C).

Development	All activities required to facilitate production of gas/condensate/oil from a reservoir, including drilling and completing of production wells, installing of a transmission system to a processing facility, installing of processing facilities as required, and installing of a transmission system from the processing facility to the clients.
Dry gas	Natural gas composed primarily of methane, and in general contains less than 10 barrels of condensate per million cubic feet of gas.
Exploration well	A well that is designed to prove the existence of natural gas/oil in a prospect, and the verification of the geological model that led to its drilling. It is the peak of the exploration activity. Depending on the size and complexity of the field, there may be more than one exploration well in a field.
Floating Production, Storage and Offloading (FPSO)	A floating processing and storage facility for oil and/or gas, which generally resembles a ship. Equipped with facilities for processing and separation of oil and/or gas and/or water and other liquids, that are produced from subsea wells and are connected to the facility through dedicated pipes (risers). The facility has a storage capacity of tens or hundreds of thousands of barrels of fluids, which are offloaded by tankers periodically.
Gas/Oil Initially In Place (GIIP/OIIP)	The total volume of gas or oil in the reservoir, prior to production, commonly reported at standard pressure and temperature. The actual volume of "in place" gas is independent of the development plan, and does not change, though estimates pertaining to it might change. They quantity of in-place gas is always greater than the quantity of recoverable gas (see also "recovery factor" and "recoverable gas/oil).
Green hydrogen	A product of electrolysis in which the water molecules are split into hydrogen and oxygen using electricity from renewable energy, generally solar or wind energy. The hydrogen produced is taken for processing, transportation and marketing and the oxygen is emitted into the atmosphere.
Hydrocarbons	Compounds composed of hydrogen and carbon. In this report, this term is used to refer mainly to natural gas and/or oil and/or condensate.
Jacket	Structure fixed to the seabed and extending above the sea level, on to which the platform topsides are installed.

Lean natural gas	In the context of the production systems of Leviathan, the term refers to the processed natural gas stream, *after* removal of liquids (e.g., water and MEG)
Liquefied Natural Gas (LNG)	Natural gas condensed by cooling to approximately 160°C below zero to a liquid state, and thus shrunk by a factor of 600. Liquifying natural gas enables its transportation to distant clients in specifically-designated tanks without the need for a pipeline.
Logs	(a) Different types of tests and measurements conducted during drilling operations, to continuously characterize and record the properties of the drilled rocks and the fluids within them. (b) The tools utilized for the aforementioned tests and measurements. Logs are divided to those utilized while drilling (Logging While Drilling, LWD) and installed on the drill string, and to those utilized when the drill string is removed from the borehole, and are carried by wireline (wireline logging).
Low/ Best/ High Estimate	According to the PRMS, the low estimate is defined as a value where there is a 90% probability that the actual volume will be equal or greater than it; the best estimate is defined as the value where there is a 50% probability that the actual volume will be equal or greater than it; the high estimate is defined as the value where there is a 10% probability that the actual volume will be equal or greater than it.
Manifold	A structure consisting of pipes and valves, used for controlling, routing and monitoring flow of various products. In the Tamar and Leviathan projects, the manifold is subsea, and routes the flow from pipelines arriving from several wells into the long tie-back pipelines that connect it to the production platforms.
Natural gas	Gaseous mixture of hydrocarbons, generated by natural processes.
Oil/Gas exploration	All activities geared to identifying oil/gas reservoirs and proving their existence, including, *inter alia*, geological, geophysical, engineering, geochemical surveys and analyses etc. By convention, the exploration phase terminates following a successful exploration well, and after the explorationists succeeded in proving the economic viability of the discovery, which sometimes requires drilling additional wells.

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Oil/Gas field	A subsurface accumulation or accumulations of oil, often consisting of a reservoir rock capped by a sealing layer. This term usually refers to reservoirs that are likely economic.
Petroleum	Natural mixture of hydrocarbons in solid, liquid or gas state. Petroleum may also contain components which are not hydrocarbons, such as carbon dioxide, nitrogen and sulfur. In this report, this term is used to refer mainly to natural gas and/or oil and/or condensate
Petroleum asset	Possession, whether directly or indirectly, of a preliminary permit, license or lease. Outside Israel, a possession, whether directly or indirectly, of an interest with an equivalent essence, granted by an authorized entity. Among petroleum rights are the right to benefit based on the possession, whether directly or indirectly, of a petroleum asset or of a right with an equivalent essence.
Petroleum Resources Management System (PRMS)	The guiding document for reliable and standard definition, classification and reporting of petroleum resources, developed and promulgated by the major professional associations in the industry. The most recent edition was released in 2018. (Replacing the edition of 2007).
Production and processing platform	A facility that is used for processing of produced fluids (natural gas/condensate/associated water, etc.), and sometimes also for remote control on the production wells and the connecting pipelines array. In the Yam Tethys, Tamar and Leviathan projects, the production and processing platforms are located offshore.
Prospective resources	Defined by the PRMS as the quantities of hydrocarbons estimated, as of a given date, to be potentially recoverable from *undiscovered* accumulations. Prospective resources are reported based on the certainty associated with the estimates, to low estimate (1U), best estimate (2U) and high estimate (3U).
Recoverable gas/oil	The volumes of gas/oil that can be produced through commercial or sub-commercial development projects, as of a given day.
Recovery factor	The ratio of recoverable to initially in-place oil or gas, as defined here. The recovery factor ranges from 0 to 1, generally lower for oil than for gas.
Reserves	Defined by the PRMS as quantities of hydrocarbons 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 reported, in accordance with the range of uncertainty associated with the estimates, as proven (P1), probable (P2) and possible (P3) quantities. The low estimate (1P) consists of P1; the best estimate (2P) of P1 and P2; and high estimate (3P) of P1, P2 and P3.
Rich natural gas	In the context of the production systems of the Tamar and Leviathan projects, the term refers to the processed natural gas stream, *before* removal of liquids (e.g., water and MEG)
Seismic survey	Methodology based on sound waves, that enables imaging of the subsurface and detection of geological structures, and is the main tool in petroleum exploration. Generally, seismic surveys are divided into those that provide a two-dimensional (2D) image of the subsurface, and to those that provide a three-dimensional (3D) image. The raw data are processed in various techniques. The geological interpretation is commonly performed on the processed products.
Topsides or Decks	A structure that contains the production and processing facilities, as well as other related facilities, situated above sea level, and installed on top of a jacket in the case of a fixed-leg platform, or on top of a floating facility in the case of an FPSO.
Umbilical cables	In the context of the production systems of the Tamar and Leviathan projects, the term refers to control and command cables through which the wells are operated, as well as conduits of liquids to the wells. In the Tamar and Leviathan projects, there are umbilical cables connecting the production platform to the subsea distribution assembly (SDA), and in-field cables, connecting the SDA to the production wells.
Wet gas	Natural gas consisting of, compared to dry gas, less light hydrocarbons (mainly methane and ethane) and more heavier hydrocarbons. By convention, gas is considered "wet" where methane content is below 85%.
Working interest	The interest in a petroleum asset granting its owner the right to participate, proportionally to its stake in a joint venture, in utilization of the asset for petroleum exploration, development and production subject to proportional participation in whatever expenditures, following the acquisition of the working interest.

Preliminary permit, priority right to receive a license, petroleum right, petroleum, license	Within the meaning thereof in the Petroleum Law.
Discovered; Discovery; On Production; Approved for Development; Justified for Development; Development Pending; Development Unclarified or on Hold; Well Abandonment; Development not Viable; Dry Hole	Within the meaning thereof in the PRMS.

Units

BCF - Billion Cubic Feet

BCM - Billion Cubic Meters

TCF - Trillion Cubic Feet

MMCF - Million Cubic Feet

MMBBL - Million Barrels

MMBTU - Million British Thermal Units

Below are conversion coefficients used in this report:

BCM	BCF	MMCF
1	35.3147	35,314.7

BCF	MMCF	BCM
1	1000	0.0283

MMCF	BCF	BCM
1	0.001	0.00003

Abbreviations, partial list

AFE – Authority For Expenditure

AOT– Ashdod Onshore Terminal

ACQ – Annual Contract Quantity

CCUS – Carbon Capture, Utilization and Storage

EGAS – Egyptian Natural Gas Holding Company

EMG – Eastern Mediterranean Gas Company S.A.E

FEED – Front-End Engineering Design

FID – Final Investment Decision

FLNG – Floating LNG

FPSO – Floating Production, Storage and Offloading

FSRU – LNG Floating Storage Regasification Unit for natural gas supply

IEC – Israel Electric Corp.

JOA – Joint Operating Agreement

JV – Joint Venture

MEG – Monoethyleneglycol (anti-freeze liquid)

NEPCO – Natural Electric Power Company (Jordanian national electric company)

NSAI – Netherland Sewel and Associates Inc.

PRMS – Petroleum Resources Management System

SPC – Special Purpose Company

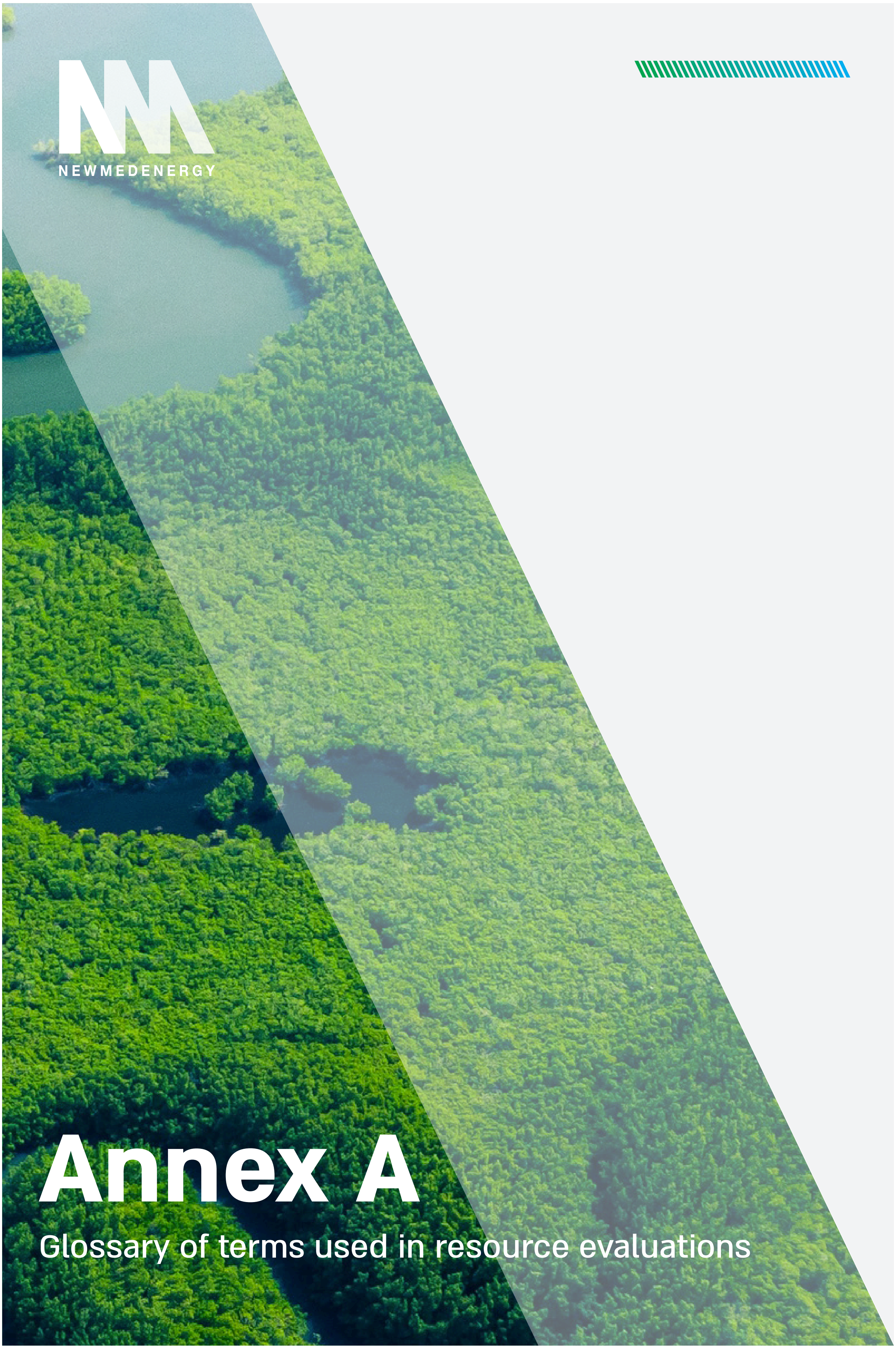
TCQ – Total Contract Quantity

TEG – Triethylen Glycol (Water-annexing liquid, used to dry natural gas)

Geological ages and periods, appearing in the report

According to the International Commission on Stratigraphy, 2024 (in million years before present):

- Miocene: 5.3 - 23.0
- Oligocene: 23.0 - 33.9
- Upper Cretaceous: 66.0 - 100.5
- Lower Cretaceous: 100.5 – 143.1
- Jurassic: 143.1 - 201.4
- Triassic: 201.4 - 251.9
- Permian: 251.9 - 298.9



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Annex A

Glossary of terms used in resource evaluations

Appendix A—Glossary of Terms Used in Resources Evaluations

This Glossary provides high-level definitions of terms used in resources evaluations. Where appropriate, sections within the PRMS document are referenced to best show the use of selected terms in context.

TERM	See PRMS Section	DEFINITION
1C	2.2.2	Denotes low estimate of Contingent Resources.
2C	2.2.2	Denotes best estimate of Contingent Resources.
3C	2.2.2	Denotes high estimate of Contingent Resources.
1P	2.2.2	Denotes low estimate of Reserves (i.e., Proved Reserves). Equal to P1.
2P	2.2.2	Denotes the best estimate of Reserves. The sum of Proved plus Probable Reserves.
3P	2.2.2	Denotes high estimate of reserves. The sum of Proved plus Probable plus Possible Reserves.
1U	2.2.2	Denotes the unrisked low estimate qualifying as Prospective Resources.
2U	2.2.2	Denotes the unrisked best estimate qualifying as Prospective Resources.
3U	2.2.2	Denotes the unrisked high estimate qualifying as Prospective Resources.
Abandonment, Decommissioning, and Restoration (ADR)	3.1.2	The process (and associated costs) of returning part or all of a project to a safe and environmentally compliant condition when operations cease. Examples include, but are not limited to, the removal of surface facilities, wellbore plugging procedures, and environmental remediation. In some instances, there may be salvage value associated with the equipment removed from the project. ADR costs are presumed to be without consideration of any salvage value, unless presented as "ADR net of salvage."
Accumulation	2.4	An individual body of naturally occurring petroleum in a reservoir.
Aggregation	4.2.5	The process of summing well, reservoir, or project-level estimates of resources quantities to higher levels or combinations, such as field, country or company totals. Arithmetic summation of incremental categories may yield different results from probabilistic aggregation of distributions.
Appraisal	1.2	The phase that may follow successful exploratory drilling. Activities to further evaluate the discovery, such as seismic acquisition, geological studies, and drilling additional wells may be conducted to reduce technical uncertainties and commercial contingencies.
Approved for Development	2.1.3.5, Table I	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is underway. A project maturity sub-class of Reserves.
Analog	4.1.1	Method used in resources estimation in the exploration and early development stages (including improved recovery projects) when direct measurement is limited. Based on evaluator's assessment of similarities of the analogous reservoir(s) together with the development plan.
Analogous Reservoir	4.1.1	Reservoirs that have similar rock properties (e.g., petrophysical, lithological, depositional, diagenetic, and structural), fluid properties (e.g., type, composition, density, and viscosity), reservoir conditions (e.g., depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide insight and comparative data to assist in estimation of recoverable resources.
Assessment	2.1.2	See Evaluation.

Associated Gas	Table 3	A natural gas found in contact with or dissolved in crude oil in the reservoir. It can be further categorized as gas cap gas or solution gas.
Basin-Centered Gas	2.4	An unconventional natural gas accumulation that is regionally pervasive and characterized by low permeability, abnormal pressure, gas-saturated reservoirs, and lack of a down dip water leg.
Barrel of Oil Equivalent (BOE)	3.2.9	The term allows for a single value to represent the sum of all the hydrocarbon products that are forecast as resources. Typically, condensate, oil, bitumen, and synthetic crude barrels are taken to be equal (1 bbl = 1 BOE). Gas and NGL quantities are converted to an oil equivalent based on a conversion factor that is recommended to be based on a nominal heating content or calorific value equivalent to a barrel of oil.
Basis for Estimate	1.2	The methodology (or methodologies) and supporting data on which the estimated quantities are based. (Also referenced as basis for the estimation.)
Behind-Pipe Reserves	2.1.3.6	Reserves that are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion before the start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling and completing a new well including hook-up to allow production.
Best Estimate	2.2.2	With respect to resources categorization, the most realistic assessment of recoverable quantities if only a single result were reported. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
C1	2.2.2	Denotes low estimate of Contingent Resources. C1 is equal to 1C.
C2	2.2.2	Denotes Contingent Resources of same technical confidence as Probable, but not commercially matured to Reserves.
C3	2.2.2	Denotes Contingent Resources of same technical confidence as Possible, but not commercially matured to Reserves.
Chance	1.1	Chance equals 1-risk. Generally synonymous with likelihood. (See Risk)
Chance of Commerciality	2.1.3	The estimated probability that the project will achieve commercial maturity to be developed. For Prospective Resources, this is the product of the chance of geologic discovery and the chance of development. For Contingent Resources and Reserves, it is equal to the chance of development.
Chance of Development	2.1.3	The estimated probability that a known accumulation, once discovered, will be commercially developed.
Chance of Geologic Discovery	2.1.3	The estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum.
Coalbed Methane (CBM)	2.4	Natural gas contained in coal deposits. Coalbed gas, although usually mostly methane, may be produced with variable amounts of inert or even non-inert gases. [Also called coal-seam gas (CSG) or natural gas from coal (NGC).]
Commercial	2.1.2	A project is commercial when there is evidence of a firm intention to proceed with development within a reasonable time-frame. Typically, this requires that the best estimate case meet or exceed the minimum evaluation decision criteria (e.g., rate of return, investment payout time). There must be a reasonable expectation that all required internal and external approvals will be forthcoming. Also, there must be evidence of a technically mature, feasible development plan and the essential social, environmental, economic, political, legal, regulatory, decision criteria, and contractual conditions are met.
Committed Project	2.1.3.1	Project that the entity has a firm intention to develop in a reasonable time-frame. Intent is demonstrated with funding/financial plans, but FID has not yet been declared (See also Final Investment Decision.)

Completion	2.1.3.6	Completion of a well. The process by which a well is brought to its operating status (e.g., producer, injector, or monitor well). A well deemed to be capable of producing petroleum, or used as an injector, is completed by establishing a connection between the reservoir(s) and the surface so that fluids can be produced from, or injected into, the reservoir.
Completion Interval	2.1.3.6	The specific reservoir interval(s) that is (are) open to the borehole and connected to the surface facilities for production or injection, or reservoir intervals open to the wellbore and each other for injection purposes.
Concession	3.3	A grant of access for a defined area and time period that transfers certain entitlements to produced hydrocarbons from the host country to an entity. The entity is generally responsible for exploration, development, production, and sale of hydrocarbons that may be discovered. Typically granted under a legislated fiscal system where the host country collects taxes, fees, and sometimes royalty on profits earned. (Also called a license.)
Condensate	3.2	A mixture of hydrocarbons (mainly pentanes and heavier) that exist in the gaseous phase at original temperature and pressure of the reservoir, but when produced, are in the liquid phase at surface pressure and temperature conditions. Condensate differs from NGLs in two respects: (1) NGL is extracted and recovered in gas plants rather than lease separators or other lease facilities, and (2) NGL includes very light hydrocarbons (ethane, propane, or butanes) as well as the pentanes-plus that are the main constituents of condensate.
Confidence Level	4.2	A measure of the estimated reliability of a result. As used in the deterministic incremental method, the evaluator assigns a relative level of confidence (high/moderate/low) to areas/segments of an accumulation based on the information available (e.g., well control and seismic coverage). Probabilistic and statistical methods use the 90% (P90) for the high confidence (low value case), 50% (P50) for the best estimate (moderate value case), and 10% (P10) for the low (high value case) estimate to represent the chances that the actual value will equal or exceed the estimate.
Constant Case	3.1.2	A descriptor applied to the economic evaluation of resources estimates. Constant-case estimates are based on current economic conditions being those conditions (including costs and product prices) that are fixed at the evaluation date and held constant, with no inflation or deflation made to costs or prices throughout the remainder of the project life other than those permitted contractually.
Consumed in Operations (CiO)	3.2.2	That portion of produced petroleum consumed as fuel in production or lease plant operations before delivery to the market at the reference point. (Also called lease fuel.)
Contingency	1.1	A condition that must be satisfied for a project in Contingent Resources to be reclassified as Reserves. Resolution of contingencies for projects in Development Pending is expected to be achieved within a reasonable time period.
Contingent Project	1.1	A project that is not yet commercial owing to one or more contingencies that have not been resolved.
Contingent Resources	1.1 Table 1	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.
Continuous-Type Deposit	2.4	A petroleum accumulation that is pervasive throughout a large area and that generally lacks well-defined OWC or GWC. Such accumulations are included in unconventional resources. Examples of such deposits include “basin-centered” gas, tight gas, tight oil, gas hydrates, natural bitumen, and oil shale (kerogen) accumulations.

Conventional Resources	2.4	Resources that exist in porous and permeable rock with buoyancy pressure equilibrium. The PIIP is trapped in discrete accumulations related to a localized geological structural feature and/or stratigraphic condition, typically with each accumulation bounded by a down dip contact with an aquifer, and is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water.
Cost Recovery	3.3	Under a typical production-sharing agreement, the contractor is responsible for the field development and all exploration and development expenses. In return, the contractor recovers costs (investments and operating expenses) out of the production stream. The contractor normally receives an entitlement interest share in the petroleum production and is exposed to both technical and market risks.
Crude Oil	3.2.9	Crude oil is the portion of petroleum that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric conditions of pressure and temperature (excludes retrograde condensate). Crude oil may include small amounts of non-hydrocarbons produced with the liquids but does not include liquids obtained from the processing of natural gas.
Cumulative Production	1.1	The sum of petroleum quantities that have been produced at a given date. (See also Production). Production is measured under defined conditions to allow for the computation of both reservoir voidage and sales quantities and for the purpose of voidage also includes non-petroleum quantities.
Current Economic Conditions	3.1.2	Economic conditions based on relevant historical petroleum prices and associated costs averaged over a specified period. The default period is 12 months. However, in the event that a step change has occurred within the previous 12-month period, the use of a shorter period reflecting the step change must be justified and used as the basis of constant-case resources estimates and associated project cash flows.
Defined Conditions	3.0	Forecast of conditions to exist and impact the project during the time period being evaluated. Forecasts should account for issues that impact the commerciality, such as economics (e.g., hurdle rates and commodity price); operating and capital costs; and technical, marketing, sales route, legal, environmental, social, and governmental factors.
Deposit	2.4	Material laid down by a natural process. In resources evaluations, it identifies an accumulation of hydrocarbons in a reservoir. (See Accumulation.)
Deterministic Incremental Method	4.2	An assessment method based on defining discrete parts or segments of the accumulation that reflect high, moderate, and low confidence regarding the estimates of recoverable quantities under the defined development plan.
Deterministic Method	4.2	An assessment method based on discrete estimate(s) made based on available geoscience, engineering, and economic data and corresponds to a given level of certainty.
Deterministic Scenario Method	4.2	Method where the evaluator provides three deterministic estimates of the quantities to be recovered from the project being applied to the accumulation. Estimates consider the full range of values for each input parameter based on available engineering and geoscience data, but one set is selected that is most appropriate for the corresponding resources confidence category. A single outcome of recoverable quantities is derived for each scenario.
Developed Reserves	2.1.3.5 Table 2	Reserves that are expected to be recovered from existing wells and facilities. Developed Reserves may be further sub-classified as Producing or Non-Producing.
Developed Producing Reserves	2.1.3.5 Table 2	Developed Reserves that are expected to be recovered from completion intervals that are open and producing at the effective date. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves	2.1.3.5 Table 2	Developed Reserves that are either shut-in or behind-pipe. (See also Shut-In Resources and Behind-Pipe Reserves.)
Development On Hold	2.1.3.5 Table 1	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. A project maturity sub-class of Contingent Resources.
Development Not Viable	2.1.3.5 Table 1	A discovered accumulation for which there are contingencies resulting in there being no current plans to develop or to acquire additional data at the time due to limited commercial potential. A project maturity sub-class of Contingent Resources.
Development Pending	2.1.3.5 Table 1	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. A project maturity sub-class of Contingent Resources.
Development Plan	2.1.3.6	The design specifications, timing, and cost estimates of the appraisal and development project(s) that are planned in a field or group of fields. The plan will include, but is not limited to, well locations, completion techniques, drilling methods, processing facilities, transportation, regulations, and marketing. The plan is often executed in phases when involving large, complex, sequential recovery and/or extensive areas.
Development Unclarified	2.1.3.5 Table 1	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information. This sub-class requires appraisal or study 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. A project maturity sub-class of Contingent Resources.
Discovered	2.1.1	A petroleum accumulation where one or several exploratory wells through testing, sampling, and/or logging have demonstrated the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In this context, “significant” implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for technical recovery. (See also Known Accumulation.)
Discovered Petroleum Initially-In-Place	1.1	Quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production. Discovered PIIP may be subdivided into commercial, sub-commercial, and the portion remaining in the reservoir as Unrecoverable.
Discovered Unrecoverable	2.1.1	Discovered petroleum in-place resources that are evaluated, as of a given date, as not able to be recovered by the commercial and sub-commercial projects envisioned.
Dry Gas	3.2.3	Natural gas remaining after hydrocarbon liquids have been removed before the reference point. It should be recognized that this is a resources assessment definition and not a phase behavior definition. (Also called lean gas.)
Economic	3.1.2	A project is economic when it has a positive undiscounted cumulative cash flow from the effective date of the evaluation, the net revenue exceeds the net cost of operation (i.e., positive cumulative net cash flow at discount rate greater than or equal to zero percent).
Economic Interest	3.3	Interest that is possessed when an entity has acquired an interest in the minerals in-place or a license and secures, by any form of legal relationship, revenue derived from the extraction of the mineral to which he must look for a return.
Economic Limit	3.1.2	Defined as the time when the maximum cumulative net cash flow (see Net Entitlement) occurs for a project.

Economically Not Viable Contingent Resources	2.1.3.7	Those quantities for which development projects are not expected to yield positive cash flows under reasonable forecast conditions. May also be subject to additional unsatisfied contingencies.
Economically Viable Contingent Resources	2.1.3.7	Those quantities associated with technically feasible projects where cash flows are positive under reasonable forecast conditions but are not Reserves because it does not meet the other commercial criteria
Economically Producible	3.1.2	Refers to the situation where the net revenue from an ongoing producing project exceeds the net expenses attributable to a certain entity's interest. The ADR costs are excluded from the determination.
Effective Date	1.2	Resource estimates of remaining quantities are "as of the given date" (effective date) of the evaluation. The evaluation must take into account all data related to the period before the "as of date."
Entitlement	3.3	That portion of future production (and thus resources) legally accruing to an entity under the terms of the development and production contract or license.
Entity	3.0	A legal construct capable of bearing legal rights and obligations. In resources evaluations, this typically refers to the lessee or contractor, which is some form of legal corporation (or consortium of corporations). In a broader sense, an entity can be an organization of any form and may include governments or their agencies.
Established Technology	2.3.4	Methods of recovery or processing that have proved to be successful in commercial applications.
Estimated Ultimate Recovery (EUR)	1.1	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities that have been already produced. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.
Evaluation	3.0	The geosciences, engineering, and associated studies, including economic analyses, conducted on a petroleum exploration, development, or producing project resulting in estimates of the quantities that can be recovered and sold and the associated cash flow under defined forward conditions. (Also called assessment.)
Evaluator	1.2	The person or group of persons responsible for performing an evaluation of a project. These may be employees of the entities that have an economic interest in the project or independent consultants contracted for reviews and audits. In all cases, the entity accepting the evaluation takes responsibility for the results, including its resources and attributed value estimates.
Exploration	2.1.3.5	Prospecting for undiscovered petroleum using various techniques, such as seismic surveys, geological studies, and exploratory drilling.
Field	1.2	In conventional reservoirs, a field is typically an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impermeable rock, laterally by local geologic barriers, or both. The term may be defined differently by individual regulatory authorities. For unconventional reservoirs without hydrodynamic influences, a field is often defined by regulatory or ownership boundaries as necessary.
Final Investment Decision (FID)	2.1.3.1	Project approval stage when the participating companies have firmly agreed to the project and the required capital funding.
Flare Gas	3.2.2	The total quantity of gas vented and/or burned as part of production and processing operations (but not as fuel).

Flow Test	2.1.1	An operation on a well designed to demonstrate the existence of recoverable petroleum in a reservoir by establishing flow to the surface and/or to provide an indication of the potential productivity of that reservoir (such as a wireline formation test). May also demonstrate the potential of certain completion techniques, particularly in unconventional reservoirs.
Fluid Contacts	4.2	The surface or interface in a reservoir separating two regions characterized by predominant differences in fluid saturations. Because of capillary and other phenomena, fluid saturation change is not necessarily abrupt or complete, nor is the surface necessarily horizontal.
Forecast Case	3.1.2	A descriptor applied to a scenario when production and associated cash-flow estimates are based on those conditions (including costs and product price schedules, inflation indexes, and market factors) forecast by the evaluator to reasonably exist throughout the evaluation life (i.e., defined conditions). Inflation or deflation adjustments are made to costs and revenues over the evaluation period.
Gas Balance	3.2.8	In gas production operations involving multiple working interest owners, maintaining a statement of volumes attributed to each, depending on each owner's portion received. Imbalances may occur that must be monitored over time and eventually balanced in accordance with accepted accounting procedures.
Gas Cap Gas	Table 3	Free natural gas that overlies and is in contact with crude oil in the reservoir. It is a subset of associated gas.
Gas Hydrates	2.4	Naturally occurring crystalline substances composed of water and gas, in which a solid water lattice accommodates gas molecules in a cage-like structure or clathrate. At conditions of standard temperature and pressure, one volume of saturated methane hydrate will contain as much as 164 volumes of methane gas. Gas hydrates are included in unconventional resources, but the technology to support commercial maturity has yet to be developed.
Gas/Oil Ratio	4.1.4	Ratio that is calculated using measured natural gas and crude oil volumes at stated conditions. The gas/oil ratio may be the solution gas/oil ratio, *Rs*; produced gas/oil ratio, *Rp*; or another suitably defined ratio of gas production to oil production.
Geostatistical Methods	4.2.2	A variety of mathematical techniques and processes dealing with the collection, methods, analysis, interpretation, and presentation of large quantities of geoscience and engineering data to (mathematically) describe the variability and uncertainties within any reservoir unit or pool, specifically related here to resources estimates.
High Estimate	2.2.2	With respect to resources categorization, this is considered to be an optimistic estimate of the quantity that will actually be recovered from an accumulation by a project. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.
Hydrates	2.4	See Gas Hydrates.
Hydrocarbons	1.1	Hydrocarbons are chemical compounds consisting wholly of hydrogen and carbon molecules.
Improved Recovery	2.3.4	The extraction of additional petroleum, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural forces in the reservoir. It includes waterflooding and gas injection for pressure maintenance, secondary processes, tertiary processes, and any other means of supplementing natural reservoir recovery processes. Improved recovery also includes thermal and chemical processes to improve the in-situ mobility of viscous forms of petroleum. (Also called enhanced recovery.)
Injection	3.2.5	The forcing, pumping, or natural flow of substances into a porous and permeable subsurface rock formation. Injected substances can include either gases or liquids.

Justified for Development	2.1.3.5 Table 1	A development project that has reasonable forecast commercial conditions at the time of reporting and there are reasonable expectation that all necessary approvals/ contracts will be obtained. A project maturity sub-class of Reserves.
Kerogen	2.4	The naturally occurring, solid, insoluble organic material that occurs in source rocks and can yield oil upon heating. Kerogen is also defined as the fraction of large chemical aggregates in sedimentary organic matter that is insoluble in solvents (in contrast, the fraction that is soluble in organic solvents is called bitumen). (See also Oil Shales.)
Known Accumulation	2.1.1	An accumulation that has been discovered.
Lead	2.1.3.5 Table 1	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. A project maturity sub-class of Prospective Resources.
Learning Curve	2.4	Demonstrated improvements over time in performance of a repetitive task that results in efficiencies in tasks to be realized and/or in reduced time to perform and ultimately in cost reductions.
Likelihood	1.1	Likelihood (the estimated probability or chance) is equal (1- risk). (See Probability and Risk.)
Low/Best/High Estimates	2.2.2	Reflects the range of uncertainty as a reasonable range of estimated potentially recoverable quantities.
Low Estimate	2.2.2	With respect to resources categorization, this is a conservative estimate of the quantity that will actually be recovered from the accumulation by a project. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
Lowest Known Hydrocarbons (LKH)	4.1.2	The deepest documented occurrence of a producible hydrocarbon accumulation as interpreted from well log, flow test, pressure measurement, core data, or other conclusive and reliable evidence.
Market	1.1	A consumer or group of consumers of a product that has been obtained through purchase, barter, or contractual terms.
Marketable Quantities	2.0	Those quantities of hydrocarbons that are estimated to be producible from petroleum accumulations and that will be consumed by the market. (Also referred to as marketable products.)
Mean	4.2.5	The sum of a set of numerical values divided by the number of values in the set.
Measurement	3.2	The process of establishing quantity (volume, mass, or energy content) and quality of petroleum products delivered to a reference point under conditions defined by delivery contract or regulatory authorities.
Mineral Lease	3.3	An agreement in which a mineral owner (lessor) grants an entity (lessee) rights. Such rights can include (1) a fee ownership or lease, concession, or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of the lease; (2) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and/or (3) those agreements with foreign governments or authorities under which a reporting entity participates in the operation of the related properties or otherwise serves as producer of the underlying reserves (as opposed to being an independent purchaser, broker, dealer, or importer).
Monte Carlo Simulation	4.2	A type of stochastic mathematical simulation that randomly and repeatedly samples input distributions (e.g., reservoir properties) to generate a resulting distribution (e.g., recoverable petroleum quantities).

Multi-Scenario Method	4.2	An extension of the deterministic scenario method. In this case, a significant number of discrete deterministic scenarios are developed by the evaluator, with each scenario leading to a single deterministic outcome. Probabilities may be assigned to each discrete input assumption from which the probability of the scenario can be obtained; alternatively, each outcome may be assumed to be equally likely.
Natural Bitumen	2.4	The portion of petroleum that exists in the semi-solid or solid phase in natural deposits. In its natural state, it usually contains sulfur, metals, and other non-hydrocarbons. Natural bitumen has a viscosity greater than 10,000 mPa·s (or 10,000 cp) measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural viscous state, it is not normally recoverable at commercial rates through a well and requires the implementation of improved recovery methods such as steam injection. Natural bitumen generally requires upgrading before normal refining.
Natural Gas	3.2.3	Portion of petroleum that exists either in the gaseous phase or is in solution in crude oil in a reservoir, and which is gaseous at atmospheric conditions of pressure and temperataure. Natural gas may include some amount of non-hydrocarbons.
Natural Gas Liquids (NGLs)	3.2.3	A mixture of light hydrocarbons that exist in the gaseous phase in the reservoir and are recovered as liquids in gas processing plants. NGLs differ from condensate in two principal respects: (1) NGLs are extracted and recovered in gas plants rather than lease separators or other lease facilities, and (2) NGLs include very light hydrocarbons (ethane, propane, or butanes) as well as the pentanes-plus that are the main constituents of condensates.
Net Entitlement	1.1 3.3	That portion of future production (and thus resources) legally accruing to an entity under the terms of the development and production contract or license. Under the terms of PSCs, the producers have an entitlement to a portion of the production. This entitlement, often referred to as “net entitlement” or “net economic interest,” is estimated using a formula based on the contract terms incorporating costs and profits.
Net Pay	4.1.1	The portion (after applying cutoffs) of the thickness of a reservoir from which petroleum can be produced or extracted. Value is referenced to a true vertical thickness measured.
Net Revenue Interest	3.3.1	An entity’s revenue share of petroleum sales after deduction of royalties or share of production owing to others under applicable lease and fiscal terms. (See also Entitlement and Net Entitlement)
Netback Calculation	3.2.1	Term used in the hydrocarbon product price determination at reference point to reflect the revenue of one unit of sales after the costs associated with bringing the product to a market (e.g., transportation and processing) are removed.
Non-Hydrocarbon Gas	3.2.4	Associated gases such as nitrogen, carbon dioxide, hydrogen sulfide, and helium that are present in naturally occurring petroleum accumulations.
Non-Sales	1.1	That portion of estimated recoverable or produced quantities that will not be included in sales as contractually defined at the reference point. Non-sales include quantities CiO, flare, and surface losses, and may include non-hydrocarbons.
Oil Sands	2.4	Sand deposits highly saturated with natural bitumen. Also called “tar sands.” Note that in deposits such as the western Canada oil sands, significant quantities of natural bitumen may be hosted in a range of lithologies, including siltstones and carbonates.
Oil Shales	2.4	Shale, siltstone, and marl deposits highly saturated with kerogen. Whether extracted by mining or in-situ processes, the material must be extensively processed to yield a marketable product (synthetic crude oil). (Often called kerogen shale.)

On Production	2.1.3.5 Table 1	A project maturity sub-class of Reserves that reflects the operational execution phase of one or multiple development projects with the Reserves currently producing or capable of producing. Includes Developed Producing and Developed Non-Producing Reserves.
Overlift/Underlift	3.2.8	Production entitlements received that vary from contractual terms resulting in overlift or underlift positions. This can occur in annual records because of the necessity for companies to lift their entitlement in parcel sizes to suit the available shipping schedules as agreed upon by the parties. At any given financial year-end, a company may be in overlift or underlift. Based on the production matching the company's accounts, production should be reported in accord with and equal to the liftings actually made by the company during the year and not on the production entitlement for the year.
P1	1.1	Denotes Proved Reserves. P1 is equal to 1P.
P2	1.1	Denotes Probable Reserves.
P3	1.1	Denotes Possible Reserves.
Penetration	Table 3	The intersection of a wellbore with a reservoir.
Petroleum	1.0	Defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbon compounds, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content of petroleum can be greater than 50%.
Petroleum Initially-in-Place (PIIP)	1.1	The total quantity of petroleum that is estimated to exist originally in naturally occurring reservoirs, as of a given date. Crude oil in-place, natural gas in-place, and natural bitumen in-place are defined in the same manner.
Pilot Project	2.3	A small-scale test or trial operation used to assess technology, including recovery processes, for commercial application in a specific reservoir.
Play	2.1.3.5 Table 1	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation to define specific Leads or Prospects. A project maturity sub-class of Prospective Resources.
Pool	4.2.2	An individual and separate accumulation of petroleum in a reservoir within a field.
Possible Reserves	2.2.2	An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. Possible Reserves are those additional reserves that analysis of geoscience and engineering data suggest 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 that the actual quantities recovered will equal or exceed the 3P estimate.
Primary Recovery	2.3.4	The extraction of petroleum from reservoirs using only the natural energy available in the reservoirs to move fluids through the reservoir rock to other points of recovery.
Probability	2.2.1	The extent to which an event is likely to occur, measured by the ratio of the favorable cases to the whole number of cases possible. PRMS convention is to quote cumulative probability of exceeding or equaling a quantity where P90 is the small estimate and P10 is the large estimate. (See also Uncertainty.)
Probabilistic Method	4.2.3	The method of estimation of resources is called probabilistic when the known geoscience, engineering, and economic data are used to generate a continuous range of estimates and their associated probabilities.

Probable Reserves	2.2.2	An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that 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.
Production	1.1	The cumulative quantities of petroleum that have been recovered at a given date. Production can be reported in terms of the sales product specifications, but project evaluation requires that all production quantities (sales and non-sales), as measured to support engineering analyses requiring reservoir voidage calculations, are recognized.
Production Forecast	2.1.3.7	A forecasted schedule of production over time. For Reserves, the production forecast reflects a specific development scenario under a specific recovery process, a certain number and type of wells and particular facilities and infrastructure. When forecasting Contingent or Prospective Resources, more than one project scope (e.g., wells and facilities) is frequently carried to determine the range of the potential project and its uncertainty together with the associated resources defining the low, best, and high production forecasts. The uncertainty in resources estimates associated with a production forecast is usually quantified by using at least three scenarios or cases of low, best, and high, which lead to the resources classifications of, respectively, 1P, 2P, 3P and 1C, 2C, 3C or 1U,2U and 3U.
Production- Sharing Contract (PSC)	3.3.2	A contract between a contractor and a host government in which the contractor typically bears the risk and costs for exploration, development, and production. In return, if exploration is successful, the contractor is given the opportunity to recover the incurred investment from production, subject to specific limits and terms. Ownership of petroleum in the ground is retained by the host government; however, the contractor normally receives title to the prescribed share of the quantities as they are produced. (Also termed production-sharing agreement (PSA).
Project	1.2	A defined activity or set of activities that provides the link between the petroleum accumulation's resources sub-class and the decision-making process, including budget allocation. A project may, for example, constitute the development of a single reservoir or field, an incremental development in a larger producing field, or the integrated development of a group of several fields and associated facilities (e.g. compression) with a common ownership. In general, an individual project will represent a specific maturity level (sub-class) at which a decision is made on whether or not to proceed (i.e., spend money), suspend, or remove. There should be an associated range of estimated recoverable resources for that project. (See also Development Plan.)
Property	1.2	A defined portion of the Earth's crust wherein an entity has contractual rights to extract, process, and market specified in-place minerals (including petroleum). In general, defined as an area but may have depth and/or stratigraphic constraints. May also be termed a lease, concession, or license.
Prospect	2.1.3.5 Table 1	A project associated with an undrilled potential accumulation that is sufficiently well defined to represent a viable drilling target. A project maturity sub-class of Prospective Resources.
Prospective Resources	1.1 Table 1	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.

Proved Reserves	2.2.2 Table 3	An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. Proved Reserves are 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 that the quantities actually recovered will equal or exceed the estimate.
Pure Service Contract	3.3	Agreement between a contractor and a host government that typically covers a defined technical service to be provided or completed during a specific time period. The service company investment is typically limited to the value of equipment, tools, and expenses for personnel used to perform the service. In most cases, the service contractor's reimbursement is fixed by the contract's terms with little exposure to either project performance or market factors. No Reserves or Resources can be attributed to these activities.
Qualified Reserves Auditor	1.2	A reserves evaluator who (1) has a minimum of ten years of practical experience in petroleum engineering or petroleum production geology, with at least five years of such experience being in responsible charge of the estimation and evaluation of Reserves information; and (2) either (a) has obtained from a college or university of recognized stature a bachelor's or advanced degree in petroleum engineering, geology, or other discipline of engineering or physical science or (b) has received, and is maintaining in good standing, a registered or certified professional engineer's license or a registered or certified professional geologist's license, or the equivalent, from an appropriate governmental authority or professional organization. (see SPE 2007 "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information")
Qualified Reserves Evaluator	1.2	A reserves evaluator who (1) has a minimum of five years of practical experience in petroleum engineering or petroleum production geology, with at least three years of such experience being in the estimation and evaluation of Reserves information; and (2) either (a) has obtained from a college or university of recognized stature a bachelor's or advanced degree in petroleum engineering, geology, or other discipline of engineering or physical science or (b) has received, and is maintaining in good standing, a registered or certified professional engineer's license or a registered or certified professional geologist's license, or the equivalent, from an appropriate governmental authority or professional organization. (modified from SPE 2007 "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information")
Range of Uncertainty	2.2	The range of uncertainty of the in-place, recoverable, and/or potentially recoverable quantities; may be represented by either deterministic estimates or by a probability distribution. (See Resources Categories.)
Raw Production	3.2.1	All components, whether hydrocarbon or other, produced from the well or extracted from the mine (hydrocarbons, water, impurities such as non-hydrocarbon gases, etc.).
Reasonable Certainty	2.2.2	If deterministic methods for estimating recoverable resources quantities are used, then reasonable certainty is intended to express a high degree of confidence that the estimated quantities will be recovered. Typically attributed to Proved Reserves or 1C Resources quantities.
Reasonable Expectation	2.1.2	Indicates a high degree of confidence (low risk of failure) that the project will proceed with commercial development or the referenced event will occur. (Differs from reasonable certainty, which applies to resources quantity technical confidence, while reasonable expectation relates to commercial confidence.).

Recoverable Resources	1.1 Table 1	Those quantities of hydrocarbons that are estimated to be producible by the project from either discovered or undiscovered accumulations.
Recovery Efficiency	1.2	A numeric expression of that portion (expressed as a percentage) of in-place quantities of petroleum estimated to be recoverable by specific processes or projects, most often represented as a percentage. It is estimated using the recoverable resources divided by the hydrocarbons initially in-place. It is also referenced to timing; current and ultimate (or estimated ultimate) are descriptors applied to reference the stage of the recovery. (Also called recovery factor.)
Reference Point	3.2.1	A defined location within a petroleum extraction and processing operation where quantities of produced product are measured under defined conditions before custody transfer (or consumption). Also called point of sale, terminal point, or custody transfer point.
Report	2.0	The presentation of evaluation results within the entity conducting the assessment. Should not be construed as replacing requirements for public disclosures under guidelines established by regulatory and/or other government agencies.
Reserves	1.1 Table 1	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: they must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied.
Reservoir	1.2	A subsurface rock formation that contains an individual and separate natural accumulation of petroleum that is confined by impermeable barriers, pressure systems, or fluid regimes (conventional reservoirs), or is confined by hydraulic fracture barriers or fluid regimes (unconventional reservoirs).
Resources	1.1	Term used to encompass all quantities of petroleum (recoverable and unrecoverable) naturally occurring in an accumulation on or within the Earth's crust, discovered and undiscovered, plus those quantities already produced. Further, it includes all types of petroleum whether currently considered conventional or unconventional. (See Total Petroleum Initially-in-Place.)
Resources Categories	2.2 Table 3	Subdivisions of estimates of resources to be recovered by a project(s) to indicate the associated degrees of uncertainty. Categories reflect uncertainties in the total petroleum remaining within the accumulation (in-place resources), that portion of the in-place petroleum that can be recovered by applying a defined development project or projects, and variations in the conditions that may impact commercial development (e.g., market availability and contractual changes). The resource quantity uncertainty range within a single resources class is reflected by either the 1P, 2P, 3P, Proved, Probable, Possible, or 1C, 2C, 3C or 1U, 2U, 3U resources categories.
Resources Classes	2.1 Table 1	Subdivisions of resources that indicate the relative maturity of the development projects being applied to yield the recoverable quantity estimates. Project maturity may be indicated qualitatively by allocation to classes and sub-classes and/or quantitatively by associating a project's estimated likelihood of commerciality.
Resources Type	2.4	Describes the accumulation and is determined by the combination of the type of hydrocarbon and the rock in which it occurs.
Revenue-Sharing Contract	3.3.2	Contracts that are very similar to the PSCs with the exception of contractor payment in these contracts, the contractor usually receives a defined share of revenue rather than a share of the production.
Risk	2.1.3	The probability of loss or failure. Risk is not synonymous with uncertainty. Risk is generally associated with the negative outcome, the term "chance" is preferred for general usage to describe the probability of a discrete event occurring.

Risk and Reward	3.3	Risk and reward associated with oil and gas production activities are attributed primarily from the variation in revenues cause by technical and economic risks. The exposure to risk in conjunction with entitlement rights is required to support an entity's resources recognition. Technical risk affects an entity's ability to physically extract and recover hydrocarbons and is usually dependent on a number of technical parameters. Economic risk is a function of the success of a project and is critically dependent on cost, price, and political or other economic factors.
Risk Service Contract (RSC)	3.3	Agreements that are very similar to the production-sharing agreements in that the risk is borne by the contractor but the mechanism of contractor payment is different. With a RSC, the contractor usually receives a defined share of revenue rather than a share of the production.
Royalty	3.3.1	A type of entitlement interest in a resource that is free and clear of the costs and expenses of development and production to the royalty interest owner. A royalty is commonly retained by a resources owner (lessor/host) when granting rights to a producer (lessee/contractor) to develop and produce that resource. Depending on the specific terms defining the royalty, the payment obligation may be expressed in monetary terms as a portion of the proceeds of production or as a right to take a portion of production in-kind. The royalty terms may also provide the option to switch between forms of payment at discretion of the royalty owner.
Sales	3.2	The quantity of petroleum and any non-hydrocarbon product delivered at the custody transfer point (reference point) with specifications and measurement conditions as defined in the sales contract and/or by regulatory authorities.
Shale Gas	2.4	Although the terms shale gas and tight gas are often used interchangeably in public discourse, shale formations are only a subset of all low-permeability tight formations, which include sandstones and carbonates, as well as shales, as sources of tight gas production
Shale Oil	2.4	Although the terms shale oil and tight oil are often used interchangeably in public discourse, shale formations are only a subset of all low-permeability tight formations, which include sandstones and carbonates, as well as shales, as sources of tight oil production
Shut-In Resources	2.1.3.6 Table 2	Resources planned to be recovered from (1) completion intervals that are open at the time of the estimate, but which have not started producing; (2) wells that were shut-in for market conditions or pipeline connections; or (3) wells not capable of production for mechanical reasons that can be remediated at a limited cost compared to the cost of the well.
Split Classification	2.2	A single project should be uniquely assigned to a sub-class along with its uncertainty range, For example, a project cannot have quantities categorized as 1C, 2P, and 3P. This is referred to as "split classification." If there are differing commercial conditions, separate sub-classes should be defined.
Split Conditions	2.2	The uncertainty in recoverable quantities is assessed for each project using resources categories. The assumed commercial conditions are associated with resource classes or sub-classes and not with the resources categories. For example, the product price assumptions are those assumed when classifying projects as Reserves, and a different price would not be used for assessing Proved versus Probable reserves. That would be referred to as "split conditions."
Stochastic	4.2.3	Adjective defining a process involving or containing a random variable or variables or involving likelihood or probability, such as a stochastic simulation.

Sub-Commercial	1.1	A project subdivision that is applied to discovered resources that occurs if either the technical or commercial maturity conditions of project have not yet been achieved. A project is sub-commercial if the degree of commitment is such that the accumulation is not expected to be developed and placed on production within a reasonable time-frame. Sub-commercial projects are classified as Contingent Resources.
Sunk Cost	3.1.2	Money spent before the effective date and that cannot be recovered by any future action. Sunk costs are not relevant to future business decisions because the cost will be the same regardless of the outcome of the decision. Sunk costs differ from committed (obligated) costs, where there is a firm and binding agreement to spend specified amounts of money at specific times in the future (i.e., after the effective date).
Synthetic Crude Oil	3.2.9	A mixture of hydrocarbons derived by upgrading (i.e., chemically altering) natural bitumen from oil sands, kerogen from oil shales, or processing of other substances such as natural gas or coal. Synthetic crude oil may contain sulfur or other non-hydrocarbon compounds and has many similarities to crude oil.
Taxes	3.1.1	Obligatory contributions to the public funds, levied on persons, property, or income by governmental authority.
Technical Forecast	2.1.2	The forecast of produced resources quantities that is defined by applying only technical limitations (i.e., well-flow-loading conditions, well life, production facility life, flow-limit constraints, facility uptime, and the facility's operating design parameters). Technical limitations do not take into account the application of either an economic or license cutoff. (See also Technically Recoverable Resources).
Technical Uncertainty	2.2	Indication of the varying degrees of uncertainty in estimates of recoverable quantities influenced by the range of potential in-place hydrocarbon resources within the reservoir and the range of the recovery efficiency of the recovery project being applied.
Technically Recoverable Resources	1.1	Those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial or accessibility considerations.
Technology Under Development	2.1.1	Technology that is currently under active development and that has not been demonstrated to be commercially viable. There should be sufficient direct evidence (e.g., a test project/pilot) to indicate that the technology may reasonably be expected to be available for commercial application.
Tight Gas	2.4	Gas that is trapped in pore space and fractures in very low-permeability rocks and/or by adsorption on kerogen, and possibly on clay particles, and is released when a pressure differential develops. It usually requires extensive hydraulic fracturing to facilitate commercial production. Shale gas is a sub-type of tight gas.
Tight Oil	2.4	Crude oil that is trapped in pore space in very low-permeability rocks and may be liquid under reservoir conditions or become liquid at surface conditions. Extensive hydraulic fracturing is invariably required to facilitate commercial maturity and economic production. Shale oil is a sub-type of tight oil.
Total Petroleum Initially-in-Place	1.1	All estimated quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.
Uncertainty	2.2	The range of possible outcomes in a series of estimates. For recoverable resources assessments, the range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities for an individual accumulation or a project. (See also Probability.)

Unconventional Resources	2.4	Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and lack well-defined OWC or GWC (also called "continuous-type deposits"). Such resources cannot be recovered using traditional recovery projects owing to fluid viscosity (e.g., oil sands) and/or reservoir permeability (e.g., tight gas/oil/CBM) that impede natural mobility. Moreover, the extracted petroleum may require significant processing before sale (e.g., bitumen upgraders).
Undeveloped Reserves	2.1.3.5 Table 2	Those quantities expected to be recovered through future investments: (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 and completing a new well) is required to recomplete an existing well.
Undiscovered Petroleum Initially-in-Place	1.1	That quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.
Unrecoverable Resources	1.1	Those quantities of discovered or undiscovered PIIP that are assessed, 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 owing to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.
Upgrader	2.4	A general term applied to processing plants that convert extra-heavy crude oil and natural bitumen into lighter crude and less viscous synthetic crude oil. While the detailed process varies, the underlying concept is to remove carbon through coking or to increase hydrogen by hydrogenation processes using catalysts.
Wet Gas	3.2.3	Natural gas from which no liquids have been removed before the reference point. The wet gas is accounted for in resources assessments, and there is no separate accounting for contained liquids. It should be recognized that this is a resources assessment definition and not a phase behavior definition.
Working Interest	3.3	An entity's equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms.

NEWMEDENERGY

Annex B

Current report on reserves, contingent resources, and DCF for the Leviathan leases

<u>NewMed Energy - Limited Partnership</u>
<u>(the "Partnership")</u>

4 February 2025

Israel Securities Authority
22 Kanfei Nesharim St.
Jerusalem
<u>Via Magna</u>

Tel Aviv Stock Exchange Ltd.
2 Ahuzat Bayit St.
Tel Aviv
<u>Via Magna</u>

Dear Sir/Madam,

Re: **<u>Report on Updated Discounted Cash Flow Figures, Reserves and Contingent Resources in the Leviathan Leases</u>**

Further to the Partnership's immediate report of 19 March 2024 (Ref.: 2024-01-027777) regarding the evaluation of the reserves and the contingent resources in the Leviathan reservoir, which is located in the area of the I/14 "Leviathan South" and I/15 "Leviathan North" leases (the "**Previous Resources Report**", the "**Leviathan Reservoir**" or the "**Reservoir**" or the "**Field**" or the "**Project**" or the "**Leviathan Project**", and the "**Leviathan Leases**", respectively), and regarding the discounted cash flow figures from the reserves and from the discounted cash flow figures from part of the contingent resources in the Leviathan Leases as of 31 December 2023 (the "**Previous Discounted Cash Flow**"), the Partnership respectfully provides a report on updated discounted cash flow figures, reserves and contingent resources, as of 31 December 2024, with respect to the Partnership's share in the Leviathan Leases (the "**Resources Report**", the "**Discounted Cash Flow**", the "**Current Discounted Cash Flow**" or the "**Cash Flow**", respectively)[1].

1. <u>Figures on reserves and contingent resources in the Leviathan Reservoir</u>

As of the date of this report, the daily gas production capacity from the Leviathan Reservoir is approx. 1.2 BCF (approx. 12 BCM on the annual level). On 29 June 2023 the partners in the Leviathan project adopted a final investment decision (FID) for the performance of a Project concerning the laying of a third subsea pipeline from the Field to the platform of the Leviathan Project, which shall enable the increase in the daily gas production capacity from the Leviathan Project, in the context of Phase 1A of the development plan for the Leviathan project ("**Phase 1A**") to approx. 1.4 BCF (approx. 14 BCM on the annual level) (the "**Third Pipeline Project**"), with a budget of approx. $568 million (100%, the Partnership's share is approx. $258 million). As of the date of this report, the estimation of the operator of the Leviathan Reservoir,

[1] For a glossary of the professional terms included herein, see the Glossary on page A-247 of Chapter A (Description of the General Development of the Partnership's Business) of the Partnership's periodic report as of 31 December 2023, as released on 19 March 2024 (Ref.: 2024-01-027798) (the "**Periodic Report**"), which is included herein by reference. For details on the Leviathan Project, see Section 7.2 of Chapter A of the Periodic Report.

Chevron Mediterranean Limited (the "**Operator**" or "**Chevron**"), is that the Third Pipeline Project shall be completed by the end of 2025.[2]

It is clarified that according to the Operator's assessment as specified above, the Discounted Cash Flow included herein assumes an increase in the daily production capacity to approx. 1.4 BCF starting from the beginning of 2026 (in lieu of H2/2025, as assessed in the prior discounted cash flow). It is further clarified that although the Discounted Cash Flow from reserves takes into account capital investments for Phase 1B of the Leviathan Project development plan ("**Phase 1B**"), for the front-end engineering design (FEED) and the advance procurement of long lead items, as specified below, the Discounted Cash Flow does not take into account the additional increase in the daily production capacity to approx. 2.1 BCF, which is expected under Phase 1B. It is noted that, as of the date of this report, the partners in the Leviathan Project are promoting negotiations at various stages with potential customers, both in the domestic market and for export, for the signing of agreements for the sale of natural gas under Phase 1B, with a total volume of more than an additional 100 BCM, according to the letter from the Petroleum Commissioner at the Ministry of Energy and Infrastructure (the "**Commissioner**").[3] It is noted that the final investment decision (FID) for the execution of Phase 1B may be adopted in the coming months.

Caution concerning forward-looking information – The information specified above regarding the completion of the Third Pipeline Project, and the adoption of the investment decision regarding Phase 1B, is based on estimates by the Operator and constitutes forward-looking information within the meaning thereof under the Securities Law, 5728- 1968 (the "Securities Law"). It is emphasized that there is no certainty as to whether or how this estimate will materialize, and in practice, the Third Pipeline Project and the adoption of the investment decision regarding Phase 1B, may materialize in a different manner or at a later date, if at all, due to various factors that are beyond the control of the Partnership or the Operator.

According to the Resources Report which the Partnership received from Netherland, Sewell & Associates Inc. (“**NSAI**” or the “**Evaluator**”), part of the resources in the Leviathan Reservoir are classified as reserves and part are

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[2] For details regarding the development plan of the Leviathan Project, see Section 7.2.5(b) of Chapter A of the Periodic Report, and the Partnership's immediate report of 6 October 2024 (Ref.: 2024-01-608146). Note that the additional resources that may be produced upon completion of the Third Pipeline Project, are included in the reserves attributed to Phase 1A within the framework of this report.

[3] 25 June 2024 saw the receipt of the Commissioner's response to in-principle applications sent to him by the Leviathan partners for approval of an increase in the volume of export of natural gas produced in Phase 1B. According to the response, the position of the professional functions at the Ministry of Energy allows, at this time, for the export of additional natural gas from the Leviathan Reservoir in an aggregate quantity of up to 118 BCM, which may, upon the fulfillment of certain conditions, increase up to 145 BCM. For further details, see the Partnership’s immediate report of 26 June 2024 (Ref.: 2024-01-064795).

classified as contingent resources. Therefore, the report that the Partnership received from NSAI includes two parts, as follows:

- A reserves report, which includes ‘on production’ reserves that shall be produced from the Leviathan Project’s facilities, including from the Third Pipeline Project’s facilities. Discounted Cash Flow figures with respect to the reserves, as of 31 December 2024, are presented in Section 1(a)(3) below.

- A contingent resources report, which includes resources which are classified as contingent at the ‘development pending’ phase, which were divided into two groups, which relate to the stages of development of the Reservoir, as follows:

  (1) Phase I – First Stage: Resources attributed to Phase I – First Stage that are contingent, *inter alia*, on approval for the drilling of additional wells and demonstration of the existence of a future market for the sale of natural gas, but are not contingent on significant development of the production system. Discounted Cash Flow figures with respect to contingent resources at this stage, as of 31 December 2024, are presented in Section 1(b)(4) below.

  (2) Future Development: Additional resources that are contingent, *inter alia*, on approval for the drilling of additional wells, demonstration of existence of a future market for the sale of natural gas, and approval for future developments to the production system beyond Phase I – First Stage, and on a commitment to develop the resources.

  Below is a summary of the Current Discounted Cash Flow figures relative to the Previous Discounted Cash Flow figures (the Partnership's share). During 2024, the Leviathan partners sold approx. 11.2 BCM of natural gas and approx. 905 thousand barrels of condensate for (gross) financial consideration of approx. U.S. $2.5 billion (“**Dollars**” or “**$**”) (100%, the Partnership’s share was approx. $1.14 billion)[4].

	31.12.2024 ($ in billions, the Partnership's share)		**31.12.2023 ($ in billions, the Partnership's share)**	
	Cap Rate 7.5%	**Cap Rate 10%**	**Cap Rate 7.5%**	**Cap Rate 10%**
2P reserves	6.02	4.95	6.20	5.09
2P+2C	6.64	5.33	6.63	5.34

[4] It is clarified that the revenue figures for 2024 are unaudited.

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 2024, the reserves in the Leviathan Project are defined at the 'on production' maturity stage. These reserves are as specified below:

Reserve Category[5]	**Total (100%) in the Petroleum Asset (Gross)**		**Total Share Attributed to the Holders of the Equity Interests of the Partnership (Net)** [6]	
	Natural Gas BCF	**Condensate Million Barrels**	**Natural Gas BCF**	**Condensate Million Barrels**
1P (Proved) Reserves	13,116.6	28.9	4,649.8	10.2
Probable Reserves	1,717.4	3.8	607.4	1.3
Total 2P (Proved+Probable) Reserves	14,834.0	32.6	5,257.2	11.6
Possible Reserves	1,174.8	2.6	415.5	0.9
Total 3P (Proved+Probable+Possible) Reserves	16,008.8	35.2	5,672.7	12.5

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

(2) In the report received by the Partnership from NSAI, NSAI stated, *inter alia*, several assumptions and reservations, including that: (a) The evaluations, as customary 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

[5] The amounts in the table may not add up due to rounding-off differences.
[6] 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 in accordance with the assumption regarding the Investment Recovery Date, as defined in Section 1(a)(3) below.

risks; (b) NSAI did not visit the Field, and did not check the mechanical operation of the facilities and the wells or the condition thereof; (c) NSAI did not examine possible exposure deriving from environmental matters. However, NSAI stated that as of the date of 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 extract 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, and in respect of which there is no certainty. The natural gas and/or condensate quantities that shall actually be produced may be different to the 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 actual production data from the Leviathan Reservoir.

(3) Discounted Cash Flow figures

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

(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 only, including expansion thereof through the Third Pipeline Project, from the beginning of 2026[7]. It is noted that the actual production rate may be lower or higher than the production rate 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 agreement with Blue Ocean Energy (BOE) for the export of natural gas from the Leviathan Project, of 26 September 2019, as amended from time to time (the "**Export to Egypt Agreement**")[8], taking into account, *inter alia*, forecasts with respect to the Brent oil barrel price (the "**Brent Price**") and its possible impact on the quantities that are sold to Egypt, the agreement for the export of gas to Jordan's national electricity company (NEPCO), as specified in Section 7.11.3(b) of Chapter A of the Periodic Report, and additional agreements for the supply of natural gas to the domestic market (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, being conducted by the Partnership, together with its partners in the Leviathan Project, a forecast of the demand for natural gas in the domestic market in Israel, prepared for the Partnership an outside consultant (BDO Consulting Group, "**BDO**")[9], and in relation to the estimate of the expected supply from other gas sources in

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[7] The sale quantities do not include sales of additional gas quantities which may be rendered possible as a result of the performance of additional development stages, which were classified in the Resources Report as contingent resources – future development.

[8] For further details, see Section 7.11.3(c) of Chapter A of the Periodic Report.

[9] The forecast of the demand for natural gas in the domestic market for the coming years on which the Partnership relied, is as follows (in BCM): 2025 – approx. 14.7; 2026 – approx. 16.3; 2027 – approx. 17.1; and 2028-2029 – approx. 17.9. The aforesaid forecast of the demand is primarily based on a forecast of demand for electricity, which is affected, *inter alia*, by the growth forecasts 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.

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 a forecast for completion of projects for increasing the natural gas production and transmission capability, as specified in Section 6 of the update of Chapter A of the Q1/2024 report, as released on 26 May 2024 (Ref.: 2024-01-051442) (the "**Q1 Report**"), in Section 9 of the update of Chapter A of the Q2/2024 report, as released on 8 August 2024 (Ref.: 2024-01-085045) (the "**Q2 Report**"), and Section 7 of the update of Chapter A of the Q3/2024 report, as released on 20 November 2024 (Ref.: 2024-01-617359) (the "**Q3 Report**"), as well as on forecasts of the supply and demand in these markets, which were prepared by consultancy firms.

(b) <u>The sale prices of natural gas and condensate</u>: 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, according to the price formulas determined therein, and the Partnership's assumptions regarding the prices that shall be determined in future agreements, based, *inter alia*, on the demand forecast in the domestic market in the Cash Flow years, as estimated by BDO, and on the Partnership's estimate of the projected demand.

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 Price, to the TAOZ (energy demand management 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 ILS 3.65 to the dollar throughout the Cash Flow period, which is based on the exchange rate as of 31 December 2024.

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, according to 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-term and short-term forecasts of third parties, including: The United States Department of Energy, the World Bank, IHS Global Insights and Wood Mackenzie. Accordingly, the Cash Flow assumes a Brent Price of approx. $76 in years 2025 and 2026, increasing to approx. $80 in 2027, and gradually rising to approx. $92 from 2034, 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 Export to Egypt Agreement)[11] 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 and general and administrative expenses of the Operator, which may be directly attributed to the project, and jointly constitute the operating expenses of the project. These expenses are represented at the Reservoir level and per production unit, and the operating expenses in the Cash Flow are not adjusted to inflation changes. NSAI confirmed that the operating expenses provided by the Partnership are reasonable, based, *inter alia*, on knowledge available thereto from similar projects.

(d) The capital expenditures ("CAPEX" or "Capital Expenditures") taken into account in the Cash Flow deriving from reserves include expenses that were approved by the Partnership and its partners in the Leviathan Project, including the costs of the Third Pipeline Project, expenses in

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

[11] The Export to Egypt Agreement includes a mechanism for updating the price at a rate of up to 10% (up or down) after the fifth year and after the tenth year of the agreement upon fulfillment of certain conditions that are set forth in the agreement. 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 7.11.4(c), 7.11.4(d) and 7.11.4(e) of Chapter A of the Periodic Report.

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 Capital Expenditures not yet approved by the Partnership, and indirect costs paid to the Operator. The total Capital Expenditures taken into account in the contingent resources Cash Flow (Phase 1 – First Stage) exceed the total costs approved by the Partnership, and include an estimate of future Capital Expenditures that may be required for the drilling of new wells, the installation of infrastructures, additional production equipment, and various engineering actions, which exceed the expenses which were included in the budget for the development of Phase I – First Stage, plus indirect costs paid to the Operator. The Capital Expenditures in the Cash Flow are not adjusted to inflation changes. NSAI has confirmed that the Capital Expenditures provided by the Partnership are reasonable, based, *inter alia*, on information in its possession.

(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 of the wells, and the cost of decommissioning of 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, 5712-1952, it is possible to extend it 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

[13] In order to increase the possible flow capacity via the EMG pipeline, it is necessary to expand the supply capacity in the INGL system and in the EMG systems in Israel and in Egypt. For further details, see Sections 7.12.2(d) and 7.12.2(e) of Chapter A of the Periodic Report, Section 6(b) of the update of Chapter A of the Q1 Report, Section 9 of the update of Chapter A of the Q2 Report, and Sections 7(b) and 7(c) of the update of Chapter A of the Q3 Report.

[14] For details regarding the draft policy document on the decommissioning of offshore exploration and production infrastructure, published by the Ministry of Energy for public comments, see Section 7.23.9 of Chapter A of the Periodic Report.

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 7.23.7(c) of Chapter A of the Periodic Report.

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 after the sale of a total quantity starting from the beginning of Reservoir production (in respect of 100% of the interests in the petroleum asset) of approx. 2,300 BCF and of approx. 5.2 million barrels of condensate from Phase I – First Stage (the "**Investment Recovery Date**"). Since the Investment Recovery Date is affected, *inter alia*, by the gas and/or condensate prices, the production rate, the production and development costs, and the rate of the royalties, and since additional agreements are expected to be signed for the sale of natural gas, the total quantity of natural gas and/or condensate that shall be sold by the Investment Recovery Date may be materially 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 detailed in Section 7.2.7 of Chapter A of the Periodic Report. For details regarding calculation of the Investment Recovery Date, see Sections 7.25.8 and 7.26.5 of Chapter A of the Periodic Report and Section 13 of the update of Chapter A of the Q2 Report.

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

(h) 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 calculations of the Levy 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, the formulas and the 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 the purpose 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.

(i) The calculation of the Discounted Cash Flow took into account expenses and investments which were actually paid from 1 January 2025 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 2025 and which is expected to continue to be produced.

(j) 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.

<u>The changes in the Current Discounted Cash Flow versus the Previous Discounted Cash Flow</u>:

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

(a) The Discounted Cash Flow from reserves takes into account capital investments for Phase 1B totaling approx. $280 million (100%) for the front-end engineering design (FEED) and the advance procurement of long lead items, which have been or are expected to be carried out by the date of the final investment decision (FID) for Phase 1B. The aforesaid out of a total budget of approx. $505 million (100%) approved by the partners in the Leviathan Project.[15]

(b) The volume, timing and type of capital investments relating to the reserves and the contingent resources (Phase I – First Stage), have been updated, including in connection with the Third Pipeline project and projects for increasing the natural gas quantities for export, *inter alia* due to the update of the Reservoir model.[16] Accordingly, the natural gas quantities expected to be sold in 2025 were reduced, *inter alia* due to a delay in the anticipated completion date of the construction of a new offshore segment between Ashdod and Ashkelon (the "**Integrated Segment**") for increasing the transmission capacity of the EMG pipeline, the completion of which, as estimated by the Operator and as of the date of this report, is expected by the end of 2025,[17] and due to the delay in the completion of the Third Pipeline Project, as specified in Section 1 above.

(c) The forecasts received from third parties have been updated, including the domestic market demand forecast, the Brent price forecast, and the production tariff price forecast, as specified in Section 1(a)(3)(b) above.

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[15] For further details, see Section 7.2.5(f) of Chapter A of the Periodic Report, and the Partnership's immediate report of 1 August 2024 (Ref.: 2024-01-081835).

[16] For further details, see Section 7.12.2(b)(2) of Chapter A of the Periodic Report, Section 6(a) of the update of Chapter A of the Q1 Report, and Section 7(a) of the update of Chapter A of the Q3 Report. The estimated budget for the project for the establishment of a compression station in the Ramat Hovav area and a new onshore pipeline connecting the Israeli and Egyptian transportation systems near Nitzana, is approx. $500 million (100% of the project, the Partnership's share approx. $113 million). The completion of such project is expected, at the Operator's estimation, during H2/2028. It is also noted that the final investment decision for such project has not yet been made, and a transmission agreement has not yet been signed.

[17] For further details, see Section 7.12.2(b)(1) of Chapter A of the Periodic Report, Section 6(b) of the update of Chapter A of the Q1 Report, Section 9 of the update of Chapter A of the Q2 Report, and Sections 7(b) and 7(c) of the update of Chapter A of the Q3 Report.

In accordance with various assumptions, which are primarily as specified above, presented below is the estimated Discounted Cash Flow, as of 31 December 2024, 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[18].

[18] 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 2024 (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%
31.12.2025	853	11.0	1,062,883	159,875	-	141,955	282,347	-	478,707	-	116,337	362,370	353,637	349,501	345,506	337,912	330,797
31.12.2026	1,015	13.1	1,278,420	234,713	-	135,579	83,736	-	824,392	-	146,354	678,038	630,188	608,333	587,712	549,803	515,801
31.12.2027	1,016	13.1	1,337,367	260,326	-	151,307	22,908	-	902,826	102,220	126,677	673,929	596,542	562,462	531,046	475,192	427,229
31.12.2028	1,027	13.2	1,389,559	270,486	-	114,015	-	-	1,005,058	303,612	96,661	604,785	509,845	469,539	433,238	370,816	319,497
31.12.2029	1,016	13.1	1,391,770	270,916	-	134,308	1,560	-	984,985	381,930	110,563	492,492	395,410	355,681	320,724	262,578	216,812
31.12.2030	1,025	13.2	1,419,813	276,375	-	113,834	-	-	1,029,604	467,398	114,908	447,298	342,023	300,504	264,812	207,376	164,097
31.12.2031	1,016	13.1	1,431,699	278,689	-	111,819	-	-	1,041,191	487,278	113,401	440,513	320,795	275,298	237,086	177,592	134,673
31.12.2032	1,027	13.2	1,470,828	286,305	-	111,292	-	-	1,073,231	502,272	117,162	453,797	314,733	263,814	222,033	159,085	115,612
31.12.2033	1,016	13.1	1,469,808	286,107	-	110,353	-	-	1,073,348	502,327	118,377	452,644	298,984	244,785	201,335	137,983	96,098
31.12.2034	1,025	13.2	1,496,055	291,216	-	129,520	-	-	1,075,318	503,249	119,703	452,367	284,572	227,567	182,919	119,912	80,033
31.12.2035	1,001	12.9	1,453,424	282,918	-	111,577	-	-	1,058,930	495,579	122,821	440,530	263,929	206,152	161,939	101,543	64,949
31.12.2036	968	12.5	1,407,191	273,918	-	108,404	-	-	1,024,869	479,639	122,583	422,648	241,158	183,985	141,242	84,714	51,927
31.12.2037	936	12.0	1,362,393	265,198	-	104,415	-	-	992,779	464,621	118,914	409,245	222,391	165,721	124,330	71,328	41,900
31.12.2038	905	11.6	1,318,690	256,691	-	102,374	-	-	959,625	449,104	117,365	393,155	203,474	148,098	108,583	59,586	33,544
31.12.2039	874	11.3	1,270,146	247,242	-	126,800	-	-	896,104	419,377	109,621	367,107	180,945	128,638	92,172	48,381	26,101
31.12.2040	845	10.9	1,212,048	235,932	-	103,337	-	-	872,779	408,461	106,793	357,525	167,831	116,540	81,606	40,972	21,183
31.12.2041	817	10.5	1,186,932	231,043	-	83,978	-	-	871,911	408,054	106,687	357,170	159,680	108,302	74,113	35,593	17,635
31.12.2042	790	10.2	1,148,312	223,526	-	81,389	-	-	843,397	394,710	103,198	345,489	147,103	97,451	65,172	29,938	14,216
31.12.2043	763	9.8	1,109,932	216,055	-	81,258	-	-	812,619	380,305	99,432	332,881	134,985	87,344	57,085	25,083	11,414
31.12.2044	738	9.5	1,072,629	208,794	-	101,738	-	-	762,097	356,661	93,250	312,185	120,565	76,199	48,669	20,455	8,920

Total Discounted Cash Flow from 1P (Proved) Reserves as of 31 December 2024 (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%
31.12.2045	713	9.2	1,036,515	201,764	-	81,009	-	-	753,742	352,751	92,228	308,763	113,565	70,105	43,760	17,592	7,352
31.12.2046	689	8.9	1,001,478	194,944	-	80,890	-	-	725,644	339,602	88,790	297,253	104,125	62,783	38,299	14,727	5,898
31.12.2047	667	8.6	968,963	188,615	-	80,781	-	-	699,568	327,398	85,599	286,571	95,603	56,304	33,566	12,346	4,739
31.12.2048	644	8.3	938,611	182,706	-	80,675	-	-	675,230	316,008	82,621	276,601	87,883	50,554	29,453	10,362	3,811
31.12.2049	622	8.0	906,985	176,550	-	101,175	-	-	629,260	294,493	76,996	257,770	78,000	43,825	24,952	8,397	2,960
31.12.2050	601	7.7	876,489	170,614	-	80,466	-	-	625,409	292,691	76,525	256,192	73,831	40,518	22,545	7,257	2,452
31.12.2051	581	7.5	847,122	164,897	-	80,368	-	-	601,856	281,669	73,643	246,544	67,667	36,272	19,724	6,073	1,966
31.12.2052	562	7.2	818,884	159,401	-	80,281	-	-	579,203	271,067	70,871	237,265	62,019	32,471	17,256	5,082	1,577
31.12.2053	543	7.0	791,776	154,124	-	80,219	-	-	557,433	260,879	68,208	228,347	56,846	29,071	15,097	4,253	1,265
31.12.2054	526	6.8	765,798	149,067	-	100,769	-	-	515,962	241,470	63,133	211,359	50,111	25,031	12,704	3,423	975
31.12.2055	508	6.5	739,820	144,010	-	80,105	-	-	515,705	241,350	63,102	211,253	47,701	23,273	11,543	2,975	812
31.12.2056	491	6.3	714,971	139,173	-	80,052	-	-	495,745	232,009	60,659	203,077	43,671	20,811	10,088	2,487	651
31.12.2057	474	6.1	691,251	134,556	-	80,004	-	-	476,691	223,091	58,328	195,272	39,993	18,615	8,818	2,080	521
31.12.2058	459	5.9	668,661	130,159	-	79,961	-	-	458,542	214,598	56,107	187,837	36,639	16,657	7,711	1,739	418
31.12.2059	443	5.7	646,071	125,762	-	100,525	-	-	419,785	196,459	48,673	174,653	32,445	14,407	6,518	1,406	324
31.12.2060	429	5.5	624,611	121,584	-	79,879	-	-	423,147	198,033	49,084	176,030	31,143	13,508	5,972	1,233	272
31.12.2061	414	5.3	603,151	117,407	-	79,842	-	-	405,902	189,962	46,974	168,966	28,470	12,061	5,212	1,029	218
31.12.2062	400	5.1	582,820	113,449	-	79,808	-	36,428	353,134	165,267	48,896	138,971	22,301	9,228	3,897	736	149
31.12.2063	387	5.0	563,618	109,712	-	79,780	-	36,428	337,699	158,043	47,007	132,648	20,273	8,194	3,381	611	119
31.12.2064	32	0.4	46,309	9,014	-	14,612	-	36,428	(13,745)	-	2,525	(16,270)	(2,368)	(935)	(377)	(65)	(12)

Total Discounted Cash Flow from 1P (Proved) Reserves as of 31 December 2024 (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%
Total	28,857	371.4	41,123,802	7,943,834	-	3,860,452	390,550	109,285	28,819,682	12,303,637	3,540,778	12,975,267	6,978,711	5,558,666	4,601,441	3,419,584	2,728,906

Total Discounted Cash Flow from Probable Reserves as of 31 December 2024 (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%
31.12.2025	45	0.6	55,741	8,384	-	2,394	-	-	44,962	-	10,341	34,621	33,787	33,391	33,010	32,284	31,604
31.12.2026	90	1.2	114,381	26,135	-	915	-	-	87,331	-	20,086	67,245	62,499	60,332	58,287	54,527	51,155
31.12.2027	90	1.2	121,348	23,621	-	317	-	-	97,410	58,532	8,942	29,936	26,499	24,985	23,589	21,108	18,978
31.12.2028	91	1.2	124,481	24,231	-	1,358	-	-	98,891	61,550	8,588	28,753	24,239	22,323	20,597	17,629	15,189
31.12.2029	90	1.2	124,573	24,249	-	1,291	-	-	99,033	73,867	5,788	19,378	15,558	13,995	12,620	10,332	8,531
31.12.2030	91	1.2	126,925	24,707	-	1,318	-	-	100,900	61,071	9,161	30,668	23,450	20,604	18,156	14,218	11,251
31.12.2031	90	1.2	127,660	24,850	-	1,243	-	-	101,567	47,534	12,428	41,606	30,299	26,002	22,393	16,773	12,720
31.12.2032	54	0.7	78,202	15,222	-	(523)	-	-	63,502	29,719	7,770	26,013	18,041	15,123	12,728	9,119	6,627
31.12.2033	42	0.5	62,283	12,124	-	(1,066)	-	-	51,226	23,974	6,268	20,984	13,861	11,348	9,334	6,397	4,455
31.12.2034	10	0.1	17,167	3,342	-	(2,397)	-	-	16,223	7,592	1,985	6,645	4,180	3,343	2,687	1,762	1,176
31.12.2035	11	0.1	18,448	3,591	-	(3,140)	-	-	17,997	8,423	2,202	7,372	4,417	3,450	2,710	1,699	1,087
31.12.2036	21	0.3	33,838	6,587	-	(2,613)	-	-	29,865	13,977	3,654	12,234	6,980	5,326	4,088	2,452	1,503
31.12.2037	32	0.4	49,167	9,571	-	(1,998)	-	-	41,595	19,466	5,090	17,039	9,259	6,900	5,176	2,970	1,745
31.12.2038	41	0.5	62,388	12,144	-	(1,532)	-	-	51,776	24,231	6,335	21,210	10,977	7,989	5,858	3,214	1,810
31.12.2039	51	0.7	76,829	14,955	-	(1,465)	-	-	63,339	29,643	7,750	25,946	12,789	9,092	6,515	3,419	1,845
31.12.2040	60	0.8	87,438	17,020	-	(51)	-	-	70,469	32,979	8,623	28,867	13,551	9,410	6,589	3,308	1,710
31.12.2041	68	0.9	99,238	19,317	-	1,158	-	-	78,762	36,861	9,637	32,264	14,424	9,783	6,695	3,215	1,593
31.12.2042	76	1.0	110,736	21,555	-	459	-	-	88,721	41,522	10,856	36,344	15,475	10,251	6,856	3,149	1,495
31.12.2043	83	1.1	120,822	23,519	-	503	-	-	96,801	45,303	11,845	39,653	16,080	10,405	6,800	2,988	1,360
31.12.2044	90	1.2	130,909	25,482	-	547	-	-	104,880	49,084	12,833	42,963	16,592	10,486	6,698	2,815	1,228
31.12.2045	97	1.2	141,002	27,447	-	592	-	-	112,963	52,867	13,822	46,274	17,020	10,507	6,558	2,637	1,102
31.12.2046	103	1.3	149,963	29,191	-	632	-	-	120,140	56,225	14,700	49,214	17,239	10,395	6,341	2,438	977
31.12.2047	108	1.4	157,812	30,719	-	668	-	-	126,425	59,167	15,469	51,789	17,277	10,175	6,066	2,231	856
31.12.2048	114	1.5	165,781	32,270	-	704	-	-	132,807	62,153	16,250	54,403	17,285	9,943	5,793	2,038	750
31.12.2049	118	1.5	172,488	33,576	-	736	-	-	138,176	64,666	16,907	56,602	17,128	9,623	5,479	1,844	650
31.12.2050	123	1.6	179,197	34,882	-	768	-	-	143,547	67,180	17,564	58,803	16,946	9,300	5,175	1,666	563
31.12.2051	128	1.6	185,910	36,188	-	801	-	-	148,921	69,695	18,222	61,004	16,743	8,975	4,880	1,503	486
31.12.2052	131	1.7	191,493	37,275	-	823	-	-	153,395	71,789	18,769	62,837	16,425	8,600	4,570	1,346	418
31.12.2053	134	1.7	195,947	38,142	-	819	-	-	156,986	73,469	19,209	64,308	16,009	8,187	4,252	1,198	356
31.12.2054	138	1.8	200,403	39,010	-	815	-	-	160,579	75,151	19,648	65,779	15,596	7,790	3,954	1,065	304
31.12.2055	141	1.8	204,860	39,877	-	810	-	-	164,173	76,833	20,088	67,252	15,186	7,409	3,675	947	259
31.12.2056	144	1.8	209,321	40,745	-	806	-	-	167,769	78,516	20,528	68,725	14,779	7,043	3,414	842	220
31.12.2057	146	1.9	212,651	41,394	-	797	-	-	170,460	79,775	20,857	69,827	14,301	6,657	3,153	744	186
31.12.2058	147	1.9	214,852	41,822	-	784	-	-	172,246	80,611	21,076	70,559	13,763	6,257	2,897	653	157
31.12.2059	150	1.9	218,186	42,471	-	774	-	-	174,940	81,872	21,406	71,663	13,313	5,912	2,675	577	133
31.12.2060	151	1.9	220,390	42,900	-	760	-	-	176,730	82,710	21,625	72,396	12,808	5,555	2,456	507	112

Total Discounted Cash Flow from Probable Reserves as of 31 December 2024 (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%
31.12.2061	154	2.0	223,728	43,550	-	751	-	-	179,427	83,972	21,955	73,500	12,385	5,247	2,267	448	95
31.12.2062	155	2.0	225,935	43,980	-	756	-	-	181,200	84,802	22,172	74,227	11,911	4,929	2,081	393	80
31.12.2063	156	2.0	227,013	44,189	-	759	-	-	182,064	85,206	22,277	74,581	11,398	4,607	1,901	343	67
31.12.2064	13	0.2	18,255	3,553	-	61	-	-	14,641	419	3,271	10,950	1,594	629	254	44	8
Total	**3,778**	**48.6**	**5,457,761**	**1,063,790**	**-**	**11,134**	**-**	**-**	**4,382,837**	**2,052,404**	**536,000**	**1,794,434**	**662,064**	**462,275**	**349,225**	**236,844**	**184,839**

Total Discounted Cash Flow from 2P (Proved + Probable Reserves) as of 31 December 2024 (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%
31.12.2025	897	11.6	1,118,624	168,259	-	144,349	282,347	-	523,669	-	126,678	396,991	387,423	382,892	378,516	370,196	362,401
31.12.2026	1,105	14.2	1,392,801	260,847	-	136,495	83,736	-	911,723	-	166,440	745,283	692,687	668,665	645,999	604,330	566,956
31.12.2027	1,106	14.2	1,458,715	283,948	-	151,624	22,908	-	1,000,236	160,752	135,619	703,865	623,040	587,446	554,635	496,301	446,207
31.12.2028	1,119	14.4	1,514,040	294,717	-	115,374	-	-	1,103,949	365,162	105,250	633,537	534,084	491,861	453,835	388,445	334,686
31.12.2029	1,106	14.2	1,516,343	295,165	-	135,599	1,560	-	1,084,019	455,797	116,352	511,870	410,968	369,676	333,344	272,910	225,343
31.12.2030	1,116	14.4	1,546,738	301,082	-	115,152	-	-	1,130,504	528,470	124,069	477,966	365,474	321,108	282,968	221,595	175,348
31.12.2031	1,106	14.2	1,559,359	303,539	-	113,062	-	-	1,142,759	534,811	125,829	482,119	351,094	301,300	259,479	194,365	147,393
31.12.2032	1,081	13.9	1,549,029	301,528	-	110,769	-	-	1,136,733	531,991	124,932	479,810	332,774	278,937	234,760	168,204	122,239
31.12.2033	1,058	13.6	1,532,091	298,231	-	109,287	-	-	1,124,573	526,300	124,645	473,628	312,844	256,133	210,668	144,380	100,553
31.12.2034	1,035	13.3	1,513,222	294,558	-	127,123	-	-	1,091,541	510,841	121,688	459,012	288,752	230,910	185,607	121,673	81,209
31.12.2035	1,012	13.0	1,471,872	286,509	-	108,437	-	-	1,076,927	504,002	125,023	447,902	268,346	209,602	164,649	103,242	66,036
31.12.2036	990	12.7	1,441,029	280,505	-	105,790	-	-	1,054,734	493,616	126,237	434,882	248,138	189,310	145,330	87,166	53,430
31.12.2037	968	12.5	1,411,560	274,769	-	102,417	-	-	1,034,374	484,087	124,004	426,283	231,650	172,621	129,506	74,298	43,645
31.12.2038	946	12.2	1,381,077	268,835	-	100,842	-	-	1,011,401	473,336	123,701	414,365	214,451	156,088	114,441	62,800	35,354
31.12.2039	926	11.9	1,346,976	262,197	-	125,335	-	-	959,444	449,020	117,371	393,053	193,734	137,730	98,686	51,800	27,946
31.12.2040	905	11.6	1,299,486	252,953	-	103,286	-	-	943,248	441,440	115,416	386,392	181,382	125,950	88,195	44,280	22,894
31.12.2041	885	11.4	1,286,170	250,361	-	85,136	-	-	950,674	444,915	116,324	389,434	174,105	118,085	80,808	38,808	19,228
31.12.2042	866	11.1	1,259,048	245,081	-	81,848	-	-	932,119	436,232	114,054	381,833	162,578	107,702	72,028	33,087	15,711
31.12.2043	846	10.9	1,230,754	239,574	-	81,761	-	-	909,419	425,608	111,277	372,534	151,065	97,748	63,885	28,071	12,774
31.12.2044	828	10.7	1,203,538	234,276	-	102,286	-	-	866,976	405,745	106,083	355,148	137,157	86,685	55,367	23,270	10,148
31.12.2045	810	10.4	1,177,517	229,211	-	81,600	-	-	866,705	405,618	106,050	355,037	130,585	80,612	50,318	20,229	8,454
31.12.2046	792	10.2	1,151,441	224,135	-	81,522	-	-	845,784	395,827	103,490	346,467	121,365	73,178	44,639	17,166	6,875
31.12.2047	775	10.0	1,126,775	219,334	-	81,448	-	-	825,993	386,565	101,069	338,360	112,881	66,480	39,632	14,577	5,595
31.12.2048	758	9.8	1,104,392	214,977	-	81,379	-	-	808,037	378,161	98,871	331,004	105,168	60,497	35,246	12,400	4,561
31.12.2049	741	9.5	1,079,472	210,126	-	101,911	-	-	767,435	359,160	93,903	314,372	95,128	53,449	30,431	10,241	3,610
31.12.2050	724	9.3	1,055,686	205,496	-	81,235	-	-	768,956	359,871	94,089	314,995	90,777	49,818	27,720	8,923	3,014
31.12.2051	709	9.1	1,033,031	201,086	-	81,169	-	-	750,776	351,363	91,865	307,548	84,411	45,247	24,604	7,576	2,453
31.12.2052	693	8.9	1,010,377	196,676	-	81,104	-	-	732,598	342,856	89,641	300,101	78,444	41,071	21,826	6,428	1,994
31.12.2053	678	8.7	987,723	192,266	-	81,038	-	-	714,419	334,348	87,416	292,655	72,855	37,258	19,349	5,451	1,621
31.12.2054	663	8.5	966,202	188,077	-	101,584	-	-	676,541	316,621	82,782	277,138	65,707	32,821	16,658	4,489	1,279
31.12.2055	648	8.3	944,680	183,888	-	80,915	-	-	679,877	318,183	83,190	278,505	62,887	30,681	15,218	3,922	1,071
31.12.2056	634	8.2	924,291	179,919	-	80,859	-	-	663,514	310,524	81,188	271,802	58,451	27,854	13,502	3,329	871
31.12.2057	620	8.0	903,902	175,950	-	80,802	-	-	647,151	302,867	79,185	265,099	54,294	25,272	11,971	2,823	708
31.12.2058	606	7.8	883,514	171,981	-	80,745	-	-	630,788	295,209	77,183	258,396	50,402	22,914	10,608	2,393	575
31.12.2059	593	7.6	864,258	168,233	-	101,299	-	-	594,725	278,331	70,079	246,315	45,757	20,319	9,193	1,983	457
31.12.2060	580	7.5	845,002	164,485	-	80,640	-	-	599,877	280,742	70,709	248,426	43,952	19,063	8,429	1,739	384

Total Discounted Cash Flow from 2P (Proved + Probable Reserves) as of 31 December 2024 (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%
31.12.2061	567	7.3	826,878	160,957	-	80,592	-	-	585,329	273,934	68,929	242,466	40,855	17,308	7,479	1,476	312
31.12.2062	555	7.1	808,755	157,429	-	80,564	-	36,428	534,334	250,068	71,068	213,198	34,212	14,157	5,978	1,129	229
31.12.2063	543	7.0	790,631	153,901	-	80,539	-	36,428	519,763	243,249	69,285	207,229	31,671	12,800	5,282	954	185
31.12.2064	44	0.6	64,564	12,568	-	14,673	-	36,428	896	419	5,796	(5,320)	(774)	(306)	(123)	(21)	(4)
Total	**32,635**	**420.1**	**46,581,563**	**9,007,623**	**-**	**3,871,586**	**390,550**	**109,285**	**33,202,519**	**14,356,041**	**4,076,777**	**14,769,701**	**7,640,774**	**6,020,941**	**4,950,666**	**3,656,428**	**2,913,744**

Total Discounted Cash Flow from Possible Reserves as of 31 December 2024 (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)	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%
31.12.2025	18	0.2	22,887	3,443	-	(1,366)	-	-	20,810	-	4,786	16,024	15,638	15,455	15,278	14,943	14,628
31.12.2026	23	0.3	30,665	5,743	-	(5,614)	-	-	30,535	-	7,023	23,512	21,853	21,095	20,380	19,065	17,886
31.12.2027	23	0.3	33,884	6,596	-	(8,563)	-	-	35,851	29,364	1,492	4,996	4,422	4,169	3,936	3,522	3,167
31.12.2028	23	0.3	32,347	6,297	-	(1,990)	-	-	28,040	20,035	1,841	6,164	5,197	4,786	4,416	3,779	3,256
31.12.2029	23	0.3	32,510	6,328	-	(2,023)	-	-	28,205	22,777	1,248	4,179	3,356	3,018	2,722	2,228	1,840
31.12.2030	23	0.3	33,247	6,472	-	(2,026)	-	-	28,801	14,086	3,385	11,331	8,664	7,613	6,708	5,253	4,157
31.12.2031	23	0.3	33,770	6,574	-	(2,007)	-	-	29,204	13,667	3,573	11,963	8,712	7,476	6,439	4,823	3,657
31.12.2032	38	0.5	56,512	11,000	-	(1,192)	-	-	46,704	21,857	5,715	19,132	13,269	11,122	9,361	6,707	4,874
31.12.2033	41	0.5	61,525	11,976	-	(1,069)	-	-	50,618	23,689	6,194	20,735	13,696	11,213	9,223	6,321	4,402
31.12.2034	45	0.6	67,503	13,140	-	(730)	-	-	55,093	25,784	6,741	22,568	14,197	11,353	9,126	5,982	3,993
31.12.2035	48	0.6	72,356	14,085	-	(1,281)	-	-	59,553	27,871	7,287	24,395	14,616	11,416	8,968	5,623	3,597
31.12.2036	52	0.7	77,940	15,172	-	(1,092)	-	-	63,861	29,887	7,814	26,160	14,927	11,388	8,742	5,243	3,214
31.12.2037	55	0.7	82,352	16,030	-	(771)	-	-	67,093	31,400	8,210	27,484	14,935	11,129	8,350	4,790	2,814
31.12.2038	59	0.8	86,866	16,909	-	(678)	-	-	70,635	33,057	8,643	28,935	14,975	10,900	7,991	4,385	2,469
31.12.2039	61	0.8	90,380	17,593	-	(981)	-	-	73,768	34,523	9,026	30,218	14,894	10,589	7,587	3,982	2,149
31.12.2040	64	0.8	93,383	18,177	-	182	-	-	75,024	35,111	9,180	30,733	14,427	10,018	7,015	3,522	1,821
31.12.2041	66	0.9	96,429	18,771	-	1,066	-	-	76,593	35,845	9,372	31,375	14,027	9,514	6,510	3,127	1,549
31.12.2042	69	0.9	100,111	19,487	-	415	-	-	80,209	37,538	9,814	32,857	13,990	9,268	6,198	2,847	1,352
31.12.2043	71	0.9	103,541	20,155	-	431	-	-	82,955	38,823	10,150	33,982	13,780	8,916	5,827	2,561	1,165
31.12.2044	74	0.9	106,967	20,822	-	447	-	-	85,698	40,107	10,486	35,105	13,558	8,569	5,473	2,300	1,003
31.12.2045	75	1.0	109,263	21,269	-	459	-	-	87,536	40,967	10,711	35,858	13,189	8,142	5,082	2,043	854
31.12.2046	77	1.0	112,688	21,935	-	475	-	-	90,278	42,250	11,046	36,981	12,954	7,811	4,765	1,832	734
31.12.2047	79	1.0	114,995	22,384	-	487	-	-	92,124	43,114	11,272	37,738	12,590	7,415	4,420	1,626	624
31.12.2048	81	1.0	117,422	22,857	-	499	-	-	94,066	44,023	11,510	38,533	12,243	7,043	4,103	1,444	531
31.12.2049	83	1.1	120,847	23,524	-	516	-	-	96,807	45,306	11,845	39,656	12,000	6,742	3,839	1,292	455
31.12.2050	85	1.1	123,139	23,970	-	528	-	-	98,641	46,164	12,070	40,407	11,645	6,391	3,556	1,145	387
31.12.2051	85	1.1	124,298	24,195	-	535	-	-	99,567	46,598	12,183	40,787	11,194	6,001	3,263	1,005	325
31.12.2052	87	1.1	126,589	24,641	-	548	-	-	101,400	47,455	12,407	41,537	10,858	5,685	3,021	890	276
31.12.2053	88	1.1	128,879	25,087	-	560	-	-	103,232	48,313	12,631	42,288	10,527	5,384	2,796	788	234
31.12.2054	89	1.1	130,037	25,313	-	568	-	-	104,157	48,745	12,745	42,667	10,116	5,053	2,565	691	197
31.12.2055	91	1.2	132,327	25,758	-	581	-	-	105,987	49,602	12,969	43,417	9,804	4,783	2,372	611	167
31.12.2056	92	1.2	133,483	25,983	-	589	-	-	106,911	50,034	13,082	43,795	9,418	4,488	2,175	536	140
31.12.2057	92	1.2	134,640	26,208	-	597	-	-	107,834	50,466	13,195	44,173	9,047	4,211	1,995	470	118
31.12.2058	94	1.2	136,927	26,654	-	610	-	-	109,663	51,322	13,418	44,922	8,762	3,984	1,844	416	100
31.12.2059	95	1.2	138,083	26,879	-	619	-	-	110,585	51,754	13,531	45,300	8,415	3,737	1,691	365	84
31.12.2060	96	1.2	139,238	27,103	-	627	-	-	111,507	52,185	13,644	45,678	8,081	3,505	1,550	320	71

Total Discounted Cash Flow from Possible Reserves as of 31 December 2024 (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)	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%
31.12.2061	96	1.2	139,260	27,108	-	631	-	-	111,521	52,192	13,646	45,684	7,698	3,261	1,409	278	59
31.12.2062	96	1.2	140,414	27,332	-	620	-	-	112,461	52,632	13,761	46,069	7,393	3,059	1,292	244	49
31.12.2063	97	1.3	141,567	27,557	-	606	-	-	113,405	53,073	13,876	46,455	7,100	2,870	1,184	214	42
31.12.2064	8	0.1	12,365	2,407	-	41	-	-	9,916	4,641	1,213	4,062	591	233	94	16	3
Total	**2,585**	**33.3**	**3,771,637**	**732,933**	**-**	**(18,147)**	**-**	**-**	**3,056,851**	**1,436,257**	**372,737**	**1,247,857**	**446,756**	**298,802**	**213,266**	**127,231**	**88,443**

Total Discounted Cash Flow from 3P (Proved + Probable + Possible) Reserves as of 31 December 2024 (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%
31.12.2025	915	11.8	1,141,510	171,701	-	142,983	282,347	-	544,480	-	131,465	413,015	403,061	398,347	393,794	385,138	377,029
31.12.2026	1,127	14.5	1,423,465	266,590	-	130,881	83,736	-	942,259	-	173,464	768,795	714,540	689,760	666,379	623,396	584,842
31.12.2027	1,129	14.5	1,492,598	290,543	-	143,060	22,908	-	1,036,087	190,115	137,111	708,861	627,462	591,616	558,572	499,823	449,374
31.12.2028	1,142	14.7	1,546,387	301,013	-	113,384	-	-	1,131,990	385,197	107,091	639,702	539,281	496,647	458,251	392,225	337,943
31.12.2029	1,129	14.5	1,548,854	301,494	-	133,576	1,560	-	1,112,224	478,574	117,600	516,049	414,323	372,695	336,066	275,138	227,183
31.12.2030	1,138	14.7	1,579,985	307,554	-	113,126	-	-	1,159,306	542,555	127,453	489,297	374,138	328,720	289,676	226,848	179,505
31.12.2031	1,129	14.5	1,593,130	310,112	-	111,054	-	-	1,171,963	548,479	129,402	494,082	359,806	308,776	265,917	199,188	151,050
31.12.2032	1,119	14.4	1,605,542	312,528	-	109,577	-	-	1,183,437	553,848	130,646	498,942	346,043	290,059	244,121	174,911	127,113
31.12.2033	1,099	14.1	1,593,616	310,207	-	108,218	-	-	1,175,191	549,990	130,839	494,363	326,540	267,346	219,891	150,700	104,956
31.12.2034	1,080	13.9	1,580,724	307,698	-	126,392	-	-	1,146,634	536,625	128,429	481,580	302,950	242,264	194,732	127,655	85,201
31.12.2035	1,060	13.6	1,544,228	300,593	-	107,156	-	-	1,136,479	531,872	132,310	472,297	282,962	221,018	173,617	108,865	69,633
31.12.2036	1,042	13.4	1,518,969	295,677	-	104,698	-	-	1,118,595	523,502	134,051	461,042	263,065	200,698	154,072	92,409	56,644
31.12.2037	1,023	13.2	1,493,912	290,799	-	101,646	-	-	1,101,467	515,487	132,213	453,768	246,585	183,750	137,856	79,088	46,459
31.12.2038	1,005	12.9	1,467,944	285,744	-	100,164	-	-	1,082,036	506,393	132,344	443,300	229,426	166,987	122,432	67,186	37,823
31.12.2039	987	12.7	1,437,356	279,790	-	124,354	-	-	1,033,211	483,543	126,397	423,271	208,629	148,319	106,273	55,783	30,095
31.12.2040	969	12.5	1,392,869	271,130	-	103,467	-	-	1,018,271	476,551	124,596	417,125	195,809	135,967	95,209	47,802	24,715
31.12.2041	952	12.3	1,382,599	269,131	-	86,202	-	-	1,027,266	480,761	125,696	420,809	188,132	127,599	87,318	41,934	20,778
31.12.2042	935	12.0	1,359,159	264,568	-	82,263	-	-	1,012,327	473,769	123,868	414,690	176,567	116,970	78,226	35,934	17,063
31.12.2043	918	11.8	1,334,295	259,729	-	82,192	-	-	992,374	464,431	121,427	406,516	164,845	106,665	69,713	30,631	13,939
31.12.2044	901	11.6	1,310,505	255,098	-	102,733	-	-	952,674	445,852	116,569	390,254	150,715	95,254	60,840	25,570	11,151
31.12.2045	885	11.4	1,286,780	250,479	-	82,059	-	-	954,242	446,585	116,761	390,896	143,774	88,754	55,400	22,272	9,308
31.12.2046	869	11.2	1,264,129	246,070	-	81,997	-	-	936,062	438,077	114,537	383,448	134,319	80,989	49,404	18,998	7,609
31.12.2047	854	11.0	1,241,770	241,718	-	81,935	-	-	918,117	429,679	112,341	376,097	125,470	73,894	44,052	16,203	6,219
31.12.2048	838	10.8	1,221,814	237,833	-	81,878	-	-	902,103	422,184	110,381	369,537	117,411	67,540	39,349	13,844	5,092
31.12.2049	824	10.6	1,200,319	233,649	-	102,427	-	-	864,243	404,466	105,749	354,028	107,127	60,191	34,270	11,533	4,065
31.12.2050	809	10.4	1,178,824	229,465	-	81,762	-	-	867,597	406,035	106,159	355,402	102,422	56,209	31,276	10,068	3,401
31.12.2051	794	10.2	1,157,330	225,281	-	81,705	-	-	850,344	397,961	104,048	348,335	95,605	51,247	27,867	8,580	2,778
31.12.2052	780	10.0	1,136,966	221,317	-	81,651	-	-	833,997	390,311	102,048	341,639	89,302	46,756	24,847	7,318	2,270
31.12.2053	766	9.9	1,116,602	217,353	-	81,598	-	-	817,651	382,661	100,048	334,943	83,383	42,641	22,145	6,239	1,855
31.12.2054	752	9.7	1,096,239	213,389	-	102,152	-	-	780,698	365,366	95,526	319,805	75,823	37,874	19,222	5,180	1,476
31.12.2055	739	9.5	1,077,007	209,646	-	81,496	-	-	785,865	367,785	96,158	321,922	72,690	35,464	17,590	4,534	1,238
31.12.2056	726	9.3	1,057,774	205,902	-	81,448	-	-	770,425	360,559	94,269	315,597	67,869	32,342	15,677	3,865	1,011
31.12.2057	713	9.2	1,038,542	202,158	-	81,399	-	-	754,985	353,333	92,380	309,272	63,342	29,483	13,966	3,294	826
31.12.2058	700	9.0	1,020,441	198,635	-	81,355	-	-	740,451	346,531	90,602	303,318	59,164	26,898	12,452	2,809	675
31.12.2059	688	8.9	1,002,340	195,112	-	101,918	-	-	705,310	330,085	83,610	291,615	54,173	24,056	10,883	2,348	541
31.12.2060	675	8.7	984,239	191,588	-	81,267	-	-	711,384	332,928	84,353	294,103	52,033	22,568	9,978	2,059	455

Total Discounted Cash Flow from 3P (Proved + Probable + Possible) Reserves as of 31 December 2024 (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%
31.12.2061	663	8.5	966,138	188,065	-	81,223	-	-	696,851	326,126	82,575	288,150	48,552	20,569	8,888	1,754	371
31.12.2062	651	8.4	949,169	184,761	-	81,184	-	36,428	646,795	302,700	84,828	259,267	41,605	17,216	7,270	1,373	278
31.12.2063	640	8.2	932,199	181,458	-	81,145	-	36,428	633,168	296,322	83,161	253,684	38,771	15,670	6,467	1,168	227
31.12.2064	53	0.7	76,929	14,975	-	14,714	-	36,428	10,812	5,060	7,010	(1,257)	(183)	(72)	(29)	(5)	(1)
Total	**35,220**	**453.3**	**50,353,200**	**9,740,556**	**-**	**3,853,439**	**390,550**	**109,285**	**36,259,370**	**15,792,298**	**4,449,514**	**16,017,558**	**8,087,531**	**6,319,743**	**5,163,932**	**3,783,658**	**3,002,187**

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 costs, royalty rates and the sale prices, in respect of which there is no certainty that they will materialize. It is noted that the quantities of natural gas and/or condensate that shall actually be produced and sold, the said expenses and the said income may be materially different from 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 2024 (Dollars in thousands) which was performed by the Partnership[19]

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	14,288,912	5,025,966	3,729,820	2,975,734	1P (Proved) Reserves	11,668,829	4,180,549	3,112,014	2,484,090
Probable Reserves	1,964,091	378,186	254,740	197,697	Probable Reserves	1,611,769	310,688	210,178	163,898
Total 2P (Proved+Probable) Reserves	16,253,004	5,404,152	3,984,560	3,173,431	Total 2P (Proved+Probable) Reserves	13,280,598	4,491,237	3,322,192	2,647,987
Possible Reserves	1,366,592	231,082	136,807	94,395	Possible Reserves	1,130,045	195,311	117,587	82,480
Total 3P (Proved+Probable+Possible) Reserves	17,619,596	5,635,234	4,121,367	3,267,827	Total 3P (Proved+Probable+Possible) Reserves	14,410,643	4,686,548	3,439,780	2,730,468
15% increase in the gas price					**15% decrease in the gas price**				
1P (Proved) Reserves	14,946,543	5,237,905	3,884,315	3,098,331	1P (Proved) Reserves	11,010,777	3,964,466	2,952,608	2,356,207
Probable Reserves	2,048,712	392,767	263,850	204,314	Probable Reserves	1,526,042	296,679	201,774	158,018
Total 2P (Proved+Probable) Reserves	16,995,255	5,630,673	4,148,165	3,302,645	Total 2P (Proved+Probable) Reserves	12,536,819	4,261,145	3,154,383	2,514,226
Possible Reserves	1,429,282	241,412	142,335	97,560	Possible Reserves	1,071,331	186,368	112,792	79,520
Total 3P (Proved+Probable+Possible) Reserves	18,424,537	5,872,084	4,290,500	3,400,205	Total 3P (Proved+Probable+Possible) Reserves	13,608,149	4,447,513	3,267,175	2,593,745

[19] 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	15,602,661	5,448,253	4,037,243	3,219,405	1P (Proved) Reserves	10,354,016	3,746,700	2,790,766	2,225,415
Probable Reserves	2,141,322	412,724	277,364	214,533	Probable Reserves	1,440,154	284,150	195,331	154,432
Total 2P (Proved+Probable) Reserves	17,743,982	5,860,977	4,314,608	3,433,938	Total 2P (Proved+Probable) Reserves	11,794,170	4,030,850	2,986,096	2,379,848
Possible Reserves	1,489,408	250,726	147,404	100,718	Possible Reserves	1,008,643	174,557	105,367	74,120
Total 3P (Proved+Probable+Possible) Reserves	19,233,391	6,111,703	4,462,012	3,534,656	Total 3P (Proved+Probable+Possible) Reserves	12,802,813	4,205,407	3,091,463	2,453,968

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	13,144,820	4,994,832	3,728,124	2,979,229	1P (Proved) Reserves	11,640,369	4,171,080	3,104,984	2,478,425
Probable Reserves	1,751,327	374,556	254,597	197,966	Probable Reserves	1,608,363	310,065	209,783	163,610
Total 2P (Proved+Probable) Reserves	14,896,146	5,369,388	3,982,721	3,177,195	Total 2P (Proved+Probable) Reserves	13,248,732	4,481,145	3,314,767	2,642,035
Possible Reserves	1,204,874	227,323	136,281	94,381	Possible Reserves	1,127,788	194,933	117,378	82,348
Total 3P (Proved+Probable+Possible) Reserves	16,101,020	5,596,710	4,119,002	3,271,576	Total 3P (Proved+Probable+Possible) Reserves	14,376,520	4,676,078	3,432,146	2,724,383
15% increase in the gas sales volume					**15% decrease in the gas sales volume**				
1P (Proved) Reserves	13,188,637	5,180,942	3,878,520	3,102,549	1P (Proved) Reserves	10,968,004	3,950,155	2,941,948	2,347,593
Probable Reserves	1,748,259	388,659	264,094	204,870	Probable Reserves	1,520,869	295,727	201,168	157,575
Total 2P (Proved+Probable) Reserves	14,936,896	5,569,601	4,142,614	3,307,419	Total 2P (Proved+Probable) Reserves	12,488,873	4,245,882	3,143,116	2,505,168
Possible Reserves	1,215,569	236,786	141,806	97,614	Possible Reserves	1,067,951	185,790	112,472	79,317
Total 3P (Proved+Probable+Possible) Reserves	16,152,465	5,806,387	4,284,420	3,405,033	Total 3P (Proved+Probable+Possible) Reserves	13,556,825	4,431,672	3,255,588	2,584,484

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[20]					**20% decrease in the gas sales volume**				
1P (Proved) Reserves	13,239,447	5,359,762	4,025,061	3,223,463	1P (Proved) Reserves	10,299,775	3,729,974	2,778,737	2,215,970
Probable Reserves	1,744,766	408,297	278,256	215,536	Probable Reserves	1,430,355	280,384	192,176	151,630
Total 2P (Proved+Probable) Reserves	14,984,213	5,768,059	4,303,317	3,438,999	Total 2P (Proved+Probable) Reserves	11,730,130	4,010,358	2,970,914	2,367,601
Possible Reserves	1,211,591	241,168	143,234	97,337	Possible Reserves	1,004,119	173,825	104,969	73,871
Total 3P (Proved+Probable+Possible) Reserves	16,195,804	6,009,226	4,446,551	3,536,337	Total 3P (Proved+Probable+Possible) Reserves	12,734,250	4,184,183	3,075,882	2,441,472

[20] Due to infrastructure restrictions, it is not possible to increase the gas quantities at this rate.

(d) Contingent resources in the Leviathan Reservoir

(1) Quantity Data

According to the report received by the Partnership from NSAI, the project relating to the contingent gas and condensate resources in the Leviathan Reservoir, is classified as a project at a 'development pending' maturity level, and the volume of the contingent resources attributed to the reservoir is as specified below:

Natural Gas[21] BCF						
Category	Total (100%) in the Petroleum Asset (Gross)			The Total Rate Attributed to the Holders of the Equity Interests of the Partnership (Net)[22]		
	Phase I – First Stage	Future Development	Total	Phase I – First Stage	Future Development	Total
1C - Low Estimate	2,057.6	0.0	2,057.6	727.7	0.0	727.7
2C - Best Estimate	3,922.7	1,736.7	5,659.4	1,387.3	614.2	2,001.5
3C - High Estimate	3,326.2	7,551.9	10,878.1	1,176.3	2,670.7	3,847.1

Condensate[23] 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)[24]		
	Phase I – First Stage	Future Development	Total	Phase I – First Stage	Future Development	Total
1C - Low Estimate	4.5	0.0	4.5	1.6	0.0	1.6
2C - Best Estimate	8.6	3.8	12.5	3.1	1.3	4.4
3C - High Estimate	7.3	16.6	23.9	2.6	5.9	8.5

[21] The amounts in the table may not add up due to rounding-off differences.
[22] It is clarified that the revenue figures for 2024 are unaudited.
[23] The amounts in the table may not add up due to rounding-off differences.
[24] It is clarified that the revenue figures for 2024 are unaudited.

(2) In view of the significant volume of contingent resources attributed to the Leviathan Project, the potential markets for these resources are the domestic market and/or the regional market and/or the international market. For details regarding the potential markets for the said resources and a review of the possibilities for export of the gas, see Section 7.12 of Chapter A to the Periodic Report. In addition, for details regarding gas export engagements and an examination of the possibility for the export of additional gas, see Sections 7.11.3(b), 7.11.3(c) and 7.12.2 of Chapter A of the Periodic Report, Section 6 of the update of Chapter A of the Q1 Report, Section 9 of the update of Chapter A of the Q2 Report and Section 7 of the update of Chapter A of the Q3 Report.

(3) The Resources Report states that reclassification of contingent resources in the Leviathan Project in the Phase I – First Stage category as reserves is contingent on approval for the drilling of additional wells, approval for future development, demonstration of the existence of a future market for the sale of natural gas and 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 said 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 said 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.

(4) Discounted Cash Flow figures

In accordance with the various assumptions, primarily as specified in Section 1(a)(3) above, set forth below is the estimated Discounted Cash Flow as of 31 December 2024, in Dollars in thousands, after levy and income tax, attributed to the Partnership's share, from the contingent resources in the Leviathan Reservoir, for each one of the contingent resource categories specified above[25]:

Total Discounted Cash Flow from the 1C - Low Estimate Contingent Resources as of 31 December 2024 (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%
31.12.2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2035	15	0.2	20,753	4,040	-	716	110,546	-	(94,548)	(44,249)	12,585	(62,885)	(37,676)	(29,428)	(23,117)	(14,495)	(9,271)
31.12.2036	59	0.8	84,643	16,476	-	2,920	-	-	65,246	30,535	5,441	29,270	16,701	12,742	9,782	5,867	3,596
31.12.2037	80	1.0	114,682	22,324	-	3,959	-	-	88,400	41,371	8,274	38,755	21,060	15,693	11,774	6,755	3,968
31.12.2038	120	1.5	171,164	33,318	-	5,911	-	-	131,935	61,746	13,601	56,588	29,287	21,316	15,629	8,576	4,828
31.12.2039	142	1.8	201,904	39,302	-	10,688	-	-	151,914	71,096	16,046	64,773	31,926	22,697	16,263	8,536	4,605
31.12.2040	183	2.4	260,347	50,678	-	8,999	-	-	200,670	93,913	22,011	84,745	39,781	27,624	19,343	9,712	5,021
31.12.2041	199	2.6	286,894	55,846	-	9,433	-	-	221,615	103,716	24,574	93,325	41,723	28,298	19,365	9,300	4,608
31.12.2042	235	3.0	341,697	66,513	-	2,516	-	-	272,667	127,608	30,821	114,238	48,641	32,223	21,550	9,899	4,700
31.12.2043	253	3.3	367,967	71,627	-	1,531	98,937	-	195,872	91,668	43,042	61,162	24,802	16,048	10,489	4,609	2,097
31.12.2044	290	3.7	421,975	82,140	-	1,763	-	-	338,073	158,218	36,548	143,306	55,344	34,978	22,341	9,390	4,095
31.12.2045	303	3.9	441,384	85,918	-	1,851	-	-	353,615	165,492	39,721	148,402	54,583	33,695	21,032	8,455	3,534

[25] 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 the 1C - Low Estimate Contingent Resources as of 31 December 2024 (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%
31.12.2046	336	4.3	488,950	95,177	-	2,060	209,483	-	182,230	85,284	65,794	31,152	10,912	6,580	4,014	1,543	618
31.12.2047	349	4.5	509,154	99,110	-	2,154	-	-	407,890	190,893	42,816	174,182	58,109	34,223	20,402	7,504	2,880
31.12.2048	383	4.9	558,644	108,743	-	2,374	110,546	-	336,981	157,707	58,294	120,980	38,439	22,111	12,882	4,532	1,667
31.12.2049	394	5.1	573,535	111,642	-	2,448	-	-	459,445	215,020	46,582	197,843	59,866	33,637	19,151	6,445	2,272
31.12.2050	423	5.4	616,583	120,021	-	2,644	197,874	-	296,044	138,548	69,823	87,672	25,266	13,866	7,715	2,484	839
31.12.2051	387	5.0	563,314	109,652	-	2,426	98,937	-	352,298	164,876	50,538	136,885	37,570	20,139	10,951	3,372	1,092
31.12.2052	303	3.9	441,960	86,030	-	1,907	98,937	-	255,086	119,380	36,367	99,339	25,966	13,595	7,225	2,128	660
31.12.2053	229	3.0	334,098	65,034	-	1,419	-	-	267,644	125,257	15,148	127,238	31,675	16,199	8,413	2,370	705
31.12.2054	165	2.1	240,853	46,883	-	992	-	-	192,977	90,313	7,150	95,514	22,646	11,311	5,741	1,547	441
31.12.2055	109	1.4	158,855	30,922	-	608	-	-	127,324	59,588	(883)	68,620	15,494	7,559	3,750	966	264
31.12.2056	60	0.8	88,100	17,149	-	295	-	-	70,656	33,067	(5,408)	42,997	9,247	4,406	2,136	527	138
31.12.2057	18	0.2	26,339	5,127	-	88	-	-	21,124	9,886	(9,060)	20,298	4,157	1,935	917	216	54
31.12.2058	(19)	(0.2)	(27,554)	(5,364)	-	(92)	-	-	(22,099)	(10,342)	(13,077)	1,321	258	117	54	12	3
31.12.2059	(50)	(0.6)	(72,449)	(14,103)	-	(242)	-	-	(58,104)	(27,193)	(19,121)	(11,790)	(2,190)	(973)	(440)	(95)	(22)
31.12.2060	(77)	(1.0)	(112,850)	(21,967)	-	(377)	-	-	(90,506)	(42,357)	(20,810)	(27,339)	(4,837)	(2,098)	(928)	(191)	(42)
31.12.2061	(100)	(1.3)	(145,378)	(28,299)	-	(486)	-	-	(116,593)	(54,565)	(20,589)	(41,438)	(6,982)	(2,958)	(1,278)	(252)	(53)
31.12.2062	(120)	(1.5)	(174,536)	(33,974)	-	(584)	-	25,300	(165,277)	(77,350)	(18,452)	(69,476)	(11,149)	(4,613)	(1,948)	(368)	(75)
31.12.2063	(136)	(1.7)	(198,075)	(38,556)	-	(662)	-	25,300	(184,156)	(86,185)	(19,624)	(78,347)	(11,974)	(4,839)	(1,997)	(361)	(70)
31.12.2064	(6)	(0.1)	(8,948)	(1,742)	-	(30)	-	25,300	(32,476)	-	(2,525)	(29,950)	(4,359)	(1,721)	(694)	(120)	(22)
Total	**4,527**	**58.3**	**6,574,001**	**1,279,669**	**-**	**67,226**	**925,259**	**75,899**	**4,225,948**	**1,992,942**	**515,626**	**1,717,380**	**624,286**	**384,363**	**240,515**	**98,863**	**43,129**

Total Discounted Cash Flow from the 2C - Best Estimate Contingent Resources as of 31 December 2024 (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%
31.12.2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2031	-	-	-	-	-	-	110,546	-	(110,546)	(51,735)	10,628	(69,438)	(50,567)	(43,395)	(37,372)	(27,994)	(21,229)
31.12.2032	38	0.5	52,548	10,229	-	1,817	-	-	40,502	18,955	2,413	19,134	13,270	11,123	9,362	6,708	4,875
31.12.2033	48	0.6	68,354	13,305	-	2,287	-	-	52,761	24,692	3,913	24,156	15,955	13,063	10,744	7,364	5,128
31.12.2034	81	1.0	115,595	22,501	-	3,828	-	-	89,266	41,776	8,380	39,109	24,603	19,674	15,814	10,367	6,919
31.12.2035	94	1.2	134,362	26,154	-	4,634	-	-	103,574	48,472	10,131	44,970	26,943	21,044	16,531	10,366	6,630
31.12.2036	129	1.7	184,328	35,881	-	6,360	-	-	142,087	66,497	14,843	60,747	34,662	26,444	20,301	12,176	7,463
31.12.2037	139	1.8	197,529	38,450	-	6,798	-	-	152,281	71,267	16,091	64,923	35,280	26,290	19,724	11,316	6,647
31.12.2038	170	2.2	241,930	47,093	-	8,265	-	-	186,572	87,315	20,286	78,970	40,870	29,747	21,810	11,968	6,738
31.12.2039	181	2.3	257,372	50,099	-	8,892	-	-	198,381	92,842	21,731	83,807	41,308	29,367	21,042	11,045	5,959
31.12.2040	214	2.8	305,122	59,394	-	10,547	98,937	-	136,244	63,762	35,746	36,736	17,245	11,975	8,385	4,210	2,177
31.12.2041	221	2.8	318,482	61,994	-	10,472	-	-	246,015	115,135	26,556	104,325	46,640	31,633	21,647	10,396	5,151
31.12.2042	250	3.2	362,712	70,604	-	4,757	-	-	287,350	134,480	32,885	119,986	51,088	33,844	22,634	10,397	4,937
31.12.2043	260	3.3	378,601	73,697	-	1,575	-	-	303,329	141,958	34,840	126,531	51,309	33,200	21,699	9,534	4,339
31.12.2044	291	3.7	424,008	82,536	-	1,771	-	-	339,701	158,980	39,290	141,431	54,620	34,521	22,049	9,267	4,041
31.12.2045	296	3.8	431,838	84,060	-	1,811	209,483	-	136,484	63,875	60,197	12,413	4,566	2,818	1,759	707	296
31.12.2046	324	4.2	471,557	91,791	-	1,986	-	-	377,780	176,801	39,131	161,847	56,694	34,184	20,853	8,019	3,212
31.12.2047	331	4.3	482,810	93,982	-	2,042	-	-	386,786	181,016	40,233	165,537	55,225	32,524	19,389	7,132	2,737
31.12.2048	361	4.6	525,952	102,380	-	2,235	110,546	-	310,792	145,451	55,089	110,252	35,030	20,151	11,740	4,130	1,519
31.12.2049	366	4.7	532,649	103,683	-	2,273	-	-	426,693	199,692	42,574	184,427	55,807	31,356	17,853	6,008	2,118
31.12.2050	391	5.0	570,103	110,974	-	2,444	98,937	-	357,748	167,426	56,893	133,429	38,452	21,102	11,742	3,780	1,277
31.12.2051	397	5.1	579,090	112,723	-	2,494	197,874	-	265,999	124,487	66,147	75,364	20,685	11,088	6,029	1,856	601
31.12.2052	425	5.5	619,967	120,680	-	2,683	-	-	496,604	232,411	46,577	217,616	56,883	29,782	15,827	4,661	1,446
31.12.2053	428	5.5	624,399	121,543	-	2,715	197,874	-	302,267	141,461	66,034	94,772	23,593	12,065	6,266	1,765	525
31.12.2054	453	5.8	659,587	128,393	-	2,882	-	-	528,313	247,250	45,906	235,156	55,754	27,849	14,134	3,809	1,085
31.12.2055	431	5.5	627,914	122,227	-	2,757	-	-	502,930	235,371	45,209	222,350	50,207	24,495	12,150	3,131	855
31.12.2056	394	5.1	574,711	111,871	-	2,536	-	-	460,304	215,422	42,403	202,479	43,543	20,750	10,058	2,480	649

Total Discounted Cash Flow from the 2C - Best Estimate Contingent Resources as of 31 December 2024 (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%
31.12.2057	359	4.6	523,773	101,956	-	2,323	-	-	419,494	196,323	37,409	185,762	38,046	17,709	8,389	1,978	496
31.12.2058	328	4.2	477,192	92,888	-	2,578	-	-	381,725	178,647	34,059	169,019	32,968	14,988	6,939	1,565	376
31.12.2059	297	3.8	432,531	84,195	-	3,742	-	-	344,595	161,270	27,554	155,770	28,937	12,850	5,813	1,254	289
31.12.2060	269	3.5	390,221	75,959	-	4,689	-	-	309,573	144,880	24,407	140,286	24,820	10,765	4,760	982	217
31.12.2061	241	3.1	350,457	68,218	-	4,905	-	-	277,333	129,792	23,875	123,666	20,837	8,828	3,814	753	159
31.12.2062	216	2.8	313,471	61,019	-	3,759	-	28,111	220,581	103,232	25,672	91,677	14,712	6,088	2,571	485	98
31.12.2063	192	2.5	278,884	54,286	-	2,266	-	28,111	194,221	90,895	24,722	78,604	12,013	4,855	2,004	362	70
31.12.2064	16	0.2	22,581	4,396	-	76	-	28,111	(10,001)	(419)	1,029	(10,611)	(1,544)	(610)	(246)	(42)	(8)
Total	**8,630**	**111.1**	**12,530,631**	**2,439,162**	**-**	**125,201**	**1,024,196**	**84,332**	**8,857,739**	**4,149,683**	**1,082,853**	**3,625,203**	**1,070,452**	**622,168**	**376,213**	**151,935**	**67,793**

Total Discounted Cash Flow from the 3C - High Estimate Contingent Resources as of 31 December 2024 (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%
31.12.2025	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2026	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2032	22	0.3	30,974	6,029	-	1,043	110,546	-	(86,645)	(40,550)	13,552	(59,647)	(41,369)	(34,676)	(29,184)	(20,910)	(15,196)
31.12.2033	30	0.4	41,774	8,132	-	1,395	-	-	32,248	15,092	1,403	15,753	10,405	8,519	7,007	4,802	3,344
31.12.2034	59	0.8	83,470	16,248	-	2,764	-	-	64,458	30,166	5,345	28,947	18,210	14,562	11,705	7,673	5,121
31.12.2035	68	0.9	97,497	18,978	-	3,363	-	-	75,156	35,173	6,654	33,330	19,968	15,597	12,252	7,682	4,914
31.12.2036	100	1.3	142,253	27,690	-	4,908	-	-	109,655	51,318	10,875	47,461	27,081	20,661	15,861	9,513	5,831
31.12.2037	106	1.4	150,625	29,320	-	5,077	-	-	116,228	54,395	11,679	50,154	27,255	20,310	15,237	8,741	5,135
31.12.2038	134	1.7	190,833	37,147	-	6,402	-	-	147,284	68,929	15,479	62,876	32,541	23,685	17,365	9,529	5,365
31.12.2039	142	1.8	202,646	39,446	-	6,985	98,937	-	57,278	26,806	26,084	4,388	2,163	1,538	1,102	578	312
31.12.2040	173	2.2	246,295	47,943	-	8,486	-	-	189,866	88,857	18,414	82,595	38,772	26,923	18,852	9,465	4,894
31.12.2041	177	2.3	255,245	49,685	-	8,393	-	-	197,167	92,274	19,307	85,586	38,263	25,951	17,759	8,529	4,226
31.12.2042	204	2.6	295,891	57,597	-	3,804	-	-	234,490	109,741	25,145	99,603	42,409	28,095	18,789	8,631	4,098
31.12.2043	211	2.7	307,814	59,918	-	1,280	-	-	246,616	115,416	27,900	103,299	41,889	27,104	17,715	7,784	3,542
31.12.2044	240	3.1	350,166	68,162	-	1,463	98,937	-	181,605	84,991	41,563	55,050	21,260	13,437	8,582	3,607	1,573
31.12.2045	244	3.1	355,329	69,167	-	1,490	-	-	284,672	133,227	30,281	121,164	44,565	27,511	17,172	6,903	2,885
31.12.2046	269	3.5	391,901	76,286	-	1,651	110,546	-	203,419	95,200	44,493	63,725	22,322	13,460	8,211	3,157	1,264
31.12.2047	275	3.5	400,582	77,976	-	1,695	-	-	320,912	150,187	32,173	138,552	46,222	27,222	16,228	5,969	2,291
31.12.2048	303	3.9	441,802	85,999	-	1,877	110,546	-	243,380	113,902	46,841	82,638	26,256	15,104	8,799	3,096	1,139
31.12.2049	305	3.9	444,703	86,564	-	1,898	98,937	-	257,304	120,418	44,603	92,283	27,924	15,690	8,933	3,006	1,060
31.12.2050	329	4.2	480,144	93,463	-	2,059	98,937	-	285,685	133,701	46,938	105,047	30,273	16,614	9,244	2,976	1,005
31.12.2051	335	4.3	487,693	94,932	-	2,101	98,937	-	291,723	136,526	45,401	109,795	30,135	16,153	8,784	2,705	876
31.12.2052	361	4.7	526,651	102,516	-	2,279	-	-	421,856	197,429	37,431	186,996	48,880	25,592	13,600	4,005	1,243
31.12.2053	363	4.7	528,420	102,860	-	2,298	197,874	-	225,388	105,482	56,627	63,280	15,753	8,056	4,184	1,179	350
31.12.2054	363	4.7	528,442	102,864	-	2,309	-	-	423,269	198,090	34,191	190,988	45,282	22,618	11,479	3,093	881
31.12.2055	343	4.4	500,122	97,352	-	2,196	-	-	400,575	187,469	32,551	180,554	40,769	19,891	9,866	2,543	694
31.12.2056	325	4.2	474,067	92,280	-	2,092	-	-	379,695	177,697	31,268	170,730	36,715	17,496	8,481	2,091	547

Total Discounted Cash Flow from the 3C - High Estimate Contingent Resources as of 31 December 2024 (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%
31.12.2057	307	4.0	447,583	87,125	-	3,113	-	-	357,346	167,238	29,805	160,304	32,832	15,282	7,239	1,707	428
31.12.2058	290	3.7	422,025	82,150	-	4,684	-	-	335,191	156,870	28,365	149,957	29,250	13,298	6,156	1,389	334
31.12.2059	274	3.5	397,488	77,373	-	6,548	-	-	313,566	146,749	24,895	141,922	26,364	11,707	5,297	1,143	263
31.12.2060	258	3.3	374,181	72,837	-	8,160	-	-	293,184	137,210	24,677	131,297	23,229	10,075	4,455	919	203
31.12.2061	244	3.1	353,432	68,798	-	9,009	-	-	275,626	128,993	24,804	121,829	20,528	8,696	3,758	742	157
31.12.2062	230	3.0	332,092	64,644	-	8,438	-	28,111	230,900	108,061	26,935	95,904	15,390	6,368	2,689	508	103
31.12.2063	216	2.8	312,030	60,739	-	7,485	-	28,111	215,696	100,946	27,350	87,401	13,358	5,399	2,228	402	78
31.12.2064	17	0.2	24,779	4,823	-	83	-	28,111	(8,238)	(3,856)	2,225	(6,607)	(962)	(380)	(153)	(26)	(5)
Total	**7,318**	**94.2**	**10,618,950**	**2,067,042**	**-**	**126,825**	**1,024,196**	**84,332**	**7,316,555**	**3,424,148**	**895,254**	**2,997,153**	**853,933**	**487,556**	**289,691**	**113,132**	**48,956**

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 and sold, the pace and duration of the natural gas sales from the project, operation costs, capital expenditures, abandonment expenses, royalty rates and the sale prices, in respect of which there is no certainty that they will materialize. It is noted that the quantities of natural gas and/or condensate that shall actually be produced and sold, the said expenses and the said income may be materially different from 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.

(e) Summary of the figures on the Discounted Cash Flow from the reserves and from the contingent resources classified at Phase 1A

Set forth below are tables summarizing the figures on the Discounted Cash Flow from the reserves and from the contingent resources which are presented in addition to the figures on the Discounted Cash Flows from the reserves and the contingent resources as stated in Sections 1(a)(3) and 1(b)(4) above[26].

Total Discounted Cash Flow from the 1P + 1C - Proved Reserves and Low Estimate Contingent Resources as of 31 December 2024 (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%**
31.12.2025	853	11.0	1,062,883	159,875	-	141,955	282,347	-	478,707	-	116,337	362,370	353,637	349,501	345,506	337,912	330,797
31.12.2026	1,015	13.1	1,278,420	234,713	-	135,579	83,736	-	824,392	-	146,354	678,038	630,188	608,333	587,712	549,803	515,801
31.12.2027	1,016	13.1	1,337,367	260,326	-	151,307	22,908	-	902,826	102,220	126,677	673,929	596,542	562,462	531,046	475,192	427,229
31.12.2028	1,027	13.2	1,389,559	270,486	-	114,015	-	-	1,005,058	303,612	96,661	604,785	509,845	469,539	433,238	370,816	319,497
31.12.2029	1,016	13.1	1,391,770	270,916	-	134,308	1,560	-	984,985	381,930	110,563	492,492	395,410	355,681	320,724	262,578	216,812
31.12.2030	1,025	13.2	1,419,813	276,375	-	113,834	-	-	1,029,604	467,398	114,908	447,298	342,023	300,504	264,812	207,376	164,097
31.12.2031	1,016	13.1	1,431,699	278,689	-	111,819	-	-	1,041,191	487,278	113,401	440,513	320,795	275,298	237,086	177,592	134,673
31.12.2032	1,027	13.2	1,470,828	286,305	-	111,292	-	-	1,073,231	502,272	117,162	453,797	314,733	263,814	222,033	159,085	115,612
31.12.2033	1,016	13.1	1,469,808	286,107	-	110,353	-	-	1,073,348	502,327	118,377	452,644	298,984	244,785	201,335	137,983	96,098
31.12.2034	1,025	13.2	1,496,055	291,216	-	129,520	-	-	1,075,318	503,249	119,703	452,367	284,572	227,567	182,919	119,912	80,033
31.12.2035	1,016	13.1	1,474,177	286,957	-	112,293	110,546	-	964,381	451,330	135,406	377,645	226,254	176,724	138,823	87,047	55,678
31.12.2036	1,027	13.2	1,491,834	290,394	-	111,324	-	-	1,090,116	510,174	128,024	451,918	257,859	196,726	151,023	90,580	55,523
31.12.2037	1,016	13.1	1,477,075	287,522	-	108,374	-	-	1,081,180	505,992	127,188	447,999	243,451	181,414	136,103	78,083	45,868
31.12.2038	1,025	13.2	1,489,854	290,009	-	108,285	-	-	1,091,560	510,850	130,966	449,744	232,761	169,415	124,212	68,162	38,372
31.12.2039	1,016	13.1	1,472,050	286,543	-	137,488	-	-	1,048,018	490,472	125,667	431,879	212,871	151,335	108,435	56,917	30,707
31.12.2040	1,027	13.2	1,472,395	286,610	-	112,336	-	-	1,073,449	502,374	128,805	442,270	207,612	144,164	100,949	50,684	26,205
31.12.2041	1,016	13.1	1,473,826	286,889	-	93,411	-	-	1,093,526	511,770	131,261	450,495	201,403	136,600	93,478	44,893	22,243
31.12.2042	1,025	13.2	1,490,009	290,039	-	83,905	-	-	1,116,065	522,318	134,019	459,727	195,744	129,674	86,722	39,837	18,916
31.12.2043	1,016	13.1	1,477,899	287,682	-	82,789	98,937	-	1,008,491	471,974	142,474	394,043	159,787	103,392	67,574	29,692	13,511

[26] 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 the 1P + 1C - Proved Reserves and Low Estimate Contingent Resources as of 31 December 2024 (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%
31.12.2044	1,027	13.2	1,494,604	290,934	-	103,501	-	-	1,100,169	514,879	129,799	455,491	175,909	111,177	71,011	29,845	13,015
31.12.2045	1,016	13.1	1,477,899	287,682	-	82,860	-	-	1,107,357	518,243	131,949	457,164	168,148	103,800	64,792	26,048	10,886
31.12.2046	1,025	13.2	1,490,428	290,121	-	82,949	209,483	-	907,875	424,885	154,584	328,405	115,038	69,363	42,312	16,271	6,516
31.12.2047	1,016	13.1	1,478,117	287,724	-	82,934	-	-	1,107,458	518,290	128,415	460,753	153,712	90,527	53,968	19,850	7,619
31.12.2048	1,027	13.2	1,497,255	291,450	-	83,048	110,546	-	1,012,211	473,715	140,915	397,582	126,322	72,665	42,335	14,895	5,479
31.12.2049	1,016	13.1	1,480,520	288,192	-	103,623	-	-	1,088,705	509,514	123,578	455,613	137,866	77,462	44,104	14,842	5,232
31.12.2050	1,025	13.2	1,493,071	290,635	-	83,110	197,874	-	921,452	431,240	146,348	343,864	99,097	54,384	30,260	9,741	3,291
31.12.2051	968	12.5	1,410,436	274,550	-	82,795	98,937	-	954,154	446,544	124,181	383,429	105,237	56,411	30,675	9,445	3,058
31.12.2052	865	11.1	1,260,844	245,431	-	82,187	98,937	-	834,289	390,447	107,238	336,603	87,986	46,067	24,480	7,210	2,237
31.12.2053	773	9.9	1,125,874	219,158	-	81,638	-	-	825,077	386,136	83,356	355,585	88,522	45,269	23,510	6,623	1,969
31.12.2054	691	8.9	1,006,651	195,951	-	101,760	-	-	708,940	331,784	70,283	306,873	72,757	36,342	18,445	4,970	1,416
31.12.2055	617	7.9	898,675	174,932	-	80,713	-	-	643,029	300,938	62,218	279,873	63,196	30,832	15,293	3,942	1,076
31.12.2056	551	7.1	803,071	156,323	-	80,347	-	-	566,401	265,076	55,251	246,074	52,918	25,217	12,224	3,014	789
31.12.2057	492	6.3	717,590	139,683	-	80,092	-	-	497,814	232,977	49,268	215,569	44,150	20,550	9,735	2,296	576
31.12.2058	440	5.7	641,107	124,795	-	79,869	-	-	436,443	204,255	43,030	189,158	36,896	16,774	7,766	1,752	421
31.12.2059	394	5.1	573,622	111,659	-	100,283	-	-	361,681	169,266	29,552	162,862	30,254	13,435	6,078	1,311	302
31.12.2060	351	4.5	511,761	99,617	-	79,502	-	-	332,642	155,676	28,274	148,691	26,307	11,410	5,045	1,041	230
31.12.2061	314	4.0	457,773	89,108	-	79,355	-	-	289,309	135,397	26,385	127,527	21,488	9,103	3,933	776	164
31.12.2062	280	3.6	408,284	79,475	-	79,225	-	61,728	187,856	87,917	30,444	69,495	11,152	4,615	1,949	368	75
31.12.2063	251	3.2	365,543	71,155	-	79,117	-	61,728	153,543	71,858	27,384	54,301	8,299	3,354	1,384	250	49
31.12.2064	26	0.3	37,362	7,273	-	14,582	-	61,728	(46,220)	-	-	(46,220)	(6,728)	(2,656)	(1,071)	(185)	(34)
Total	**33,383**	**429.7**	**47,697,804**	**9,223,502**	**-**	**3,927,678**	**1,315,809**	**185,184**	**33,045,630**	**14,296,579**	**4,056,404**	**14,692,647**	**7,602,997**	**5,943,028**	**4,841,956**	**3,518,447**	**2,772,035**

Total Discounted Cash Flow from the 2P + 2C - Proved + Probable Reserves and Best Estimate Contingent Resources as of 31 December 2024 (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%
31.12.2025	897	11.6	1,118,624	168,259	-	144,349	282,347	-	523,669	-	126,678	396,991	387,423	382,892	378,516	370,196	362,401
31.12.2026	1,105	14.2	1,392,801	260,847	-	136,495	83,736	-	911,723	-	166,440	745,283	692,687	668,665	645,999	604,330	566,956
31.12.2027	1,106	14.2	1,458,715	283,948	-	151,624	22,908	-	1,000,236	160,752	135,619	703,865	623,040	587,446	554,635	496,301	446,207
31.12.2028	1,119	14.4	1,514,040	294,717	-	115,374	-	-	1,103,949	365,162	105,250	633,537	534,084	491,861	453,835	388,445	334,686
31.12.2029	1,106	14.2	1,516,343	295,165	-	135,599	1,560	-	1,084,019	455,797	116,352	511,870	410,968	369,676	333,344	272,910	225,343
31.12.2030	1,116	14.4	1,546,738	301,082	-	115,152	-	-	1,130,504	528,470	124,069	477,966	365,474	321,108	282,968	221,595	175,348
31.12.2031	1,106	14.2	1,559,359	303,539	-	113,062	110,546	-	1,032,213	483,076	136,457	412,681	300,527	257,905	222,107	166,371	126,164
31.12.2032	1,119	14.4	1,601,578	311,757	-	112,586	-	-	1,177,235	550,946	127,345	498,944	346,044	290,060	244,122	174,911	127,114
31.12.2033	1,106	14.2	1,600,445	311,536	-	111,574	-	-	1,177,335	550,993	128,558	497,784	328,800	269,196	221,413	151,743	105,682
31.12.2034	1,116	14.4	1,628,817	317,059	-	130,951	-	-	1,180,807	552,618	130,068	498,121	313,355	250,585	201,421	132,040	88,128
31.12.2035	1,106	14.2	1,606,234	312,663	-	113,071	-	-	1,180,500	552,474	135,153	492,873	295,289	230,646	181,181	113,608	72,666
31.12.2036	1,119	14.4	1,625,357	316,385	-	112,150	-	-	1,196,821	560,112	141,080	495,629	282,800	215,754	165,631	99,342	60,894
31.12.2037	1,106	14.2	1,609,089	313,219	-	109,215	-	-	1,186,655	555,355	140,094	491,206	266,930	198,911	149,230	85,613	50,292
31.12.2038	1,116	14.4	1,623,007	315,928	-	109,107	-	-	1,197,972	560,651	143,987	493,334	255,321	185,835	136,251	74,769	42,092
31.12.2039	1,106	14.2	1,604,348	312,296	-	134,227	-	-	1,157,825	541,862	139,103	476,860	235,042	167,097	119,728	62,845	33,905
31.12.2040	1,119	14.4	1,604,608	312,347	-	113,832	98,937	-	1,079,492	505,202	151,162	423,128	198,627	137,924	96,580	48,490	25,070
31.12.2041	1,106	14.2	1,604,652	312,355	-	95,608	-	-	1,196,689	560,050	142,880	493,758	220,745	149,718	102,455	49,204	24,379
31.12.2042	1,116	14.4	1,621,760	315,685	-	86,606	-	-	1,219,469	570,712	146,939	501,819	213,665	141,546	94,662	43,485	20,648
31.12.2043	1,106	14.2	1,609,355	313,271	-	83,336	-	-	1,212,748	567,566	146,116	499,066	202,374	130,949	85,584	37,605	17,112
31.12.2044	1,119	14.4	1,627,546	316,812	-	104,057	-	-	1,206,678	564,725	145,374	496,579	191,777	121,206	77,416	32,537	14,189
31.12.2045	1,106	14.2	1,609,355	313,271	-	83,412	209,483	-	1,003,190	469,493	166,247	367,450	135,151	83,431	52,077	20,936	8,749
31.12.2046	1,116	14.4	1,622,998	315,926	-	83,508	-	-	1,223,564	572,628	142,622	508,314	178,058	107,362	65,492	25,184	10,086
31.12.2047	1,106	14.2	1,609,585	313,315	-	83,491	-	-	1,212,779	567,581	141,302	503,896	168,106	99,004	59,021	21,709	8,332
31.12.2048	1,119	14.4	1,630,344	317,356	-	83,614	110,546	-	1,118,828	523,612	153,960	441,256	140,198	80,648	46,985	16,531	6,080
31.12.2049	1,106	14.2	1,612,122	313,809	-	104,185	-	-	1,194,128	558,852	136,477	498,799	150,934	84,804	48,284	16,249	5,728
31.12.2050	1,116	14.4	1,625,789	316,470	-	83,679	98,937	-	1,126,703	527,297	150,983	448,423	129,229	70,921	39,462	12,703	4,291
31.12.2051	1,106	14.2	1,612,122	313,809	-	83,663	197,874	-	1,016,775	475,851	158,012	382,913	105,095	56,335	30,633	9,432	3,053
31.12.2052	1,119	14.4	1,630,344	317,356	-	83,786	-	-	1,229,202	575,266	136,218	517,717	135,328	70,853	37,653	11,089	3,440
31.12.2053	1,106	14.2	1,612,122	313,809	-	83,753	197,874	-	1,016,686	475,809	153,450	387,427	96,448	49,323	25,615	7,216	2,145

Total Discounted Cash Flow from the 2P + 2C - Proved + Probable Reserves and Best Estimate Contingent Resources as of 31 December 2024 (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%
31.12.2054	1,116	14.4	1,625,789	316,470	-	104,465	-	-	1,204,854	563,872	128,687	512,295	121,461	60,669	30,792	8,297	2,364
31.12.2055	1,079	13.9	1,572,594	306,115	-	83,672	-	-	1,182,807	553,554	128,399	500,854	113,094	55,176	27,367	7,054	1,926
31.12.2056	1,029	13.2	1,499,003	291,790	-	83,394	-	-	1,123,818	525,947	123,590	474,281	101,994	48,604	23,560	5,808	1,520
31.12.2057	980	12.6	1,427,675	277,906	-	83,125	-	-	1,066,645	499,190	116,594	450,861	92,340	42,980	20,360	4,801	1,204
31.12.2058	934	12.0	1,360,705	264,869	-	83,323	-	-	1,012,513	473,856	111,242	427,415	83,370	37,902	17,547	3,958	951
31.12.2059	890	11.5	1,296,789	252,428	-	105,041	-	-	939,320	439,602	97,633	402,085	74,694	33,169	15,006	3,238	746
31.12.2060	848	10.9	1,235,223	240,444	-	85,329	-	-	909,450	425,623	95,116	388,712	68,771	29,828	13,188	2,722	601
31.12.2061	809	10.4	1,177,335	229,175	-	85,497	-	-	862,662	403,726	92,804	366,132	61,692	26,135	11,293	2,229	472
31.12.2062	771	9.9	1,122,226	218,448	-	84,324	-	64,539	754,915	353,300	96,740	304,875	48,924	20,244	8,549	1,614	327
31.12.2063	734	9.5	1,069,515	208,188	-	82,805	-	64,539	713,984	334,145	94,007	285,833	43,684	17,656	7,286	1,316	256
31.12.2064	60	0.8	87,145	16,963	-	14,748	-	64,539	(9,105)	-	6,825	(15,930)	(2,319)	(915)	(369)	(64)	(12)
Total	**41,265**	**531.1**	**59,112,194**	**11,446,786**	**-**	**3,996,787**	**1,414,746**	**193,617**	**42,060,258**	**18,505,724**	**5,159,630**	**18,394,904**	**8,711,227**	**6,643,108**	**5,326,879**	**3,808,363**	**2,981,537**

Total Discounted Cash Flow from the 3P + 3C - Proved + Probable + Possible Reserves and High Estimate Contingent Resources as of 31 December 2024 (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%
31.12.2025	915	11.8	1,141,510	171,701	-	142,983	282,347	-	544,480	-	131,465	413,015	403,061	398,347	393,794	385,138	377,029
31.12.2026	1,127	14.5	1,423,465	266,590	-	130,881	83,736	-	942,259	-	173,464	768,795	714,540	689,760	666,379	623,396	584,842
31.12.2027	1,129	14.5	1,492,598	290,543	-	143,060	22,908	-	1,036,087	190,115	137,111	708,861	627,462	591,616	558,572	499,823	449,374
31.12.2028	1,142	14.7	1,546,387	301,013	-	113,384	-	-	1,131,990	385,197	107,091	639,702	539,281	496,647	458,251	392,225	337,943
31.12.2029	1,129	14.5	1,548,854	301,494	-	133,576	1,560	-	1,112,224	478,574	117,600	516,049	414,323	372,695	336,066	275,138	227,183
31.12.2030	1,138	14.7	1,579,985	307,554	-	113,126	-	-	1,159,306	542,555	127,453	489,297	374,138	328,720	289,676	226,848	179,505
31.12.2031	1,129	14.5	1,593,130	310,112	-	111,054	-	-	1,171,963	548,479	129,402	494,082	359,806	308,776	265,917	199,188	151,050
31.12.2032	1,142	14.7	1,636,516	318,558	-	110,620	110,546	-	1,096,792	513,299	144,199	439,294	304,674	255,383	214,937	154,000	111,917
31.12.2033	1,129	14.5	1,635,390	318,338	-	109,612	-	-	1,207,439	565,082	132,242	510,116	336,945	275,865	226,898	155,502	108,300
31.12.2034	1,138	14.7	1,664,195	323,946	-	129,157	-	-	1,211,093	566,791	133,774	510,528	321,160	256,826	206,438	135,329	90,323
31.12.2035	1,129	14.5	1,641,725	319,572	-	110,518	-	-	1,211,636	567,046	138,963	505,627	302,930	236,615	185,869	116,547	74,546
31.12.2036	1,142	14.7	1,661,223	323,367	-	109,606	-	-	1,228,249	574,821	144,926	508,503	290,146	221,358	169,933	101,922	62,475
31.12.2037	1,129	14.5	1,644,537	320,119	-	106,723	-	-	1,217,695	569,881	143,892	503,922	273,840	204,060	153,093	87,829	51,594
31.12.2038	1,138	14.7	1,658,777	322,891	-	106,566	-	-	1,229,320	575,322	147,823	506,176	261,966	190,672	139,798	76,715	43,187
31.12.2039	1,129	14.5	1,640,002	319,236	-	131,339	98,937	-	1,090,490	510,349	152,481	427,659	210,792	149,856	107,375	56,361	30,407
31.12.2040	1,142	14.7	1,639,164	319,073	-	111,953	-	-	1,208,138	565,408	143,010	499,720	234,581	162,890	114,062	57,268	29,609
31.12.2041	1,129	14.5	1,637,844	318,816	-	94,595	-	-	1,224,434	573,035	145,004	506,395	226,395	153,550	105,078	50,463	25,003
31.12.2042	1,138	14.7	1,655,050	322,165	-	86,067	-	-	1,246,817	583,511	149,014	514,293	218,977	145,065	97,015	44,565	21,161
31.12.2043	1,129	14.5	1,642,109	319,646	-	83,473	-	-	1,238,990	579,847	149,327	509,816	206,734	133,769	87,428	38,415	17,481
31.12.2044	1,142	14.7	1,660,671	323,260	-	104,195	98,937	-	1,134,279	530,843	158,133	445,304	171,975	108,690	69,422	29,178	12,724
31.12.2045	1,129	14.5	1,642,109	319,646	-	83,549	-	-	1,238,914	579,812	147,042	512,060	188,339	116,264	72,572	29,175	12,193
31.12.2046	1,138	14.7	1,656,031	322,356	-	83,648	110,546	-	1,139,481	533,277	159,030	447,174	156,641	94,448	57,615	22,155	8,873
31.12.2047	1,129	14.5	1,642,352	319,694	-	83,630	-	-	1,239,029	579,865	144,514	514,649	171,693	101,116	60,280	22,172	8,510
31.12.2048	1,142	14.7	1,663,617	323,833	-	83,755	110,546	-	1,145,483	536,086	157,222	452,175	143,667	82,643	48,148	16,940	6,231
31.12.2049	1,129	14.5	1,645,022	320,213	-	104,325	98,937	-	1,121,547	524,884	150,352	446,311	135,052	75,881	43,203	14,539	5,125
31.12.2050	1,138	14.7	1,658,968	322,928	-	83,821	98,937	-	1,153,282	539,736	153,097	460,449	132,695	72,822	40,520	13,043	4,406
31.12.2051	1,129	14.5	1,645,022	320,213	-	83,805	98,937	-	1,142,067	534,487	149,449	458,130	125,740	67,401	36,651	11,285	3,653
31.12.2052	1,142	14.7	1,663,617	323,833	-	83,930	-	-	1,255,853	587,739	139,479	528,635	138,182	72,347	38,447	11,323	3,513
31.12.2053	1,129	14.5	1,645,022	320,213	-	83,896	197,874	-	1,043,039	488,142	156,674	398,222	99,136	50,697	26,329	7,417	2,205

Total Discounted Cash Flow from the 3P + 3C - Proved + Probable + Possible Reserves and High Estimate Contingent Resources as of 31 December 2024 (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%
31.12.2054	1,115	14.4	1,624,681	316,254	-	104,461	-	-	1,203,966	563,456	129,717	510,793	121,105	60,492	30,702	8,273	2,357
31.12.2055	1,082	13.9	1,577,129	306,998	-	83,692	-	-	1,186,439	555,254	128,710	502,476	113,460	55,355	27,456	7,077	1,932
31.12.2056	1,051	13.5	1,531,842	298,182	-	83,539	-	-	1,150,120	538,256	125,537	486,327	104,584	49,838	24,158	5,956	1,559
31.12.2057	1,020	13.1	1,486,126	289,283	-	84,511	-	-	1,112,331	520,571	122,185	469,576	96,173	44,764	21,205	5,001	1,254
31.12.2058	991	12.8	1,442,466	280,785	-	86,039	-	-	1,075,642	503,401	118,967	453,275	88,414	40,196	18,608	4,197	1,009
31.12.2059	962	12.4	1,399,828	272,485	-	108,466	-	-	1,018,876	476,834	108,505	433,537	80,537	35,763	16,180	3,491	804
31.12.2060	934	12.0	1,358,420	264,425	-	89,427	-	-	1,004,568	470,138	109,030	425,400	75,262	32,644	14,433	2,979	657
31.12.2061	907	11.7	1,319,571	256,862	-	90,232	-	-	972,476	455,119	107,379	409,979	69,080	29,265	12,645	2,496	528
31.12.2062	881	11.3	1,281,260	249,405	-	89,622	-	64,539	877,695	410,761	111,763	355,171	56,995	23,584	9,959	1,880	381
31.12.2063	855	11.0	1,244,229	242,197	-	88,630	-	64,539	848,864	397,268	110,511	341,085	52,128	21,069	8,694	1,570	305
31.12.2064	70	0.9	101,708	19,798	-	14,797	-	64,539	2,574	1,205	9,234	(7,865)	(1,145)	(452)	(182)	(31)	(6)
Total	**42,537**	**547.5**	**60,972,150**	**11,807,599**	**-**	**3,980,264**	**1,414,746**	**193,617**	**43,575,924**	**19,216,446**	**5,344,767**	**19,014,711**	**8,941,463**	**6,807,299**	**5,453,623**	**3,896,791**	**3,051,143**

(f) <u>Set forth below is an analysis of sensitivity to the main parameters comprising the Discounted Cash Flow of reserves and contingent resources (the gas price and the gas sales volume) as of 31 December 2024 (Dollars in thousands) which was performed by the Partnership</u>[27]

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**				
Proved Reserves and Low Estimate Contingent Resources	16,218,017	5,296,741	3,841,500	3,024,704	Proved Reserves and Low Estimate Contingent Resources	13,174,484	4,390,804	3,198,060	2,521,378
Proved+Probable Reserves and Best Estimate Contingent Resources	20,283,435	5,825,794	4,155,992	3,250,694	Proved+Probable Reserves and Best Estimate Contingent Resources	16,502,076	4,822,055	3,454,637	2,706,310
Proved+Probable+Possible Reserves and High Estimate Contingent Resources	20,958,062	5,961,609	4,249,927	3,324,136	Proved+Probable+Possible Reserves and High Estimate Contingent Resources	17,064,536	4,939,511	3,537,476	2,772,069
15% increase in the gas price					**15% decrease in the gas price**				
Proved Reserves and Low Estimate Contingent Resources	16,981,511	5,523,810	4,002,404	3,150,221	Proved Reserves and Low Estimate Contingent Resources	12,410,569	4,159,591	3,032,245	2,390,576
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%**

[27] With respect to a sensitivity analysis for the Discounted Cash Flow to the variable of the gas sales volume, it is noted that no changes were made in the drilling forecast for adjustment to the number of required wells, and no costs were included for additional wells which may be required for adjustment to the increase in gas sale quantities.

15% increase in the gas price					15% decrease in the gas price				
Proved+Probable Reserves and Best Estimate Contingent Resources	21,227,885	6,075,020	4,329,343	3,384,643	Proved+Probable Reserves and Best Estimate Contingent Resources	15,556,727	4,569,340	3,277,136	2,567,854
Proved+Probable+Possible Reserves and High Estimate Contingent Resources	21,933,659	6,216,801	4,426,774	3,460,191	Proved+Probable+Possible Reserves and High Estimate Contingent Resources	16,089,948	4,682,101	3,357,152	2,631,669

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**				
Proved Reserves and Low Estimate Contingent Resources	17,743,491	5,749,288	4,161,741	3,274,215	Proved Reserves and Low Estimate Contingent Resources	11,647,946	3,926,695	2,863,993	2,256,863
Proved+Probable Reserves and Best Estimate Contingent Resources	22,177,994	6,328,011	4,505,529	3,520,670	Proved+Probable Reserves and Best Estimate Contingent Resources	14,613,089	4,316,734	3,099,392	2,428,959
Proved+Probable+Possible Reserves and High Estimate Contingent Resources	22,913,169	6,474,762	4,606,000	3,598,319	Proved+Probable+Possible Reserves and High Estimate Contingent Resources	15,112,972	4,421,630	3,173,722	2,488,213

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**				
Proved Reserves and Low Estimate Contingent Resources	14,867,753	5,251,215	3,836,117	3,027,255	Proved Reserves and Low Estimate Contingent Resources	13,141,769	4,380,709	3,190,762	2,515,591
Proved+Probable Reserves and Best Estimate Contingent Resources	18,488,206	5,780,426	4,152,620	3,254,344	Proved+Probable Reserves and Best Estimate Contingent Resources	16,461,975	4,811,010	3,446,800	2,700,157
Proved+Probable+Possible Reserves and High Estimate Contingent Resources	19,112,257	5,916,185	4,246,742	3,327,900	Proved+Probable+Possible Reserves and High Estimate Contingent Resources	17,023,220	4,928,265	3,529,515	2,765,827
15% increase in the gas sales volume					**15% decrease in the gas sales volume**				
Proved Reserves and Low Estimate Contingent Resources	14,884,177	5,440,411	3,989,344	3,152,419	Proved Reserves and Low Estimate Contingent Resources	12,361,439	4,144,343	3,021,184	2,381,777
Proved+Probable Reserves and Best Estimate Contingent Resources	18,538,236	5,998,575	4,321,680	3,389,329	Proved+Probable Reserves and Best Estimate Contingent Resources	15,496,541	4,552,672	3,265,268	2,558,506
Proved+Probable+Possible Reserves and High Estimate Contingent Resources	19,096,527	6,138,394	4,419,114	3,465,020	Proved+Probable+Possible Reserves and High Estimate Contingent Resources	16,027,861	4,665,097	3,345,073	2,622,172

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%[28] increase in the gas sales volume					**20% decrease in the gas sales volume**				
Proved Reserves and Low Estimate Contingent Resources	14,989,377	5,626,774	4,139,714	3,275,385	Proved Reserves and Low Estimate Contingent Resources	11,585,268	3,908,726	2,851,433	2,247,174
Proved+Probable Reserves and Best Estimate Contingent Resources	18,507,103	6,210,775	4,490,631	3,525,478	Proved+Probable Reserves and Best Estimate Contingent Resources	14,532,875	4,294,399	3,083,426	2,416,340
Proved+Probable+Possible Reserves and High Estimate Contingent Resources	19,133,174	6,354,538	4,588,269	3,599,998	Proved+Probable+Possible Reserves and High Estimate Contingent Resources	15,030,248	4,398,861	3,157,487	2,475,405

[28] With respect to a sensitivity analysis for the Discounted Cash Flow to the variable of the gas sales volume, it is noted that no costs were included for additional wells which may be required for adjustment to the increase in gas sale quantities.

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 an update to the mapping and model of the reservoir, based, *inter alia*, on reprocessing of the seismic surveys and on production data. In addition, in 2024, approx. 400 BCF of natural gas and approx. 921 thousand barrels of condensate were produced.

The table below presents the main differences between the current estimates and the ones included in the previous resources report:

Reserves/Resources category	The difference between the estimates according to the resources report and the estimates included in the previous resources report (in terms of BCF and 100% of the petroleum asset)		
	1C/1P	2C/2P	3C/3P
Reserves	-355.6	-337.4	153.0
Contingent resources – Phase 1A (Phase I – First Stage)	7.3	780.4	379.2
Contingent resources – Future development	0.0	-1,423.8	-48.1
Quantities produced	400.3	400.3	400.3
Total reserves + contingent resources + quantities produced	52.0	-580.6	884.3

3. Production data

Below is a table which includes data on natural gas and condensate production in 2023 and 2024 in the Leviathan Project:[29,30,31]

	Y2023	Q4/2024		Y2024	
	Natural Gas	Natural Gas	Condensate	Natural Gas	Condensate
Total output (attributed to the holders of the Partnership's equity interests) in the period (in MMCF for natural gas and thousands of barrels for condensate, as applicable)	175,605.33	43,831.83	61.69	179,395.53	254.55

[29] 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.
[30] The figures presented in the table with respect to the production of condensate, do not include additional quantities of condensate which were produced for no consideration. The costs and expenses in connection with such additional quantities of condensate were attributed to the natural gas production costs.
[31] It is clarified that the production data for 2024 are based on unaudited financial data.

		Y2023	Q4/2024		Y2024	
		Natural Gas	Natural Gas	Condensate	Natural Gas	Condensate
Average price per output unit (attributed to the holders of the Partnership's equity interests) (Dollars per MCF and per barrel, as applicable)		6.23	5.94	61.63	6.24	65.87
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)	The State	0.67	0.62	6.45	0.66	6.96
	Third parties	0.16	0.15	1.55	0.16	1.67
	Interested parties	0.08	0.07	0.77	0.08	0.84
Average production costs per output unit (attributed to the holders of the Partnership's equity interests) (Dollars per MCF and per barrel, as applicable)[32,33]		0.84	0.92	6.01	0.93	5.71
Average net revenues per output unit (attributed to the holders of the Partnership's equity interests) (Dollars per MCF and per barrel, as applicable)		4.48	4.18	46.85	4.41	50.69
Depletion rate in the reported period relative to the total quantities of gas in the project (in %)		2.49	0.64		2.61	

[32] 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.

[33] The average production costs per natural gas output unit include costs for the transmission of natural gas via the INGL transmission system to the EMG terminal in Ashkelon, to the terminal of FAJR on the Jordanian border, and costs of transmission via the Jordanian transmission system (FAJR) to the delivery point in Aqaba in Jordan, for the supply of the gas to Egypt in the sum of approx. $153.9 million, approx. $158.5 million, and approx. $33.2 million (100%) in 2023, 2024 and Q4/2024, respectively. In addition, the average production costs per output unit of condensate, include costs for transporting the condensate through the Europe-Asia pipeline (EAPC), in the sum of approx. $1.8 million and approx. $0.4 million (100%) in 2024 and in Q4/2024, respectively.

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 2024, and NSAI's consent to its inclusion herein is attached to this chapter as **Annex A**.

5. Management declaration

(1) Date of the declaration: 4 February 2025;

(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 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

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

February 4, 2025

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 February 4, 2025, 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, 2024, to the NewMed interest in certain gas properties located in Leviathan Field, Leases I/14 and I/15, offshore Israel. The February 4 report also sets forth our estimates of the contingent resources and cash flow, as of December 31, 2024, to the NewMed 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 AND CASH FLOW

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, 2024

BASED ON PRICE AND COST PARAMETERS

specified by

NEWMED ENERGY LIMITED PARTNERSHIP

NETHERLAND, SEWELL & ASSOCIATES, INC.

WORLDWIDE PETROLEUM CONSULTANTS

ENGINEERING • GEOLOGY
GEOPHYSICS • PETROPHYSICS

February 4, 2025

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, 2024, 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 and cash flow, as of December 31, 2024, to the NewMed interest in these properties. It is our understanding that NewMed owns a direct working interest in these properties. We completed our evaluation on or about the date of this letter. For the reserves and the Phase I – First Stage contingent resources, 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, 2024, exchange rate was 3.64 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, 2024, to be:

Category	Gas Reserves (BCF) Gross (100%)	Gas Reserves (BCF) Working Interest	Condensate Reserves (MMBBL) Gross (100%)	Condensate Reserves (MMBBL) Working Interest
Proved (1P)	13,116.6	5,947.0	28.9	13.1
Probable	1,717.4	778.7	3.8	1.7
Proved + Probable (2P)	14,834.0	6,725.7	32.6	14.8
Possible	1,174.8	532.7	2.6	1.2
Proved + Probable + Possible (3P)	16,008.8	7,258.4	35.2	16.0

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, 2024, 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)	12,975.3	6,978.7	4,601.4	3,419.6	2,728.9
Probable	1,794.4	662.1	349.2	236.8	184.8
Proved + Probable (2P)	14,769.7	7,640.8	4,950.7	3,656.4	2,913.7
Possible	1,247.9	446.8	213.3	127.2	88.4
Proved + Probable + Possible (3P)	16,017.6	8,087.5	5,163.9	3,783.7	3,002.2

Totals may not add because of rounding.

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

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, 2024, 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.

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 approval of additional drilling, project approval for additional future developments, demonstration of a market for future gas sales, and commitment to develop the resources. For the purposes of this report, the contingent resources have been divided into two development phases: Phase I – First Stage and Future Development. The Phase I – First Stage contingent resources can be recovered through drilling without significant upgrades to the production system. The Future Development contingent resources may require upgrades to the production system and additional or accelerated drilling relative to the Phase I – First Stage. If the 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 pending.

We estimate the gross (100 percent) contingent resources by development phase for these properties, as of December 31, 2024, to be:

	Gross (100%) Contingent Resources					
	Gas (BCF)			Condensate (MMBBL)		
Development Phase	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)
Phase I – First Stage[(1)]	2,057.6	3,922.7	3,326.2	4.5	8.6	7.3
Future Development	0.0	1,736.7	7,551.9	0.0	3.8	16.6
Total	2,057.6	5,659.4	10,878.1	4.5	12.5	23.9

Totals may not add because of rounding.

(1) The contingent resources shown in this report represent volumes that are incrementally recoverable over volumes classified as reserves. For Phase I – First Stage, the 3C contingent resources are less than the 2C contingent resources because a larger portion of the estimated volumes for the high estimate case has been classified as reserves.

We estimate the NewMed working interest contingent resources by development phase for these properties, as of December 31, 2024, to be:

	Working Interest Contingent Resources					
	Gas (BCF)			Condensate (MMBBL)		
Development Phase	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)
Phase I – First Stage[(1)]	932.9	1,778.6	1,508.1	2.1	3.9	3.3
Future Development	0.0	787.4	3,424.0	0.0	1.7	7.5
Total	932.9	2,566.0	4,932.1	2.1	5.6	10.9

Totals may not add because of rounding.

(1) The contingent resources shown in this report represent volumes that are incrementally recoverable over volumes classified as reserves. For Phase I – First Stage, the 3C contingent resources are less than the 2C contingent resources because a larger portion of the estimated volumes for the high estimate case has been classified as reserves.

As requested, economic analysis was only performed on the Phase I – First Stage contingent resources. We estimate the net contingent cash flow 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, 2024, to be:

	Net Contingent Cash Flow After Levy and Corporate Income Taxes (MM$)				
Category	Discounted at 0%	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Low Estimate (1C)	1,717.4	624.3	240.5	98.9	43.1
Best Estimate (2C)	3,625.2	1,070.5	376.2	151.9	67.8
High Estimate (3C)	2,997.2	853.9	289.7	113.1	49.0

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.

Working interest contingent revenue shown in this report is NewMed's share of the gross (100 percent) revenue from the properties prior to any deductions. Net contingent cash flow 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 net contingent cash flow has been discounted at annual rates of 0, 5, 10, 15, and 20 percent to indicate the effect of time on the value of money; the contingent cash flow, whether discounted or undiscounted, should not be construed as being the fair market value of the properties. Tables VII through IX present cash flow, costs, and taxes by resources category for the Phase I – First Stage contingent resources. As requested, we have included an appendix to this report that presents tables of cash flow, costs, and taxes resulting from aggregating our estimates of reserves and the Phase I – First Stage contingent resources.

ECONOMIC PARAMETERS

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 escalated on January 1 of each year through December 31, 2034, 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 a third gathering line, 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.

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 and contingent resources 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 X. 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, 2024, 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

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STATE OF TEXAS
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Date Signed: February 4, 2025

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Date Signed: February 4, 2025

JRC:MDK

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.

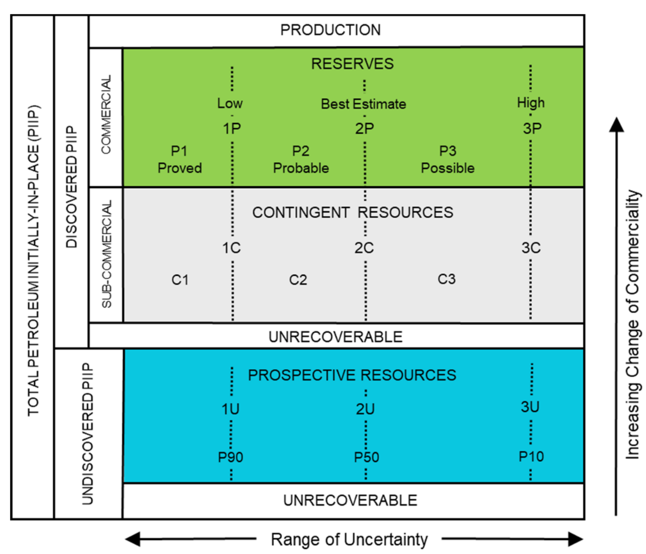

Figure 1.1—Resources classification framework

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.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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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).

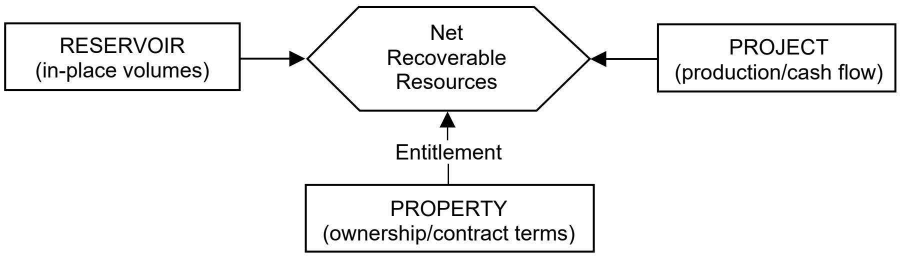

Figure 1.2—Resources evaluation

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.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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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

Excerpted from the 2018 Petroleum Resources Management System (PRMS), version 1.03
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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, 2024

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$)
12-31-2025	1,062.9	117.6	14.1	28.2	159.9	282.3	0.0	142.0	478.7
12-31-2026	1,278.4	141.4	59.4	33.9	234.7	83.7	0.0	135.6	824.4
12-31-2027	1,337.4	147.9	76.9	35.5	260.3	22.9	0.0	151.3	902.8
12-31-2028	1,389.6	153.7	79.9	36.9	270.5	0.0	0.0	114.0	1,005.1
12-31-2029	1,391.8	153.9	80.0	36.9	270.9	1.6	0.0	134.3	985.0
12-31-2030	1,419.8	157.0	81.7	37.7	276.4	0.0	0.0	113.8	1,029.6
12-31-2031	1,431.7	158.3	82.3	38.0	278.7	0.0	0.0	111.8	1,041.2
12-31-2032	1,470.8	162.7	84.6	39.0	286.3	0.0	0.0	111.3	1,073.2
12-31-2033	1,469.8	162.6	84.5	39.0	286.1	0.0	0.0	110.4	1,073.3
12-31-2034	1,496.1	165.5	86.0	39.7	291.2	0.0	0.0	129.5	1,075.3
12-31-2035	1,453.4	160.7	83.6	38.6	282.9	0.0	0.0	111.6	1,058.9
12-31-2036	1,407.2	155.6	80.9	37.4	273.9	0.0	0.0	108.4	1,024.9
12-31-2037	1,362.4	150.7	78.4	36.2	265.2	0.0	0.0	104.4	992.8
12-31-2038	1,318.7	145.8	75.8	35.0	256.7	0.0	0.0	102.4	959.6
12-31-2039	1,270.1	140.5	73.0	33.7	247.2	0.0	0.0	126.8	896.1
Subtotal	20,560.0	2,273.9	1,121.3	545.7	3,941.0	390.6	0.0	1,807.6	14,421.0
Remaining	20,563.8	2,274.4	1,182.7	545.8	4,002.9	0.0	109.3	2,052.9	14,398.7
Total	41,123.8	4,548.3	2,304.0	1,091.6	7,943.8	390.6	109.3	3,860.5	28,819.7

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$)	Discounted at 20% (MM$)
12-31-2025	0.0	0.0	478.7	23.0	116.3	362.4	353.6	345.5	337.9	330.8
12-31-2026	0.0	0.0	824.4	23.0	146.4	678.0	630.2	587.7	549.8	515.8
12-31-2027	11.3	102.2	800.6	23.0	126.7	673.9	596.5	531.0	475.2	427.2
12-31-2028	30.2	303.6	701.4	23.0	96.7	604.8	509.8	433.2	370.8	319.5
12-31-2029	38.8	381.9	603.1	23.0	110.6	492.5	395.4	320.7	262.6	216.8
12-31-2030	45.4	467.4	562.2	23.0	114.9	447.3	342.0	264.8	207.4	164.1
12-31-2031	46.8	487.3	553.9	23.0	113.4	440.5	320.8	237.1	177.6	134.7
12-31-2032	46.8	502.3	571.0	23.0	117.2	453.8	314.7	222.0	159.1	115.6
12-31-2033	46.8	502.3	571.0	23.0	118.4	452.6	299.0	201.3	138.0	96.1
12-31-2034	46.8	503.2	572.1	23.0	119.7	452.4	284.6	182.9	119.9	80.0
12-31-2035	46.8	495.6	563.4	23.0	122.8	440.5	263.9	161.9	101.5	64.9
12-31-2036	46.8	479.6	545.2	23.0	122.6	422.6	241.2	141.2	84.7	51.9
12-31-2037	46.8	464.6	528.2	23.0	118.9	409.2	222.4	124.3	71.3	41.9
12-31-2038	46.8	449.1	510.5	23.0	117.4	393.2	203.5	108.6	59.6	33.5
12-31-2039	46.8	419.4	476.7	23.0	109.6	367.1	180.9	92.2	48.4	26.1
Subtotal		5,558.6	8,862.4		1,771.4	7,090.9	5,158.6	3,954.7	3,163.8	2,619.1
Remaining		6,745.0	7,653.7		1,769.3	5,884.4	1,820.1	646.8	255.8	109.8
Total		12,303.6	16,516.0		3,540.8	12,975.3	6,978.7	4,601.4	3,419.6	2,728.9

Totals may not add because of rounding.

Note: Remaining represents estimates after December 31, 2039, 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.

NETHERLAND, SEWELL & ASSOCIATES, INC.

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, 2024

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$)
12-31-2025	55.7	6.2	0.7	1.5	8.4	0.0	0.0	2.4	45.0
12-31-2026	114.4	12.7	10.4	3.0	26.1	0.0	0.0	0.9	87.3
12-31-2027	121.3	13.4	7.0	3.2	23.6	0.0	0.0	0.3	97.4
12-31-2028	124.5	13.8	7.2	3.3	24.2	0.0	0.0	1.4	98.9
12-31-2029	124.6	13.8	7.2	3.3	24.2	0.0	0.0	1.3	99.0
12-31-2030	126.9	14.0	7.3	3.4	24.7	0.0	0.0	1.3	100.9
12-31-2031	127.7	14.1	7.3	3.4	24.8	0.0	0.0	1.2	101.6
12-31-2032	78.2	8.6	4.5	2.1	15.2	0.0	0.0	-0.5	63.5
12-31-2033	62.3	6.9	3.6	1.7	12.1	0.0	0.0	-1.1	51.2
12-31-2034	17.2	1.9	1.0	0.5	3.3	0.0	0.0	-2.4	16.2
12-31-2035	18.4	2.0	1.1	0.5	3.6	0.0	0.0	-3.1	18.0
12-31-2036	33.8	3.7	1.9	0.9	6.6	0.0	0.0	-2.6	29.9
12-31-2037	49.2	5.4	2.8	1.3	9.6	0.0	0.0	-2.0	41.6
12-31-2038	62.4	6.9	3.6	1.7	12.1	0.0	0.0	-1.5	51.8
12-31-2039	76.8	8.5	4.4	2.0	15.0	0.0	0.0	-1.5	63.3
Subtotal	1,193.4	132.0	70.0	31.7	233.7	0.0	0.0	-5.9	965.6
Remaining	4,264.3	471.6	245.3	113.2	830.1	0.0	0.0	17.0	3,417.2
Total	5,457.8	603.6	315.3	144.9	1,063.8	0.0	0.0	11.1	4,382.8

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$)	Discounted at 20% (MM$)
12-31-2025	0.0	0.0	45.0	23.0	10.3	34.6	33.8	33.0	32.3	31.6
12-31-2026	0.0	0.0	87.3	23.0	20.1	67.2	62.5	58.3	54.5	51.2
12-31-2027	16.1	58.5	38.9	23.0	8.9	29.9	26.5	23.6	21.1	19.0
12-31-2028	33.1	61.6	37.3	23.0	8.6	28.8	24.2	20.6	17.6	15.2
12-31-2029	42.0	73.9	25.2	23.0	5.8	19.4	15.6	12.6	10.3	8.5
12-31-2030	46.7	61.1	39.8	23.0	9.2	30.7	23.5	18.2	14.2	11.3
12-31-2031	46.8	47.5	54.0	23.0	12.4	41.6	30.3	22.4	16.8	12.7
12-31-2032	46.8	29.7	33.8	23.0	7.8	26.0	18.0	12.7	9.1	6.6
12-31-2033	46.8	24.0	27.3	23.0	6.3	21.0	13.9	9.3	6.4	4.5
12-31-2034	46.8	7.6	8.6	23.0	2.0	6.6	4.2	2.7	1.8	1.2
12-31-2035	46.8	8.4	9.6	23.0	2.2	7.4	4.4	2.7	1.7	1.1
12-31-2036	46.8	14.0	15.9	23.0	3.7	12.2	7.0	4.1	2.5	1.5
12-31-2037	46.8	19.5	22.1	23.0	5.1	17.0	9.3	5.2	3.0	1.7
12-31-2038	46.8	24.2	27.5	23.0	6.3	21.2	11.0	5.9	3.2	1.8
12-31-2039	46.8	29.6	33.7	23.0	7.8	25.9	12.8	6.5	3.4	1.8
Subtotal		459.6	506.0		116.4	389.7	296.8	237.7	197.9	169.7
Remaining		1,592.8	1,824.4		419.6	1,404.8	365.2	111.5	38.9	15.2
Total		2,052.4	2,330.4		536.0	1,794.4	662.1	349.2	236.8	184.8

Totals may not add because of rounding.

Note: Remaining represents estimates after December 31, 2039, 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.

NETHERLAND, SEWELL & ASSOCIATES, INC.

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, 2024

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$)
12-31-2025	1,118.6	123.7	14.8	29.7	168.3	282.3	0.0	144.3	523.7
12-31-2026	1,392.8	154.0	69.8	37.0	260.8	83.7	0.0	136.5	911.7
12-31-2027	1,458.7	161.3	83.9	38.7	283.9	22.9	0.0	151.6	1,000.2
12-31-2028	1,514.0	167.5	87.1	40.2	294.7	0.0	0.0	115.4	1,103.9
12-31-2029	1,516.3	167.7	87.2	40.2	295.2	1.6	0.0	135.6	1,084.0
12-31-2030	1,546.7	171.1	89.0	41.1	301.1	0.0	0.0	115.2	1,130.5
12-31-2031	1,559.4	172.5	89.7	41.4	303.5	0.0	0.0	113.1	1,142.8
12-31-2032	1,549.0	171.3	89.1	41.1	301.5	0.0	0.0	110.8	1,136.7
12-31-2033	1,532.1	169.4	88.1	40.7	298.2	0.0	0.0	109.3	1,124.6
12-31-2034	1,513.2	167.4	87.0	40.2	294.6	0.0	0.0	127.1	1,091.5
12-31-2035	1,471.9	162.8	84.7	39.1	286.5	0.0	0.0	108.4	1,076.9
12-31-2036	1,441.0	159.4	82.9	38.3	280.5	0.0	0.0	105.8	1,054.7
12-31-2037	1,411.6	156.1	81.2	37.5	274.8	0.0	0.0	102.4	1,034.4
12-31-2038	1,381.1	152.7	79.4	36.7	268.8	0.0	0.0	100.8	1,011.4
12-31-2039	1,347.0	149.0	77.5	35.8	262.2	0.0	0.0	125.3	959.4
Subtotal	21,753.5	2,405.9	1,191.3	577.4	4,174.7	390.6	0.0	1,801.7	15,386.6
Remaining	24,828.1	2,746.0	1,427.9	659.0	4,832.9	0.0	109.3	2,069.9	17,815.9
Total	46,581.6	5,151.9	2,619.2	1,236.5	9,007.6	390.6	109.3	3,871.6	33,202.5

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$)	Discounted at 20% (MM$)
12-31-2025	0.0	0.0	523.7	23.0	126.7	397.0	387.4	378.5	370.2	362.4
12-31-2026	0.0	0.0	911.7	23.0	166.4	745.3	692.7	646.0	604.3	567.0
12-31-2027	16.1	160.8	839.5	23.0	135.6	703.9	623.0	554.6	496.3	446.2
12-31-2028	33.1	365.2	738.8	23.0	105.2	633.5	534.1	453.8	388.4	334.7
12-31-2029	42.0	455.8	628.2	23.0	116.4	511.9	411.0	333.3	272.9	225.3
12-31-2030	46.7	528.5	602.0	23.0	124.1	478.0	365.5	283.0	221.6	175.3
12-31-2031	46.8	534.8	607.9	23.0	125.8	482.1	351.1	259.5	194.4	147.4
12-31-2032	46.8	532.0	604.7	23.0	124.9	479.8	332.8	234.8	168.2	122.2
12-31-2033	46.8	526.3	598.3	23.0	124.6	473.6	312.8	210.7	144.4	100.6
12-31-2034	46.8	510.8	580.7	23.0	121.7	459.0	288.8	185.6	121.7	81.2
12-31-2035	46.8	504.0	572.9	23.0	125.0	447.9	268.3	164.6	103.2	66.0
12-31-2036	46.8	493.6	561.1	23.0	126.2	434.9	248.1	145.3	87.2	53.4
12-31-2037	46.8	484.1	550.3	23.0	124.0	426.3	231.6	129.5	74.3	43.6
12-31-2038	46.8	473.3	538.1	23.0	123.7	414.4	214.5	114.4	62.8	35.4
12-31-2039	46.8	449.0	510.4	23.0	117.4	393.1	193.7	98.7	51.8	27.9
Subtotal		6,018.2	9,368.4		1,887.8	7,480.6	5,455.5	4,192.4	3,361.7	2,788.7
Remaining		8,337.9	9,478.1		2,188.9	7,289.1	2,185.3	758.2	294.7	125.0
Total		14,356.0	18,846.5		4,076.8	14,769.7	7,640.8	4,950.7	3,656.4	2,913.7

Totals may not add because of rounding.

Note: Remaining represents estimates after December 31, 2039, 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.

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, 2024

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$)
12-31-2025	22.9	2.5	0.3	0.6	3.4	0.0	0.0	-1.4	20.8
12-31-2026	30.7	3.4	1.5	0.8	5.7	0.0	0.0	-5.6	30.5
12-31-2027	33.9	3.7	1.9	0.9	6.6	0.0	0.0	-8.6	35.9
12-31-2028	32.3	3.6	1.9	0.9	6.3	0.0	0.0	-2.0	28.0
12-31-2029	32.5	3.6	1.9	0.9	6.3	0.0	0.0	-2.0	28.2
12-31-2030	33.2	3.7	1.9	0.9	6.5	0.0	0.0	-2.0	28.8
12-31-2031	33.8	3.7	1.9	0.9	6.6	0.0	0.0	-2.0	29.2
12-31-2032	56.5	6.3	3.3	1.5	11.0	0.0	0.0	-1.2	46.7
12-31-2033	61.5	6.8	3.5	1.6	12.0	0.0	0.0	-1.1	50.6
12-31-2034	67.5	7.5	3.9	1.8	13.1	0.0	0.0	-0.7	55.1
12-31-2035	72.4	8.0	4.2	1.9	14.1	0.0	0.0	-1.3	59.6
12-31-2036	77.9	8.6	4.5	2.1	15.2	0.0	0.0	-1.1	63.9
12-31-2037	82.4	9.1	4.7	2.2	16.0	0.0	0.0	-0.8	67.1
12-31-2038	86.9	9.6	5.0	2.3	16.9	0.0	0.0	-0.7	70.6
12-31-2039	90.4	10.0	5.2	2.4	17.6	0.0	0.0	-1.0	73.8
Subtotal	814.7	90.1	45.6	21.6	157.4	0.0	0.0	-31.4	688.8
Remaining	2,956.9	327.0	170.1	78.5	575.6	0.0	0.0	13.2	2,368.1
Total	3,771.6	417.1	215.7	100.1	732.9	0.0	0.0	-18.1	3,056.9

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$)	Discounted at 20% (MM$)
12-31-2025	0.0	0.0	20.8	23.0	4.8	16.0	15.6	15.3	14.9	14.6
12-31-2026	0.0	0.0	30.5	23.0	7.0	23.5	21.9	20.4	19.1	17.9
12-31-2027	18.3	29.4	6.5	23.0	1.5	5.0	4.4	3.9	3.5	3.2
12-31-2028	34.0	20.0	8.0	23.0	1.8	6.2	5.2	4.4	3.8	3.3
12-31-2029	43.0	22.8	5.4	23.0	1.2	4.2	3.4	2.7	2.2	1.8
12-31-2030	46.8	14.1	14.7	23.0	3.4	11.3	8.7	6.7	5.3	4.2
12-31-2031	46.8	13.7	15.5	23.0	3.6	12.0	8.7	6.4	4.8	3.7
12-31-2032	46.8	21.9	24.8	23.0	5.7	19.1	13.3	9.4	6.7	4.9
12-31-2033	46.8	23.7	26.9	23.0	6.2	20.7	13.7	9.2	6.3	4.4
12-31-2034	46.8	25.8	29.3	23.0	6.7	22.6	14.2	9.1	6.0	4.0
12-31-2035	46.8	27.9	31.7	23.0	7.3	24.4	14.6	9.0	5.6	3.6
12-31-2036	46.8	29.9	34.0	23.0	7.8	26.2	14.9	8.7	5.2	3.2
12-31-2037	46.8	31.4	35.7	23.0	8.2	27.5	14.9	8.3	4.8	2.8
12-31-2038	46.8	33.1	37.6	23.0	8.6	28.9	15.0	8.0	4.4	2.5
12-31-2039	46.8	34.5	39.2	23.0	9.0	30.2	14.9	7.6	4.0	2.1
Subtotal		328.0	360.8		83.0	277.8	183.4	129.2	96.6	76.1
Remaining		1,108.3	1,259.8		289.8	970.1	263.4	84.0	30.6	12.3
Total		1,436.3	1,620.6		372.7	1,247.9	446.8	213.3	127.2	88.4

Totals may not add because of rounding.

Note: Remaining represents estimates after December 31, 2039, 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 + POSSIBLE (3P) RESERVES
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2024

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$)
12-31-2025	1,141.5	126.3	15.2	30.3	171.7	282.3	0.0	143.0	544.5
12-31-2026	1,423.5	157.4	71.4	37.8	266.6	83.7	0.0	130.9	942.3
12-31-2027	1,492.6	165.1	85.8	39.6	290.5	22.9	0.0	143.1	1,036.1
12-31-2028	1,546.4	171.0	88.9	41.0	301.0	0.0	0.0	113.4	1,132.0
12-31-2029	1,548.9	171.3	89.1	41.1	301.5	1.6	0.0	133.6	1,112.2
12-31-2030	1,580.0	174.7	90.9	41.9	307.6	0.0	0.0	113.1	1,159.3
12-31-2031	1,593.1	176.2	91.6	42.3	310.1	0.0	0.0	111.1	1,172.0
12-31-2032	1,605.5	177.6	92.3	42.6	312.5	0.0	0.0	109.6	1,183.4
12-31-2033	1,593.6	176.3	91.7	42.3	310.2	0.0	0.0	108.2	1,175.2
12-31-2034	1,580.7	174.8	90.9	42.0	307.7	0.0	0.0	126.4	1,146.6
12-31-2035	1,544.2	170.8	88.8	41.0	300.6	0.0	0.0	107.2	1,136.5
12-31-2036	1,519.0	168.0	87.4	40.3	295.7	0.0	0.0	104.7	1,118.6
12-31-2037	1,493.9	165.2	85.9	39.7	290.8	0.0	0.0	101.6	1,101.5
12-31-2038	1,467.9	162.4	84.4	39.0	285.7	0.0	0.0	100.2	1,082.0
12-31-2039	1,437.4	159.0	82.7	38.2	279.8	0.0	0.0	124.4	1,033.2
Subtotal	22,568.2	2,496.0	1,236.9	599.1	4,332.0	390.6	0.0	1,770.3	16,075.4
Remaining	27,785.0	3,073.0	1,598.0	737.5	5,408.5	0.0	109.3	2,083.2	20,184.0
Total	50,353.2	5,569.1	2,834.9	1,336.6	9,740.6	390.6	109.3	3,853.4	36,259.4

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$)	Discounted at 20% (MM$)
12-31-2025	0.0	0.0	544.5	23.0	131.5	413.0	403.1	393.8	385.1	377.0
12-31-2026	0.0	0.0	942.3	23.0	173.5	768.8	714.5	666.4	623.4	584.8
12-31-2027	18.3	190.1	846.0	23.0	137.1	708.9	627.5	558.6	499.8	449.4
12-31-2028	34.0	385.2	746.8	23.0	107.1	639.7	539.3	458.3	392.2	337.9
12-31-2029	43.0	478.6	633.6	23.0	117.6	516.0	414.3	336.1	275.1	227.2
12-31-2030	46.8	542.6	616.8	23.0	127.5	489.3	374.1	289.7	226.8	179.5
12-31-2031	46.8	548.5	623.5	23.0	129.4	494.1	359.8	265.9	199.2	151.1
12-31-2032	46.8	553.8	629.6	23.0	130.6	498.9	346.0	244.1	174.9	127.1
12-31-2033	46.8	550.0	625.2	23.0	130.8	494.4	326.5	219.9	150.7	105.0
12-31-2034	46.8	536.6	610.0	23.0	128.4	481.6	302.9	194.7	127.7	85.2
12-31-2035	46.8	531.9	604.6	23.0	132.3	472.3	283.0	173.6	108.9	69.6
12-31-2036	46.8	523.5	595.1	23.0	134.1	461.0	263.1	154.1	92.4	56.6
12-31-2037	46.8	515.5	586.0	23.0	132.2	453.8	246.6	137.9	79.1	46.5
12-31-2038	46.8	506.4	575.6	23.0	132.3	443.3	229.4	122.4	67.2	37.8
12-31-2039	46.8	483.5	549.7	23.0	126.4	423.3	208.6	106.3	55.8	30.1
Subtotal		6,346.2	9,729.2		1,970.8	7,758.4	5,638.8	4,321.7	3,458.4	2,864.8
Remaining		9,446.1	10,737.9		2,478.7	8,259.2	2,448.7	842.3	325.3	137.3
Total		15,792.3	20,467.1		4,449.5	16,017.6	8,087.5	5,163.9	3,783.7	3,002.2

Totals may not add because of rounding.

Note: Remaining represents estimates after December 31, 2039, 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.

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, 2024

Year	NewMed Working Interest Production (BCF)	Average Per Production Unit ($/MCF)				Reserves Depletion Rate[1] (%)
		Price Received	Royalties Paid	Production Costs	Net Revenue	
2024[2]	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
2022	182.2	6.28	0.94	0.73	4.61	3.0

Note: Values in this table have been provided by NewMed; these values are based on historical data since January 2022 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 2024 data are representative of unaudited financial data.

CASH FLOW, COSTS, AND TAXES
PHASE I – FIRST STAGE LOW ESTIMATE (1C) CONTINGENT RESOURCES
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2024

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 Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2032	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2033	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2034	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2035	20.8	2.3	1.2	0.6	4.0	110.5	0.0	0.7	-94.5
12-31-2036	84.6	9.4	4.9	2.2	16.5	0.0	0.0	2.9	65.2
12-31-2037	114.7	12.7	6.6	3.0	22.3	0.0	0.0	4.0	88.4
12-31-2038	171.2	18.9	9.8	4.5	33.3	0.0	0.0	5.9	131.9
12-31-2039	201.9	22.3	11.6	5.4	39.3	0.0	0.0	10.7	151.9
Subtotal	593.1	65.6	34.1	15.7	115.5	110.5	0.0	24.2	342.9
Remaining	5,980.9	661.5	344.0	158.8	1,164.2	814.7	75.9	43.0	3,883.0
Total	6,574.0	727.1	378.1	174.5	1,279.7	925.3	75.9	67.2	4,225.9

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Cash Flow After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Cash Flow After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2025	0.0	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2026	0.0	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2027	11.3	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2028	30.2	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2029	38.8	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2030	45.4	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2031	46.8	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2032	46.8	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2033	46.8	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2034	46.8	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2035	46.8	-44.2	-50.3	23.0	12.6	-62.9	-37.7	-23.1	-14.5	-9.3
12-31-2036	46.8	30.5	34.7	23.0	5.4	29.3	16.7	9.8	5.9	3.6
12-31-2037	46.8	41.4	47.0	23.0	8.3	38.8	21.1	11.8	6.8	4.0
12-31-2038	46.8	61.7	70.2	23.0	13.6	56.6	29.3	15.6	8.6	4.8
12-31-2039	46.8	71.1	80.8	23.0	16.0	64.8	31.9	16.3	8.5	4.6
Subtotal		160.5	182.4		55.9	126.5	61.3	30.3	15.2	7.7
Remaining		1,832.4	2,050.6		459.7	1,590.9	563.0	210.2	83.6	35.4
Total		1,992.9	2,233.0		515.6	1,717.4	624.3	240.5	98.9	43.1

Totals may not add because of rounding.

Note: Remaining represents estimates after December 31, 2039, 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.

Table VII

CASH FLOW, COSTS, AND TAXES
PHASE I – FIRST STAGE BEST ESTIMATE (2C) CONTINGENT RESOURCES
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2024

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 Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2031	0.0	0.0	0.0	0.0	0.0	110.5	0.0	0.0	-110.5
12-31-2032	52.5	5.8	3.0	1.4	10.2	0.0	0.0	1.8	40.5
12-31-2033	68.4	7.6	3.9	1.8	13.3	0.0	0.0	2.3	52.8
12-31-2034	115.6	12.8	6.6	3.1	22.5	0.0	0.0	3.8	89.3
12-31-2035	134.4	14.9	7.7	3.6	26.2	0.0	0.0	4.6	103.6
12-31-2036	184.3	20.4	10.6	4.9	35.9	0.0	0.0	6.4	142.1
12-31-2037	197.5	21.8	11.4	5.2	38.5	0.0	0.0	6.8	152.3
12-31-2038	241.9	26.8	13.9	6.4	47.1	0.0	0.0	8.3	186.6
12-31-2039	257.4	28.5	14.8	6.8	50.1	0.0	0.0	8.9	198.4
Subtotal	1,252.0	138.5	72.0	33.2	243.7	110.5	0.0	42.9	854.9
Remaining	11,278.6	1,247.4	648.7	299.4	2,195.4	913.7	84.3	82.3	8,002.9
Total	12,530.6	1,385.9	720.7	332.6	2,439.2	1,024.2	84.3	125.2	8,857.7

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Cash Flow After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Cash Flow After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2025	0.0	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2026	0.0	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2027	16.1	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2028	33.1	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2029	42.0	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2030	46.7	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2031	46.8	-51.7	-58.8	23.0	10.6	-69.4	-50.6	-37.4	-28.0	-21.2
12-31-2032	46.8	19.0	21.5	23.0	2.4	19.1	13.3	9.4	6.7	4.9
12-31-2033	46.8	24.7	28.1	23.0	3.9	24.2	16.0	10.7	7.4	5.1
12-31-2034	46.8	41.8	47.5	23.0	8.4	39.1	24.6	15.8	10.4	6.9
12-31-2035	46.8	48.5	55.1	23.0	10.1	45.0	26.9	16.5	10.4	6.6
12-31-2036	46.8	66.5	75.6	23.0	14.8	60.7	34.7	20.3	12.2	7.5
12-31-2037	46.8	71.3	81.0	23.0	16.1	64.9	35.3	19.7	11.3	6.6
12-31-2038	46.8	87.3	99.3	23.0	20.3	79.0	40.9	21.8	12.0	6.7
12-31-2039	46.8	92.8	105.5	23.0	21.7	83.8	41.3	21.0	11.0	6.0
Subtotal		400.1	454.8		108.4	346.4	182.3	98.0	53.3	29.1
Remaining		3,749.6	4,253.3		974.4	3,278.8	888.1	278.3	98.6	38.7
Total		4,149.7	4,708.1		1,082.9	3,625.2	1,070.5	376.2	151.9	67.8

Totals may not add because of rounding.

Note: Remaining represents estimates after December 31, 2039, 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.

CASH FLOW, COSTS, AND TAXES
PHASE I – FIRST STAGE HIGH ESTIMATE (3C) CONTINGENT RESOURCES
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2024

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 Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2032	31.0	3.4	1.8	0.8	6.0	110.5	0.0	1.0	-86.6
12-31-2033	41.8	4.6	2.4	1.1	8.1	0.0	0.0	1.4	32.2
12-31-2034	83.5	9.2	4.8	2.2	16.2	0.0	0.0	2.8	64.5
12-31-2035	97.5	10.8	5.6	2.6	19.0	0.0	0.0	3.4	75.2
12-31-2036	142.3	15.7	8.2	3.8	27.7	0.0	0.0	4.9	109.7
12-31-2037	150.6	16.7	8.7	4.0	29.3	0.0	0.0	5.1	116.2
12-31-2038	190.8	21.1	11.0	5.1	37.1	0.0	0.0	6.4	147.3
12-31-2039	202.6	22.4	11.7	5.4	39.4	98.9	0.0	7.0	57.3
Subtotal	940.1	104.0	54.1	25.0	183.0	209.5	0.0	31.9	515.7
Remaining	9,678.9	1,070.5	556.7	256.9	1,884.1	814.7	84.3	94.9	6,800.9
Total	10,618.9	1,174.5	610.7	281.9	2,067.0	1,024.2	84.3	126.8	7,316.6

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Cash Flow After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Cash Flow After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2025	0.0	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2026	0.0	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2027	18.3	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2028	34.0	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2029	43.0	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2030	46.8	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2031	46.8	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2032	46.8	-40.5	-46.1	23.0	13.6	-59.6	-41.4	-29.2	-20.9	-15.2
12-31-2033	46.8	15.1	17.2	23.0	1.4	15.8	10.4	7.0	4.8	3.3
12-31-2034	46.8	30.2	34.3	23.0	5.3	28.9	18.2	11.7	7.7	5.1
12-31-2035	46.8	35.2	40.0	23.0	6.7	33.3	20.0	12.3	7.7	4.9
12-31-2036	46.8	51.3	58.3	23.0	10.9	47.5	27.1	15.9	9.5	5.8
12-31-2037	46.8	54.4	61.8	23.0	11.7	50.2	27.3	15.2	8.7	5.1
12-31-2038	46.8	68.9	78.4	23.0	15.5	62.9	32.5	17.4	9.5	5.4
12-31-2039	46.8	26.8	30.5	23.0	26.1	4.4	2.2	1.1	0.6	0.3
Subtotal		241.3	274.3		91.1	183.3	96.3	51.3	27.6	14.8
Remaining		3,182.8	3,618.1		804.2	2,813.9	757.7	238.3	85.5	34.1
Total		3,424.1	3,892.4		895.3	2,997.2	853.9	289.7	113.1	49.0

Totals may not add because of rounding.

Note: Remaining represents estimates after December 31, 2039, 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.

NETHERLAND, SEWELL & ASSOCIATES, INC.

VOLUMETRIC INPUT SUMMARY
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2024

	Gross Rock Volume (acre-feet)			Area (acres)			Average Gross Thickness[1][2] (feet)			Net-to-Gross Ratio (decimal)		
Reservoir	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
A Sand	10,124,586	10,985,488	11,762,406	75,579	79,624	83,312	134	138	141	0.75	0.81	0.84
B Sand	2,762,597	3,049,025	3,375,025	37,233	40,319	46,377	74	76	73	0.37	0.42	0.48
BC Sand	1,329,794	1,513,503	1,699,234	26,424	29,403	32,411	50	51	52	0.13	0.14	0.15
C Sand	1,800,039	2,180,388	2,644,385	18,422	20,927	24,844	98	104	106	0.71	0.75	0.78

	Porosity[3] (decimal)			Gas Saturation (decimal)			Gas Formation Volume Factor (SCF/RCF)[4]			Gas Recovery Factor (decimal)		
Reservoir	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
A Sand	0.24	0.23	0.23	0.73	0.76	0.79	374	374	374	0.60	0.65	0.70
B Sand	0.24	0.23	0.23	0.68	0.70	0.72	374	374	374	0.60	0.65	0.70
BC Sand	0.24	0.24	0.23	0.66	0.68	0.71	374	374	374	0.60	0.65	0.70
C Sand	0.23	0.23	0.23	0.74	0.77	0.81	374	374	374	0.60	0.65	0.70

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.

APPENDIX

NETHERLAND, SEWELL & ASSOCIATES, INC.

CASH FLOW, COSTS, AND TAXES
PHASE I – FIRST STAGE LOW ESTIMATE (1C) CONTINGENT RESOURCES (INCLUDING 1P RESERVES)
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2024

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 Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2025	1,062.9	117.6	14.1	28.2	159.9	282.3	0.0	142.0	478.7
12-31-2026	1,278.4	141.4	59.4	33.9	234.7	83.7	0.0	135.6	824.4
12-31-2027	1,337.4	147.9	76.9	35.5	260.3	22.9	0.0	151.3	902.8
12-31-2028	1,389.6	153.7	79.9	36.9	270.5	0.0	0.0	114.0	1,005.1
12-31-2029	1,391.8	153.9	80.0	36.9	270.9	1.6	0.0	134.3	985.0
12-31-2030	1,419.8	157.0	81.7	37.7	276.4	0.0	0.0	113.8	1,029.6
12-31-2031	1,431.7	158.3	82.3	38.0	278.7	0.0	0.0	111.8	1,041.2
12-31-2032	1,470.8	162.7	84.6	39.0	286.3	0.0	0.0	111.3	1,073.2
12-31-2033	1,469.8	162.6	84.5	39.0	286.1	0.0	0.0	110.4	1,073.3
12-31-2034	1,496.1	165.5	86.0	39.7	291.2	0.0	0.0	129.5	1,075.3
12-31-2035	1,474.2	163.0	84.8	39.1	287.0	110.5	0.0	112.3	964.4
12-31-2036	1,491.8	165.0	85.8	39.6	290.4	0.0	0.0	111.3	1,090.1
12-31-2037	1,477.1	163.4	84.9	39.2	287.5	0.0	0.0	108.4	1,081.2
12-31-2038	1,489.9	164.8	85.7	39.5	290.0	0.0	0.0	108.3	1,091.6
12-31-2039	1,472.0	162.8	84.7	39.1	286.5	0.0	0.0	137.5	1,048.0
Subtotal	21,153.2	2,339.5	1,155.4	561.5	4,056.4	501.1	0.0	1,831.7	14,763.9
Remaining	26,544.6	2,935.8	1,526.6	704.6	5,167.1	814.7	185.2	2,095.9	18,281.7
Total	47,697.8	5,275.4	2,682.0	1,266.1	9,223.5	1,315.8	185.2	3,927.7	33,045.6

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Cash Flow After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Cash Flow After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2025	0.0	0.0	478.7	23.0	116.3	362.4	353.6	345.5	337.9	330.8
12-31-2026	0.0	0.0	824.4	23.0	146.4	678.0	630.2	587.7	549.8	515.8
12-31-2027	11.3	102.2	800.6	23.0	126.7	673.9	596.5	531.0	475.2	427.2
12-31-2028	30.2	303.6	701.4	23.0	96.7	604.8	509.8	433.2	370.8	319.5
12-31-2029	38.8	381.9	603.1	23.0	110.6	492.5	395.4	320.7	262.6	216.8
12-31-2030	45.4	467.4	562.2	23.0	114.9	447.3	342.0	264.8	207.4	164.1
12-31-2031	46.8	487.3	553.9	23.0	113.4	440.5	320.8	237.1	177.6	134.7
12-31-2032	46.8	502.3	571.0	23.0	117.2	453.8	314.7	222.0	159.1	115.6
12-31-2033	46.8	502.3	571.0	23.0	118.4	452.6	299.0	201.3	138.0	96.1
12-31-2034	46.8	503.2	572.1	23.0	119.7	452.4	284.6	182.9	119.9	80.0
12-31-2035	46.8	451.3	513.1	23.0	135.4	377.6	226.3	138.8	87.0	55.7
12-31-2036	46.8	510.2	579.9	23.0	128.0	451.9	257.9	151.0	90.6	55.5
12-31-2037	46.8	506.0	575.2	23.0	127.2	448.0	243.5	136.1	78.1	45.9
12-31-2038	46.8	510.9	580.7	23.0	131.0	449.7	232.8	124.2	68.2	38.4
12-31-2039	46.8	490.5	557.5	23.0	125.7	431.9	212.9	108.4	56.9	30.7
Subtotal		5,719.1	9,044.8		1,827.4	7,217.4	5,219.9	3,985.0	3,179.0	2,626.8
Remaining		8,577.5	9,704.2		2,229.0	7,475.2	2,383.1	856.9	339.4	145.2
Total		14,296.6	18,749.1		4,056.4	14,692.6	7,603.0	4,842.0	3,518.4	2,772.0

Totals may not add because of rounding.

Notes: As requested, cash flows presented in this table include revenue and costs from proved (1P) reserves; the 1P reserves are inclusive of proved developed producing and proved undeveloped reserves. 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.

Remaining represents estimates after December 31, 2039, 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.

CASH FLOW, COSTS, AND TAXES
PHASE I – FIRST STAGE BEST ESTIMATE (2C) CONTINGENT RESOURCES (INCLUDING 2P RESERVES)
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2024

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 Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2025	1,118.6	123.7	14.8	29.7	168.3	282.3	0.0	144.3	523.7
12-31-2026	1,392.8	154.0	69.8	37.0	260.8	83.7	0.0	136.5	911.7
12-31-2027	1,458.7	161.3	83.9	38.7	283.9	22.9	0.0	151.6	1,000.2
12-31-2028	1,514.0	167.5	87.1	40.2	294.7	0.0	0.0	115.4	1,103.9
12-31-2029	1,516.3	167.7	87.2	40.2	295.2	1.6	0.0	135.6	1,084.0
12-31-2030	1,546.7	171.1	89.0	41.1	301.1	0.0	0.0	115.2	1,130.5
12-31-2031	1,559.4	172.5	89.7	41.4	303.5	110.5	0.0	113.1	1,032.2
12-31-2032	1,601.6	177.1	92.1	42.5	311.8	0.0	0.0	112.6	1,177.2
12-31-2033	1,600.4	177.0	92.0	42.5	311.5	0.0	0.0	111.6	1,177.3
12-31-2034	1,628.8	180.1	93.7	43.2	317.1	0.0	0.0	131.0	1,180.8
12-31-2035	1,606.2	177.6	92.4	42.6	312.7	0.0	0.0	113.1	1,180.5
12-31-2036	1,625.4	179.8	93.5	43.1	316.4	0.0	0.0	112.1	1,196.8
12-31-2037	1,609.1	178.0	92.5	42.7	313.2	0.0	0.0	109.2	1,186.7
12-31-2038	1,623.0	179.5	93.3	43.1	315.9	0.0	0.0	109.1	1,198.0
12-31-2039	1,604.3	177.4	92.3	42.6	312.3	0.0	0.0	134.2	1,157.8
Subtotal	23,005.5	2,544.4	1,263.3	610.7	4,418.4	501.1	0.0	1,844.5	16,241.5
Remaining	36,106.7	3,993.4	2,076.6	958.4	7,028.4	913.7	193.6	2,152.3	25,818.8
Total	59,112.2	6,537.8	3,339.9	1,569.1	11,446.8	1,414.7	193.6	3,996.8	42,060.3

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Cash Flow After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Cash Flow After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2025	0.0	0.0	523.7	23.0	126.7	397.0	387.4	378.5	370.2	362.4
12-31-2026	0.0	0.0	911.7	23.0	166.4	745.3	692.7	646.0	604.3	567.0
12-31-2027	16.1	160.8	839.5	23.0	135.6	703.9	623.0	554.6	496.3	446.2
12-31-2028	33.1	365.2	738.8	23.0	105.2	633.5	534.1	453.8	388.4	334.7
12-31-2029	42.0	455.8	628.2	23.0	116.4	511.9	411.0	333.3	272.9	225.3
12-31-2030	46.7	528.5	602.0	23.0	124.1	478.0	365.5	283.0	221.6	175.3
12-31-2031	46.8	483.1	549.1	23.0	136.5	412.7	300.5	222.1	166.4	126.2
12-31-2032	46.8	550.9	626.3	23.0	127.3	498.9	346.0	244.1	174.9	127.1
12-31-2033	46.8	551.0	626.3	23.0	128.6	497.8	328.8	221.4	151.7	105.7
12-31-2034	46.8	552.6	628.2	23.0	130.1	498.1	313.4	201.4	132.0	88.1
12-31-2035	46.8	552.5	628.0	23.0	135.2	492.9	295.3	181.2	113.6	72.7
12-31-2036	46.8	560.1	636.7	23.0	141.1	495.6	282.8	165.6	99.3	60.9
12-31-2037	46.8	555.4	631.3	23.0	140.1	491.2	266.9	149.2	85.6	50.3
12-31-2038	46.8	560.7	637.3	23.0	144.0	493.3	255.3	136.3	74.8	42.1
12-31-2039	46.8	541.9	616.0	23.0	139.1	476.9	235.0	119.7	62.8	33.9
Subtotal		6,418.3	9,823.2		1,996.3	7,826.9	5,637.8	4,290.4	3,415.0	2,817.9
Remaining		12,087.5	13,731.3		3,163.4	10,568.0	3,073.4	1,036.5	393.3	163.7
Total		18,505.7	23,554.5		5,159.6	18,394.9	8,711.2	5,326.9	3,808.4	2,981.5

Totals may not add because of rounding.

Notes: As requested, cash flows presented in this table include revenue and costs from proved plus probable (2P) reserves. 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.
Remaining represents estimates after December 31, 2039, 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.

CASH FLOW, COSTS, AND TAXES
PHASE I – FIRST STAGE HIGH ESTIMATE (3C) CONTINGENT RESOURCES (INCLUDING 3P RESERVES)
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2024

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 Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2025	1,141.5	126.3	15.2	30.3	171.7	282.3	0.0	143.0	544.5
12-31-2026	1,423.5	157.4	71.4	37.8	266.6	83.7	0.0	130.9	942.3
12-31-2027	1,492.6	165.1	85.8	39.6	290.5	22.9	0.0	143.1	1,036.1
12-31-2028	1,546.4	171.0	88.9	41.0	301.0	0.0	0.0	113.4	1,132.0
12-31-2029	1,548.9	171.3	89.1	41.1	301.5	1.6	0.0	133.6	1,112.2
12-31-2030	1,580.0	174.7	90.9	41.9	307.6	0.0	0.0	113.1	1,159.3
12-31-2031	1,593.1	176.2	91.6	42.3	310.1	0.0	0.0	111.1	1,172.0
12-31-2032	1,636.5	181.0	94.1	43.4	318.6	110.5	0.0	110.6	1,096.8
12-31-2033	1,635.4	180.9	94.1	43.4	318.3	0.0	0.0	109.6	1,207.4
12-31-2034	1,664.2	184.1	95.7	44.2	323.9	0.0	0.0	129.2	1,211.1
12-31-2035	1,641.7	181.6	94.4	43.6	319.6	0.0	0.0	110.5	1,211.6
12-31-2036	1,661.2	183.7	95.5	44.1	323.4	0.0	0.0	109.6	1,228.2
12-31-2037	1,644.5	181.9	94.6	43.7	320.1	0.0	0.0	106.7	1,217.7
12-31-2038	1,658.8	183.5	95.4	44.0	322.9	0.0	0.0	106.6	1,229.3
12-31-2039	1,640.0	181.4	94.3	43.5	319.2	98.9	0.0	131.3	1,090.5
Subtotal	23,508.3	2,600.0	1,291.0	624.0	4,515.0	600.0	0.0	1,802.2	16,591.0
Remaining	37,463.9	4,143.5	2,154.6	994.4	7,292.6	814.7	193.6	2,178.1	26,984.9
Total	60,972.2	6,743.5	3,445.6	1,618.4	11,807.6	1,414.7	193.6	3,980.3	43,575.9

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Cash Flow After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Cash Flow After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2025	0.0	0.0	544.5	23.0	131.5	413.0	403.1	393.8	385.1	377.0
12-31-2026	0.0	0.0	942.3	23.0	173.5	768.8	714.5	666.4	623.4	584.8
12-31-2027	18.3	190.1	846.0	23.0	137.1	708.9	627.5	558.6	499.8	449.4
12-31-2028	34.0	385.2	746.8	23.0	107.1	639.7	539.3	458.3	392.2	337.9
12-31-2029	43.0	478.6	633.6	23.0	117.6	516.0	414.3	336.1	275.1	227.2
12-31-2030	46.8	542.6	616.8	23.0	127.5	489.3	374.1	289.7	226.8	179.5
12-31-2031	46.8	548.5	623.5	23.0	129.4	494.1	359.8	265.9	199.2	151.1
12-31-2032	46.8	513.3	583.5	23.0	144.2	439.3	304.7	214.9	154.0	111.9
12-31-2033	46.8	565.1	642.4	23.0	132.2	510.1	336.9	226.9	155.5	108.3
12-31-2034	46.8	566.8	644.3	23.0	133.8	510.5	321.2	206.4	135.3	90.3
12-31-2035	46.8	567.0	644.6	23.0	139.0	505.6	302.9	185.9	116.5	74.5
12-31-2036	46.8	574.8	653.4	23.0	144.9	508.5	290.1	169.9	101.9	62.5
12-31-2037	46.8	569.9	647.8	23.0	143.9	503.9	273.8	153.1	87.8	51.6
12-31-2038	46.8	575.3	654.0	23.0	147.8	506.2	262.0	139.8	76.7	43.2
12-31-2039	46.8	510.3	580.1	23.0	152.5	427.7	210.8	107.4	56.4	30.4
Subtotal		6,587.5	10,003.5		2,061.9	7,941.6	5,735.1	4,373.0	3,486.0	2,879.7
Remaining		12,628.9	14,356.0		3,282.9	11,073.1	3,206.4	1,080.6	410.8	171.5
Total		19,216.4	24,359.5		5,344.8	19,014.7	8,941.5	5,453.6	3,896.8	3,051.1

Totals may not add because of rounding.

Notes: As requested, cash flows presented in this table include revenue and costs from proved plus probable plus possible (3P) reserves. 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.
Remaining represents estimates after December 31, 2039, 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.

NEWMEDENERGY

Annex C

Current report on prospective resources for the Leviathan leases

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

March 9, 2025

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 March 9, 2025, to be filed with the Israel Securities Authority and the Tel Aviv Stock Exchange. This report sets forth our estimates of the unrisked prospective resources, as of December 31, 2024, to the NewMed working interest in two Leviathan Deep prospects located in Leases I/14 and I/15, offshore Israel.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.

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

JRC:LFG

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ESTIMATES

of

UNRISKED PROSPECTIVE RESOURCES

to the

NEWMED ENERGY LIMITED PARTNERSHIP WORKING INTEREST

in two

LEVIATHAN DEEP PROSPECTS

located in

LEASES I/14 AND I/15, OFFSHORE ISRAEL

as of

DECEMBER 31, 2024

NETHERLAND, SEWELL & ASSOCIATES, INC.

WORLDWIDE PETROLEUM CONSULTANTS

ENGINEERING • GEOLOGY
GEOPHYSICS • PETROPHYSICS

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

March 9, 2025

NewMed Energy Limited Partnership
19 Abba Eban Boulevard
Herzliya 4612001
Israel

Ladies and Gentlemen:

In accordance with your request, we have estimated the unrisked prospective resources, as of December 31, 2024, to the NewMed Energy Limited Partnership (NewMed) working interest in two Leviathan Deep prospects located in Leases I/14 and I/15, offshore Israel. It is our understanding that NewMed owns a direct working interest in these prospects. Prospective resources that extend beyond the boundaries of Leases I/14 and I/15 have not been included in this report. We completed our evaluation on or about the date of this letter. 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. The prospective resources included in this report should not be construed as reserves or contingent resources; they represent exploration opportunities and quantify the development potential in the event a petroleum discovery is made. A geologic risk assessment was performed for these prospects, as discussed in subsequent paragraphs. This report does not include economic analysis for these prospects. Based on analogous field developments, it appears that, assuming a discovery is made, the unrisked best estimate prospective resources in this report have a reasonable chance of being economically viable. There is no certainty that any portion of the prospective resources will be discovered. If they are discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources. The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2018 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE) and in accordance with internationally recognized standards, as stipulated by the Israel Securities Authority (ISA). Definitions are presented immediately following this letter. This report has been prepared for 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.

Totals of unrisked prospective resources beyond the prospect level are not reflective of volumes that can be expected to be recovered and are therefore not shown. Because of the geologic risk associated with each prospect, meaningful totals beyond this level can be defined only by summing risked prospective resources. Such risk is often significant.

We estimate the unrisked gross (100 percent) prospective resources for these prospects, as of December 31, 2024, to be:

	Unrisked Gross (100%) Prospective Resources					
	Low Estimate (1U)		Best Estimate (2U)		High Estimate (3U)	
Prospect	Oil (MMBBL)	Gas (BCF)	Oil (MMBBL)	Gas (BCF)	Oil (MMBBL)	Gas (BCF)
Lower Cretaceous Channel	46.9	44.7	212.7	217.7	374.3	407.9
Mesozoic Carbonate	26.6	25.4	155.3	161.0	736.0	793.7

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info@nsai-petro.com
netherlandsewell.com

We estimate the NewMed unrisked working interest prospective resources for these prospects, as of December 31, 2024, to be:

	Unrisked Working Interest Prospective Resources					
	Low Estimate (1U)		Best Estimate (2U)		High Estimate (3U)	
Prospect	Oil (MMBBL)	Gas (BCF)	Oil (MMBBL)	Gas (BCF)	Oil (MMBBL)	Gas (BCF)
Lower Cretaceous Channel	21.2	20.3	96.5	98.7	169.7	184.9
Mesozoic Carbonate	12.1	11.5	70.4	73.0	333.7	359.9

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

The prospective resources shown in this report have been estimated using probabilistic methods and are dependent on a petroleum discovery being made. If a discovery is made and development is undertaken, the probability that the recoverable volumes will equal or exceed the unrisked estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. Our estimates are based on the assumption that, if a discovery is made, the prospects would be oil filled; we have not included any sensitivity estimates that are based on the assumption that the prospects would be gas filled.

Unrisked prospective resources are estimated ranges of recoverable oil and gas volumes assuming their discovery and development and are based on estimated ranges of undiscovered in-place volumes. Geologic risking of prospective resources addresses the probability of success for the discovery of a significant quantity of potentially recoverable petroleum; this risk analysis is conducted independent of estimations of petroleum volumes and without regard to the chance of development. Principal geologic risk elements of the petroleum system include (1) trap and seal characteristics; (2) reservoir presence and quality; (3) source rock capacity, quality, and maturity; and (4) timing, migration, and preservation of petroleum in relation to trap and seal formation. Risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators and is subject to revision with further data acquisition or interpretation. The primary geologic risk for these prospects is trap integrity. The geologic risk elements and overall probability of geologic success for each prospect are shown in the following table:

	Geologic Risk Element (%)				Probability of Geologic
Prospect	Trap Integrity	Reservoir Quality	Source Evaluation	Timing/ Migration	Success (%)
Lower Cretaceous Channel	45	70	80	75	19
Mesozoic Carbonate	40	70	80	80	18

Each prospect was evaluated to determine ranges of in-place and recoverable petroleum and was risked as an independent entity without dependency between potential prospect drilling outcomes. If petroleum discoveries are made, smaller-volume prospects may not be commercial to independently develop, although they may become candidates for satellite developments and tie-backs to existing infrastructure at some future date. The development infrastructure and data obtained from early discoveries will alter both geologic risk and future economics of subsequent discoveries and developments.

These prospects are covered by a 3-D seismic data set. The 3-D seismic data were acquired in 2009 by Petroleum Geo-Services and reprocessed in 2019 by WesternGeco. All seismic interpretation was performed on the depth-migrated data.

It should be understood that the prospective resources discussed and shown herein are those undiscovered, highly speculative resources estimated beyond reserves or contingent resources where geological and geophysical data suggest the potential for discovery of petroleum but where the level of proof is insufficient for classification as reserves or contingent resources. The unrisked prospective resources shown in this report are the range of volumes that could reasonably be expected to be recovered in the event of the discovery and development of these prospects.

For the purposes of this report, we did not perform any field inspection of the prospects. We have not investigated possible environmental liability related to the prospects; however, we are not currently aware of any possible environmental liability that would have any material effect on the resources quantities estimated in this report or the commerciality of such estimates.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs from offset wells, geologic maps, seismic data, and property ownership interests. We were provided with all the necessary data to prepare the resources estimate for the prospects, and we were not limited from access to any material we believe may be relevant. The resources in this report have been estimated using probabilistic 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 volumetric analysis and analogy, that we considered to be appropriate and necessary to classify, categorize, and estimate volumes in accordance with the 2018 PRMS definitions and guidelines. Certain parameters used in our volumetric analysis are summarized in Table I. 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. The prospective information is not an assessment regarding the reserves and contingent resources, which can be assessed only after exploratory drilling, if at all.

Netherland, Sewell & Associates, Inc. (NSAI) was engaged on December 15, 2024, 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 prospects; 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 prospects 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 prospects 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

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

Date Signed: March 9, 2025

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

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

Date Signed: March 9, 2025

JRC:LFG

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.

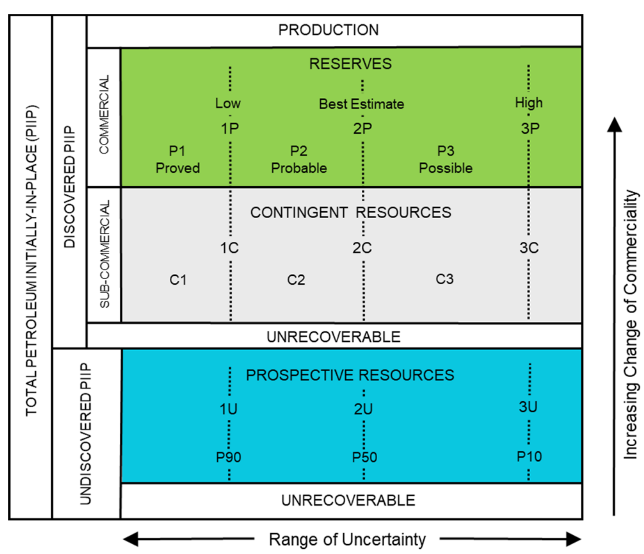

Figure 1.1—Resources classification framework

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

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

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

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

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

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

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

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

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

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

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

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

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

1.1.0.8 Other terms used in resource assessments include the following:

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

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

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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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).

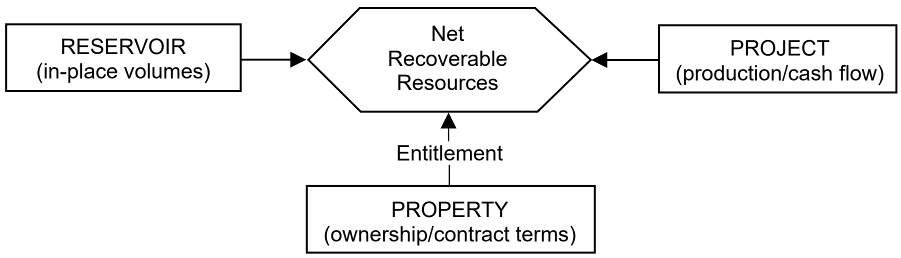

Figure 1.2—Resources evaluation

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.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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Approved by the Society of Petroleum Engineers (SPE) Board of Directors

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
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
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
Excerpted from the 2018 Petroleum Resources Management System (PRMS), version 1.03
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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

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

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.

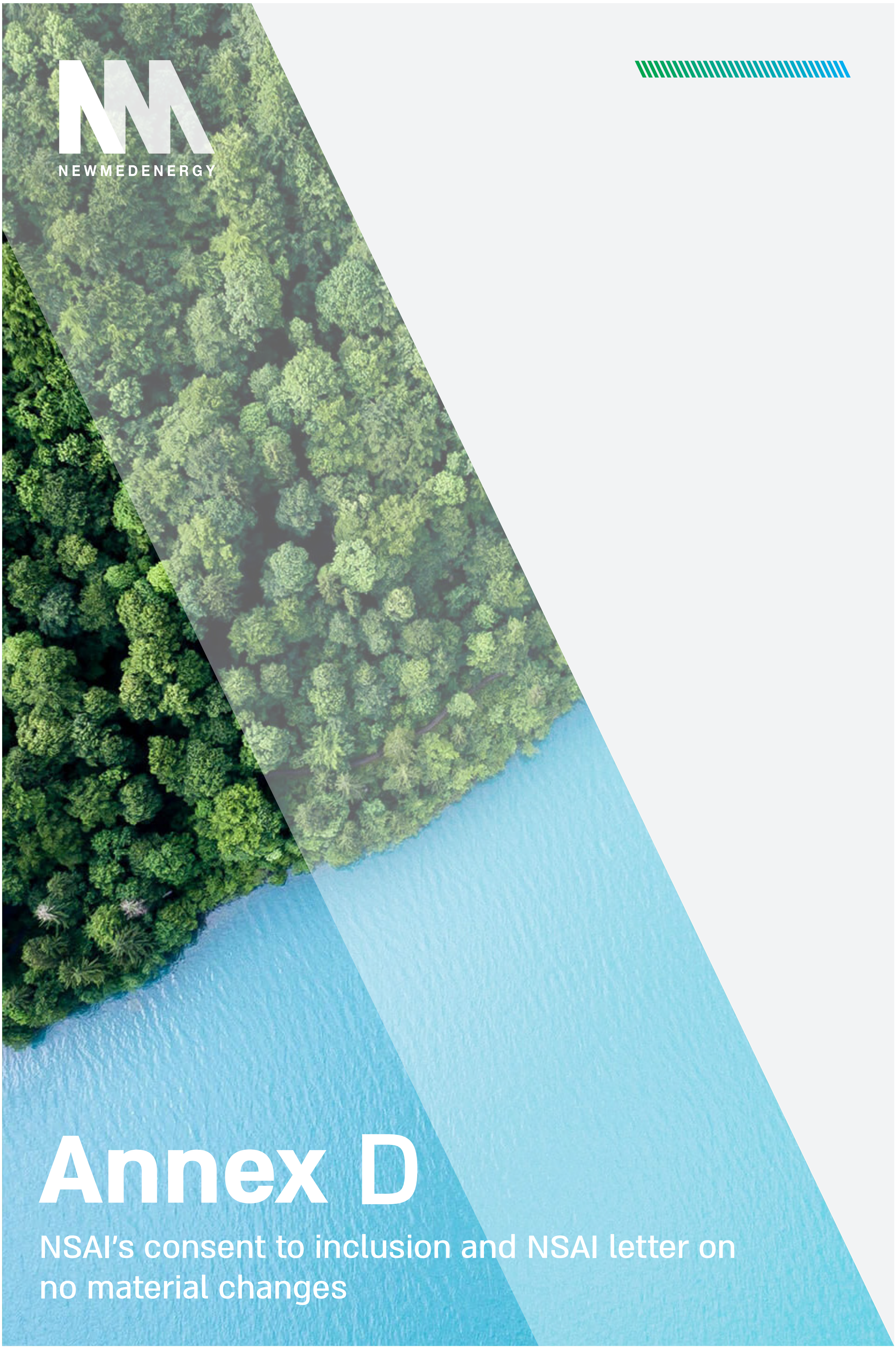
VOLUMETRIC INPUT SUMMARY
LEVIATHAN DEEP PROSPECTS, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2024

Prospect	Gross Rock Volume[1] (acre-feet) Lognormal Distribution		Area (acres) Lognormal Distribution		Average Gross Thickness[2] (feet)		Net-to-Gross Ratio (decimal) Triangular Distribution			Porosity (decimal) Triangular Distribution		
	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
Lower Cretaceous Channel	660,818	17,297,896	4,628	22,380	143	773	0.20	0.50	0.80	0.12	0.17	0.22
Mesozoic Carbonate	370,734	16,051,915	1,443	19,619	257	818	0.20	0.50	0.80	0.10	0.15	0.25

Prospect	Oil Saturation (decimal) Triangular Distribution			Initial Oil Formation Volume Factor (RB/STB)[3] Uniform Distribution		Average Producing Gas-Oil Ratio (SCF/STB)[4] Uniform Distribution		Oil Recovery Factor (decimal) Normal Distribution	
	Low Estimate	Best Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
Lower Cretaceous Channel	0.55	0.65	0.75	2.20	1.10	200	2,200	0.15	0.45
Mesozoic Carbonate	0.45	0.65	0.85	2.20	1.10	200	2,200	0.15	0.45

Note: For the purposes of this report, we used technical and economic data including, but not limited to, well logs from offset wells, geologic maps, seismic data, and property ownership interests.

(1) A portion of the gross rock volume for each prospect extends beyond the boundaries of Leases I/14 and I/15; however, the prospective resources shown in this report include only the on-lease volumes.
(2) Average gross thickness is calculated by dividing the gross rock volume by the area.
(3) The abbreviation RB/STB represents reservoir barrels per stock tank barrel.
(4) The abbreviation SCF/STB represents standard cubic feet per stock tank barrel.



Annex D

NSAI's consent to inclusion and NSAI letter on no material changes

March 9, 2025

NewMed Energy Limited Partnership
19 Abba Eban Boulevard
Herzliya 4612001
Israel

Ladies and Gentlemen:

As independent consultants, Netherland, Sewell & Associates, Inc. (NSAI) hereby grant permission to NewMed Energy Limited Partnership (NewMed) to use the following NSAI reports in the 2024 Annual Report of NewMed to be published in March 2025 and in public reports to be filed with the Israel Securities Authority and the Tel Aviv Stock Exchange (including by way of reference):

- The report dated March 9, 2025, which sets forth our estimates of the unrisked prospective resources, as of December 31, 2024, to the NewMed working interest in two Leviathan Deep prospects located in Leases I/14 and I/15, offshore Israel.

- The report dated February 4, 2025, which sets forth our estimates of the proved, probable, and possible reserves and future revenue, as of December 31, 2024, to the NewMed interest in certain gas properties located in Leviathan Field, Leases I/14 and I/15, offshore Israel. The February 4 report also sets forth our estimates of the contingent resources and cash flow, as of December 31, 2024, to the NewMed interest in these properties.

- The report dated November 28, 2024, which sets forth our estimates of the unrisked prospective gas resources, as of November 30, 2024, to the Potential Acquisition interest in certain prospects located in Block 1-21 Han Asparuh, offshore Bulgaria.

- The report dated September 5, 2023, which sets forth our estimates of the unrisked contingent and prospective resources, as of August 31, 2023, to the NewMed working interest in discoveries and prospects located in the Aphrodite Field Area, Block 12, offshore Cyprus.

Since our February 4 report, we have received daily well production data for Leviathan Field through March 6, 2025. This daily well production data has been reviewed by NSAI and it is our opinion that there are no material changes to the production profile for each category or the reserves referenced in our February 4 report.

As of the date hereof, nothing has come to our attention regarding Block 1-21 Han Asparuh and the Aphrodite Field Area that could cause us to make any revisions in our November 28 and September 5 reports or in our conclusions based on data available when our reports were prepared. It is our opinion that there are no material changes to the unrisked prospective gas resources referenced in our November 28 report and the unrisked contingent and prospective resources referenced in our September 5 report.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.

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

JRC:MDK

NEWMEDENERGY

Part B

Board of Directors report

This report is a translation of the Hebrew-language Report of the Board of Directors of the General Partner of NewMed Energy – Limited Partnership. It is provided solely for convenience purposes. Please note that the Hebrew version is the binding version, and in any event of discrepancy, the Hebrew version shall prevail.

9 March 2025

NewMed Energy – Limited Partnership

Report of the Board of Directors of the General Partner for the Year Ended 31 December 2024

The board of directors of NewMed Energy Management Ltd. (the "**General Partner**") hereby respectfully submits the board of directors' report for the year ended 31 December 2024 (the "**Report Year**").

Part One – Explanations of the Board of Directors on the State of the Partnership's Business

1. Key information from the description of the Partnership's business

For a description of the Partnership's business and the developments that occurred in the Report Year – see the Description of the Partnership's Business (Chapter A of this Report).

Since 7 October 2023, and throughout 2024, Israel has been fighting a multiple-front war, including against the terrorist organization Hamas in the Gaza Strip, the terrorist organization Hezbollah in Lebanon, the Houthi terrorist organization in Yemen, Shia militias in Iraq and military targets in Iran. Furthermore, in Q1/2025 the fight against terrorist activity originating in the territories of Judea and Samaria has intensified. Concurrently, throughout 2024, the Israeli market operated under a routine overshadowed by the War.

On 27 November 2024, a ceasefire agreement between Israel and Lebanon took effect, aimed at stopping the fighting on the northern front. As of the Report approval date, the ceasefire at this front is generally sustained.

On 19 January 2025, an agreement between Israel and the terrorist organization Hamas took effect, for the exchange of hostages and prisoners and restoration of a sustainable calm, in a two-stage deal: a first stage of 42 days which has come to an end, and a second stage which has not yet begun. As of the Report approval date, it cannot be assessed whether an agreement to extend the ceasefire will be reached or, alternatively, whether the fighting in Gaza will be resumed, and how it will develop. For further details, se Section 6.8 of the Description of the Partnership's Business (Chapter A of this Report) and Section 3F below.

2. Results of operations

A. General

NewMed Energy – Limited Partnership (the "**Partnership**") is a publicly traded limited partnership. As of the date of approval of the report, the Partnership operates in the energy sector and mainly engages in the exploration, development, production and marketing of natural gas, condensate and oil in Israel, Cyprus, Morocco and Bulgaria[1], as well as in the promotion of various natural gas-based projects, with the aim of increasing the volume of sales of the natural gas produced by the Partnership. At the same time, the Partnership is examining business opportunities for exploration, development, production, and marketing of natural gas, condensate and oil in additional countries, is considering and promoting possible investments in renewable energy projects, in the context of the collaboration with Enlight Renewable Energy Ltd.[2], and is further examining potential projects for the production of hydrogen, including blue hydrogen which is produced from natural gas and may constitute a low-carbon substitute for energy consumers[3].

The Partnership's net profit in 2024 totaled approx. $524.6 million, compared with approx. $433.6 million last year, an increase of approx. 21%. The increase in profit derived mainly from the increase in net income, from the sale of natural gas and condensate from the Leviathan reservoir and from a decrease in net financial expenses, that was partly offset by the increase in the cost of natural gas and condensate production and an increase in income tax expenses, as specified below.

The Partnership's net profit in Q4/2024 totaled approx. $119.5 million compared with approx. $102.1 million in the same quarter last year, an increase of approx. 17%. The increase in profit derived mainly from the decrease in net financial expenses, that was partly offset by a decrease in the net income from the sale of natural gas, as specified below.

[1] For details with respect to the Partnership's operations in Bulgaria, see Section 7.8 of Chapter A (Description of the Partnership's Business) of this Report.

[2] For details regarding the collaboration with Enlight, see Section 7.10 of Chapter A (Description of the Partnership's Business) of this Report.

[3] For details regarding potential projects for hydrogen production, see Section 7.28 of Chapter A (Description of the Partnership's Business) of this Report.

B. Analysis of statements of comprehensive income

Below are key figures with regard to the Partnership's statements of comprehensive income (dollars in millions):

	1-3/24	4-6/24	7-9/24	10-12/24	2024	10-12/23	2023
Revenues							
From natural gas and condensate sales	263.2	295.3	313.6	264.2	1,136.3	276.7	1,094.4
Net of royalties	37.1	42.6	46.0	37.5	163.2	40.4	159.8
Revenues, net	**226.1**	**252.7**	**267.6**	**226.7**	**973.1**	**236.3**	**934.6**
Expenses and costs:							
Cost of natural gas and condensate production	44.4	43.0	40.5	40.5	168.4	38.6	148.6
Depreciation, depletion and amortization expenses	19.0	19.3	25.6	16.8	80.7	19.1	79.2
Other direct expenses	0.8	1.3	1.4	2.4	5.9	2.5	5.3
G&A expenses	3.2	4.9	5.1	3.7	16.9	4.4	20.8
Total expenses and costs	**67.4**	**68.5**	**72.6**	**63.4**	**271.9**	**64.6**	**253.9**
The Partnership's share in the profits (losses) of entities accounted for at equity	1.0	1.4	-	0.5	2.9	0.8	(1.3)
Operating income	**159.7**	**185.6**	**195.0**	**163.8**	**704.1**	**172.5**	**679.4**
Financial expenses	(29.6)	(29.4)	(27.4)	(27.4)	(113.8)	(34.2)	(133.8)
Financial income	27.4	23.8	24.2	15.5	90.9	(5.9)[4]	28.7
Financial expenses, net	**(2.2)**	**(5.6)**	**(3.2)**	(11.9)	(22.9)	(40.1)	(105.1)
Profit before taxes on the income	**157.5**	**180.0**	**191.8**	**151.9**	**681.2**	**132.4**	**574.3**
Taxes on the income	(36.4)	(43.6)	(44.5)	(32.1)	(156.6)	(32.4)	(142.8)
Income from continuing operations	**121.1**	**136.4**	**147.3**	**119.8**	**524.6**	**100.0**	**431.5**
Income (loss) from discontinued operations	-	0.6	(0.3)	(0.3)	*)	2.1	2.1
Net profit and comprehensive income	**121.1**	**137.0**	**147.0**	**119.5**	**524.6**	**102.1**	**433.6**

*) Profit lower than $0.1 million

[4] The negative financial income in Q4/2023 derives from a negative revaluation (expense) in the quarter of production-based royalties from the Karish and Tanin leases.

Net revenues totaled approx. $973.1 million in the Report Year, compared with approx. $934.6 million last year, up around 4.1%. The increase in net revenues mainly derived from the increase in the natural gas quantities produced and sold from the Leviathan reservoir, from approx. 10.97 BCM (100%) last year to approx. 11.20 BCM (100%) in the Report Year, from income from the sale of approx. 561 thousand condensate barrels, which began in 2024 (the Partnership's share in the gross revenues is approx. $16.8 million, see Note 12C6 of the Financial Statements (Chapter C of this report), and from a moderate increase in the average price per thermal unit (MMBTU) from approx. $6.11 in 2023 to approx. $6.12 in 2024.

Net revenues in Q4/2024 totaled approx. $226.7 million compared with approx. $236.3 million in the same period last year, down around 4.1%. The decrease mainly derived from a decrease in the average price per thermal unit (MMBTU) from approx. $6.17 in Q4/2023 to approx. $5.82 in Q4/2024, which mainly resulted from a decrease in the Brent barrel price, from which the price of natural gas for export is derived. Furthermore, the drop in the quantities of natural gas that were produced and sold from the Leviathan reservoir, from 2.75 BCM in Q4/2023 (100%) to 2.73 BCM in Q4/2024 (100%), resulted from initiated halts of gas production from the Leviathan reservoir in October 2024. Conversely, the decrease was offset by the revenues from the sale of approx. 136 thousand barrels of condensate (100%) (the Partnership's share in the gross revenues is approx. $3.8 million).

The table below specifies the gas quantities (100%) sold from the Leviathan reservoir in the Report Year and in 2023, referring to the customers' geographic location and the average sale price per thermal unit (MMBTU):

2024 - (BCM)*					
	Israel	Jordan	Egypt	Total	Average Price**
Q1	0.2	0.6	1.8	2.6	**$6.16**
Q2	0.4	0.6	1.8	2.8	**$6.29**
Q3	0.5	0.8	1.8	3.1	**$6.18**
Q4	0.4	0.7	1.6	2.7	**$5.82**
Total/Average annual price	**1.5**	**2.7**	**7.0**	**11.2**	**$6.12**

2023 - (BCM)*					
	Israel	Jordan	Egypt	Total	Average Price**
Q1	0.6	0.7	1.5	2.8	**$6.14**
Q2	0.3	0.56	1.6	2.5	**$6.06**
Q3	0.4	0.8	1.7	2.9	**$6.17**
Q4	0.7	0.6	1.5	2.8	**$6.17**
Total/Average annual price	**2.0**	**2.7**	**6.3**	**11.0**	**$6.11**

* The figures are rounded off to one tenth of a BCM.

** Average price per MMBTU in dollars, rounded off to 2 digits after the decimal point.

Cost of natural gas and condensate production in the Report Year totaled approx. $168.4 million compared with approx. $148.6 million last year, demonstrating an increase of approx. 13.3% and consisting mainly of expenses of management and operation of the Leviathan project which include, *inter alia*, expenses of haulage and transport, salaries, professional consulting, maintenance, environment, guarding and security, insurance and the cost of transmission of natural gas to Egypt. The rise in the Report Year mainly derives from an increase in the cost of transmission of the gas to Egypt, which derive, *inter alia*, from the rise in the quantity of gas sold to Egypt, an increase in maintenance expenses resulting, *inter alia*, from the postponement of works from the end of 2023, a rise in insurance tariffs and an increase in the costs of foreign contractors, *inter alia* as a consequence of the War.

The cost of gas and condensate production in Q4/2024 totaled approx. $40.5 million, compared with approx. $38.6 million in the same quarter last year. The increase in the period derived mainly from the aforesaid reasons.

Depreciation, depletion and amortization expenses totaled approx. $80.7 million in the Report Year, compared with approx. $79.2 million last year, demonstrating an increase of approx. 1.9%. The increase mainly derives from an increase in the depreciation, depletion and amortization expenses in the Leviathan project, and was partly offset by an update of the abandonment obligation in the Yam Tethys project.

Depreciation and amortization expenses in Q4/2024 totaled approx. $16.8 million, compared with approx. $19.1 million in the same quarter last year. The decrease mainly derives from an update of the Yam Tethys asset retirement obligation relative to the same quarter last year.

Other direct expenses in the Report Year totaled approx. $5.9 million, compared with approx. $5.3 million last year, an increase of approx. 11.3%. The expenses include, *inter alia*, expenses of geologists, engineers and consulting as well as G&A expenses of various projects which are not at the production stage, including renewable energy projects. The increase derives mainly from an increase in expenses related to the project in Morocco.

Other direct expenses in Q4/2024 totaled approx. $2.4 million, comparable to the corresponding quarter last year ($2.5 million).

G&A expenses totaled approx. $16.9 million in the Report Year, compared with approx. $20.8 million last year, a decrease of approx. 18.8%. G&A expenses include, *inter alia,* salary expenses, professional services and D&O insurance. The decrease in expenses mainly derived from a decrease in the revaluation of the cost of a participation-unit based payment to the Partnership's CEO and from a decrease in the cost of professional services.

G&A expenses in Q4/2024 totaled approx. $3.7 million, compared to approx.

$4.4 million in the corresponding quarter last year.

The Partnership's share in the profits (losses) of entities accounted for at equity totaled a profit of approx. $2.9 million in the Report Year, compared with a loss of approx. $1.3 million last year. The profit in the period derived mostly from the profit of the company accounted for at equity, EMED Pipeline B.V. ("**EMED BV**"), which holds 39% of the shares of Eastern Mediterranean Gas Company S.A.E ("**EMG**"). The increase in profit results from the increase in the profits of the company accounted for at equity from the natural gas transmission, which was offset by the amortization of the excess cost of the investment.

The Partnership's share in the profits (losses) of entities accounted for at equity in Q4/2024 totaled a profit of approx. $0.5 million, compared to approx. $0.8 million in the corresponding quarter last year.

Financial expenses totaled approx. $113.8 million in the Report Year, compared with approx. $133.8 million last year, showing a decrease of approx. 14.9%. The financial expenses in the Report Year mainly derived from interest on the Leviathan Bond bonds that were issued by Leviathan Bond Ltd., a wholly owned subsidiary of the Partnership, in the sum of approx. $113.0 million compared with approx. $126.9 million last year. Furthermore, in the Report Year the Partnership capitalized financial expenses for eligible assets in the sum of approx. $6.3 million (last year, approx. $5.2 million) The drop in financial expenses mainly derived from repayment of the first series (6/2023) of Leviathan Bond bonds in Q2/2023, and implementation of the Buyback Plan as specified in Section 3E below.

Financial expenses in Q4/2024 totaled approx. $27.4 million, compared with approx. $34.2 million in the same quarter last year. The decrease in financial expenses mainly derived from the aforesaid reasons.

Financial income totaled approx. $90.9 million in the Report Year, compared with approx. $28.7 million last year, an increase of approx. 216.7%. The increase in financial income mainly derives from the revaluation of royalties based on future production from the Karish and Tanin leases in the sum of approx. $60.9 million, compared with (negative) revaluation of approx. $5.0 million last year, from an increase in interest income from deposits of approx. $17.5 million, compared with approx. $13.1 million last year, and conversely, a decrease in the revaluation of a loan extended to Energean as part of the sale of the Partnership's rights in the Karish and Tanin leases, from approx. $5.9 million last year to approx. $1.2 million in the Report Year, following the repayment of the loan in March and May of 2024. For further details, see Note 8B to the financial statements (Chapter C of this Report).

Financial income in Q4/2024 amounted to approx. $15.5 million compared with negative financial income of approx. $5.9 million in the same quarter last year. The Increase in financial income mainly derived from the aforesaid reasons. The negative financial income in Q4/2023 derived from negative revaluation (expense) of royalties based on future production from the Karish and Tanin leases.

Taxes on income in the Report Year totaled approx. $156.6 million compared with approx. $142.8 million last year, demonstrating an increase of approx. 9.7%. The increase derived from the increase in profit before tax in the Report Year compared with last year, which was partly offset by the difference between the measurement base as reported for tax purposes (ILS) and the measurement base as reported in the financial statements (dollar).

Taxes on income in Q4/2024 totaled an expense of approx. $32.1 million, compared to $32.4 million in the corresponding quarter last year. The expense in Q4/2024 remained similar quarter-over-quarter notwithstanding the increase in profit before tax resulting from the decrease in temporary differences between the tax basis of the oil and gas assets and their book value, as aforesaid.

Income (loss) from discontinued operations totaled a profit lower than $0.1 million in the Report Year, compared with a profit of approx. $2.1 million last year. The discontinued operations originate from the sale of the Partnership's holdings in the Tamar project in December 2021. The profit this year derived mainly from a refund of insurance premiums and a refund on account of the oil and gas profits levy, offset by an update of the overriding royalties in reference to the investment recovery date and the agreements in respect thereof. The profit last year derived mostly from excess advance payments of royalties previously paid by the Tamar partners according to the draft royalty audit reports for the years 2013-2018 that were received from the Ministry of Energy. For further details, See Notes 7C'9 and 15B to the financial statements (Chapter C of this Report).

Income (loss) from discontinued operations in Q4/2024 totaled a loss of approx. $0.3 million compared with a profit of approx. $2.1 million in the same quarter last year. The decrease in profit derives from the aforesaid reasons.

3. Financial position, liquidity and financing sources

A. Financial position

The main changes in the items of the statement of financial position as of 31 December 2024, compared with the statement of financial position as of 31 December 2023, are specified below:

Total assets as of 31 December 2024 totaled approx. $3,992.3 million, compared with approx. $3,846.2 million as of 31 December 2023.

Current assets as of 31 December 2024 totaled approx. $734.1 million compared with approx. $568.3 million as of 31 December 2023, as specified below:

(1) **Cash and cash equivalents** as of 31 December 2024 totaled approx. $51.2 million, compared with approx. $29.1 million as of 31 December 2023. The

increase in the cash balance mainly derives from net receipts from the sale of natural gas and condensate from the Leviathan project, from the reimbursement of royalty advancements which were paid for the Tamar project as stated in Note 15B7 to the financial statements (Chapter C of this Report), and from receipts from Energean in respect of royalties from the Karish and Tanin leases and from repayment of a seller's loan provided in the Karish and Tanin transaction. Conversely, the Partnership made payments in the Report Year, mainly for profit distributions to the participation unit holders, repayment of a loan provided to the Partnership by a banking corporation out of a credit facility, buyback of Leviathan Bond bonds, and advance tax payments.

(2) **Short-term deposits** as of 31 December 2024 totaled approx. $333.3 million, compared with approx. $157.6 million as of 31 December 2023. The deposits are mainly for Leviathan Bond bonds, and consist of, *inter alia*, a fixed safety cushion in the sum of approx. $100 million and another safety cushion for the bond principal in the sum of approx. $150 million, intended for repayment of the Leviathan Bond Series 2025 in accordance with the Leviathan Bond deed of bonds.

(3) **Trade receivables** as of 31 December 2024 totaled approx. $209.6 million, compared with approx. $194.5 million as of 31 December 2023. The increase mainly derived from a change in the composition of sales to customers in Q4/2024 compared with the same quarter last year.

(4) **Other receivables** as of 31 December 2024 totaled approx. $140.0 million compared with approx. $187.1 million as of 31 December 2023. The decrease mainly derived from the repayment of the loan provided to Energean and a refund of advance royalties overpaid to the State and to related and third parties in respect of the Tamar project (for further details, see Note 15B to the financial statements (Chapter C of this Report), which was offset by an increase in the balance of the operator in the joint venture in the Leviathan project, as well as by an increase receivables from a company accounted for at equity.

Non-current assets as of 31 December 2024 totaled approx. $3,258.2 million, compared with approx. $3,277.9 million on 31 December 2023, as specified below:

(1) **Investments in oil and gas assets** as of 31 December 2024 totaled approx. $2,682.3 million, compared with approx. $2,647.3 million as of 31 December 2023. The movement in the Report Year mainly derived from investments in the sum total of approx. $103.1 million in the Leviathan project and approx. $4.1 million in the Block 12 project in Cyprus. Conversely, the Partnership recorded depreciation, depletion, and amortization expenses in the Leviathan project in the sum of approx. $69.7 million.

(2) **Investment in entities accounted for at equity**, as of 31 December 2024, totaled approx. $61.7 million, compared with approx. $58.4 million as of 31

December 2023, for investments in shares of EMED BV and in Enlight NewMed Development Limited Partnership. The increase mainly derived from a profit recorded on the investment in EMED BV in the Report Year.

(3) **Long-term bank deposits** as of 31 December 2024 totaled approx. $0.5 million, compared with approx. $101.9 million as of 31 December 2023. The long-term deposits as of 31 December 2023 mostly included a safety cushion for the Leviathan Bond bond series, classified in the report period as a short-term deposit and intended for repayment of the 2025 bond series of Leviathan Bond.

(4) **Other long-term assets** as of 31 December 2024 totaled approx. $513.7 million, compared with approx. $470.3 million as of 31 December 2023. The increase mainly derived from the Partnership's investments in pipelines for export to Jordan and Egypt and from the update of royalties receivable based on future production from the Karish and Tanin leases. The said increase was mainly offset by repayment and short-term classification in the report period of amounts receivable from a company accounted for at equity and from depreciation of access fees for the Blue Ocean agreement.

Current liabilities as of 31 December 2024 totaled approx. $603.0 million, compared with approx. $211.0 million as of 31 December 2023, as specified below:

(1) **Current maturities of bonds** as of 31 December 2024 totaled approx. $485.6 million and include the Series 2025 bonds of Leviathan Bond, net of issue expenses, and net of bonds which were purchased under a buyback plan as of 31 December 2024 (for details, see Part Five and Section (e) below).

(2) **Income taxes payable** as of 31 December 2024 totaled approx. $10.8 million, compared with approx. $27.7 million as of 31 December 2023. These mainly include an estimate of income tax payable in respect of the Partnership's taxable income in the Report Year and in 2023, net of the advances paid by the Partnership to the tax authorities for these years.

(3) **Short-term liability to a banking corporation** as of 31 December 2023 totaled approx. $80.0 million and derived from a loan taken out of the credit facility provided to the Partnership by a banking corporation. This liability was repaid in January 2024. For further details see Note 10D to the financial statements (Chapter C of this Report).

(4) **Trade and other payables** as of 31 December 2024 totaled approx. $106.6 million, compared with approx. $101.1 million as of 31 December 2023. The increase mainly derived from an increase in payables in the context of the joint ventures.

(5) **Other short-term liabilities** as of 31 December 2023 totaled approx. $2.2 million, and derived from the oil and gas asset retirement obligation in the Yam Tethys project. The decrease in the balance of the liability derived from

the completion of the planned abandonment actions, as stated in Note 7C3B to the financial statements (Chapter C of this Report).

Non-current liabilities as of 31 December 2024 totaled approx. $1,602.0 million, compared with approx. $2,122.7 million as of 31 December 2023, as specified below:

(1) **Bonds** as of 31 December 2024 totaled approx. $1,140.0 million and include the Leviathan Bond bonds (net of issue expenses) (for details see Part Five below), compared with approx. $1,735.1 million as of 31 December 2023. The decrease derives from the classification as current maturities of the Leviathan Bond Series 2025 bonds net of issue expenses and net of bonds purchased under the buyback plan.

(2) **Deferred taxes** as of 31 December 2024 totaled approx. $391.5 million, compared with approx. $313.9 million as of 31 December 2023. The increase mainly derives from an increase in the temporary differences between the tax basis of oil and gas assets and their value in the financial statements.

(3) **Other long-term liabilities** as of 31 December 2024 totaled approx. $70.5 million, compared with approx. $73.7 million as of 31 December 2023. The decrease mainly derives from an update to an oil and gas asset retirement obligation in the Leviathan and Yam Tethys projects, due to an increase in the capitalization interest rate used to measure the obligation, and from a decrease in the estimated abandonment costs.

The capital of the limited partnership as of 31 December 2024 totaled approx. $1,787.3 million, compared with approx. $1,512.5 million as of 31 December 2023. The change in capital mainly derived from the comprehensive income recorded in the Report Year in the sum of approx. $524.6 million, which was partly offset by profit distributions made in the Report Year in the sum of approx. $250 million.

B. <u>Cash flow</u>

(1) Cash flows generated by the Partnership from operating activities in the Report Year totaled approx. $577.5 million, compared with approx. $559.5 million last year.

(2) Cash flows used by the Partnership for investment activities totaled, in the Report Year, approx. $114.2 million, compared with cash flows generated from investment activities in the sum of approx. $36.1 million last year. In the Report Year, the Partnership invested mainly in oil and gas assets and in other long-term assets, and in short-term deposits, and conversely recorded revenues mainly for a loan given to Energean and royalties based on production from the Karish lease. Last year, the Partnership generated cash mainly from the withdrawal of short-term deposits to pay the 2023 Series of the Leviathan Bond bonds, offset mainly by investment in oil and gas assets and other long-term assets.

(3) Cash flows used for financing activities in the Report Year totaled approx. $441.2 million, compared with approx. $588.9 million last year. Cash flows in the Report Year were primarily used for a profit distribution to the participation unit holders, for repurchase of Leviathan Bond bonds, and for repayment of an $80 million loan taken by the Partnership in 2023 from the credit facility provided thereto by a banking corporation (see Section C1 below). Last year the cash flows were used primarily for a profit distribution to unit holders, and for repurchase and repayment of Series 2023 Leviathan Bond bonds, and conversely, the Partnership drew down $80 million from the credit facility provided thereto by a banking corporation as aforesaid.

C. Financing

(1) On 11 January 2024 the Partnership repaid $80 million drawn down from a credit facility received from an Israeli bank in 2023. On 8 October 2024 the Partnership signed agreements for the provision of credit facilities by two Israeli banks in the sum of $200 million each (the "**Lenders**" and the "**Credit Facilities**", respectively). These facilities are in lieu of a $100 million credit facility provided to the Partnership on 14 March 2024 (for details on this facility, see Note 10D to the financial statements (Chapter C of this Report)). The Credit Facilities are intended to be used by the Partnership for its current operations, including in connection with Phase 1B of the Leviathan reservoir development plan. According to the terms and conditions of the Credit Facilities, the Partnership may from time to time, in a period which commenced on 8 October 2024 and ends on 8 October 2025, draw down loans in U.S. dollars, up to a sum total of $200 million from each one of the Lenders (the "**Loans**"). The Loans drawn down as aforesaid shall be repaid in part by 15 April 2027, and the balance by 15 October 2027. As of the date of approval of the financial statements the Partnership has not yet drawn down any amounts from the said Credit Facilities (for further details see Note 10E to the consolidated financial statements (Chapter C of this Report)).

(2) As a result of the War, the Leviathan Bond bonds were placed on negative watch by the rating agencies Moody's and Fitch. In addition, the rating agency S&P downgraded the bonds' rating outlook to negative. In February 2024, upon the downgrade of the credit rating of the State of Israel and Israeli banks by the Moody's rating agency, Moody's announced that following consideration of a downgrade, it had decided to affirm, rather than downgrade, the rating of the Leviathan Bond bonds. However, under the shadow of the War, Moody's changed the rating outlook of the Leviathan Bond bonds to negative and affirmed the rating and outlook in October 2024. In March 2024, the rating agency S&P released a rating affirmation report in which it left the rating of the Leviathan Bond bonds unchanged as well as the negative rating outlook, due to the risk of escalation of the War. S&P affirmed this rating and outlook in October 2024. In June 2024, rating agency Fitch released a rating report leaving the rating of the Leviathan Bond bonds unchanged, and removed the bonds from negative watch.

Volatility in the returns on the Leviathan Bond bonds does not affect the nominal interest of the bonds, the Partnership's cash flow and the ability to repay the bonds, although it may have an adverse effect on the Partnership's ability to raise additional debt, and increase the financing costs of raising additional debt as aforesaid.

D. **Profit distributions:**

(1) On 18 March 2024, after receiving the recommendation of the General Partner's financial statements review committee, the General Partner's board of directors approved a profit distribution in the sum total of $60 million ($0.05112 per participation unit), with the record date for the distribution being 28 March 2024, and such profit distribution was carried out on 11 April 2024.

(2) On 23 May 2024, after receiving the recommendation of the General Partner's financial statements review committee, the General Partner's board of directors approved a profit distribution in the sum total of $60 million ($0.05112 per participation unit), with the record date for the distribution being 2 June 2024, and such profit distribution was carried out on 20 June 2024.

(3) On 7 August 2024, after receiving the recommendation of the General Partner's financial statements review committee, the General Partner's board of directors approved a profit distribution in the sum total of $65 million ($0.05538 per participation unit), with the record date for the distribution being 25 August 2024, and such profit distribution was carried out on 5 September 2024.

(4) On 19 November 2024, after receiving the recommendation of the General Partner's financial statements review committee, the General Partner's board of directors approved a profit distribution in the sum total of $65 million ($0.05538 per participation unit), with the record date for the distribution being 28 November 2024, and such profit distribution was carried out on 12 December 2024.

(5) On 28 March 2024 and 19 November 2024, the General Partner's board of directors approved a minimal distribution to the limited partner in the sum of ILS 0.5 million each (approx. $0.1 million), to be used for payment of the supervisor's fees and the trustee's fees and expenses, in accordance with the provisions of the trust agreement.

(6) On 9 March 2025 the General Partner's board of directors, after receiving the recommendation of the General Partner's Financial Statements Review Committee, approved a profit distribution in the sum total of $60 million ($0.05112 per participation unit). The record date for the distribution is 20 March 2025, and the said profit distribution will be carried out on 3 April 2025.

E. **Plan for buyback of Leviathan Bond bonds**:

On 15 November 2023, the General Partner's board of directors approved the continued performance of buybacks pursuant to the buyback plan dated 22 January 2023, out of the bond series maturing on 30 June 2025 and/or the bond series maturing on 30 June 2027.

On 15 October 2024, the board of directors of the Partnership's General Partner approved the adoption of an additional plan for the buyback of the bonds, whereby the Partnership and/or Leviathan Bond may, from time to time, at the discretion of the Partnership's management and pursuant to the provisions of the additional buyback plan, perform buybacks of the bonds in an aggregate amount of up to $100 million, by way of an OTC purchase, a purchase on the TACT-Institutional system on TASE or by other methods, which took effect on 15 October 2024, and will expire at the lapse of two years, i.e. on 15 October 2026.

Until the date of approval of the financial statements, the Partnership has performed buybacks in the amount of approx. $135.3 million par value of the Leviathan Bond bonds Series 2025, for approx. $134.9 million, including the aggregate interest as of the buyback date, in accordance with the Leviathan Bond bonds buyback plan as approved by the General Partner's board of directors.

For further details regarding the bonds, see Part Five below and Note 10C to the financial statements (Chapter C of this Report).

F. **The Swords of Iron War and its possible impact on the Partnership's business**:

Further to Part One above against the background of the escalated War, on 18 April 2024 the credit rating agency S&P Global Ratings downgraded by one notch Israel's long-term credit rating, to A+ (from AA-), and also downgraded the short-term credit rating, to A-1 (from A-1+), leaving a negative outlook regarding the long-term credit rating. On 1 October 2024 S&P Global Ratings downgraded the credit rating of Israel's government by one additional notch, to A (from A+), adding a negative outlook in view of the expected escalation of the War on the northern front.

In August 2024, rating agency Fitch also announced a downgrade of the credit rating of the Government of Israel to A (in lieu of A+), with a negative outlook.

Furthermore, on 27 September 2024, the credit rating agency Moody's downgraded the credit rating of Israel's Government by two notches, to Baa1 (from A2), adding a negative outlook in view of the expected escalation of the War on the northern front, the risk of greater escalation including vis-à-vis Iran, uncertainty regarding Israel's long-term security and growth opportunities, and negative developments that may have a grave impact on the financial position of the Israeli government.

To the Partnership's best knowledge, with the outbreak of the War on 7 October 2023, as aforesaid, Chevron received notice from the Ministry of Energy, whereby in view of the security situation in Israel because of the War, it is required to halt the production of natural gas from the Tamar reservoir. Gas production from the Tamar reservoir was resumed on 13 November 2023. Concurrently, due to the War, gas transmission in the EMG pipeline was halted, and resumed on 14 November 2023.

At the beginning of Q4/2024, in view of the escalation of the War on the northern front and vis-à-vis the Islamic Republic of Iran, the operator of the Leviathan project initiated several halts in the production from the Leviathan reservoir, for short periods of time. Other than that, production from the Leviathan, Tamar and Karish reservoirs generally continued in an orderly manner throughout 2024.

Against the background of the initiated halting of production, in October 2024 the operator of the Leviathan project notified customers of the occurrence of a force majeure event which relieves the Leviathan Partners of their obligations to supply gas under the gas agreements, in respect of the non-supply of gas deriving from the war situation, and in December 2024 the operator notified the customers that the said event was concluded.

As a result of the War, the operating expenses entailed by gas production from the Leviathan reservoir increased in the Report Year by an immaterial rate, mainly due to the difficulty experienced by foreign companies in sending work teams to the region, as well as vessels for the import of equipment and spare parts, which has led to a rise in the rates paid, including insurance costs of such companies, and to a need for additional logistics to transport manpower and equipment. In addition, scheduled maintenance actions have been delayed, changed and adapted according to the instructions of the security functions.

Sue to the War, the availability of the equipment and contractors required for performance of scheduled work in connection with the Levithan project work plans was impaired, as aforesaid, and an increase was recorded in insurance premiums and foreign contractor costs. Such factors, among others, hampered in 2024 the timetables for the performance of scheduled projects and operations, including the suspension and delay of the timetable for the performance and completion of the laying of a third subsea transmission pipeline from the Leviathan field to the platform (for further details, see Section 7.2.5(b) of the Description of the Partnership's Business (Chapter A of this Report)), and there were also delays in the schedule for the performance and completion of the INGL project to lay offshore pipelines in the new Ashdod-Ashkelon offshore transmission segment (for further details, see Section 7.13.2(b) to the Description of the Partnership's Business (Chapter A of this Report)). To emphasize, with the exclusion of the aforesaid, the War did not have a material adverse effect on the Partnership's business in 2024, including on the scope of natural gas sales to customers, and the revenues and profitability in this period were not materially affected as a result of the War.

As of the report approval date, it is impossible to estimate whether the ceasefire on the northern front and the Gaza Strip will be sustained, and whether the war will resume and/or expand in 2025 and the coming years, as well as the results and repercussions of such development and their impact on the Partnership. Notwithstanding the fact that the War did not have a material impact on the Partnership's business in 2024 as aforesaid, under these circumstances, it is impossible to estimate the chances of materialization of the risk factors arising from the War and their possible effect, including the specific risk factors specified in Section 7.30.1 to the Description of the Partnership's Business (Chapter A of this Report), whose materialization could have a material adverse effect on the Partnership, its assets and its business.

G. <u>Inflation and the rise in the interest rate and their possible impact on the Partnership's business and the financial reporting and disclosure</u>:

As a result of global macro-economic developments, including Covid, the war between Russia and Ukraine, trade wars and the imposition of tariffs, the inflation rates have risen in recent years in Israel, the U.S. and in other countries. As a result, and in order to curb the price increase, the central banks in Israel, the U.S. and other countries have started to increase the interest rates.

Energy product prices, the interest rate environment, trade wards, including in connection with the imposition of tariffs, and the inflation rate also have an effect on the operating costs of gas production, as well as on the development costs in the Partnership's projects, including the drilling of development, appraisal and exploration wells. The Partnership, together with its partners in the various projects, particularly Leviathan and Aphrodite, is examining the impact of the said factors on the additional development options and/or expansion of its assets. The impact of the interest rate rises as aforesaid on the financial position of the Partnership is evident mainly in the assets and liabilities in the Statement of Financial Position, which include capitalization components (see Part Two below for further details in connection with the sensitivity tests). In this context it is noted that the Leviathan Bond bonds bear fixed interest and therefore the interest expenses in respect thereof are not affected by the interest rate changes, but insofar as the Partnership shall need, in the future, to raise debt or, alternatively, shall use the credit facility as stated in Section C above and as specified in Note 10E to the financial statements (Chapter C hereof), this may also affect the Partnership's financial expenses.

Caution concerning forward-looking information – The Partnership's assessments regarding the possible consequences of the Swords of Iron war and the inflation and the rise in the interest rate constitute forward-looking information, as defined in Section 32A of the Securities Law, 5728-1968. This information is based, *inter alia*, on the Partnership's assessments and estimates as of the date of approval of the Financial Statements and relies on reports published in Israel and around the world on this issue and directives of the relevant authorities, the materialization of which is uncertain, in whole or in part, and beyond the Partnership's control.

Part Two – Exposure to and Management of Market Risks

Report on exposure to and management of market risks

1. **The officer in charge of market risk management in the Partnership**

The officer in charge of market risk management at the Partnership is the VP Finance, Mr. Tzach Habusha.

2. **Description of the main market risks to which the Partnership is exposed**

a. The exchange rate risk

Changes in the ILS/Dollar exchange rate may affect the Partnership's results in several ways, as follows: (a) The Partnership's functional currency is the Dollar. Since some of the Partnership's expenses are stated in ILS or affected by the ILS/Dollar exchange rate, a decrease in the ILS/Dollar exchange rate (a strengthening of the ILS against the Dollar) increases such expenses in Dollar terms; (b) Since the gas prices in part of the agreements for the sale of gas from the Leviathan reservoir are determined by price formulas that include various linkage components, and, *inter alia*, linkage to the ILS/Dollar exchange rate and linkage to the electricity production tariff, which is partly affected by the ILS/Dollar exchange rate. A change of the ILS/Dollar exchange rate may have an immaterial negative effect on the Partnership's revenues; and (c) Since the Partnership reports its taxable income in ILS and pays tax advances in ILS, changes in the ILS/Dollar exchange rate affect the amount of the Partnership's taxable income and the amount of the cash flow which is used for payment of such tax advances.

b. The risk of linkage components and formulas of natural gas and condensate prices in the supply contracts

The price of gas in agreements for natural gas supply, was determined according to price formulas that include various linkage components, including mostly linkage to the Brent barrel price, the electricity production tariff, the general TAOZ (energy demand management) index published by the Electricity Authority, the ILS/Dollar exchange rate, and in one of the agreements also to the Crack Spread index. In all the agreements for natural gas supply in which the Partnership engaged, apart from agreements that include a fixed, unlinked price, floor prices were set alongside the price formulas, which to some extent limit the exposure to fluctuations in the linkage components. However, there is no certainty that the Partnership will be able to set floor prices as aforesaid also in new agreement to be signed thereby in the future.

In addition, a decrease in the Brent prices and/or a decrease in the electricity production tariffs (the production tariff and the general TAOZ tariff) and/or a change in the ILS/Dollar exchange rate may adversely affect the Partnership's revenues from the existing and future gas sale agreements.

The frequent methodological changes made by the PUA-E to the method of calculation of the electricity production tariff make its predictability difficult and may lead to disputes between gas suppliers and customers in connection with the method of calculation thereof. In this context, it is noted that in relation to some of the private power plants (including plants which were sold by the IEC), the PUA-E instituted SMP regulation (System-Marginal Price) according to which every half hour the wholesale electricity tariff is determined by the marginal cost for the production of one additional kWh in the sector, based on half-hour tenders that are held by the manager of the electricity system between the various electricity producers, every day. The aforesaid pricing method may have an effect on the prices of the natural gas which is sold by the Partnership to the electricity producers in the domestic market, in the event that the gas prices are linked to the aforesaid pricing in futures contracts.

The demand for natural gas from the Partnership's customers and its price are affected, *inter alia*, by significant changes in the prices of oil, natural gas, including LNG, and the prices of other sources of energy, including coal, sources of renewable energy and other alternatives to the produced natural gas marketed by the Partnership, both in the domestic market and in the international markets. Thus, for example, low LNG prices in the international markets may lead to an increase in the import of LNG to Israel and/or the regional markets, reduce natural gas demand in markets that are relevant to the Partnership and impair the Partnership's revenues from the Leviathan reservoir.

An increase in supply, a decrease in demand or a decrease in the prices of alternative energy sources for natural gas, including coal, sources of renewable energy and other products, in the domestic market or global markets may reduce demand from existing and potential customers and lead to a decrease in the price of the natural gas sold by the Partnership, which may adversely affect the Partnership, its financial position and the results of its operation.

Furthermore, reforms and decisions relating to the electricity sector, and the energy sector, including changes in the environmental laws, may also reduce the demand for the natural gas sold by the Partnership and/or affect its price.

In addition, material events in the global economy such as local or regional wars or military conflicts, economic slowdown, recession, inflation, irregular volatility in foreign exchange rates, trade wars, an impairment of the efficient functioning of the global manufacture and supply chains in general, and the segments of engineering, manufacture and supply of components for the oil and gas industry in particular, as well as weather conditions, including global warming, the eruption of epidemics such as the Covid pandemic, and natural disasters, may also reduce the demand for the natural gas sold by the Partnership and/or affect its price and/or adversely affect the Partnership's revenues from the existing and future agreements for the sale of gas, as well as the making of decisions on investment in new natural gas projects and/or expansion of existing projects.

c. **The interest rate risk**

Further to Section 3C(1) of Part 1 above regarding the Partnership's engagement with Israeli banks for the provision of the credit facilities, it is noted that according to the terms of the credit facilities, the Partnership is exposed to possible changes in cash flows that may derive from changes in the SOFR interest, insofar as such facilities are used.

In addition, interest rate risk arises from the risk that the fair value or future cash flows of a financial instrument will change as a result of changes in market interest rates. Financial instruments that bear a variable interest rate expose the Partnership to cash flow and P&L risks due to a change in the interest rate.

Changes in interest rates may also affect the cost of financing of the Partnership's future investments in oil and gas assets, *inter alia* in the development of Phase 1B of the Leviathan project and the development of the Aphrodite reservoir.

Furthermore, the liquid financial assets of the Partnership are invested as of the date of approval of the consolidated financial statements in dollar deposits. Changes in interest rates may affect the current yield of the deposits.

3. The Partnership's policy on exchange rate market risk management

a. The Partnership invests its surplus liquidity in accordance with the provisions of the Partnership Agreement with the aim of obtaining appropriate yield with a suitable yield/risk ratio.

b. The Partnership's funds are intended, *inter alia*, for exploration activities in its oil and gas assets and for their development. In view of the aforesaid, the General Partner, which manages the Partnership, invested the Partnership's available funds in Dollar-denominated financial assets, which mainly include (as of the date of the statement of financial position) bank deposits.

c. When the Partnership is aware of material payments in foreign currency or ILS it aspires to protect, insofar as possible and at its discretion, the payment and hedge against currency rate changes.

d. No events have been determined regarding which there is an obligation to adopt a special resolution at the board of directors with regard to market risks.

4. The Partnership's policy in market risk management in SOFR interest

The Partnership periodically examines its exposure to changes in the SOFR interest rate insofar as the credit facilities are used, relative to other sources of financing, and it examines the possibility to buy hedges, as needed.

5. Means of supervision and implementation of the policy

The Partnership's investment policy is set forth in the Partnership Agreement. On 20 November 2018, the board of directors of the General Partner decided to approve the setup of an investment committee, the purpose of which is to hold thorough discussions on the Partnership's investments and recommend methods of action on such issue to the board of directors of the Partnership's General Partner. The committee was established in view of the need for professional and thorough discussions by a special forum (designated by the board of directors of the General Partner). The investment committee convenes at least once every six months and when necessary. The committee's powers are as follows: To discuss the Partnership's investment portfolio, *inter alia*, in order to ascertain that the method of investment of the Partnership's available cash is in keeping with the investment policy set forth in Section 9.4 of the Partnership Agreement of 1 July 1993 (as amended from time to time); to determine the mix and structure of the Partnership's investment portfolio according to the management's recommendation and insofar as the investment committee believes that there is need to modify the investment policy, to recommend such change to the board of directors of the General Partner. The committee is required to report its recommendations to the board of directors on an ongoing basis and also report the mix and structure of the Partnership's investment portfolio as part of the annual report.

The members of the investment committee, as of the date of approval of the consolidated financial statements, are: Messrs. Efraim Sadka (Chairman of the Investment Committee, external director), Yoram Cohen (external director) and Eliyahu Zamir (independent director).

The handling of currency and interest risk exposure, formulation of hedging strategies and supervision of the performance thereof is entrusted to the board of directors of the General Partner.

6. Sensitivity tests

In accordance with Amendment 5767 to the provisions of the Second Schedule to the Securities Regulations (Immediate and Periodic Reports), 5730-1970, the Partnership carried out tests of sensitivity to changes in risk factors affecting the fair value of "sensitive instruments".

Description of the parameters, assumptions and models

Parameter	Source/Manner of Treatment
ILS/Dollar exchange rate	Representative rate as of 31 December 2024
Dollar interest	Capitalization interest/SOFR interest

a. For details regarding an analysis of the sensitivity of the value of royalties receivable based on future production from the Karish and Tanin leases to changes in the cap rate, see Note 21F2 to the financial statements (Chapter C of this Report).

b. For details regarding an analysis of the sensitivity of the value of royalties receivable based on future production from the Karish and Tanin leases to changes in the price of natural gas and condensate, see Note 21F3 to the financial statements (Chapter C of this Report).

c. For details regarding an analysis of the sensitivity of financial instruments with variable interest see Note 21F2 to the financial statements (Chapter C of this Report).

d. Tests of sensitivity to changes in the Dollar/ILS exchange rate ($ in millions):

Sensitive Instrument	Profit/(Loss) from Changes		Fair Value	Profit/(Loss) from Changes	
	10%	5%		-5%	-10%
Cash and cash equivalents	(0.1)	*)	0.8	*)	(0.1)
Bank deposits	*)	*)	0.2	*)	*)
Trade and other payables	0.1	*)	(0.9)	*)	0.1
Total	***)**	***)**	**0.1**	***)**	***)**

*) Less than $0.1 million.

7. Report on linkage bases in Dollars in thousands, as of 31 December 2024:

	Financial Balances		Non-financial balances	Total
	In foreign currency	In non-linked ILS		
Assets				
Cash and cash equivalents	50.4	0.8	-	51.2
Short-term deposits	333.1	0.2	-	333.3
Trade receivables	209.6	-	-	209.6
Other receivables	127.5	-	12.5	140.0
Investments in oil and gas assets	-	-	2,682.3	2,682.3
Investment in entities accounted for at equity	-	-	61.7	61.7
Long-term deposits	0.5	-	-	0.5
Other long-term assets	227.2	-	286.5	513.7
Total assets	**948.3**	**1.0**	**3,043.0**	**3,992.3**
Liabilities				
Trade and other payables	1.4	0.6	104.6	106.6
Income tax payable	-	-	10.8	10.8
Bonds	1,625.6	-	-	1,625.6
Deferred taxes	-	-	391.5	391.5
Other long-term liabilities	-	-	70.5	70.5
Total liabilities	**1,627.0**	**0.6**	**577.4**	**2,205.0**
Total net balance	**(678.7)**	**0.4**	**2,465.6**	**1,787.3**

8. Report on linkage bases in Dollars in thousands, as of 31 December 2023:

	Financial Balances			
	In dollars or dollar-linked	In non-linked ILS	Non-financial	Total
Assets				
Cash and cash equivalents	28.5	0.6	-	29.1
Short-term deposits	157.4	0.2	-	157.6
Trade receivables	194.5	-	-	194.5
Other receivables	155.6	-	31.5	187.1
Investments in oil and gas assets	-	-	2,647.3	2,647.3
Investment in entities accounted for at equity	-	-	58.4	58.4
Long-term deposits	101.9	-	-	101.9
Other long-term assets	229.2	-	241.1	470.3
Total assets	**867.1**	**0.8**	**2,978.3**	**3,846.2**
Liabilities				
Other short-term liabilities	-	-	2.2	2.2
Trade and other payables	75.9	0.4	24.8	101.1
Income tax payable	-	-	27.7	27.7
Short-term loan from banking corporation	80.0	-	-	80.0
Bonds	1,735.1	-	-	1,735.1
Deferred taxes	-	-	313.9	313.9
Other long-term liabilities	-	-	73.7	73.7
Total liabilities	**1,891.0**	**0.4**	**442.3**	**2,333.7**
Total net balance	**(1,023.9)**	**0.4**	**2,536.0**	**1,512.5**

Part Three – Corporate Governance Aspects

1. The Partnership's donation policy

In November 2023, the General Partner's board of directors resolved to adopt a detailed donation policy, under which, *inter alia*, the total annual donations shall not exceed 0.25% of the Partnership's annual pre-tax profit. The General Partner's board of directors intends to allocate a significant portion of the donation budget to support the many communities who have been negatively affected by the Swords of Iron War as described above. In 2024, the Partnership donated approx. ILS 4.5 million.

2. Directors having accounting and financial expertise

The board of directors of the General Partner has determined, pursuant to Section 92(a)(12) of the Companies Law, that the minimum appropriate number of directors having accounting and financial expertise shall be one. The board of directors of the General Partner believes that considering the type of business of the company which, as aforesaid, is the General Partner in a partnership that is primarily engaged in the field of natural gas, condensate and oil exploration, development and production and the vast business experience of the directors (also those who do not fulfill the definition of "having accounting and financial expertise"), the minimum number as aforesaid allows the board of directors to fulfill the obligations imposed thereon pursuant to the law and the documents of incorporation of the Partnership, in respect of the examination of the Partnership's financial position and the preparation and approval of the financial statements. The aforesaid reasons are accompanied by the fact that pursuant to the Partnership's work procedure, the auditors of the financial statements are invited to every board meeting at which the financial statements are discussed, and are available to give the members of the board of directors any explanation required in relation to the financial statements and the financial position of the Partnership, both in and outside of the meetings in which they participate. In addition, it is noted that under the law any director who so wishes is entitled, in circumstances that so justify and under the conditions set forth in the law, to receive professional advice, at the expense of the General Partner, in order to perform his work, including accounting and financial advice.

As of the report approval date, 5 directors with accounting and financial expertise serve on the General Partner's board of directors (Messrs. Efraim Sadka, Yoram Cohen, Eli Zamir, Tamir Poliker and Yair Neuman). For details regarding the education, experience and qualifications of these directors, see Section 26 of Chapter D of this Report (Additional Details regarding the Partnership).

3. Independent directors

The Partnership did not adopt a clause in the Trust and Partnership Agreements with regard to the number of independent directors, as they are defined by the Companies Law. As of the date of approval of the report, 2 external directors and another independent director serve on the General Partner's board of directors. For details on the independence of the directors, see Section 26 of Chapter D of this Report (Additional Details on the Partnership).

4. Disclosure on the internal auditor at the Partnership

a. Details of the internal auditor

1) Internal auditor's name: CPA Gali Gana.

   Date of commencement of office: 1 February 2016.

2) His qualifications for the position:

   The internal auditor fulfills the terms and conditions set forth in Sections 3(a) and 8 of the Internal Audit Law, 5752-1992 (the "**Internal Audit Law**") and Section 146(b) of the Companies Law.

   A CPA with a degree in Business Administration majoring in accounting, and an M.A. in Public Administration and Internal Audit, Certified Information Systems Auditor (CISA), Certified Internal Auditor (CIA), Certified in Risk Management Assurance (CRMA), Certified in Risk and Information Systems Control (CRISC), Certified in Data Privacy Solutions Engineer (CDPSE).

3) The internal auditor is not an employee of the Partnership, but rather provides internal audit services thereto by outsourcing. In addition, the internal auditor provides the Partnership with services for examination of the effectiveness of the controls over processes in connection with the internal control of the Partnership's financial statement (ISOX). The internal auditor is a partner at the accounting firm Rosenblum Holtzman.

4) The internal auditor holds no other office at the Partnership in addition to the internal audit.

5) The internal auditor also serves as the internal auditor of the General Partner of the Partnership and of the control holder. His service as the internal auditor of the aforesaid corporations does not create a conflict of interests with his function as the internal auditor at the Partnership.

6) The internal auditor is not an interested party of the Partnership or a relative of an interested party of the Partnership and is also not the auditor or another on his behalf.

7) The internal auditor does not hold securities of the Partnership or of a body affiliated therewith.

b. **Appointment procedure**

The appointment of Mr. Gana as the internal auditor was approved by the board of directors of the General Partner on 27 January 2016, following its acceptance of the recommendation of the audit committee, and after it found him to have the appropriate qualifications for the position, *inter alia* in view of his specialization and vast experience in the field of internal audit, and after Mr. Gana declared that he meets all of the eligibility requirements needed to fulfill his position as internal auditor pursuant to law, considering, *inter alia*, the Partnership's type, size and the scope and complexity of its operations.

c. **Identity of the organizational supervisor of the internal auditor**

The chairman of the board of directors of the General Partner.

d. **The work plan**

The internal audit performs audits on many issues in accordance with a carefully crafted plan, the results of which are discussed at the audit committee. The internal audit budget is approved by the audit committee. The work plan of the internal audit is prepared by the internal auditor in coordination with the General Partner's management, and is based on the risk survey for the determination of the audit targets performed by the internal auditor, from which the audit topics are derived. The plan is presented to the audit committee and the board of directors of the General Partner and is approved by the audit committee.

The work plan leaves the internal auditor discretion to deviate therefrom, subject to the approval of the audit committee.

Transactions as set forth in Sections 65UU-65YY of the Partnerships Ordinance [New Version], 5735-1975 which were performed in the Report Year, including their approval processes, are examined by the internal auditor as part of his multi-year work plan.

In addition to the internal auditor's work and pursuant to the joint operating agreement (JOA), the Partnership performs, through external companies, a joint audit with its partners in the projects Leviathan and Block 12 in Cyprus, over the work of the operator in the projects as aforesaid. The Partnership's VP Budget and Control participates in the preparation, monitoring and supervision meetings of the audit as aforesaid and the internal auditor reports to the audit committee and the board of directors of the General Partner on its findings and results.

e. **Scope of engagement**

The number of hours is determined according to the needs of the approved annual audit, in the budget determined upon commencement of the internal auditor's term of office. The scope of the internal auditor's engagement at the Partnership and at the General Partner in the reporting year totaled approx. 600 hours.

The scope of the internal auditor's engagement was determined, *inter alia*, based on the size and complexity of the Partnership's business activity. The General Partner's management, the audit committee and the board of directors of the General Partner have the option to expand the scope of the plan according to the circumstances.

The management, the audit committee and the Chairman of the Board have the option to change the scope of the plan, upon the request of the internal auditor and according to his recommendations or according to the instructions of the audit committee.

f. **Conduct of the audit**

The internal audit is conducted according to the internal audit standards that are accepted in Israel and worldwide, and in accordance with professional directives in the field of internal auditing, as set forth in Section 4(b) of the Internal Audit Law.

The board of directors of the General Partner is satisfied, in accordance with the audit committee's examination, that the auditor has fulfilled all of the requirements and the conditions that were stated above, considering the internal auditor's notice, as delivered to the audit committee and the board of directors of the General Partner.

g. **Access to information**

The internal auditor has full, unlimited, constant and direct access to the Partnership's information systems, including financial figures for the purpose of the audit pursuant to Section 9 of the Internal Audit Law.

h. **The internal auditor's report**

The internal auditor's report was submitted in writing.

After submission of the audit reports to the General Partner's management and receipt of its position, audit reports were submitted to the chairman of the board, the members of the audit committee and the members of the General Partner's board of directors and discussed at length by the audit committee. Below are dates on which the audit committee discussed the internal auditor's reports: 24 June 2024, 17 November 2024 and 24 December 2024.

i. **Board of directors' assessment of the internal auditor's activity**

The board of directors of the General Partner estimates, in accordance with the audit committee's examination, that the scope, nature and continuousness of the activity and work plan of the internal auditor of the General Partner are reasonable, considering the organizational structure, the nature and scope of the business activities of the Partnership, and achieve the objectives of the internal audit.

j. **Compensation**

In 2024, the Partnership recorded a total annual expense of ILS 136 thousand in respect of the internal audit services. The General Partner's board of directors has determined, in accordance with the audit committee's examination, that the compensation is reasonable and does not affect the exercise of the internal auditor's independent professional discretion.

5. Auditors' fees

The Partnership has joint auditors: BDO Ziv Haft and EY – Kost Forer Gabbay & Kasierer.

Following is a specification of the amounts of the fees of the auditors at the Partnership, and the Partnership's share of the auditors' fees in the joint ventures:

	Y2024		Y2023	
	For audit, audit-related and tax services	For other services*	For audit, audit-related and tax services	For other services*
	ILS in thousands			
Kost Forer Gabbay & Kasierer and Ziv Haft, co-auditors	1,090	555	1,093	542

*** Other services, mainly in connection with offerings and tax consultancy.**

According to the Companies Law, the auditor's fee for the audit work is determined by the general meeting, which has empowered the General Partner's board of directors for this purpose. The organ that authorizes the auditors' fees for the audit work as well as for other services is the board of directors of the General Partner, after the audit committee examines the scope of the auditors' work and their fees (in the context of such examination considers the financial statements review committee's evaluation and the auditor's work) and presents its recommendations to the board of directors of the General Partner.

6. The Partnership's policy on negligible transactions

On 11 March 2009, the board of directors of the General Partner adopted, for the first time, guidelines and rules for the classification of a transaction of the Partnership with an interested party therein as a negligible transaction, as stated in Regulation 41(a3) of the Securities Regulations (Annual Financial Statements), 5710-2010 (the "**Negligibility Procedure**" and "**Reporting Regulations**", respectively). The Negligibility Procedure has been updated over the years and was updated by the audit committee and the board of the General Partner on 14 March 2019 and 17 March 2019, respectively.

The audit committee and board of directors of the General Partner (within the approval of the annual report) determined that a transaction shall be considered a negligible transaction if it fulfills all of the following conditions:

a. It is not an irregular transaction (as this term is defined in the Companies Law).

b. In any transaction for which the negligibility threshold is examined, the criterion that is relevant to the contemplated transaction shall be examined before the event as specified below: insofar as each of the criteria that are relevant to the transaction (as specified in sub-sections 1-5 below) is at a rate of no more than 0.8% and the scope of the transaction does not exceed $1,000,000 (the "**Negligibility Threshold**"), the transaction shall be considered as negligible:

1) In a purchase/sale of a fixed asset – the scope of the asset contemplated in the transaction divided by the total assets of the Partnership according the last reviewed or audited financial statements, as the case may be.

2) A sale of products or services: the sale volume contemplated in the transaction divided by the total annual sales, calculated based on the last four quarters regarding which reviewed or audited financial statements were released.

3) A purchase of products or services – the scope of the expenses contemplated in the transaction divided by the total annual operating expenses that are relevant to the transaction calculated based on the last four quarters regarding which reviewed or audited financial statements were released.

4) An assumption of a financial liability – the undertaking contemplated in the transaction divided by the total liabilities according to the latest reviewed or audited financial statements, as the case may be.

5) Insurance transactions – the premium shall be examined as the transaction amount, as distinguished from the scope of the

insurance coverage that is given.

The aforesaid notwithstanding, in transactions in which the Partnership will enter into joint agreements with an interested party therein and/or the control holder for the receipt of consultation and/or management services from employees or third parties in various fields – the transaction shall be considered negligible if it meets all of the rules of the Negligibility Procedure (other than the Negligibility Threshold), provided that the scope of the annual expenses for the services contemplated in the transaction does not exceed ILS 1.5 million and that the terms of the engagement in joint agreements in respect of the Partnership do not differ from the terms with respect to the interested party and/or the control holder, considering their proportionate share.

c. In cases where, according to the discretion of the audit committee, all of the criteria as aforesaid are irrelevant to the contemplated transaction, the audit committee shall determine other criteria, provided that the scope of the transaction shall not exceed the rules that have been set forth above.

d. The transaction is negligible also from the qualitative aspect. Thus, one of the criteria for such examination is that the transaction is not classified by the Partnership as an event which is required to be reported according to the provisions of Regulation 36 to the Reporting Regulations.

e. In multi-annual transactions (such as a lease of a property for several years) the negligibility of the transaction shall be examined on an annual basis (by calendar year) (in other words, in the aforesaid example, the annual rent shall be examined).

f. The negligibility of each transaction shall be examined separately, although the negligibility of integrated or contingent transactions shall be examined in the aggregate. Transactions that are performed frequently during the year and in close time proximity to one another shall be deemed as integrated transactions.

g. For the purpose of disclosure in the periodic report the negligibility of each transaction shall be examined on an annual basis while combining all of the same-kind transactions that were performed with the interested party or the control holder, as the case may be, in the Report Year.

h. In cases where questions arise with regard to the implementation of the aforesaid criteria, the Partnership shall exercise discretion and examine the negligibility of the transaction based on the purpose of the Reporting Regulations and the rules and guidelines above.

i. Each year, the Partnership's management shall present to the audit committee transactions with interested parties to which the

Partnership is a party and which were classified as negligible transactions under the procedure, and the audit committee will review the implementation of the provisions of the said procedure by the Partnership.

7. Internal enforcement and code of ethics

a. The board of directors of the General Partner has determined that the audit committee will be in charge of the adoption of an internal enforcement program in respect of securities, for the management of the program and for the ongoing follow-up and supervision of the performance thereof. Accordingly, in July 2022, the audit committee approved an updated internal enforcement program in respect of securities (the "**Enforcement Program**"), according to the criteria published by the ISA and based on the results of a current compliance survey that was conducted at the Partnership prior to approval of the Enforcement Program. In this context, among other things, the procedures were updated according to the changes in the law from the adoption of the previous enforcement program and in accordance with the results of the said survey. The Partnership updates the Enforcement Program on a regular basis, according to developments in its business and to changes in the law (if any).

b. The Partnership adopted a monitoring and control procedure for the operator's environmental, health & safety activity (the "**EHS Procedure**") which is designed to ensure that the operator acts in compliance with the provisions of the law in these matters. The audit committee approved the EHS Procedure and appointed an EHS officer at the Partnership.

c. The Partnership is acting to implement the provisions of the Privacy Protection Law, 5741-1981 and the Privacy Protection Regulations (Information Security), 5777-2017. Furthermore, the Partnership established an information security and cyber protection policy and is acting to implement the same by assimilation of organizational procedures. The audit committee was authorized as the entity in charge of ongoing reporting, monitoring and supervision of these matters.

d. The Partnership has a code of ethics specifying the proper rules of conduct and principles for the purpose of guidance of the actions of all of the officers and employees at the Partnership, in accordance with the fundamental values according to which the Partnership operates.

The Partnership provides training for its officers and employees in accordance with the provisions of the enforcement plan and the procedures thereunder, the information security procedures and the code of ethics.

8. Corporate Social Responsibility at the Partnership ("ESG")

In view of the importance that the Partnership attributes to the corporate responsibility **("ESG")**, the General Partner's board of directors decided in February 2022 to update the Partnership's targets and strategy in this area, and for such purpose, it authorized the audit committee as the function responsible for handling the corporate responsibility matters within the Partnership. The audit committee appointed a corporate responsibility officer within the Partnership, who is in charge of managing the risks in this area. The audit committee receives periodic reports from such officer and from the internal auditor of the Partnership, who conducts independent audits on ESG, with a focus on environmental issues and climate change. The most recent audit on this issue was conducted in 2024.

In addition, the Partnership's board of directors oversees the management of the risks and opportunities related to climate change. In this context, the audit committee supervises the ESG area and has appointed a person responsible for, *inter alia*, the management of risks and performance in this area. The audit committee, which operates under the board of directors, receives periodic reports from the ESG officer and the internal auditor of the Partnership, who conducts independent audits on ESG-related matters, with a focus on environmental issues and climate change. The most recent audit on this issue was conducted in 2024.

In February 2022, a first corporate social responsibility report for 2020-2021 was posted on the Partnership's website, and in June 2024, a second report for 2022-2023 was posted, which was prepared in accordance with GRI (Global Reporting Initiatives) standards and in the spirit of the recommendations of the TCFD (Task Force on Climate-related Financial Disclosures). The Partnership intends to release an ESG report for 2024 in H1/2025.

Part Four – Disclosure in connection with the Partnership's Financial Reporting

1. Initial presentation of consolidated financial statements

See Note 1D6 to the financial statements (Chapter C of this Report)

2. Subsequent events

See Note 22 to the financial statements (Chapter C of this Report).

Part Five – Details of bonds issued by Leviathan Bond Ltd.

Leviathan Bond bond series	2025	2027	2030
Par value on the issue date	600	600	550
Issue date	18 August 2020	18 August 2020	18 August 2020
Par value as of 31 December 2024	600	600	550
Linked par value as of 31 December 2024	600	600	550
Value on the Partnership's books as of 31 December 2024[5]	485.6	596.5	543.5
TASE value as of 31 December 2024[6]	484.3	582.8	522.5
Fixed annual interest rate	6.125%	6.500%	6.750%
Principal payment date	30 June 2025	30 June 2027	30 June 2030
Interest payment dates	Semiannual interest payable on every June 30th and every December 30th from the issue date in 2020-2025	Semiannual interest payable on every June 30th and every December 30th from the issue date in 2020-2027	Semiannual interest payable on every June 30th and every December 30th from the issue date in 2020-2030
Linkage base: base index[7]	None		
Conversion right	None		
Right to prepayment or mandatory conversion[8]	Right to prepayment		
Guarantee for payment of the liability	See Note 10B to the financial statements (Chapter C of this Report)		
Name of the trustee	HSBC Bank USA, National Association		
Name of person in charge at the trust company	Asma Alghofailey		
Trustee's address and e-mail	HSBC Bank USA, National Association, as TRUSTEE 452 5th Avenue, 8E6 New York, NY 10018 asma.x.alghofailey@us.hsbc.com		
Rating as of the issue date[9]	Fitch Rating: BB stable Moody's: Ba3 Stable S&P: BB- Stable Standard & Poor's Maalot: ilA+ stable		

[5] See Section [3E] of Part One above on the bond buyback plan adopted by the board of directors.
[6] The bonds are traded in Israel on the "TACT-institutional" system on TASE.
[7] The bonds' principal and interest are stated in dollars.
[8] The financing documents prescribe provisions regarding early redemption of the bonds, including (1) early redemption initiated by the issuer, subject to payment of a prepayment fee (make whole premium); and (2) mandatory early redemption in certain cases that were defined, including by way of a buyback of bonds and/or the issue of a tender offer to all of the bondholders, including upon a sale of all or some of the interests in the Leviathan project.
[9] See the Partnership's immediate reports of 19 August 2020 (Ref. No. 2020-01-090852 and 2020-01-091134) and 23 August 2020 (Ref. No. 2020-01-092247), the information in which is incorporated herein by reference.

Leviathan Bond bond series	2025	2027	2030
Rating as of the report approval date[10]	Fitch Rating: BB Rating Watch Negative Moody's: Ba3 Negative S&P: BB- Negative Standard & Poor's Maalot: ilA+ Negative		
Has the Partnership fulfilled, by 31 December 2024 and during the Report Year, all of the conditions and obligations under the indenture	Yes		
Is the bond series material[11]	Yes		
Have any conditions establishing cause for acceleration of the bonds been fulfilled	No		
Pledges to secure the bonds	See Note 10B to the financial statements (Chapter C of this Report)		

[10] In view of the aforesaid regarding the events of the Swords of Iron War, the rating agencies have updated the bonds' rating outlook and forecast - see immediate reports of 26 October 2023, 1 November 2023, 6 November 2023, 6 November 2023, 4 March 2024, 18 March 2024, 18 March 2024, 9 April 2024, 26 June 2024, 15 October 2024, 15 October 2024 and 29 October 2024 (Ref.: 2023-01-098338, 2023-01-100228, 2023-01-122076, 2023-01-122103, 2024-01-022044, 2024-01-027651, 2024-01-027663, 2024-01-035209, 2024-01-064786, 2024-01-611118, 2024-01-611121 and 2024-01-612302 respectively), the information in which is incorporated herein by reference. On 13 February 2025, Moody's rating agency informed that it prepared a periodic review of the bonds rating, and left the rating and rating outlook unchanged.

[11] A series of bond certificates will be deemed material if the total liabilities of the corporation thereunder as of the end of the Report Year, as presented in the financial statements, constitute five percent or more of the total liabilities of the corporation.

Additional information

The General Partner's board of directors expresses its appreciation for the Partnership's management, the officers and the entire team of employees for their dedicated work and their significant contribution to the promotion of the Partnership's business.

Sincerely,

Yossi Abu	**Gabi Last**
CEO	Chairman of the Board

NewMed Energy Management Ltd.
On behalf of: NewMed Energy – Limited Partnership

Annex A to the Board of Directors' Report

Figures regarding Leviathan Bond Ltd.

Further to Note 10B to the financial statements (Chapter C of this Report) and to Part Five of the Board of Directors' Report, and following a tax ruling received by the Partnership immediately prior to the bond offering, below are financial figures which will be disclosed to the holders of the Leviathan Bond bonds.

Statements of Financial Position (Expressed in US$ Thousands)

	31.12.2024 Audited	31.12.2023 Audited
Assets:		
Current Assets:		
Short term Bank deposits	258,039	33
Loans to shareholders	599,611	-
Related parties	**	**
	857,650	33
Noncurrent Assets:		
Loans to shareholders	1,148,799	1,749,034
Long term bank deposits	-	101,411
	1,148,799	1,850,445
	2,006,449	1,850,478
Liabilities and Equity:		
Current Liabilities:		
Bonds	600,000	-
Related parties	158,039	1,444
	758,039	1,444
Noncurrent Liabilities:		
Bonds	1,150,000	1,750,000
Loans from shareholders	100,000	100,000
	1,250,000	1,850,000
Equity (Deficit)	(1,590)	(966)
	2,006,449	1,850,478

** Less than $1,000

Statements of Comprehensive Income (Expressed in US$ Thousands)

	For the year Ended 31.12.2024 Audited	For the year Ended 31.12.2023 Audited
Financial expenses	125,079	134,437
Financial income	(124,455)	(134,243)
Total comprehensive expenses (income)	624	194

SPONSOR FINANCIAL DATA REPORT[12]

	ITEM	YEAR ENDED 31.12.2024 QUANTITY/ACTUAL AMOUNT (IN USD$,000)
A.	Total Offtake (BCM)	11.2[13]
B.	Leviathan Revenues (100%)	2,506,067[14]
C.	Loss Proceeds, if any, paid to Revenue Account	-
D.	Sponsor Deposits, if any, into Revenue Account	-
E.	Gross Revenues (before Royalties)	1,129,565
F.	Overriding Royalties	
	(a) Statutory Royalties	(124,866)
	(b) Third Party Royalties	(49,526)
G.	Net Revenues	955,173
H.	Costs and Expenses:	
	(a) Interest Income (Fees Under the Financing Documents)	4,399
	(b) Taxes	(94,214)
	(c) Operation and Maintenance Expenses	(156,999)
	(d) Capital Expenditures	(155,593)
	(e) Insurance	(24,852)
I.	Total Costs and Expenses (sum of Items H(a), (b), (c), (d) and (e))	(472,259)
J.	Total Cash Flows Available for Debt Service (Item G *minus* Item H)	527,914
K.	Total Cash Flow from operation (Item G minus Items H(c) and H(e)	773,322
L.	Total Debt Service	166,173[15]
M.	Total Distribution to the Sponsor	282,500

[12] The aforesaid report is delivered to the trustee for the bonds on a quarterly and annual basis and represents the cash flow deriving for the Partnership from the Leviathan project relative to the amounts required for the debt service in such period.

[13] Gas sales from 1 January 2024 until 31 December 2024 for 100% of the Leviathan partners on an accrual basis.

[14] Gas sales from 1 January 2024 until 31 December 2024 for 100% of the Leviathan partners on an accrual basis.

[15]Including buyback of bonds by the sponsor of approximately $53 Million.

Annex B to the Board of Directors' Report

Summary of Data from a Valuation of Royalties from the Karish and Tanin Leases

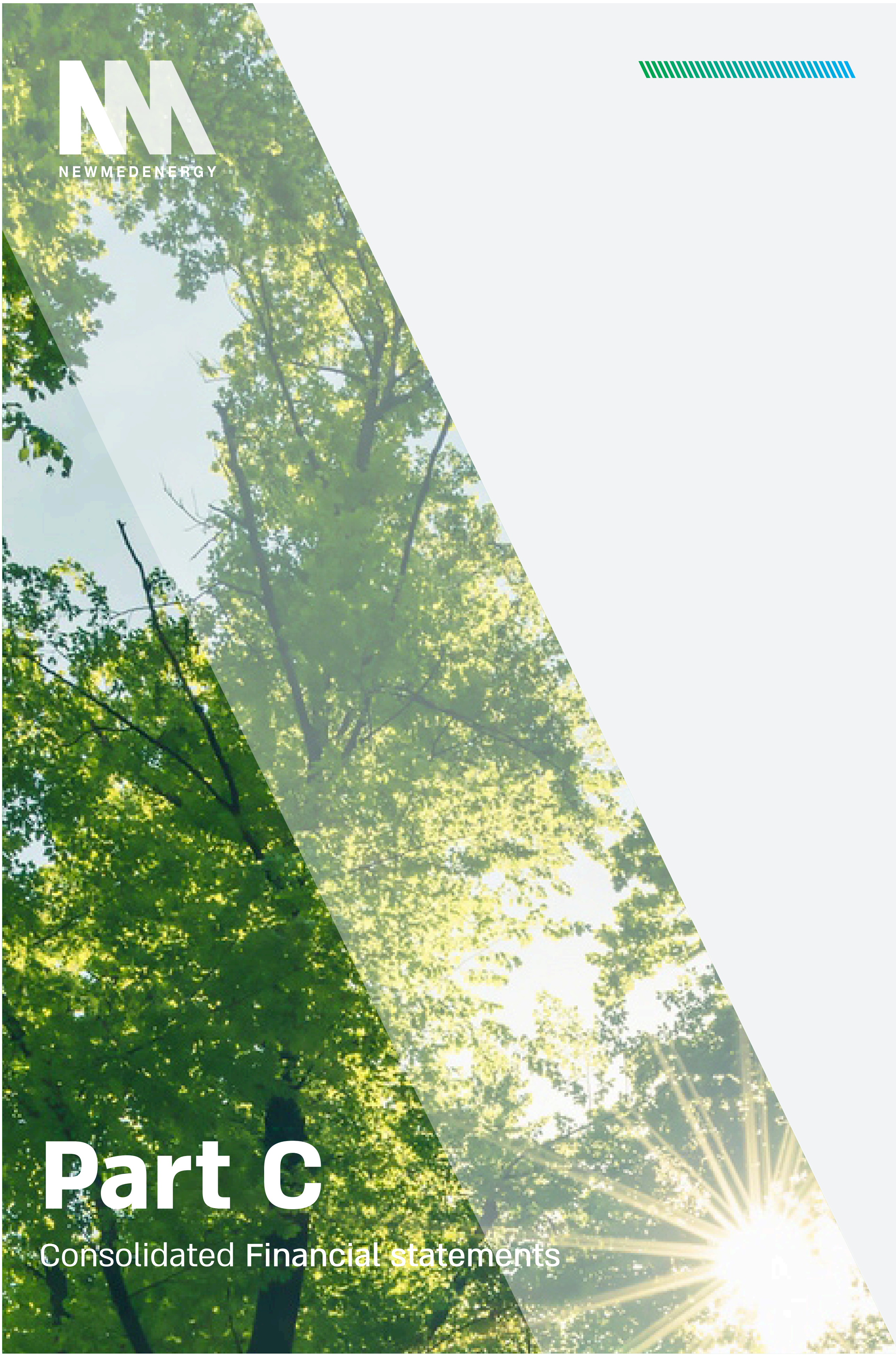
Following are details of a highly material valuation with respect to the profit from the revaluation of royalties from the sale of the Partnership's interests in the Karish and Tanin leases (for further details, see Note 8B to the financial statements (Chapter C of this Report) and the valuation attached below):

Identification of the object of the valuation:	**Royalties in respect of the sale of all of the interests in the Karish and Tanin leases.**
Timing of the valuation:	31 December 2024
Value of the object of the valuation shortly before the date of the valuation, if GAAP, including depreciation and amortization, did not warrant a change in its value according to the valuation:	Not applicable.
Value of the object of the valuation determined according to the valuation:	A sum of approx. $278 million, which is included under other long-term assets of the Partnership and in the Partnership's short-term receivables.
Identification of the valuator and his/its characteristics, including education, experience in the preparation of valuations for accounting purposes in reporting corporations and in scopes similar to or exceeding those of the reported valuation, and dependence on the party commissioning the valuation, including reference to indemnification agreements with the valuator:	Giza Singer Even Financial Advisory Ltd. is a subsidiary of Giza Singer Even Ltd. (jointly: the "**Valuator**"), which is a leading financial consulting and investment banking firm in Israel. The firm has vast experience in supporting the largest companies in the most prominent privatizations and the most important transactions in the Israeli market, which experience was gained thereby over the course of its 30 years of activity. Giza Singer Even is active in three segments, through autonomous and independent business divisions: economic consulting; investment banking; analytical research and corporate governance. The work was performed by a team headed by CPA Gadi Beeri, Head of Economic Division and Corporate Finance and a senior executive at Giza Singer Even. Mr. Beeri has expertise and vast experience in corporate finance and financial consultancy. He holds a B.A. in Economics and an MBA from the Tel Aviv University. The Valuator has no personal interest in and/or dependence on the Partnership and/or NewMed Energy Management Ltd., the general partner of the Partnership (the "**General Partner**"), other than the fact that it

Identification of the object of the valuation:	Royalties in respect of the sale of all of the interests in the Karish and Tanin leases.
	received a fee for the valuation. Furthermore, the Valuator has confirmed that its fee is not contingent on the results of the valuation. In addition, insofar as the Valuator shall be bound by a peremptory judgment to pay any sum to a third party in connection with the work, the Partnership shall pay the Valuator the sum charged to the Valuator in excess of the fee paid for the work multiplied by 3. This indemnification undertaking shall not apply should it be ruled that the Valuator acted with negligence or intentional misconduct in connection with the performance of the work.
The valuation model applied by the Valuator:	Discounting expected cash flows while adjusting the discount rates to the risks entailed by the cash flow forecasts.
The assumptions based on which the Valuator prepared the valuation according to the valuation model:	The key assumptions underlying the valuation are as follows: 1. Period of production from the Karish lease: 1 October 2022 to 31 December 2044; 2. Average annual rate of natural gas production from the Karish lease: approx. 3.25 BCM; average annual rate of condensate production from the Karish lease: approx. 4.43 million barrels; 3. Period of production of gas from the Tanin reservoir: 1 January 2029 to 31 December 2041; 4. Average annual rate of natural gas production from the Tanin lease: approx. 1.99 BCM; average annual rate of condensate production from the Tanin lease: approx. 0.34 million barrels; 5. Royalty component cap rate: 11.4%; 6. Effective royalty rate to be paid to the State for the gas and the condensate: 11.06%; 7. Gas price formula: The basic price in the contracts according to which the valuation was prepared was estimated based on the formula

Identification of the object of the valuation:	Royalties in respect of the sale of all of the interests in the Karish and Tanin leases.
	specified in the price mechanism between Energean and ICL and ORL and between Energean and OPC and weighting the price of the gas in the Ramat Hovav contract; 8. Condensate price: The condensate price forecast was estimated based on a long-term oil price forecast average of the World Bank[16] and the EIA[17] and the forward prices of Brent according to Bloomberg data and based on the assumption that the condensate price will be derived from the Brent price with adjustments to oil quality differences; 9. On 21 March 2024, Energean released an updated resource report of D&M (the "**Updated Report**"), a certified reserves and resources valuator, for the Karish and Tanin leases. According to the Updated Report, the gas quantity in the Karish reservoir is approx. 33.4 BCM and the quantity of the hydrocarbon liquids is approx. 53.2 MMBBL; the gas quantity in the Karish North reservoir is approx. 37.0 BCM and the quantity of the hydrocarbon liquids is approx. 40.7 MMBBL; and the gas quantity in the Tanin lease is approx. 25.9 BCM and the quantity of the hydrocarbon liquids is approx. 4.4 MMBBL. 10. Petroleum profit levy: According to the Petroleum Profit Taxation Law, 5771-2011; 11. Corporate tax rate: 23%.

[16] A World Bank quarterly report: Commodity Markets Outlook, October 2024.
[17] U.S Energy Information Administration: Short-Term Energy Outlook, December 2024.



Part C

Consolidated Financial statements

9 March 2025

To

The Board of Directors of the General Partner of NewMed Energy – Limited Partnership (the "Partnership")

19 Abba Eban, Herzliya

Dear Sir/Madam,

Re: Consent given simultaneously with the release of a periodic report in connection with the shelf prospectus of the Partnership (the "Offering Document")

We hereby notify you that we agree to the inclusion (including by way of reference) in the above referenced Offering Document of our reports as specified below:

1. Auditors' report of 9 March 2025 on the Partnership's consolidated financial statements as of 31 December 2024 and 2023 and for each of the three years in the period ended 31 December 2024.

2. The Auditors' report of 9 March 2025 on the audit of components of internal control over financial reporting of the Partnership as of 31 December 2024.

Kost Forer Gabbay & Kasierer	Ziv Haft
Certified Public Accountants	Certified Public Accountants

NewMed Energy – Limited Partnership

Consolidated Financial Statements as of 31 December 2024

in U.S. Dollars in Millions

This report is a translation of NewMed Energy - Limited Partnership's Hebrew-language financial statements, prepared solely for convenience purposes. Please note that the Hebrew version is the binding version, and in any event of discrepancy, the Hebrew version shall prevail.

NewMed Energy – Limited Partnership

Consolidated Financial Statements as of 31 December 2024

in U.S. Dollars in Millions

Contents

Independent Auditors' Report to the Partners of NewMed Energy - Limited Partnership regarding Audit of Components of Internal Control over Financial Reporting pursuant to Section 9B(c) of the Securities Regulations (Periodic and Immediate Reports), 5730-1970

We have audited components of internal control over financial reporting of NewMed Energy – Limited Partnership **and subsidiaries (jointly:** the "**Partnership**") as of 31 December 2024. These components of control were determined as explained in the next paragraph. The Board of Directors of the general partner and the Partnership's Management are responsible for maintaining effective internal control over financial reporting and for their assessment of the effectiveness of the components of internal control over financial reporting, attached to the periodic report as of the above date. Our responsibility is to express an opinion on the components of internal control over financial reporting of the Partnership, based on our audit.

The components of the internal control over financial reporting that were audited were determined pursuant to Audit Standard (Israel) 911 of the Institute of Certified Public Accountants in Israel "Audit of Components of Internal Control over Financial Reporting" ("**Audit Standard (Israel) 911**"). These Components are: 1) Entity-level controls, including controls over the financial reporting and closing process and ITGCs; 2) Controls over the calculating process versus the operators of the joint ventures; 3) Controls over the process of cash management including investments and process of raising and management of bonds and loans (all hereinafter jointly referred to as: the "**Audited Components of Control**").

We conducted our audit pursuant to Audit Standard (Israel) 911. This Standard requires that we plan and perform the audit with the purpose of identifying the Audited Components of Control, and to obtain reasonable assurance about whether these components of control were effectively maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, identifying the Audited Components of Control, assessing the risk that a material weakness exists in the Audited Components of Control, and testing and evaluating the design and operating effectiveness of such components of control, based on the assessed risk. Our audit of such components of control also included performing such other procedures as we considered necessary in the circumstances. Our audit only referred to the Audited Components of Control, as opposed to internal control over all of the material processes in connection with the financial reporting, and therefore our opinion refers only to the Audited Components of Control. In addition, our audit did not address mutual effects between the Audited Components of Control and non-audited controls, and therefore, our opinion does not take into consideration such possible effects. We believe that our audit provides a reasonable basis for our opinion in the context described above.

Because of its inherent limitations, internal control over financial reporting in general and components thereof in particular, may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Partnership effectively maintained, in all material respects, the Audited Components of Control as of 31 December 2024.

We have also audited, based on Generally Accepted Auditing Standards in Israel, the consolidated financial statements of the Partnership as of 31 December 2024 and 2023, and for each of the three years in the period ended 31 December 2024, and our report of 9 March 2025 included an unqualified opinion on the aforesaid financial statements.

Tel Aviv, 9 March 2025

Kost Forer Gabbay & Kasierer	**Ziv Haft**
Certified Public Accountants	**Certified Public Accountants**

Independent Auditors' Report to the Partners of NewMed Energy – Limited Partnership

We have audited the accompanying consolidated statements of financial position of NewMed Energy – Limited Partnership (the "**Partnership**") as of 31 December 2024 and 2023 and the consolidated statements of comprehensive income, changes in equity and f cash flows for each of the years in the three-year period ended 31 December 2024. The board of the general partner and the management of the Partnership are responsible for these financial statements. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Generally Accepted Auditing Standards in Israel, including standards set in the Accountants Regulations (Mode of Operation of Accountants) 5733-1973. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by the board of the general partner and the management of the Partnership, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Partnership and its consolidated companies as of 31 December 2024 and 2023 and the results of their operations, the changes in equity and the cash flows thereof for each of the years in the three-year period ended 31 December 2024 in accordance with International Financial Reporting Standards (IFRS Accounting Standards) and the provisions of the Securities Regulations (Annual Financial Statements), 5770-2010.

Key audit matters

Key audit matters are matters that were communicated, or should have been communicated, to the board of directors of the Partnership's general partner, and which, in our professional judgement, were highly significant to the audit of the consolidated financial statements in the current period. These matters include, *inter alia*, any matter that: (1) refers or may refer to material sections or disclosures in the financial statements, and (2) our judgment in respect thereof was especially complicated, subjective or challenging. These matters will be addressed in our audit and the formation of our opinion regarding the financial statements as a whole. The communication of the following matters does not change our opinion regarding the consolidated financial statements as a whole and we are not using it as a means to provide a separate opinion regarding these matters or regarding the sections or disclosures to which they refer.

Evaluation of gas and condensate reserves

As described in Note 7 to the Partnership's consolidated financial statements, the balance of investments in oil and gas assets as of 31 December 2024 is $2,682.3 million and the depletion costs for the investments in oil and gas assets for the year ended 31 December 2024 amounts to a total of $69.7 million.

According to the Partnership's accounting policies, gas and oil assets are amortized in the depletion method based on the estimated amount of proved and probable reserves from said assets (2P).

Estimation of the gas and condensate reserves is a subjective process involving a significant degree of discretion based on the management's judgment and assumptions, via external experts having relevant knowledge and understanding regarding geological data, price estimation, future production costs, expected production rate and future development costs, if required.

Due to the extent of the impact of the estimate of gas and condensate reserves on the consolidated financial statements, and due to the judgments and subjectivity involved in the estimate as aforesaid, we identified the subject as a key audit matter. The investments in oil and gas assets, evaluation of reserves and the depletion costs of the Partnership's oil and gas assets are described in Note 7 and 2I to the financial statements.

The audit procedures applied to address the key audit matter

The main procedures we applied to this key audit matter in the framework of our audit are as follows:

- Achieving an understanding of the Partnership's existing processes and procedures regarding the estimate of the evaluation of gas and condensate reserves, and auditing the planning and implementation of controls used in the process.
- Evaluating the qualifications of the experts on behalf of the Partnership, including their skill and objectivity in performing the gas and condensate estimate, and considering whether they have professional qualifications to carry out reserves estimates for oil and gas reservoirs.
- Checking the completeness of the data underlying the evaluation of the reserves, *inter alia*, by analyzing the key changes in 2024 and comparing the reserves estimated by the Partnership to, and checking their agreement with, the information included in the gas and condensate reserves report prepared by the external experts on behalf of the Partnership.
- Checking that the updated estimates of gas and condensate reserves were properly included in the accounting treatment for determination of the depletion rate of the oil and gas assets.
- Checking the agreement of the calculations and adequacy of disclosures in the Partnership's financial statements.

We have also audited, pursuant to Audit Standard (Israel) 911 of the Institute of Certified Public Accountants in Israel "Audit of Components of Internal Control over Financial Reporting", components of the Partnership's internal control over financial reporting as of 31 December 2024 and our report as of 9 March 2025 included an unqualified opinion on the effective maintenance of such components.

Tel Aviv, 9 March 2025

Kost Forer Gabbay & Kasierer	**Ziv Haft**
Certified Public Accountants	**Certified Public Accountants**

NewMed Energy – Limited Partnership

Consolidated Statements of Financial Position (Dollars in millions)

	Note	31.12.2024	31.12.2023
Assets:			
Current assets:			
Cash and cash equivalents	3	51.2	29.1
Short-term deposits	4	333.3	157.6
Trade receivables	21G	209.6	194.5
Trade and other receivables	5	140.0	187.1
		734.1	568.3
Non-current assets:			
Investments in entities accounted for at equity	6	61.7	58.4
Investments in oil and gas assets	7	2,682.3	2,647.3
Long-term deposits	4	0.5	101.9
Other long-term assets	8	513.7	470.3
		3,258.2	3,277.9
		3,992.3	3,846.2
Liabilities and equity:			
Current liabilities:			
Current maturities of bonds	10A-C	485.6	-
Short-term liability to a banking corporation	10D	-	80.0
Income taxes payable	19	10.8	27.7
Trade and other payables	9	106.6	101.1
Other short-term liabilities	11	-	2.2
		603.0	211.0
Non-current liabilities:			
Bonds	10A-C	1,140.0	1,735.1
Deferred taxes	19	391.5	313.9
Other long-term liabilities	11	70.5	73.7
		1,602.0	2,122.7
Equity:	13		
Partners' equity		154.8	154.8
Capital reserves		(28.1)	(28.6)
Retained earnings		1,660.6	1,386.3
		1,787.3	1,512.5
		3,992.3	3,846.2

The attached notes constitute an integral part of the consolidated financial statements.

9 March 2025			
Date of approval of the Financial Statements	Gabi Last Chairman of the Board	Yossi Abu CEO	Tzachi Habusha VP Finance

NEWMEDENERGY

NewMed Energy – Limited Partnership

Consolidated Statements of Comprehensive Income (Dollars in millions)

	Note	For the year ended on		
		31.12.2024	31.12.2023	31.12.2022
Revenues:				
From natural gas and condensate sales	14	1,136.3	1,094.4	1,143.9
Net of royalties	15	163.2	159.8	172.0
Net revenues		**973.1**	**934.6**	**971.9**
Expenses and costs:				
Cost of production of natural gas and condensate	16	168.4	148.6	134.1
Depreciation, depletion and amortization expenses	7	80.7	79.2	131.0
Other direct expenses		5.9	5.3	5.2
G&A	17	16.9	20.8	19.7
Total expenses and costs		**271.9**	**253.9**	**290.0**
The Partnership's net share of earnings (losses) of entities accounted for at equity	6	2.9	(1.3)	(3.1)
Operating income		**704.1**	**679.4**	**678.8**
Financial expenses	18	(113.8)	(133.8)	(155.3)
Financial income	18	90.9	28.7	71.1
Net financial expenses		(22.9)	(105.1)	(84.2)
Income before income taxes		**681.2**	**574.3**	**594.6**
Taxes on income	19	(156.6)	)142.8(	(116.0)
Income from continuing operations		**524.6**	**431.5**	**478.6**
Income (loss) from discontinued operations		*)	2.1	(13.2)
Income from the sale of gas and oil assets		-	-	4.3
Total income (loss) from discontinued operations	7C9	*)	**2.1**	**(8.9)**
Total comprehensive income		**524.6**	**433.6**	**469.7**
Basic and diluted income (loss) per participation unit (in Dollars):				
from continuing operations		0.447	0.368	0.408
from discontinued operations		**)	0.001	(0.008)
Income per participation unit		0.447	0.369	0.400
Number of participation units weighted for the purpose of the aforesaid calculation (in thousands)		1,173,815	1,173,815	1,173,815

*) Less than $0.1 million

**) Less than $0.000

The attached notes constitute an integral part of the consolidated financial statements.

NewMed Energy – Limited Partnership –

Consolidated Statements of Changes in the Partnership's Equity (Dollars in millions)

	Equity of the Partnership	Capital Reserve for Equity-Based Financial Instruments at Fair Value against Other Comprehensive Income	Other Capital Reserves	Retained Earnings	Total
Balance as of 31 December 2021	**154.8**	**(57.0)**	**26.3**	**814.4**	**938.5**
Changes in the year ended 31 Dec. 2022:					
Comprehensive income	-	-	-	469.7	469.7
Profit distributed (Note 13C)	-	-	-	(100.3)	(100.3)
Distributable profit declared (Note 13C)	-	-	-	(50.0)	(50.0)
Balancing payments for previous years (Note 19A4)	-	-	-	2.1	2.1
Advance tax payments receivable for previous years (Note 13D)	-	-	-	26.6	26.6
Participation unit-based payment (Note 13G)	-	-	0.8	-	0.8
Balance as of 31 December 2022	**154.8**	**(57.0)**	**27.1**	**1,162.5**	**1,287.4**
Changes in the year ended 31 Dec. 2023:					
Comprehensive income	-	-	-	433.6	433.6
Profit distributed (Note 13C)	-	-	-	(210.6)	(210.6)
Advance tax payments receivable for previous years (Note 13D)	-	-	-	0.8	0.8
Participation unit-based payment (Note 13G)	-	-	1.3	-	1.3
Balance as of 31 December 2023	**154.8**	**(57.0)**	**28.4**	**1,386.3**	**1,512.5**
Changes in the year ended 31 Dec. 2024:					
Comprehensive income	-	-	-	524.6	524.6
Profit distributed (Note 13C)	-	-	-	(250.3)	(250.3)
Participation unit-based payment (Note 13G)	-	-	0.5	-	0.5
Balance as of 31 December 2024	**154.8**	**(57.0)**	**28.9**	**1,660.6**	**1,787.3**

The attached notes constitute an integral part of the consolidated financial statements.

NewMed Energy – Limited Partnership
Consolidated Statements of Cash Flows (Dollars in millions)

	31.12.2024	31.12.2023	31.12.2022
Cash Flows - Current Operations:			
Net profit	**524.6**	**433.6**	**469.7**
Adjustments for:			
Depreciation, depletion and amortization	85.2	84.3	137.6
Taxes on income	57.8	75.4	59.5
Update of asset retirement obligations	(*	(1.3)	(34.3)
Revaluation of short-term and long-term investments and deposits	(2.6)	(0.1)	(0.2)
Participation unit-based payment (Note 13G)	0.5	1.0	1.0
Revaluation of other long-term assets	(67.6)	(8.1)	(66.4)
The Partnership's net share of losses (earnings) of entities accounted for at equity	(2.9)	1.3	3.1
Income from the sale of oil and gas assets	-	-	(4.3)
Changes in asset and liability items:			
Decrease (increase) in trade receivables	(15.1)	4.5	(46.5)
Increase in trade and other receivables (including operator of joint ventures)	(1.7)	(3.1)	(4.6)
Decrease (increase) in other long-term assets	(7.5)	19.0	1.1
Increase (decrease) in trade and other payables (including operator of joint ventures)	6.8	(29.7)	(5.2)
Decrease in oil and gas profit levy liability	-	-	(5.8)
Increase in oil and gas profit levy assets	(*	(17.3)	-
	52.9	**125.9**	**35.0**
Net cash deriving from current operations	**577.5**	**559.5**	**504.7**
Cash Flows - Investment Activity:			
Investment in oil and gas assets	(114.2)	(136.4)	(98.5)
Investment in partnership accounted for at equity	(0.4)	-	-
Proceeds from the sale of oil and gas assets	-	-	14.9
Investment in other long-term assets	(31.8)	(13.2)	(28.4)
Royalties based on production from the Karish lease (Note 8B)	55.0	36.7	-
Repayment of loan provided to Energean in the context of sale of the Karish and Tanin leases (Note 8B5)	47.4	13.3	12.5
Net withdrawal of (deposit into) short-term deposits	(71.7)	238.4	(194.1)
Net decrease (increase) in short-term investments	-	-	19.2
Deposit into long-term bank deposits	-	(101.4)	-
Decrease (increase) in other receivables – for operator of the joint ventures	1.5	(1.3)	1.4
Net cash deriving from (used for) investment activity	**(114.2)**	**36.1**	**(273.4)**
Cash Flows - Financing Activity:			
Receipt (Repayment) of a short-term loan from a banking corporation	(80.0)	80.0	-
Profit distributed	(250.3)	(260.6)	(100.3)
Profit, balancing payments and tax distributed for the period up to and including 2021	-	-	(99.1)
Payments on account of the tax owed by participation unit holders for the period up to and including 2021	-	-	(170.2)
Refunds received from income tax for previous years	2.9	17.1	15.1
Early redemption of issued bonds	(113.8)	-	(74.6)
Repayment of bonds	-	(425.4)	-
Net cash used in financing activity	**(441.2)**	**(588.9)**	**(429.1)**
Increase (decrease) in cash and cash equivalents	22.1	6.7	(197.8)
Cash and cash equivalents balance at the beginning of the year	29.1	22.4	220.2
Cash and cash equivalents balance at the end of the year	51.2	29.1	22.4
Annex A – Non-cash flow finance and investment activity:			
Net investments in oil and gas assets against liabilities	59.1	63.0	3.6
Net investments in other long-term assets against liabilities	12.7	5.1	5.3
Distributable profit, balancing payments and tax declared	-	-	50.0

*) Less than $0.1 million

The attached notes constitute an integral part of the consolidated financial statements.

NewMed Energy – Limited Partnership

Consolidated Statements of Cash Flows (Dollars in millions)

	For the year ended on		
	31.12.2024	31.12.2023	31.12.2022
Annex B - Additional information on cash flows:			
Interest paid (including capitalized interest)	108.1	124.9	143.3
Interest received	24.8	17.6	7.3
Taxes and levy paid	94.3	53.1	81.6
Annex C – Sale of interests in the Tamar and Dalit Leases (see also Note 7C9)			
Includes the following assets and liabilities as of the selling date:			
Net working capital	-	-	-
Oil and gas assets	-	-	-
Other long-term assets	-	-	-
Oil and gas asset retirement obligations	-	-	-
Total assets net of liabilities	-	-	-
Proceeds received from the sale	-	-	14.8
Proceeds not yet received from the sale	-	-	(10.5)
Profit from sale of oil and gas assets	-	-	**4.3**

The attached notes constitute an integral part of the consolidated financial statements.

Note 1 – General:

A. NewMed Energy – Limited Partnership (the "**Partnership**") was founded according to a partnership agreement signed on 1 July 1993 between NewMed Energy Management Ltd. as general partner of the first part (the "**General Partner**"), and NewMed Energy Trusts Ltd. as a limited partner of the second part (the "**Limited Partner**"), as amended from time to time (the "**Partnership Agreement**").

The ongoing management of the Partnership is carried out by the General Partner under the supervision of the supervisors, Fahn Kanne & Co., Accountants, together with Keidar Supervision & Management (jointly: the "**Supervisors**" or the "**Supervisor**"). On 1 July 1993, the Limited Partner and the Supervisor signed a trust agreement, amended from time to time (the "**Trust Agreement**"), which confers on the Supervisor powers of supervision over the Partnership's management by the General Partner, as well as powers of supervision over the fulfillment of the Limited Partner's obligations to the unit holders.

The parent company of the General Partner is Delek Energy Systems Ltd. (the "**Parent Company**" and/or "**Delek Energy**"), a private company wholly owned by Delek Group Ltd. ("**Delek Group**").

The participation units of the Partnership are listed on the Tel Aviv Stock Exchange ("**TASE**") and have been traded thereon since 1993.

The address of the Partnership's registered office is 19 Abba Eban Boulevard, Herzliya.

B. As of the date of approval of the financial statements, the Partnership operates in the energy sector and its primary business is the exploration, development, production and marketing of natural gas, condensate and oil in Israel, Cyprus, Morocco and Bulgaria, and the promotion of various natural gas-based projects, aiming to increase the volume of the sales of natural gas produced by the Partnership. At the same time, the Partnership is exploring various business opportunities in the exploration, development, production and marketing of natural gas, condensate and oil in other countries, examining and promoting opportunities for investments in renewable energy projects, as part of the collaboration with Enlight Renewable Energy Ltd. ("**Enlight**") (see Note 12G(1) below), and examining possible hydrogen production projects, including blue hydrogen, which is produced from natural gas and may serve as a low-carbon substitute for energy consumers (see Note 12G(2) below).

C. The Partnership's primary petroleum asset, as of the date of approval of the consolidated financial statements, is its holding of 45.34% (out of 100%) of the Leviathan natural gas reservoir, the transmission of gas from which began in December 2019, and the partners and their holding rates in which, as of the date of approval of the consolidated financial statements, are the Partnership, Chevron Mediterranean Ltd (39.66%) and Ratio Energies – Limited Partnership (15%) ("**Chevron**" or the "**Operator**" and "**Ratio Energies**", respectively, and jointly: the "**Leviathan Partners**"). The Leviathan reservoir currently supplies natural gas to several customers in the Israeli and regional markets, and among its prominent customers are, *inter alia*, Blue Ocean Energy in Egypt ("**Blue Ocean**") and the Jordanian National Electric Power Company ("**NEPCO**"). In addition to its interests in the Leviathan reservoir, the Partnership holds interests in the Aphrodite reservoir discovered in the area of Block 12 in Cyprus ("**Aphrodite**" or "**Block 12**"), and in other petroleum assets, as specified in Notes 7 and 8B below.

Note 1 - General (Cont.):

D. As of the date of approval of the consolidated financial statements, the Partnership has holdings in several corporations:

1) Leviathan Transmission System Ltd. is a special purpose company (SPC) ("**Leviathan Transmission System**") whose shareholders are the Leviathan Partners, which hold the company's shares according to their respective holding rates in the I/14 Leviathan South and I/15 Leviathan North leases (the "**Leviathan South Lease**" and the "**Leviathan North Lease**", respectively. The Leviathan South Lease and Leviathan North Lease shall hereinafter be jointly referred to as the "**Leviathan Leases**"). The company was incorporated for the purpose of obtaining a license for natural gas transmission from the production platform of the Leviathan project to the northern entry point of the national transmission system of Israel Natural Gas Lines Ltd. ("**INGL**"), as mandated by the provisions of the Natural Gas Sector Law, 5762-2002 (the "**Natural Gas Sector Law**").
2) Yam Tethys Ltd. is an SPC incorporated by the partners in the Yam Tethys project (the "**Yam Tethys Partners**") for the purpose of obtaining a license for gas transmission from the production platform of the Yam Tethys project to the Ashdod onshore terminal ("**AOT**"), as mandated by the provisions of the Natural Gas Sector Law. As of the date of approval of the consolidated financial statements, Yam Tethys Ltd. has no operations other than its being the holder of a license for construction and operation of a gas transmission pipeline, granted thereto by the Minister of Energy & Infrastructures (the "**Minister of Energy**") on 29 April 2002, as well as other operations related to its being the license holder as aforesaid, including its being a party to various agreements in connection with the AOT and security issues.
3) NBL Jordan Marketing Limited (the "**Marketing Company**") is an SPC whose shareholders are the Leviathan Partners, which hold the company's shares according to their respective holding rates in the Leviathan Leases. The company was incorporated in connection with the Leviathan Partners' entry into a gas supply agreement with NEPCO, whereby the Marketing Company would purchase the natural gas from the Leviathan Partners at the point of entry to INGL's transmission system and sell it to NEPCO at a delivery point near the Israel-Jordan border on the same terms and conditions as specified in such gas supply agreement (back to back). For further details, see Note 12C2A below.
4) EMED Pipeline B.V. is an SPC ("**EMED BV**") registered in the Netherlands and incorporated for the purpose of the transaction for acquisition of the shares of Eastern Mediterranean Gas Company S.A.E ("**EMG**"), whose shares are held as follows: EMED Pipeline Holding Limited, a subsidiary registered in Cyprus and wholly owned by the Partnership – 25%; Chevron Cyprus Limited – 25%; and Sphinx EG BV, a wholly owned subsidiary of East Gas Company S.A.E., which holds, among other things, gas pipelines and infrastructures in Egypt (the "**Egyptian Partner**") – 50%.
5) Leviathan Bond Ltd. is an SPC ("**Leviathan Bond**") wholly owned by the Partnership, which was incorporated for the purpose of issuing bonds to the institutional markets in Israel and abroad, which bonds are secured by the Partnership's interests in the Leviathan Leases. For further details, see Note 10B below.
6) NewMed Energy UK Limited (formerly: Delek Energy Limited) is an SPC ("**NewMed Morocco**") incorporated in England and wholly owned by the Partnership, which holds interests in the Boujdour Atlantique exploration licenses situated in the Atlantic Ocean off the coast of Morocco. For further details, see Note 7C4 below. The Partnership is preparing consolidated financial statements for the first time due to NewMed Morocco's operations.

Note 1 - General (Cont.):

D. (Cont.):

7) NewMed Energy Balkan Limited is an SPC ("**NewMed Balkan**") incorporated in England and wholly owned by the Partnership, which is expected to hold interests in the Block 1-21 Han Asparuh exploration license situated in the exclusive economic zone of the Republic of Bulgaria in the Black Sea. On 9 March 2025, the compensation committee and the board of directors of the Partnership's General Partner, notwithstanding the objection of the meeting of the holders of the Partnership's participation units, approved the granting of equity compensation to Mr. Yossi Abu, CEO of the Partnership ("**Mr. Abu**"), which includes, *inter alia*, the allotment of 5% of the issued share capital of NewMed Balkan, such that following such allotment, the Partnership shall hold 95% of the issued share capital of NewMed Balkan. For further details, see Notes 7C7 and 20C6 below.
8) Enlight-NewMed Development (UK) Ltd. is an SPC ("**MedLight**") incorporated in England as part of the collaboration with Enlight, as specified in Note 12G1 below. MedLight is wholly owned by Enlight-NewMed Development, Limited Partnership (the "**Enlight Corporation**"), the participation units of which are held as follows: The Partnership – 33.33%; Yes-Enlight Holdings, Limited Partnership – 66.66% (the participation units of which are held by Enlight – 70%, and by Mr. Abu – 30%).
9) EMG is a private company registered in Egypt, which owns a subsea natural gas transmission pipeline that connects the Egyptian natural gas transmission system in the el-Arish area and the Israeli transmission system in the Ashkelon area (the "**EMG Pipeline**"), and whose shares are held as follows: EMED BV – 39%; Snam S.p.A. ("**SNAM**") – 25%; East Gas Company S.A.E. – 26%; Egyptian General Petroleum Corporation[1] – 10%.

E. The Swords of Iron War (the "War") and its impact on the Partnership's business:

Since 7 October 2023 and in the course of 2024, Israel contended with war on several fronts, including against the Hamas terrorist organization in the Gaza Strip, the Hezbollah terrorist organization in Lebanon, the Houthis terrorist organization in Yemen, the Shia Muslim militias in Iraq and against military targets in Iran. Moreover, Q1/2025 saw intensification of the fight against terrorism originating in the areas of Judea and Samaria. At the same time, during 2024, the Israeli economy has maintained a routine under the shadow of the War. 27 November 2024 saw the entry into effect of a ceasefire agreement between Israel and Lebanon, intended to stop the armed conflict on the northern front of the Swords of Iron War. As of the date of approval of the consolidated financial statements, the ceasefire on this front has generally been maintained. 19 January 2025 saw the entry into effect of an agreement signed between Israel and the Hamas terrorist organization for a hostages-and-prisoners exchange and restoration of a sustainable truce, which deal consists of two stages: A first stage of 42 days which has been concluded, and a second stage which has yet to commence. It is impossible to predict whether an agreement to extend the ceasefire will be reached or, alternatively, whether and how the armed conflict in Gaza will be resumed and unfold. To the best of the Partnership's knowledge, when the War broke out on 7 October 2023, Chevron received a notice from the Ministry of Energy, whereby, due to the security situation in Israel as a result of the War, it was required to halt the operations of natural gas production from the Tamar reservoir. Production of gas from the Tamar reservoir subsequently resumed on 13 November 2023.

[1] An Egyptian government-owned company.

Note 1 - General (Cont.):

E. The Swords of Iron War (the "War") and its impact on the Partnership's business (Cont.):

Concurrently therewith, due to the War, gas piping through the EMG Pipeline was discontinued, and resumed on 14 November 2023. At the beginning of Q4/2024, due to the escalation of the War on the northern front and against the Islamic Republic of Iran, the Operator of the Leviathan project voluntarily brought production from the Leviathan reservoir to a halt on several occasions for short periods of time. Otherwise, in the course of 2024, production from the Leviathan, Tamar and Karish reservoirs mostly proceeded as usual. In view of the voluntary suspensions of production, in October 2024, the Operator of the Leviathan project sent customers notices regarding the occurrence of a *force majeure* event that exempted the Leviathan Partners from their gas supply obligations under the gas agreements, in respect of the failure to supply gas due to the state of war, and in December 2024, the Operator sent customers notice of the conclusion of the said event. As a result of the War, operating expenses entailed by the production of gas from the Leviathan reservoir have increased in an immaterial amount, primarily due to the difficulty encountered by foreign companies in sending work crews and marine vessels to the region for the purpose of importing equipment and spare parts, which led to an increase in the rates paid, including the insurance costs of such companies, and the need for additional logistics for manpower and equipment transport. Furthermore, planned maintenance activities have been postponed, changed and modified in accordance with the instructions of security officials. Due to the state of war, the availability of equipment and contractors required for the performance of planned work in connection with the Leviathan project work plans was adversely affected, as noted, and an increase in insurance premiums and the costs of foreign contractors has also been recorded. As a result of these factors, *inter alia*, timetables for execution of projects and planned operations were adversely affected in 2024, including the postponement of the schedule for execution and completion of the project for installation of the third subsea transmission pipeline from the Leviathan field to the platform (for details, see Note 7C1(c)(1) below), and the delay and postponement of the schedule for execution and completion of the INGL project for installation of a subsea pipeline in the new offshore transmission segment between Ashdod and Ashkelon (for further details, see Note 12F2(a) below). It is emphasized that, except for the foregoing, the War had no material adverse effect on the Partnership's business in 2024, including the volumes of natural gas sales to customers and there has been no material adverse effect on revenues and profitability in this period in consequence of the War. As of the date of approval of the consolidated financial statements, it is impossible to predict whether the ceasefire on the northern front and in the Gaza Strip will be sustained and whether the War will resume and/or expand in 2025 and in the upcoming years, and what the ramifications and consequences of such developments will be and their impact on the Partnership. Under these circumstances, despite the fact that the War did not have a material effect on the Partnership's business in 2024 as noted, it is impossible to estimate the chances of materialization of the risk factors deriving from the War and their possible impact, the materialization of which might have a material adverse effect on the Partnership, its assets and its business.

Note 1 - General (Cont.):

F. On 27 March 2023, the General Partner received a non-binding indicative offer (the "**Offer**") from Abu Dhabi National Oil Company (ADNOC) P.J.S.C. and BP Exploration Operating Company Limited ("**BP**"), two international energy companies (collectively: the "**Consortium**"), regarding a possible transaction under which the Consortium will acquire, for cash, all the issued unit capital held by the public (approx. 45%) and approx. 5% of the issued unit capital from Delek Group, such that after the transaction is closed, each of the Consortium and Delek Group would hold 50% of the equity interests and control of the Partnership, by way of approval of an arrangement under Section 350 of the Companies Law, 5759-1999 (the "**Companies Law**"). On 13 March 2024, the Partnership and the Committee informed by way of an immediate report that the Committee and the Consortium had agreed, due to the uncertainty created in the external environment, to suspend discussions in relation to the transaction. They further reported that the Consortium had reiterated its interest in the transaction and that the process would be on hold until such time as discussions are resumed or the process is terminated. Of note, there is no certainty that discussions will be resumed or that an agreement will be reached in the future, nor is there certainty with respect to the terms and conditions of the agreement, if reached.

G. The financial figures of the joint ventures used by the Partnership in the preparation of its consolidated financial statements are based, *inter alia*, on documents and accounting data provided by the operators of the joint ventures in Israel, Chevron and S.O.A. Energy Israel Ltd. ("**SOA**") and the operator of the joint venture in Cyprus, Chevron Cyprus Ltd. ("**Chevron Cyprus**").

Note 2 - Significant Accounting Policies:

The accounting policy specified below was consistently applied to the consolidated financial statements of the Partnership in all the periods presented, unless otherwise indicated. The description of the accounting policy in these consolidated financial statements was pared down and modified in accordance with the requirements of International Accounting Standard 1 (**IAS 1**) which concerns the presentation of financial statements.

A. Principles of preparation of the financial statements:

1. The consolidated financial statements comply with the provisions of International Financial Reporting Standards ("**IFRS**") and include the additional disclosure required in accordance with the Securities Regulations (Annual Financial Statements), 5770-2010.
2. The consolidated financial statements were prepared applying the cost principle, with the exception of financial assets measured at fair value through profit or loss, financial liabilities measured at amortized cost and investments in companies accounted for at equity.
3. The Partnership has elected to present profit or loss items according to the expense function method.
4. The Partnership's operating cycle period is one year.

B. Functional currency:

The functional currency which best and most faithfully represents the economic effects of transactions, events and circumstances on the Partnership's business is the U.S. Dollar. Any transaction that is not in the Partnership's functional currency is a foreign currency transaction.

C. Joint ventures:

1) A joint venture constitutes a contractual arrangement, according to which two or more parties assume economic activity of oil and gas exploration in a jointly owned asset. Certain joint ventures often involve joint ownership of one or more assets.
Ventures, without the formal requirement for unanimous consent of the parties who are partners to the venture, do not meet the definition of joint control according to IFRS 11.
Nevertheless, examination of such ventures indicates that the ventures themselves have no rights in the assets and do not commit to engagements on behalf of the participants. Engagements are made directly between the participants and a third party (which is not a partner in the joint venture). However, there are engagements in which the Operator engages directly with a third party.

Note 2 - Significant Accounting Policies (Cont.):

C. Joint ventures (Cont.):

1. (Cont.)

Each participant may pledge its rights in the assets and each participant is entitled to the economic benefits deriving from the joint venture. Consequently, the participants have a relative share of the assets and liabilities attributed to the joint venture.

In respect of the Partnership's rights in activity in the jointly owned assets, the Partnership recognized in its financial statements:

a) Its share in the jointly owned assets.
b) Any liabilities it incurred.
c) Its share in any liabilities it jointly incurred in connection with activity in the jointly owned assets.
d) Any income from the sale or use of its share in the period of the jointly owned assets, together with its share in any expenses it incurred for activity in the jointly owned assets.
e) Any expenses it incurred due to its right in the jointly owned assets.

2) The Partnership presents its share in payments transferred to the Operator of the joint ventures and not yet used under the 'trade and other receivables' item, since such amounts do not meet the definition of cash and cash equivalents.

3) The Partnership presents its share in the liabilities of the joint ventures to third parties under the 'trade and other payables' item.

D. Leases:

The Partnership reached the conclusion with respect to the contracts in which the Operator engages in the context of the joint ventures, that in view of the nature of the Operator's engagement with lessors and the joint operating agreement signed in connection with the leases ("**JOA**"), such contracts do not meet the definition of a lease (head lease or sub-lease) vis-à-vis the Operator or the lessors according to the provisions of IFRS 16.

E. Financial instruments:

1) **Financial assets:**

Financial assets were recognized when the Partnership became a party to the contractual provisions of the instrument using transaction settlement date accounting. Financial assets are measured upon initial recognition at their fair value, together with transaction costs which may be directly attributed to the purchase of the financial asset, except in respect of financial assets that are measured at fair value through profit or loss, in respect of which transaction costs are carried to profit or loss.

The Partnership classifies and measures the debt instruments in its financial statements based on the following criteria:

a) The Partnership's business model for management of the financial assets, and
b) The characteristics of the contractual cash flow of the financial asset.

<u>The Partnership measures debt instruments at fair value through profit or loss where:</u>

A financial asset which constitutes a debt instrument does not meet the criteria for measurement thereof at amortized cost or at fair value through other comprehensive income. After the initial recognition, the financial asset is measured at fair value where profits or losses as a result of fair value adjustments are carried to profit or loss.

Note 2 - Significant Accounting Policies (Cont.):

E. Financial instruments (Cont.):

1. (Cont.)

The Partnership measures debt instruments at amortized cost where:
The Company's business model is holding financial assets in order to collect contractual cash flows; and, in addition, the contractual terms and conditions of the financial assets provide for entitlement, at defined dates, to cash flows that are strictly principal payments and interest in respect of the outstanding amount of the principal. After initial recognition, instruments in this category are measured pursuant to their terms and conditions at amortized cost using the effective interest method and net of a provision for impairment.

2) **Financial liabilities:**

On the date of initial recognition, the Partnership measures the financial liabilities at fair value, less transaction costs that can be directly attributed to the issuance of the financial liability.

Subsequently to the date of initial recognition, the Partnership measures all of the financial liabilities at amortized cost method.

F. Provisions:

A provision is recognized when the Partnership has a liability in the present (legal or implicit) as a result of an event that occurred in the past, economic resources are expected to be required in order to settle the liability, and it may be reliably estimated. When the Partnership expects to recover the expenditure, in whole or in part, the recovery will be recognized as a separate asset, only on the date on which receipt of the asset is in fact certain.

Below are the types of provisions included in the financial statements:

Legal claims:

A provision for claims is recognized when the Partnership has a present legal liability or an implicit liability as a result of an event that occurred in the past, where it is more likely than not that the Partnership will require its economic resources to settle the liability, and it may be reliably estimated.

Levies:

Levies imposed on the Partnership by government institutions through legislation are treated in accordance with IFRIC 21, according to which the levy payment liability is only recognized upon the occurrence of the event that creates the payment liability (see Section K below).

Asset retirement obligation:

An asset retirement obligation was recorded on the Partnership's books. See Section I below regarding costs in respect of asset retirement obligations.

G. Recognition of revenues:

The Partnership recognizes revenues from the sale of natural gas and condensate when the customer obtains control of the promised goods. The income is measured according to the amount of consideration to which the Partnership expects to be entitled in exchange for the transfer of the goods transferred to the customer, other than amounts collected for the benefit of third parties, such as the entitlement of the state, interested parties and third parties to receive royalties as a certain percentage of that income. A contract for the sale of natural gas and/or condensate includes a series of distinct goods that are in fact identical and have the same pattern of transfer to the customer. Therefore, they are identified as a single performance obligation. Income from the sale of natural gas and/or condensate is recognized throughout the term of the contract since the end customer receives and consumes the supplied goods at the same time.

Note 2 - Significant Accounting Policies (Cont.):

H. **Expenses of oil and gas exploration, development of proved reservoirs and investment in oil and gas assets:**

The Partnership's accounting policy in respect of the treatment of investments in oil and gas exploration is the "successful efforts" method, whereby:

1) The expenses of participation in the performance of geological and seismic surveys and tests which occur at the preliminary stages of the exploration are carried to profit or loss upon the forming thereof, until the date on which, following the performance of these surveys and tests, a specific drilling plan is formulated.

2) Investments in reservoirs before they are proven uncommercial, were classified as "exploration and appraisal assets", and are presented at cost (see Note 7 below).

3) Investments in reservoirs that have been proven dry and were abandoned or determined to be uncommercial, are fully amortized from the "exploration and appraisal assets" item to expenses in the statement of comprehensive income.

4) Investments in reservoirs with regards to which it has been determined that there is technical feasibility and commercial viability of gas or oil production, which are examined in a gamut of events and circumstances, are classified and are presented in the statement of financial position, subject to the performance of an examination of impairment, from the "exploration and appraisal assets" item to the "oil and gas assets" item, at cost (see Note 7 below). Such oil and gas assets, which include, *inter alia*, reservoir development planning costs, development wells, purchase and construction of production facilities, pipelines for the transmission of gas from the wells to the production platform and from the production platform to the onshore terminal, drilling equipment, construction of a terminal credit costs and asset retirement costs (see also Section I below), are amortized to the statement of comprehensive income as specified in Paragraph 5 below.

5) Investments in oil and gas assets, which commenced commercial production, are amortized according to the production unit method and based on proved + probable reserves ("**2P**"). In accordance with the depreciation based on 2P, the estimate of future investments (in non-discounted values) required to produce such reserves is added to the book value (only for the purpose of calculating the depreciation costs). These sums are multiplied by the amount of gas produced during the period proportionately to the 2P reserves estimate.

6) Impairment of exploration and appraisal assets and oil and gas assets is examined when facts and circumstances indicate that the value on the books of an exploration and appraisal asset and oil and gas assets may exceed its recoverable amount in accordance with international accounting standards IAS 36 and IFRS 6 (see Section J below).

Note 2 - Significant Accounting Policies (Cont.):

I. Asset retirement obligation costs:

The Partnership recognizes a liability in respect of its share in the asset retirement obligation at the end of the period of use thereof. The liability is initially recorded at its present value against an asset, and the expenses deriving from the revaluation of its present value, as a result of the lapse of time, are carried to profit or loss. The asset is initially measured at the present liability value and amortized to the statement of comprehensive income as stated in Paragraph H5 above.

Changes deriving from timing, cap rates and the amount of financial resources required to retire the obligation, are added to or subtracted from the asset (if not fully amortized) in the current period concurrently with the change in the liability; insofar as the asset was fully amortized, such changes are attributed directly to depreciation, depletion and amortization expenses in the consolidated statement of comprehensive income. The items of the consolidated statement of financial position record the balance of the liability (under the "**trade and other payables**" and "**other long-term liabilities**" items), see Note 11B below, and the asset balance after amortization (under the "**investments in oil and gas assets**" item), see Note 7A below.

J. Impairment of non-financial assets:

For the purpose of examination of impairment, a cash-producing unit is comprised of all of the Partnership's investments in the single reservoir.

The recoverable value of oil and gas assets, in accordance with economic valuations which include use of appraisal techniques and assumptions in respect of estimates of future cash flows expected from the asset and an estimate of an appropriate cap rate for these cash flows. In the measurement of the recoverable value of oil and gas assets, the management of the Partnership's General Partner is required to use certain assumptions with respect to expected investments and costs, the likelihood of the existence of development plans, quantities of the resources in the reservoir, the expected sale prices, repercussions of the Levy Law determination of the cap rates etc., in order to estimate the future cash flows from the assets. If possible, fair value is determined in relation to transactions made recently in assets with a similar character and location to the subject of the assessment.

K. Oil and gas profit levy:

The Partnership includes, in its financial statements, expenses in respect of its levy payment liability under the Taxation of Profits from Natural Resources Law, 5771-2011 (the "**Levy Law**"). The levy is calculated for each project separately. The Partnership recognized as an asset the payment of a levy due to the Tamar Project that exceeds the amount of the expected provision for the levy.

L. Critical accounting estimates and judgements:

Preparation of the Partnership's consolidated financial statements in accordance with international financing reporting standards requires the management of the Partnership's General Partner to make estimates and assumptions that affect the amounts presented in its financial statements. These estimates occasionally require judgment in an environment of uncertainty and have a material effect on the presentation of the data in the financial statements. Below is a description of the critical accounting estimates and judgments used in the preparation of the Partnership's consolidated financial statements, during the preparation of which the management of the Partnership's General Partner was required to make assumptions as to circumstances and events that involve significant uncertainty.

Note 2 - Significant Accounting Policies (Cont.):

L. Critical accounting estimates and judgements (Cont.):

In exercising its judgment when making the estimates, the management of the Partnership's General Partner relies on past experience, various facts, external factors and reasonable assumptions according to the circumstances relevant to each estimate. Actual results differ from the estimates of the management of the Partnership's General Partner.

Estimate of gas and condensate reserves (jointly: the "**Gas Reserves**") – The estimate of the Gas Reserves is used, *inter alia*, in determining the rate of amortization of the producing assets serving the operations during the reported period, as well as in examining indications of impairment. Investments related to the discovery and production of proved and probable Gas Reserves are amortized according to the depletion method as stated in Section H5 above. The estimated gas quantity in the proven and probable reservoirs in the reported period is determined on an annual basis, according to the opinions of independent external experts on the evaluation of reserves in oil and gas reservoirs. Evaluation of the proved and probable Gas Reserves according to the above principles is a subjective process and the evaluations of different experts may occasionally be materially different. In light of the materiality of the amortization expenses, the abovementioned changes may have a material effect on the results of the operations and the financial condition of the Partnership.

Asset retirement obligation – the Partnership recognizes the asset concurrently with a liability in respect of its oil and gas asset retirement obligation at the end of the period of use thereof. The timing and amount of the economic resources required for the settlement of the liability are based on estimation by the management of the General Partner of the Partnership, which relies, *inter alia*, on opinions of independent professional consultants and are examined periodically to ensure the fairness of such estimations.

Claims and legal proceedings – In the assessment of the chances of the results of the legal claims filed against the Partnership, the Partnership relied on opinions of its legal counsel. This assessment of the legal counsel is based on their best professional judgment, considering the stage of the proceedings, and on the legal experience accrued on the various issues. Since the outcome of the claims shall be determined in court, this outcome may be different to this assessment.

Determination of the fair value of a non-negotiable financial asset – The fair value of a non-negotiable financial asset classified at level 3 of the fair value scale is determined according to valuation methods, generally according to the evaluation of the discounted future cash flow according to current cap rates for items with similar conditions and risk characteristics. Changes in the estimate of future cash flow, in the estimate of cash flow due to resource valuation and the estimate of cap rates, considering the assessment of risks such as the liquidity risk, credit risk and volatility, may affect the fair value of these assets.

Petroleum profit levy – Pursuant to the Levy Law, since 2020, the Partnership has recognized an expense in respect of the petroleum profit levy in respect of the Tamar Project. As of the date of approval of the consolidated financial statements, there are several interpretation disputes vis-à-vis the Tax Authority (see also Note 19C below). In accordance with the estimates made by the Partnership, as of 31 December 2024, the Partnership recorded a provision on its books for payment of a levy for 2020-2021 for the Tamar Project. The Partnership's estimates were made to the best of its understanding and based, *inter alia*, on the opinion of its legal counsel with respect to the issues in dispute, in respect of most of which it is estimated that the prospects of the Partnership's claims being accepted exceed the prospects of their being rejected.

Note 2 - Significant Accounting Policies (Cont.):

L. Critical accounting estimates and judgements (Cont.):

Deferred taxes – Deferred taxes are calculated in respect of temporary differences between the amounts included in the financial statements and the amounts taken into account for tax purposes. The calculation of deferred tax assets requires an estimate by management to determine the recognizable amount of deferred taxes based on timing, the amount and source of the projected taxable income and the tax planning strategy. According to changes in these assumptions, the Partnership will create or rescind recognition of deferred taxes.

M. Fair value:

1. **Measurement of fair value:**

   The Partnership measures fair value as the price that would have been received in the sale of an asset or the price that would have been paid for the transfer of a liability in a regular transaction between market participants on the measurement date. When the price of an identical asset or identical liability is not observable (i.e. there is no price that is quoted in an active market), the Partnership measures fair value using a different appraisal technique that is suited to the circumstances and for which there are sufficient obtainable data to measure fair value, while making maximum use of relevant observable data and minimum use of non-observable data. The Partnership measures fair value under the assumption that the transaction for the sale of the asset or for the transfer of the liability occurs in the main market of the asset or the liability to which the Partnership has access;

   In the measurement of fair value of a non-financial asset, the Partnership takes into account the ability of a market participant to generate economic benefits through the asset in its optimal use or through the sale thereof to another market participant that will make optimal use of the asset.

2. **Fair value hierarchy:**

   For disclosure purposes, the Partnership classifies fair value measurements under one of the levels in the fair value hierarchy that reflects the significance of the data used when making the measurements. The fair value hierarchy is:

Level 1	-	Quoted prices (unadjusted) in active markets for identical assets or identical liabilities.
Level 2	-	Inputs other than quoted prices included within Level 1, which are observable with regard to the asset or liability, directly or indirectly.
Level 3	-	Inputs that are not observable for the asset or liability.

   When the data used to measure fair value are classified at different levels in the fair value hierarchy, the Partnership classifies the fair value measurement in its entirety at the lowest level of the datum that is significant to the measurement on the whole.

   The Partnership exercises discretion in assessing the significance of a particular datum to the measurement on the whole, while taking into account factors that are specific to the asset or the liability.

N. Participation unit-based payment:

Some of the Partnership's employees are entitled to benefits by way of participation unit-based payment that is settled in equity instruments and some of the employees are entitled to benefits by way of participation unit-based payment that is settled in cash and measured on the basis of increases in the value of the Partnership's participation units.

Note 2 – Significant Accounting Policies (Cont.):

N. Participation unit-based payment (Cont.):

1) **Equity-settled transactions**
   The cost of equity-settled transactions with employees is measured according to the fair value of the equity instruments at the date of grant. Fair value is determined using a standard option pricing model. The cost of equity-settled transactions is recognized in profit or loss together with a corresponding increase in equity over the period in which the service and/or the performance conditions are fulfilled and ending on the date of entitlement to renumeration of the relevant employees (the "**Vesting Period**").
2) **Cash-settled transactions**
   The cost of a cash-settled transaction is measured at fair value on the granting date, using a customary option pricing model. The fair value is recognized as an expense over the vesting period, in parallel to recognition of a liability. The liability is remeasured each reporting period at fair value, until it is settled, and changes to the fair value are carried to profit or loss.

O. Taxes on income:

In 2021 an amendment to the Income Tax Regulations was published, changing the tax regime that applies to the Partnership from the tax year 2022, such that it is taxed as a company (see Note 19A below). In view thereof, the Partnership recognized, for the first time as of 30 September 2021, a deferred tax liability for temporary differences that were reversed after 1 January 2022. In addition, since 2022, the consolidated financial statements include current income tax expenses, because up to and including 2021, the tax liability on the Partnership's profit was borne by its partners. Income tax payments made by the Partnership for the period up to and including 2021 are on account of the tax for which the holders of the Partnership's participation units are liable and were deducted from the 'retained earnings' item of the Partnership's equity.

P. Non-inclusion of a separate financial statement in the consolidated financial statements

In accordance with the provisions of Section 9C and Schedule X to the Securities Regulations (Periodic and Immediate Reports), 5730-1970, the Partnership has not included in the consolidated financial statements a separate financial statement, following examination by the Partnership's management, jointly with its legal counsel, of the need to attach a separate financial statement, on the grounds that the additional information that a separate financial statement attributed to the Partnership would provide as compared with the information included in the consolidated financial statements is negligible, and thus, under securities laws, not required to be attached.

The underlying parameters of the Partnership's decision are:

1) Total assets under the separate statement out of the Partnership's total assets under the consolidated statement.
2) Total liabilities under the separate statement out of the Partnership's total liabilities under the consolidated statement.
3) Cash flow from operating activities under the separate statement out of the cash flow from operating activities under the consolidated statement.
4) Total net profit under the separate statement out of the Partnership's total net profit under the consolidated statement.

The Partnership will continue to examine the future effect of inclusion of a separate financial statement in every reporting period.

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 2 – Significant Accounting Policies (Cont.):

Q. Disclosure on new standards in the period preceding their application:

Amendment to IFRS 18 – Presentation and Disclosure in Financial Statements

In April 2024, the International Accounting Standards Board (IASB) published International Financial Reporting Standard 18 (IFRS 18) – Presentation and Disclosure in Financial Statements (the "**New Standard**"), which supersedes International Accounting Standard 1 (IAS 1) – Presentation of Financial Statements ("**IAS 1**"). The purpose of the New Standard is to enhance the comparability and transparency of financial statements.

The New Standard will include preexisting IAS 1 requirements and new requirements for presentation in the statement of profit or loss, including the presentation of totals and subtotals as required under the New Standard, the provision of disclosure on management-defined performance measures and new requirements for aggregation and disaggregation of financial information.

The New Standard does not change the provisions for recognition and measurement of financial statement items. However, since items in the statement of profit or loss are required to be classified into one of five categories (operating, investing, financing, income taxes and discontinued operations), it may change the entity's operating income. Furthermore, the release of the New Standard has brought on small-scale amendments to other accounting standards, including IAS 7 – Statement of Cash Flows and IAS 34 – Interim Financial Reporting.

The New Standard will be applied retrospectively for annual periods beginning on or after January 2027. Earlier application is permitted for annual periods beginning on 1 January 2025, provided that this fact is disclosed. The Partnership is examining the effect of the New Standard, including the effect of the amendments to other accounting standards resulting from the New Standard, on the Partnership's consolidated financial statements.

Note 3 – Cash and Cash Equivalents:

Composition:

	Interest Rate as of 31.12.2024	31.12.2024	31.12.2023
In foreign currency:	%		
Cash in banks		10.2	0.9
Deposits in banks	3.8-5.35	40.2	27.6
		50.4	**28.5**
In shekels:			
Cash in banks		0.5	0.3
Deposits in banks	1.55	0.3	0.3
		0.8	**0.6**
Total		**51.2**	**29.1**

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 4 – Short-Term and Long-Term Deposits[2]:

Composition:

	Interest Rate as of 31.12.2024	31.12.2024	31.12.2023
Under current assets:	**%**		
in dollars	3.8-4	333.1	157.4
in shekels	3.5	0.2	0.2
		333.3	**157.6**
Under non-current assets:			
in dollars		**0.5**	**101.9**

Note 5 – Trade and Other Receivables:

Composition:

	31.12.2024	31.12.2023
Trade and other receivables in the context of joint ventures	39.8	27.1
Receivables from a company accounted for at equity (see Note 21G3 below)	17.6	10.6
Loan to Energean in the context of sale of the Karish and Tanin leases (see Note 8B5 below)	-	46.2
Royalties based on future production from the Karish and Tanin leases (see Note 8B below)	69.9	71.7
The Ministry of Energy in respect of royalties (see Note 15)	5.7	18.5
Interested parties in respect of overriding royalties (see Notes 12B and 15)	-	2.6
Third party in respect of overriding royalties (see Notes 12B and 15)	-	5.7
Prepaid expenses and other receivables	7.0	4.7
Total	**140.0**	**187.1**

Note 6 – Investment in Entities Accounted for at Equity:

Composition:

	31.12.2024	31.12.2023
Investment in EMED BV (see Note 1D4)	61.5	58.4
Investment in the Enlight Corporation (see Note 1D8)	0.2	-
	61.7	**58.4**

[2] For security interests and guarantees, see Notes 12D and 10B.

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 7 – Investments in Oil and Gas Assets:

A. Composition:

1. Composition by oil and gas assets and exploration and appraisal assets:

	Exploration and Appraisal Assets	Oil and Gas Assets[3]	Total
Cost			
Balance as of 31 December 2022	**127.6**	**2,927.6**	**3,055.2**
Changes in the course of 2023:			
Investments	29.5	139.4	168.9
Write-offs	-	(1.2)	(1.2)
Balance as of 31 December 2023	**157.1**	**3,065.8**	**3,222.9**
Changes in the course of 2024:			
Investments	4.1	103.1	107.2
Write-offs	-	(2.6)	(2.6)
Balance as of 31 December 2024	**161.2**	**3,166.3**	**3,327.5**
Accumulated depreciation[4]			
Balance as of 31 December 2022	-	**508.0**	**508.0**
Changes in the course of 2023:			
Depreciation and amortization[5]	-	67.7	67.7
Write-offs	-	(0.1)	(0.1)
Balance as of 31 December 2023	-	**575.6**	**575.6**
Changes in the course of 2024:			
Depreciation and amortization[4]	-	69.7	69.7
Write-offs	-	(0.1)	(0.1)
Balance as of 31 December 2024	-	**645.2**	**645.2**
Amortized cost as of 31 December 2023	**157.1**	**2,490.2**	**2,647.3**
Amortized cost as of 31 December 2024	**161.2**	**2,521.1**	**2,682.3**

[3] Including the balance of the amortized cost of asset retirement as of the date of the statement of financial position in the sum of approx. $29.1 million (31 December 2023: approx. $32.2 million).

[4] In 2024, the Leviathan project depletion rate was !2.6% (2023: 2.5%).

[5] In 2024, the figure does not include an update in connection with an oil and gas asset retirement obligation in the Yam Tethys project in the sum of approx. $6.0 million recorded directly in the statement of comprehensive income under the 'depletion, depreciation and amortization' item (2023: approx. $(3.3) million).

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 7 – Investments in Oil and Gas Assets (Cont.):

A. Composition (Cont.)

2. Composition by joint venture:

	31.12.2024	31.12.2023
Oil and gas assets:		
Ratio-Yam joint venture (Section C1)	2,521.1	2,490.2
Exploration and appraisal assets:		
Block 12 Cyprus (Section C2)	161.2	157.1
Total	**2,682.3**	**2,647.3**

B. Details with respect to the Partnership's rights in oil and gas assets and in exploration and appraisal assets (as of 31 December 2024):

	Type of Right	Name of Right	Right Valid Through	Partnership's Share
Ratio-Yam	Lease	I/15 Leviathan North	13.2.2044	45.34%
Ratio-Yam	Lease	I/14 Leviathan South	13.2.2044	45.34%
Yam Tethys	Lease	I/10 Ashkelon	10.6.2032	48.5%
Yam Tethys	Lease	I/7 Noa	31.1.2030	48.5%
Block 12 in Cyprus	Production and utilization license	Block 12	7.11.2044	30%
Morocco	Exploration license	Boujdour Atlantique	30.11.2025[6]	37.5%

The effective term of petroleum rights is extended from time to time, and it is contingent on the fulfillment of certain obligations on such dates as specified in the terms and conditions of the petroleum assets. In the event of failure to fulfill the conditions, the petroleum right may be revoked. For further information, see Section C11 below and for security interests registered on some of the oil and gas assets see Note 10B.

C. The Partnership's oil and gas exploration business:

1. The Ratio-Yam joint venture:

a) The Ratio-Yam joint venture is a venture for the exploration, development and production of oil and gas in the area of the I/15 Leviathan North and I/14 Leviathan South leases (the "**Leases**" and/or the "**Leviathan Leases**").

[6] The agreement with the Government of Morocco grants the right to carry out oil and/or natural gas exploration operations in the area of the block for a term of 8 years in total – an initial period of 2.5 years; a first extension (subject to the Partnership's decision and subject to commitment to the work plan for the second period – 2 years; a second extension (subject to the Partnership's decision and subject to commitment to the work plan for the third period) – 3.5 years.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

1. **The Ratio-Yam joint venture (Cont.):**

b) **Plan for development of the Leviathan reservoir:**
On 2 June 2016, the development plan was approved by the Petroleum Commissioner at the Ministry of Energy (the "**Commissioner**"). This plan, which is divided into two phases (Phase 1A and Phase 1B), includes the supply of natural gas to the domestic market and for export at a total annual volume of up to ~21 BCM, and the supply of condensate to the domestic market (in this section: the "**Development Plan**" or the "**Plan**"). According to the Plan, a production system will be built that includes up to 8 first wells that will be connected by a subsea pipeline to a permanent platform, which is located in the territorial waters of Israel in accordance with the provisions of NOP 37/H and on which the gas and condensate processing systems will be installed. Gas will be piped from the Platform to the shore to the northern entry point of the national transmission system of INGL as defined in NOP 37/H (the "**INGL Connection Point**"). Condensate will be piped to the shore via a separate pipeline, running parallel to the gas pipeline, and will be connected to a refinery via a preexisting fuel pipeline. Of note, condensate was first piped through a pipeline that belongs to Europe Asia Pipeline Co. ("**EAPC**"), which leads to the container site of Energy Infrastructures Ltd. ("**PEI**") and from there to Oil Refineries Ltd. ("**ORL**"). March 2024 saw the commencement of condensate piping through a PEI pipeline directly to Ashdod Refinery Ltd. ("**ARF**"). Furthermore, the Development Plan includes the construction of a condensate storage and unloading site close to the Hagit Power Plant (the "**Hagit Site**"), for backup purposes in case condensate piping to a refinery is not possible. See Notes 12C6 and 12F1 below.

c) **The Development Plan is implementable in full or in two main phases, according to the maturity of the relevant markets, as specified below:**

1. **Phase 1A** – The current stage, in which the 5 first subsea production wells were drilled, a subsea production system was built which connects the production wells to the platform, and a transmission system to the shore and related onshore facilities were built. According to the Development Plan, annual gas production capacity at this phase is ~12 BCM, and under certain operating conditions, it may even be possible to accomplish greater production. On 23 February 2017, the Leviathan Partners adopted a final investment decision (FID) for the development of Phase 1A, with a budget of approx. $3.75 billion (100%). The total cost invested in the development of Phase 1A, as of 31 December 2024, is approx. $4.2 billion (100%). After a preliminary running-in period, on 31 December 2019, piping of natural gas from the Leviathan reservoir commenced. On 1 January 2020, the sale of natural gas from the Leviathan reservoir to Jordan began under the agreement with NEPCO, and on 15 January 2020, piping of natural gas from the Leviathan reservoir to Egypt began under the agreement with Blue Ocean (as specified in Notes 12C2A and 12C3 below, respectively). In order to increase the gas production capacity to ~14 BCM per year, the Leviathan Partners adopted a final investment decision (FID) on 29 June 2023 to carry out a project in which a third subsea transmission pipeline will be laid from the field to the platform, and improvements on the platform will be upgraded (the "**Third Pipeline**") with a total budget of approx. $568 million (100%, the Partnership's share – approx. $258 million).

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

1. The Ratio-Yam joint venture (Cont.):

c) (Cont.)

1. (Cont.)

On 6 October 2024, the Operator of the Leviathan project announced that due to the escalation of the security situation, the work for installing the subsea pipeline in the Third Pipeline project had been postponed, and that completion of this project (which was scheduled for mid-2025) would be postponed for at least 6 months, depending on the timetables and backlog of the construction contractor. As of the date of approval of the consolidated financial statements, in the Operator's estimation, the Third Pipeline project is expected to be completed at the beginning of 2026, depending on various factors beyond the Leviathan Partners' control, including the security situation prevailing in the region.

Phase 1B – On 23 February 2025, the Leviathan Partners submitted for the Commissioner's approval an updated plan for the development of the Leviathan reservoir, which primarily includes updated in connection with Phase 1B (the "**Updated Leviathan Reservoir Development Plan**"), including as pertains to the processing facilities on the platform, the location and timing of well drilling and the possibility of executing the second stage of Phase 1B, as specified below.

According to the Updated Leviathan Reservoir Development Plan, Phase 1B may be implemented in full or in stages, as follows:

a) First stage – consists of drilling 3 additional production wells, adding related subsea systems and expanding the processing facilities on the platform, which is expected to increase the system's total gas production capacity to ~21 BCM per annum.

b) Second stage –mainly consists of drilling additional production wells and related subsea systems, including, insofar as required, laying down a fourth pipeline between the field and the platform (the "**Fourth Pipeline**"), which is expected to increase the maximum daily production capacity by another ~2 BCM per annum, i.e., up to a total quantity of ~23 BCM per annum.

As of the date of approval of the consolidated financial statements, the Leviathan Partners are promoting the receipt of the required regulatory approvals and the signing of agreements for the sale of natural gas to the domestic market and for export under Phase 1B, at an aggregate scale exceeding 100 BCM, in accordance with the Commissioner's Letter, as specified in Paragraph 2 below, in order to make a final investment decision (FID) on execution of the first stage of Phase 1B in the upcoming months. It is clarified that as of the date of approval of the consolidated financial statements, the Commissioner's approval of the Updated Leviathan Reservoir Development Plan has not yet been obtained.

2. On 21 June 2023 and 21 December 2023, the Leviathan Partners sent an in-principle application to the Commissioner to approve an increase in the natural gas export volume produced from the Leviathan project, according to the government resolution applicable to the export of gas from the Leviathan reservoir, via an existing and future regional pipeline or via an FLNG facility, in addition to an increase in the volumes of natural gas which will be piped from the Leviathan project to the domestic market.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

1. The Ratio-Yam joint venture (Cont.):

c) (Cont.)

2. (Cont.)

On 25 June 2024, the Commissioner's response to the said application was received, whereby the position of the professional functions at the Ministry of Energy allows, at this time, the export of additional natural gas from the Leviathan reservoir in a quantity up to 118 BCM, which may increase up to 145 BCM, given the satisfaction of certain conditions (the "**Commissioner's Letter**"). The Commissioner's Letter further states that, beginning in 2044, the export of natural gas from the Leviathan reservoir will only be allowed on an interruptible basis, subject to assurance of the supply to the domestic market, and that export on a firm basis from that year onward will only be allowed after reexamination of the needs of the domestic market. The Commissioner's Letter clarified, *inter alia*, that this professional position is in keeping with the future picture of market-wide supply and demand, in accordance with the estimation of the professional functions at present, and does not constitute export authorization nor an undertaking to grant export authorization, which, insofar as granted, is expected to include additional conditions and restrictions, and that the content of the Commissioner's Letter will not bind the Commissioner when making a future decision on this issue. It is clarified that, in the Partnership's estimation, the government resolutions with respect to natural gas export and the Commissioner's Letter allow the Leviathan Partners to advance the signing of natural gas sale agreements under Phase 1B at the scale required in order to make a final investment decision (FID) on execution of the first stage of Phase 1B in the upcoming months.

In the context of promotion of Phase 1B the Leviathan Partners approved, in 2023 and 2024, in accordance with the joint operating agreement (JOA), budgets in the sum total of approx. $75.4 million (100%, the Partnership's share –approx. $34.2 million), for performance and completion of the pre-FEED of the alternatives for expansion of the Leviathan reservoir's production system, including the construction of subsea infrastructures, connection of additional production wells, and performance of the required changes on the platform. As of the date of approval of the consolidated financial statements, the pre-FEED phase has been completed, and on 31 July 2024 the Leviathan Partners made the decision to conduct FEED and advance procurement of long lead items, under an additional budget of approx. $429 million (100%, the Partnership's share – approx. $194.5 million). The Leviathan Partners intend to compete the FEED in order to make a final investment decision (FID) for the development of Phase 1B during the upcoming months, and to that end, the Leviathan Partners are advancing, *inter alia*, negotiations of various stages with prospective customers, both in the domestic market and for export, toward the signing of natural gas sale agreements in the context of Phase 1B, the aggregate amount of which is more than 100 additional BCM, in accordance with the Commissioner's Letter. According to the estimate of the operator in the Leviathan project, prior to completion of the FEED, the estimated cost of the first stage of Phase 1B (i.e., without the costs of the

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

1. **The Ratio-Yam joint venture (Cont.):**

c) (Cont.)

2. (Cont.)

fourth pipeline), is approx. $2.4 billion (100%)[7]. Insofar as a Final Investment Decision (FID) is adopted to develop the first stage of Phase 1B in 2025 as aforesaid, the estimate for first gas production is in H2/2029.

During the years of operation of the project, additional production wells will be required to allow for production of such volume as required and according to the level of redundancy of the production system and the wells in the field as defined from time to time by the Leviathan Partners.

d) Evaluation of reserves and contingent resources in the Leviathan Leases:

In February 2025, a report was received from Netherland Sewell & Associates Inc ("**NSAI**", a qualified, expert an independent reserve and resource appraiser), on evaluation of the reserves and contingent resources in the Leases according to the SPE-PRMS, updated as of 31 December 2024. According to the report, the overall quantity of natural gas and condensate resources which is composed of the amount of reserves classified as proved+probable reserves and the amount of contingent resources under the best estimate is ~580.3 BCM and ~45.1 million barrels, respectively, and it is divided into categories of resources classified as reserves and resources classified as contingent resources. The quantity of proved reserves is ~371.4 BCM and the quantity of proved + probable reserves is ~420.1 BCM. In addition, proved condensate reserves total ~28.9 million barrels, and the quantity of proved + probable reserves totals ~32.6 million barrels.

In the contingent resources report, which includes resources classified as contingent – development pending, which are contingent on approval for drilling of further wells, on approval of future developments, on the demonstration of the existence of a future market for the sale of natural gas and on commitment to development of the resources, the said contingent resources were classified under two categories that pertain to each one of the reservoir development phases, as follows: Phase 1A – Resources attributed to Phase 1A of the development of the Leviathan reservoir, plus the Third Pipeline project. Future Development – Resources attributed to development stages beyond Phase 1A. Accordingly, the quantity of contingent resources of natural gas ranges between ~308.0 BCM (high estimate) and ~58.3 BCM (low estimate). The quantity of contingent resources of condensate ranges between ~23.9 million barrels (high estimate) and ~4.5 million barrels (low estimate). See Note 7C10 below regarding the evaluation of reserves of natural gas, condensate, contingent and prospective resources.

[7] Of the said amount, the partners have approved a budget of approx. $505 million (100%).

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

1. The Ratio-Yam joint venture (Cont.):

e) Deep targets:

In 2019, an analysis was performed of reprocessing of seismic surveys, *inter alia* in connection with exploration drilling to the deep targets in the Leviathan Leases (the "**Data Reprocessing**"), as a result of which a new 'isolated carbonate buildup' deep target was defined in the area of the Leviathan Leases. In addition, the analysis of the Data Reprocessing revealed that it is necessary to reclassify and redefine the two deep targets which were previously defined in the area of the lease as a single 'submarine clastic channel' target.

Following and based on a 2019 seismic survey reprocessing analysis, a prospective resources report for the Leviathan Leases was prepared for the Partnership by NSAI, according to SPE-PRMS rules (in this section: the "**Resources Report**"), updated as of 31 December 2024. According to the report, the best estimate in the carbonate buildup for gas and oil is estimated at ~4.6 BCM and ~155.3 million barrels, respectively, and the best estimate in the clastic channel for gas and oil is estimated at ~6.2 BCM and ~212.7 million barrels, respectively. See Note 7C10 below with regards to uncertainty in the evaluation of reserves. The Partnership intends to promote the performance of a seismic survey for finalization of exploration prospects for deep targets in the Leviathan Leases. In this context, the Partnership approached key international seismic survey providers to receive detailed quotes for the performance of a 3D seismic survey during the course of this year, the purpose of which is imaging and specification of the deep targets in the Leviathan Leases. As of the date of approval of the consolidated financial statements, preliminary quotes have been received which are being examined by the Partnership with the assistance of its outside consultants.

2. Block 12 in Cyprus:

On 11 February 2013, the authorities in Cyprus approved the transfer of 30% of Chevron Cypris' interests in a production sharing contract (PSC) dated 24 October 2008 (the "**PSC**"), which grants oil and/or gas exploration, evaluation, development and production rights in the exclusive economic zone (EEZ) of Cyprus in the area known as Block 12 ("**Block 12**") and in an exploration license under the PSC (the "**Exploration License**").

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

2. Block 12 in Cyprus (Cont.):

a) On 7 November 2019, the right holders under the PSC and the Government of Cyprus signed an amendment to the PSC (the "**First Amendment to the PSC**"), concurrently with which the right holders were granted an exploitation license (in this section: the "**License**" or "**Exploitation License**" or "**Block 12 License**") and a development and production plan for the reservoir was approved (in this section: the "**Original Development Plan**"). Under the First Amendment to the PSC, additional changes and updates were made, *inter alia*, with respect to the transfer of rights by the parties, approval of an annual budget and work plan, the manner of approval of changes to plans and budgets, the manner of calculation of the various expenses, changes in connection with grounds for termination of the PSC, arrangements with respect to ensuring the plugging, dismantling and removal of wells and facilities at the end of the term of the PSC, etc. On 21 September 2022, the general meeting of unit holders approved refrainment from profit distributions for the purpose of investing in Block 12. Further thereto, on 9 November 2022, an additional amendment to the PSC was signed extending the Partner's commitment to drill an additional appraisal/development well, A-3 (Aphrodite 3) (the "**A-3 Well**") and complete it by August 2023; see Section e) below. Further to the foregoing, on 14 February 2025, the Government of Cyprus approved an updated development plan for the reservoir, which is based on the Original Development Plan (the "**Updated Development Plan**"), concurrently with which another amendment to the PSC was signed, which provides for updated milestones for development of the reservoir and rescinds the notice of breach given to the partners in the reservoir, as specified in Section C below.

b) Under the PSC, as amended on 14 February 2025 concurrently with the approval of the Updated Development Plan (the "**Plan Approval Date**"), the Partners have undertaken, *inter alia*, to meet principal milestones for advancement of the reservoir's development, as follows:

1. Completion of the Pre-FEED within 9 months of the Plan Approval Date.
2. Commencement of the FEED within 11 months of the Plan Approval Date.
3. Completion of the FEED within 23 months of the Plan Approval Date.
4. Adoption of a final investment decision (FID) for development of the reservoir within 28 months of the Plan Approval Date.

Up to the date of approval of the consolidated financial statements, the binding work plan for Block 12 above, as updated on 14 February 2025 under the last amendment to the PSC, has been fully executed. It is noted that failure to meet the milestones defined under the PSC will constitute grounds for termination of the PSC, unless it shall have derived from "*force majeure*" (as defined in the PSC).

c) For details regarding a performance guarantee in an unlimited amount provided by Delek Group in favor of the Republic of Cyprus to secure fulfillment of all of the undertakings of the Partnership under the PSC, see Note 20D.

d) The Original Development Plan of the Aphrodite reservoir, as approved by the Cypriot Government on 7 November 2019 as mentioned, included the construction of a floating production and processing facility on top of the reservoir in the area of the License (the "**Floating Production Facility**") and a subsea system for transmission to the Egyptian market.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

2. Block 12 in Cyprus (Cont.):

d) (Cont.)

In 2023-2024, the Partners had applied to the Government of Cyprus for approval thereby of changes in the outline of the Original Development Plan, but such applications were not approved, and during this period the Partners failed to meet the FEED milestone as stipulated in the PSC at that time. Against this background, on 25 August 2024, the operator of the Aphrodite reservoir received a notice of breach from the Minister of Energy of the Cypriot Government, whereby the partners in the reservoir have 3 months to remedy the alleged breach (the "**Cure Period**"). Subsequently thereto, meetings and discussions were held between the parties' representatives, and on 17 September 2024, an agreement was signed between the Partners in the reservoir and the Government of Cyprus, whereby a standstill was agreed with the aim of proceeding with discussions to obtain approval of an updated development plan prepared by the Partners based on the original plan. Further thereto, on 14 February 2025, as mentioned, the Cypriot Government approved the Updated Development Plan, which is based on the Original Development Plan, whereby the Floating Production Facility would be built, with a maximum daily capacity of approx. 800 MMCG by means of 4 production wells at the first stage, from which natural gas would be transmitted through a subsea pipeline to the Egyptian transmission system. According to an up-to-date assessment by the reservoir operator's, prior to completion of technical-economic feasibility studies, including preparation of the Pre-FEED and the FEED, the projected cost of the Updated Development Plan is estimated at approx. $400 billion (100%). It is emphasized that executing the Updated Development Plan and reaching the adoption of a final investment decision (FID) are contingent, *inter alia*, on the execution and results of the Pre-FEED and FEED, the formulation of commercial arrangements for development and construction of the export pipelines, the signing of natural gas supply agreements and fulfillment of the conditions precedent to such agreements, the obtainment of regulatory approvals and the formulation of financing arrangements. Insofar as the aforesaid conditions precedent are satisfied, the supply of first natural gas from the reservoir is expected to take place in 2031.

On 17 February 2025, the Partners, together with the Government of Cyprus, Cyprus Hydrocarbons Company (CHC), the Government of Egypt and the Egyptian National Gas Company ("**EGAS**"), signed a non-binding memorandum of understandings that outlines the framework for the continued negotiations in connection with the export of natural gas from the reservoir to Egypt, including construction of the required transmission infrastructure and sale arrangements (in this section: the "**MOU**"). Under the MOU, EGAS will serve as the exclusive buyer of the natural gas to be produced form the reservoir, with the Partners being afforded the option to buy certain quantities of the gas sold to EGAS as liquefied natural gas (LNG). Furthermore, the MOU specifies principles in connection with the construction of the required transmission infrastructure and the sale arrangements, which will be established in the detailed agreements intended to be signed between the parties down the line.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

2. Block 12 in Cyprus (Cont.):

e) In accordance with the terms and conditions of the PSC, on 15 September 2022, the Partners approved a budget for the drilling of the A-3 Well in the sum of $130 million (100%, the Partnership's share – approx. $39 million). The A-3 Well is an appraisal well whose purpose was to corroborate the estimates of the Operator and the Partnership regarding the nature and scope of the reservoir, and which is designed to be used in the future as a production well. The drilling of the A-3 Well began in May 2023 and was completed in July 2023, on schedule and on budget.

f) Following completion of the A-3 Well in September 2023 a report was prepared by NSAI according to the rules of the Petroleum Resource Management System (SPE-PRMS), the quantity of contingent resources of natural gas classified under the "Development Pending" stage at the Aphrodite reservoir, as of 31 August 2023, ranges between ~126 BCM (the high estimate) and ~74 BCM (the low estimate). According to the aforesaid report, the quantity of contingent resources of condensate in the Aphrodite reservoir, classified under the "Development Pending" stage, ranges between ~10.6 million barrels (the high estimate) and ~5.1 million barrels (the low estimate). As of 31 December 2024, the details specified in the aforesaid report remain unchanged. See Note 7C10 below with respect to uncertainty in the evaluation of reserves.

g) Most of the Aphrodite reservoir is situated in the EEZ of Cyprus, and a few percent thereof are situated in the area of the Ishai/370 license (the "**Ishai License**"), which is located in the EEZ of Israel. It is further noted that the partners in the Aphrodite reservoir have previously received letters from the partners in the Ishai License, from the Israeli Ministry of Energy and from the Cypriot Ministry of Energy, with respect to the need for regulation of such parties' interests prior to the adoption of a decision regarding development of the Aphrodite reservoir. As of the date of approval of the consolidated financial statement, the position of the partners in the Aphrodite reservoir is that the matter is subject to the authority of the governments, and that they will act in accordance with such mechanism for regulation of the parties' interests as shall be determined by the governments, and in accordance with international law and as per the common practices in the industry. On 11 April 2022, the Israeli Ministry of Energy reported that the Israeli and Cypriot Ministers of Energy had agreed to appoint an outside expert to examine the quantity of natural gas in the reservoir and determine the division thereof between the exclusive economic zones of Israel and Cyprus. To the best of the Partnership's knowledge, on 29 January 2024, a discussion was held between the Israeli and Cypriot Ministers of Energy, in which it was agreed to intensify the inter-government efforts to resolve the issue as soon as possible. As of the date of approval of the consolidated financial statements, to the best of the Partnership's knowledge, as informed by Chevron Cyprus, the President of Cyprus has expressed a commitment to reaching mutual agreements with the State of Israel in connection with the appointment of an independent outside expert in order to resolve the matter. Besides the above, Cyprus and Turkey are in dispute over the rights in Cyprus' EEZ, which may affect the Partnership's operations in the License. It is noted, however, that according to its official reports, the Government of Turkey does not claim ownership of the areas in which Block 12 is situated.

Note 7 – Investments in Oil and Gas Assets (Cont.):
C. The Partnership's oil and gas exploration business (Cont.):

3. The Yam Tethys joint venture:

a) The Yam Tethys joint venture is situated in the areas of the Ashkelon and Noa leases. Production of natural gas from the Yam Tethys project commenced in March 2004 and was discontinued in May 2019, due to the depletion of the reservoirs.

b) In 2021, the operator commenced activities for decommissioning of the project facilities, apart from the platform, two subsea gas pipes (the "**Two Subsea Gas Pipes**") and the AOT, according to a plan that had been approved by the Commissioner. In July 2024 the operator notified the partners in the Yam Tethys project that such activities had been completed and that summary reports had been submitted to the Commissioner. At the same time, a discussion is being held with respect to possible future uses and/or decommissioning of the Yam Tethys platform, considering the existing connection between the facilities of the Yam Tethys project and the production from the Tamar Project. The cost of the activities for decommissioning of the Yam Tethys facilities, apart from the platform, the Two Subsea Gas Pipes and the onshore AOT as noted, totaled approx. $273 million (100%, the Partnership's share - approx. $130 million). In addition, at his request, the Commissioner was presented with a comparative survey, prepared by an independent expert, which supports leaving the Two Subsea Gas Pipes, after they have been washed and sealed in accordance with the plan approved by the Commissioner as noted. According to the expert's opinion, the cost entailed by removing the Two Subsea Gas Pipes is expected to amount to approx. $45 million (100%).

As of the date of approval of the consolidated financial statements, approval by the Commissioner in connection with the conclusion of the Yam Tethys decommissioning activities, including as relating to the Two Subsea Gas Pipes, has yet to be obtained. For details regarding a draft policy document on the decommissioning of offshore exploration and production infrastructures released for public comment by the Ministry of Energy, see Note 12H8 below.

c) For details with respect to a natural gas supply agreement between the Leviathan Partners and the Yam Tethys Partners, which has come to an end, see Note 12C7 below.

d) For details with respect to an agreement for the grant of usage rights in the facilities of the Yam Tethys project, see Note 12J below.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

4. The Boujdour License in Morocco:

On 6 December 2022, the Partnership, jointly with Adarco Energy Limited[8] ("**Adarco**"), signed agreements concerning oil and natural gas exploration and production activities in the Boujdour Atlantique exploration license, which is situated in the Atlantic Ocean off the coast of Morocco (in this section, the "**Petroleum Asset**" or the "**License**")[9], with the National Office of Hydrocarbons and Mines of Morocco (Office National des Hydrocarbures et des Mines, "**ONHYM**") (in this section, the "**Agreements**"). *Inter alia*, the Agreements grant each of the Partnership and Adarco 37.5% of the interests[10] in the License, with the remaining interests in the License, the rate of which is 25%, granted to ONHYM, in accordance with existing regulation in Morocco. On 1 June 2023, NewMed Morocco signed the Agreements *in lieu* of the Partnership and stepped into its shoes. The Agreements further grant the Partnership, Adarco and ONHYM the right to search for hydrocarbons in the area of the License for a term of 8 years, subject to compliance with a work plan, which may be extended in the event of discovery. NewMed Morocco is the operator of the License. During the exploration period, in addition to their respective share of the costs, the Partnership and Adarco shall also bear the costs in respect of ONHYM's share, in accordance with the existing regulation in Morocco. Furthermore, the agreements with ONHYM include additional provisions, *inter alia*, with respect to bonuses that are payable to ONHYM according to accomplishment of milestones of output from the License, royalties to the State of Morocco, fines in the event of noncompliance with obligations under the agreements, guarantees, stability in respect of economic terms, obligations of professional training in the domestic market, as well as provisions pertaining to the joint operation of the License. On 2 January 2023, the general meeting of the unit holders approved the Partnership's engagement in the Agreements, which are also subject to receipt of the approval of the Ministry of Energy Transition and Sustainable Development and Ministry of Finance of Morocco, and to approve refrainment from distribution of profits for the purpose of performance of the aforesaid actions in accordance with a work plan and budgets to be approved by the partners in the license and according to its terms.

In December 2022, the Partnership provided a bank guarantee in the sum of approx. $1.75 million (100%) in favor of ONHYM. Furthermore, the License is located off the coast of a which, historically, has been occasionally referred to as "Western Sahara", a region sovereignty over which is under dispute, according to the U.N. In December 2020, a normalization agreement was signed between Israel and Morocco, under which, *inter alia*, Israel and the United States recognized Morocco's sovereignty over this region. In July 2024, the partners in the License were informed that they had been given the rights thereunder by the Ministry of Energy Transition and Sustainable Development of Morocco. As of the date of approval of the consolidated financial statements, the partners in the Boujdour license have approved a budget for the years 2024-2025 in the sum of approx. $4.7 million (100%, the Partnership's share – approx. $4 million).

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[8] Adarco has informed the Partnership that Adarco is a company controlled by Mr. Yariv Elbaz (a Moroccan investor) and members of his family.

[9] *De facto*, the License includes 17 areas of different licenses.

[10] The Partnership's interests in the Petroleum Asset are subject to royalties paid to the State of Morocco. According to local regulation in Morocco, the royalty amount depends on the well's water depth and the findings (gas or oil). Where the well's water depth exceeds 200 meters, an oil discovery requires payment of royalties at the rate of 7% per annum. On the other hand, a gas discovery at such depth or deeper requires payment of royalties at the rate of 3.5%. The royalty payment obligation applies in relation to quantities exceeding 500,000 tons of oil or 0.5 BCM of natural gas. The figures in the above table were calculated assuming a gas discovery (i.e., royalties at the rate of 3.5%). It is further noted that according to Moroccan regulation, an exemption from corporate tax applies for a period of 10 years as of production commencement, after which corporate tax at the rate of 31% is paid (for both gas discoveries and oil discoveries).

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

5. **The Eran license:**
   The Partnership had previously held approx. 22.67% of the interests in the Eran license, which expired on 14 June 2013. Following the decision of the Commissioner not to extend the Eran license, on 3 October 2013, the holders of the interests in the Eran license (including the Partnership, which had held approx. 45.34% of the interests in the license) submitted an appeal to the Minister of Energy from the said Commissioner's decision. This appeal was denied by the Minister of Energy on 10 August 2014. On 17 November 2014, the holders of the interests in the Eran license, including the Partnership, filed a petition on this decision with the High Court of Justice. On 2 June 2016, the High Court of Justice entered a decision on the parties' agreement to defer to mediation as proposed thereby. With the parties' consent, (Ret.) Chief Justice of the Supreme Court A. Grunis was appointed as mediator. At the end of the mediation proceeding, the parties reached agreements that were established in a mediation arrangement. On 20 March 2019, this mediation arrangement was filed with the court, which was moved to enter a judgment on the arrangement. Under the mediation arrangement, the parties to the mediation (with the Tamar partners' consent) agreed to divide the Tamar SW reservoir between the area of the Tamar lease (78%) and the area of the Eran license (22%). It was further agreed that the interest in the Eran license area would be divided at a proportion of 76% to the State and 24% to the Eran license interest holders prior to its expiration (pro rata to their holdings in the license). On 11 April 2019, the parties' agreed mediation arrangement was entered as a judgment, as noted. The Tamar partners and the State of Israel and the interest holders in the Eran license are negotiating the regulation of the rights of the State and the holders of interests in the Eran license on additional related matters. As of the date of approval of the consolidated financial statements, the parties have not yet reached an agreement on how to implement the mediation arrangement, as specified above.

6. **Exploration licenses in Zone I in the area of Blocks 4, 5, 6, 7, 8 and 11 in the EEZ of the State of Israel (in this section: the "Zone I Licenses"** or the "**Licenses**"):
   On 29 October 2023, the Commissioner gave the Partnership, the State Oil Company of Azerbaijan Republic ("**SOCAR**"), and BP (in this section, collectively: the "**Partners**"), a notice of the award of the bid they submitted in connection with the Zone I Licenses, under the fourth competitive process for natural gas exploration in the northwest area of Israel's EEZ. The Partnership and BP each hold 33.33% of the joint venture, and SOCAR holds 33.34% thereof. The Partners continue to comply with the terms and conditions of an agreement that regulated, *inter alia*, the terms of the said bid and also specified the principles for the joint operating agreement expected to be signed after the Licenses are granted. On 18 December 2023, the general meeting of the unit holders approved the Partnership's participation in oil and/or natural gas exploration and production operations in the area of the Licenses and the avoidance of profit distributions in the interest of investment in operations in the area of the Licenses, in accordance with such work programs as approved by the Partners in the Licenses from time to time.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

6. (Cont.)

Completion of the process of issuance of the Licenses to the Partners, in accordance with the provisions of the Petroleum Law, the regulations and the terms and conditions of the competitive process, requires, *inter alia*, the provision of a $5-million guarantee (100%, the Partnership's share – approx. $1.7 million) and the payment of a $5-million signing bonus to the Ministry of Energy (100%, the Partnership's share – approx. $1.7 million) by 28 December 2023. In December 2023, the Partners provided the guarantee and paid the signing bonus, as noted.

Due to the War, which persisted throughout 2024, the Licenses' issuance process has been delayed, and, in the Partnership's estimation, the Licenses are expected to be granted by the end of March 2025.

7. Block 1-21 Han Asparuh within the EEZ of the Republic of Bulgaria in the Black Sea (the "Bulgaria License" or the "Block")

In November 2024, the Partnership entered into an agreement for acquisition of a 50%-interest in a license granted by the Government of Bulgaria in relation to the area of the Block, rights under an agreement for natural gas and oil exploration in the area of the Block signed with the Government of Bulgaria, and rights under the joint operating agreement (JOA) that shall apply between the partners in the Block (in this section: the "**Interest Acquisition Agreement**" or the "**Agreement**"). The Agreement was signed between NewMed Balkan (in this section: the "**Buyer**") and OMV Offshore Bulgaria GmbH (in this section: "**OMV Bulgaria**" or the "**Seller**"), a subsidiary of OMV Petrom, which, to the best of the Partnership's knowledge, is a public company listed on the Bucharest Stock Exchange in Romania and considered the largest energy corporation in Southeast Europe. As of the date of approval of the consolidated financial statements, OMV Bulgaria holds all the interests (100%) in the Block.

It is clarified that the information specified in this section is based on the assumption that the transfer of interests to the Buyer will be closed in the upcoming days, such that the Buyer hold 50% of the interests in the license and the remaining rights be held by the Seller. Of note, on 9 January 2025, the general meeting of unit holders approved the Partnership's entry into the Agreement and further approved refrainment from profit distributions in the interest of the investment. For details regarding equity-based compensation at the rate of 5% of the issued share capital of NewMed Balkan to Mr. Abu, see Note 20C6.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

7. Block 1-21 Han Asparuh within the Exclusive Economic Zone (EEZ) of the Republic of Bulgaria in the Black Sea (the "Bulgaria License" or the "Block") (Cont.):

A concise description of the principles of the Agreement follows:

a. In consideration for transfer of the interests in the Block, the Buyer has undertaken to fund the Seller's share of the costs of the next exploration well to be drilled in the Vinekh prospect in the area of the Block (out of several prospects and leads) (the "**First Well**"), up to a total amount that shall not exceed €50 million (approx. $52 million), and also fund the Seller's share of the costs of an additional well in the Block, which will be either an exploration well in another prospect in the area of the Block or an appraisal well in the Vinekh prospect (in the case of commercial discovery therein), according to the recommendation of OMV Bulgaria as operator and approval by NewMed Balkan, after completion of the First Well, up to a total (additional) amount that shall not exceed €50 million (the "**Second Well**", and together with the First Well: the "**Two Wells**"). It is clarified that, under the terms of the Agreement, the Buyer does not have the right to be reimbursed by the Seller for the amounts provided in its favor by the Buyer, as specified in this section above, and that beyond such amounts, the Seller and the Buyer shall bear their *pro rata* share (50%-50%) in the expenses of the project. Of note, the aforesaid amounts include €5 million (approx. $5.2 million) in operating expenses in connection with the license during the interim period between the Agreement signing date and the transaction closing date, as well as approx. €5 million in expenses incurred by the Seller in relation to preparations for the wells. It has been further agreed that the Buyer will bear the fees to be paid to the Bulgarian Government in respect of transfer of the interests.

b. As of the date of approval of the consolidated financial statements, the Partnership is examining, through its outside legal counsel, whether the obligation to pay overriding royalties to Delek Group and a subsidiary thereof and to third-party royalty interest owners, also applies to its rights in the Bulgaria License. With respect thereto, the royalty interest owners clarified their position on the obligation to pay overriding royalties for the Partnership's interests in the Bulgaria License, and added that they would take action against any attempt to shirk such payment obligation.

c. As of the transaction closing date, the Buyer shall bear, according to its share of the license, all the expenses, payments, liabilities and obligations imposed in respect of the Block and pursuant to the provisions of any law, except as set out above in connection with the Two Wells and except for certain liabilities and obligations for which, as stipulated in the Agreement, the Seller shall remain responsible also after the transaction closing date, as relating to the period preceding the closing of the transaction, including payment demands issued in respect of the Block prior to the closing of the transaction as well as liabilities and obligations pertaining to environmental protection or to compliance with provisions of law pertaining to environmental protection, insofar as existing prior to the transaction closing date or known to the Seller prior to the transaction closing date.

d. On the transaction closing date, the parties shall enter into a joint operating agreement (JOA) in such form as agreed, which shall stipulate, among other things, that the Seller will continue to serve as the operator of the license.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

7. **Block 1-21 Han Asparuh within the Exclusive Economic Zone (EEZ) of the Republic of Bulgaria in the Black Sea (the "Bulgaria License" or the "Block") (Cont.):**

   e. The Agreement stipulates several conditions precedent to closing of the transaction, including the condition regarding the parties' entry with the Bulgarian Government into an agreement that allows for transfer of the interests to the Buyer, which, as of the date of approval of the consolidated financial statements, has not been satisfied yet.
   f. Closing of the transaction will be carried out on the day on which the parties and the Government of Bulgaria enter into an agreement that authorizes the transfer of the interests to the Buyer or at such later time as shall be agreed by the parties.
   g. The Agreement sets out provisions with respect to the parties' rights to terminate the Agreement prior to the transaction closing date in each of the following cases:
      1) Non-fulfillment of the closing conditions within 180 days of the Agreement signing date (or such later date as shall be agreed by the parties);
      2) An event of insolvency of the counterparty;
      3) Failure by the counterparty to comply with its obligations in relation to the period preceding the transaction closing date and failure to cure such breach within 14 days of receipt of written notice;
      4) The Buyer shall have the right to terminate the Agreement in the event of a "material adverse change" in relation to the transferred interests, and, under certain stipulated conditions, in the event of breach of the Seller's representations.
   h. The Agreement is governed by UK law and any dispute that pertains to the Agreement will be resolved by arbitration in Paris, to be conducted under the rules of the International Court of Arbitration in Paris under the auspices of the International Chamber of Commerce.
   i. The Agreement sets out such additional provisions as are standard in agreements of this type, including mutual indemnification undertakings in case of breach of representations and obligations.

8. **New Ofek/405 ("Ofek") and New Yahel/406 ("Yahel") Licenses:**

   On 19 March 2019, the Partnership entered into an agreement with SOA (in this section: the "**Operator**") for acquisition of a 25%-interest (out of 100%) in each of the onshore Ofek and Yahel licenses. The partners in the Ofek license intended to conduct production tests in an existing well, Ofek 2-Bypass (in this section: the "**Well**"). 20 June 2022 saw the expiration of the Ofek and Yahel licenses. On 7 November 2024, the partners in the Ofek license received a letter from the Commissioner, whereby, *inter alia*, abandonment of the Well should be completed by 31 March 2025. As of the date of approval of the consolidated financial statements, the Operator has informed the Partnership that the preparation work for plugging and abandoning the Well had commenced, and that it was maintaining ongoing contact with the Commissioner in relation to the timetables for completion of such work.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

9. **The Michal-Matan joint venture (discontinued operations):**

   a) The Michal-Matan joint venture is a venture for exploration, development and production of oil and gas in the area of the Tamar I/12 and Dalit I/13 leases (in this section: the "**Tamar Project**" and/or the "**Tamar and Dalit Leases**" and/or "**Leases**").

   b) According to the provisions of the Gas Framework that, *inter alia*, required the Partnership to sell its entire holdings in the Tamar and Dalit Leases, on 2 September 2021, the Partnership engaged in an agreement for the sale of the remaining interests of the Partnership at the rate of 22% in the Tamar Project to Tamar Investment 1 RSC Limited and Tamar Investment 2 RSC Limited[11] (in this section: the "**Buyers**" and the "**Agreement**", as applicable). On 9 December 2021, the transaction was closed and the Partnership received the sale proceeds in the sum of approx. $955[12] million.

   Below is a concise description of the principles of the Agreement:

   1) The Object of Sale, as defined in the Agreement, includes the Partnership's interests at the rate of 22% in each one of the Tamar and Dalit Leases, together with the Partnership's share in the shares of Tamar 10-Inch Pipeline Ltd. (the holder of the transmission license pursuant to Section 10 of the Natural Gas Sector Law), and the Partnership's rights and undertakings in the joint operating agreement that applies to the Leases, the agreement for use of the Yam Tethys facilities (in relation to the Partnership's share as a holder of interests in the Tamar lease), in agreements for the sale of natural gas and condensate from the Tamar lease, in agreements for the export of natural gas (including the agreements relating to the export agreements and export permits from Jordan to Egypt), and in other ancillary agreements between the holders of the interests in the Leases.
   2) The Partnership's interests in the Leases will be transferred to the Buyers subject to the existing royalties in the Leases which were borne by the Partnership, and accordingly, the obligation to pay the royalty interest owners will apply to the Buyers.
   3) As of 1 August 2021 (the "**Effective Date**"), the Buyers will bear, each according to its share, any and all expenses, payments, guaranties, securities and liabilities that apply in respect of the Object of Sale and pursuant to the provisions of any law, with the exception of certain liabilities in respect of which the Agreement determined would remain the Partnership's responsibility also after the closing of the transaction, as described below. Of note, under the terms and conditions of the Agreement, the Partnership is entitled to receive amounts for royalties paid in excess to the State and to the overriding royalty interest owners in respect of the Tamar Project, if the arguments of the Tamar partners on this issue are accepted (see Note 15B7 below).

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[11] To the best of the Partnership's knowledge, the Buyers are SPCs that were established for the purpose of the transaction and are held (indirectly) by MDC Oil & Gas Holding Company LLC, a corporation belonging to the group of Mubadala Investment Company PJSC, a company owned by the Government of Abu Dhabi.

[12] See Footnote 5 above.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

9. The Michal-Matan joint venture (discontinued operations) (Cont.):

b) (Cont.)

4) The Partnership will bear any and all expenses, payments, guaranties, securities and liabilities that apply in respect of the Object of Sale and pursuant to the provisions of any law until the Effective Date, including the taxes in respect of the sale of the Object of Sale and the levy under the Levy for the quantities of hydrocarbons that were sold until the Effective Date.
   The Partnership will remain responsible for the following liabilities also after the closing of the transaction: (a) liabilities in connection with the Object of Sale in relation to the period that preceded the Effective Date (with the exception of faults and wear and tear in facilities and equipment of the Tamar Project which existed prior to the Effective Date but were not known to the Partnership); (b) liabilities in relation to hydrocarbons which were produced from the Leases prior to the Effective Date; (c) liabilities in connection with the class certification motion which was filed by a consumer of the Israel Electric Corporation ("**IEC**") against the holders of the interests in the Tamar lease, including any appeal and other proceeding in connection therewith; (d) payment demands according to the joint operating agreement in the Leases, which were sent by the operator in the Tamar Project prior to the Effective Date; and (e) liabilities in connection with environmental hazards in the area of the Leases, insofar as they existed prior to the Effective Date or were known to the Partnership prior to the transaction closing date.
5) In the context of the Agreement, the Partnership made various representations to the Buyers, as is standard in transactions of this type, including representations with respect to its rights in the Object of Sale and disclosure to the Buyers of the material information pertaining to the Object of Sale, including, *inter alia*, compliance with the terms and conditions of the Leases, the validity of the material agreements and absence of breach, legal proceedings relevant to the Object of Sale, compliance with the legal provisions that apply to the Object of Sale, the applicable taxation and financial data of the joint project.
   The Agreement sets out provisions whereby the Partnership undertook to indemnify the Buyers in respect of any damage or liability that shall be caused thereto in connection with lawsuits, claims or another legal proceeding as a result of a breach of a representation, provided that the Partnership shall not be liable for damage until the total damage exceeds $2.5 million, and that the indemnity amount for which the Partnership shall be liable shall not exceed 35% of the consideration paid for the Object of Sale, other than with respect to certain representations that were defined as 'fundamental representations' (for which the total indemnity will not exceed 100% of the consideration) or fraud (with respect to which no liability cap was determined). The Partnership will not be liable to the Buyers for breach of the representations unless an indemnity demand is delivered within 18 months from the transaction closing date (or 36 months with respect to the fundamental representations as aforesaid, until expiration of the applicable statute of limitations with respect to representations pertaining to tax liabilities).

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

9. The Michal-Matan joint venture (discontinued operations) (Cont.):

b) (Cont.)

6) The Partnership undertook to indemnify the Buyers for irregular events, including the overcharging of the Buyers with the Petroleum Profits Levy in connection with certain disputes existing between the Partnership and the tax authorities with respect to the method of calculation of the levy in relation to revenues and expenses in the period prior to the Effective Date, in accordance with the mechanism determined in the Agreement, up to a maximum indemnity cap of $15 million.
7) The law that governs the Agreement is the English law. Any dispute between the parties to the Agreement will be decided in an arbitration proceeding to be held before 3 arbitrators in London according to the London Court of International Arbitration rules.

c) Tamar Project discontinued operations -

The following table presents activity results' figures relating to the discontinued operations in the periods of the consolidated financial statements:

	For the year ended		
	31.12.2024	31.12.2023	31.12.2022
Revenues:			
From natural gas and condensate sales	-	-	-
Plus (net of) royalties	[11](1.0)	[13]2.6	[14](15.3)
Net revenues (expenses)	**(1.0)**	**2.6**	**(15.3)**
Other revenues (expenses)			
Reimbursement of insurance expenses	0.6	-	0.4
Operating income (loss) before oil and gas profit levy	(0.4)	2.6	(14.9)
Oil and gas profit levy	0.4	-	(2.1)
Operating income (loss)	-	**2.6**	**(17.0)**
Income taxes	*)	(0.5)	3.8
Profit (loss) from discontinued operations	*)	2.1	(13.2)
Profit from the sale of oil and gas assets	-	-	4.3
Total profit (loss) from discontinued operations	*)	**2.1**	**(8.9)**

***) Less than $0.1 million**

[13] The amount includes the update of overriding royalties due to adjustment of the investment recovery date and the update of State royalties and overriding royalties as set out in Note 15B7 below and the update of State royalties and overriding royalties relating to Footnote 12.

[14] Mostly consisting of royalties paid to the State, in excess and under protest, for revenues generated by the Partnership from gas supply agreements that were signed between natural gas consumers and the Yam Tethys Partners. In view of the judgment that has been handed down as specified in Note 12E1 below, an asset in respect of such payments has been amortized in the statement of comprehensive income.

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

9. The Michal-Matan joint venture (discontinued operations) (Cont.):

c) Tamar Project discontinued operations (Cont.)

The following table presents net cash flow figures relating to the discontinued operations and deriving from (used for) the operations:

	For the year ended		
	31.12.2024	31.12.2022	31.12.2022
Current	20.2	(17.3)	4.0
Investment	-	-	15.8
Financing	-	-	-

10. **Evaluations of reserves of natural gas, condensate, contingent and prospective resources:**

The above evaluations regarding the reserves of natural gas, condensate, and contingent and prospective resources of natural gas and oil in the Partnership's interests in the leases, licenses and oil and gas exploration concession are based, *inter alia*, on geological, geophysical, engineering and other information received from the results of wells that have been drilled and from the operator of such interests. The above evaluations constitute professional conjectures and evaluations by NSAI, which are uncertain. The quantities of natural gas and/or condensate to be actually produced may differ from the said evaluations and conjectures, *inter alia* as a result of operating and technical conditions and/or regulatory changes and/or supply and demand conditions in the natural gas and/or condensate markets and/or commercial terms and/or the actual performance of the reservoirs. The above evaluations and conjectures may be updated insofar as additional information is accrued and/or as a result of a gamut of factors relating to oil and natural gas exploration and production projects.

11. **Additional information**:

The deeds of the leases in Israel were granted subject to the Petroleum Law and confer on the partners in the leases the exclusive right to produce oil and natural gas in the areas of the leases for a 30-year period, with the right to extend them by 20 additional years, in accordance with and subject to the provisions of the Petroleum Law.

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 8 – Other Long-Term Assets:

A. Composition:

	31.12.2024	31.12.2023
Future production-based royalties from the Karish and Tanin leases (see Paragraph B below)	217.4	209.7
Ministry of Energy for royalties (see Note 15)	21.3	15.7
Interested parties in respect of overriding royalties (see Notes 12B and 15)	2.6	1.9
Third party in respect of overriding royalties (see Notes 12B and 15)	5.7	4.3
Access fees in respect of the Blue Ocean agreement (see Note 12C3)[15]	85.7	92.6
Receivables from a company accounted for at equity (see Note 21G3)	9.7	19.5
Fixed Assets	0.3	0.3
Lease right-of-use asset	2.2	2.5
Oil and gas profit levy (see Note 19C)	12.6	12.6
Investment in a joint project with Airovation Technologies (see Note 12G2)	1.0	-
Investment in condensate transmission infrastructure and pipeline (see Note 12F1)	6.4	5.2
Investment in natural gas transmission infrastructures and pipelines for export to Jordan and Egypt (see Note 12F2)[13]	148.8	106.0
Total	**513.7**	**470.3**

B. Agreement for the sale of interests in the Karish I/17 and Tanin I/16 leases (in this section: "Leases"):

1) On 16 August 2016[16], an agreement was signed between the Partnership and Ocean Energean Oil and Gas Ltd. (the "**Buyer**" or "**Energean**"), for the sale of all of the interests of the Partnership and Chevron[17] in the Leases (the "**Agreement**" and the "**Sold Interests**", respectively), in consideration for royalties in connection with the natural gas and condensate to be produced from the Leases: Approx. 5.12% – prior to payment of the Petroleum Profit Levy under the Levy Law and prior to the investment recovery date, approx. 2.47% – prior to payment of the Levy and after the investment recovery date, and approx. 3.22% – from the commencement of payment of the Levy and after the investment recovery date; and for financial consideration in the amount of $40 million, which was paid upon closing of the transaction, and contingent consideration in the amount of $108 million plus interest, in 10 installments beginning on the date of adoption of a final investment decision for the Leases (see Section 5 below).

[15] Such investments are depreciated on a straight-line basis over the term of the agreements with NEPCO and Blue Ocean, as applicable.

[16] Pursuant to the Gas Framework, the Partnership and Chevron were required to sell their entire interests in the leases; see Note 12H1.

[17] In November 2015, the Partnership entered into a right conferral agreement with Chevron, whereby Chevron conferred upon the Partnership the right to sell its interests in the Leases.

Note 8 – Other Long-Term Assets (Cont.):

B. Agreement for the sale of rights in the Karish I/17 and Tanin I/16 Leases (Cont.):

2) Energean and the Partnership have exchanged letters in relation to claims raised by Energean with respect to the Partnership's royalty interests in the Karish and Tanin leases. According to Energean (1) the Partnership's overriding royalty does not apply to the Karish North reservoir (as opposed to the Karish reservoir), which was announced as a natural gas discovery in April 2019 (2) not all hydrocarbon liquids to be produced from the Karish lease are deemed condensate under the Agreement which is subject to the duty to pay royalties. In the Partnership's position, based on its legal counsel, Energean's duty to pay royalties applies to anything pertaining to natural gas and condensate to be produced from the Leases, including the Karish North reservoir, and that any and all hydrocarbon liquids to be produced from the reservoirs situated in the area of the Leases constitute condensate, as defined in the Agreement, which is subject to royalties. Toward the end of October 2022, Energean reported the production of first gas from the Karish lease and sale thereof to its customers and has accordingly started paying royalties to the Partnership according to the Agreement as noted above. According to Energean's reports, production of first gas from the Karish North reservoir began at the end of February 2024. Up to the date of approval of the consolidated financial statements, Energean has been paying the Partnership, under protest, royalties in respect of the condensate produced from the Karish lease, including the Karish North reservoir.

3) The Partnership engaged an independent outside appraiser to assess the fair value of the royalties as of 31 December 2024. The main parameters used to measure the royalties and annual payments under the valuations were as follows: The pre-tax cap rate for the royalty component was estimated at 11.4% (2023: 10.88%); the rate of the value of State royalties at the wellhead was 11.06%[18]; gas production from the Karish lease: from 2022 until 2044; forecasted average annual rate of production from the Karish lease: ~3.25 BCM of natural gas; average annual rate of production from the Karish lease of ~4.43 million barrels of condensate; time of gas production from the Tanin lease: from 2029 until 2041; forecasted average annual rate of production from the Tanin lease: ~1.99 BCM of natural gas; average annual rate of production from the Tanin lease of ~0.34 million barrels of condensate; the total of reserves and resources of natural gas and hydrocarbon liquids used in the valuation is in line with the Resource Report.

[18] The royalty rate at the wellhead is based on the rate of advance payments required by the Ministry of Energy. This rate may change in the future in view of the royalty audit by the Ministry of Energy.

Note 8 – Other Long-Term Assets (Cont.):

B. Agreement for the sale of interests in the Karish I/17 and Tanin I/16 Leases (Cont.):

4) (Cont.)

The update to the valuation primarily derives from the cap rates, adjustment to the actual quantity produced in 2024 according to estimations released by Energean in relation thereto, update of the sale prices of natural gas and hydrocarbon liquids and the lapse of time (for sensitivity analyses in relation to the aforementioned parameters, see also Note 21F below).

To the best of the Partnership's knowledge, on 21 March 2024, Energean released an updated resources and reserve report for the Leases as of 31 December 2023, attributed to the Karish, Karish North and Tanin reservoirs. According to this report, the 2P natural gas reserves total ~96.3 BCM of and hydrocarbon liquids total ~98.3 MMBBL. Based on Energean's financial statements as of 30 September 2024, the royalties received in practice from Energean, the conversion ratio between the quantity of natural gas and the quantity of hydrocarbon liquids in the Reservoirs and Energean's release of 23 January 2025, it has been assumed that the quantity of natural gas and hydrocarbon liquids produced by Energean in 2024 is estimated at ~4.45 BCM and ~5.3 MMBBL, respectively.

4) On 24 March 2022, Energean informed the Partnership that according to its position, it was operating under a *force majeure* clause, as defined in the Agreement, as a result of which, the periodic payment for 2022 on account of the Loan, scheduled for March 2022, would be postponed. On 31 May 2022, the Partnership filed a pecuniary claim against Energean for a total amount of U.S. $65.1 million, plus lawful linkage differentials and differentials for the agreed annual interest rate of 4.6%. In September 2022 and in April 2023 Energean made annual payments of approx. $12.4 million and approx. $13.3 million, respectively. On 13 August 2023, the court approved an agreed procedural arrangement between the parties, and on 5 November 2023, mutual agreements the parties had reached were entered as a judgment, whereby Energean will pay the Partnership, in two installments during 2024, a total amount of approx. $47.4 million, which constitutes the entire balance of the consideration plus agreed annual interest. This constitutes the full and final discharge of the parties' claims in relation to the disputes to which the legal proceeding pertained. According to the arrangement, in March and May 2024, Energean paid the Partnership the full aforesaid balance of the consideration.

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 9 – Trade and Other Payables:

Composition:

	31.12.2024	31.12.2023
Related parties (see also Note 20)	0.3	0.3
Related parties for overriding royalties (see Notes 12B and 15)	3.6	4.9
Third parties for overriding royalties (see Notes 12B and 15)	7.7	8.7
Ministry of Energy in respect of royalties (see Notes 12B and 15)	12.4	10.1
Payables in the context of joint ventures[19]	78.2	75.2
Current maturities for a lease liability (see Note 20E2)	0.3	0.3
Expenses due	0.8	0.3
Trade and other payables	3.3	1.3
Total	**106.6**	**101.1**

[19] Mostly consisting of expenses incurred by the operator of the joint ventures and not yet paid.

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 10 – Bonds, loans and credit facilities from banking corporations:

A. Composition and maturities by years after the date of the consolidated statement of financial position:

1) Composition of bonds:

	31.12.2024	31.12.2023
Leviathan Bond (see Section B below)	1,625.6	1,735.1
Net of current maturities[20]	(485.6)	-
Total (net of current maturities)	**1,140.0**	**1,735.1**

2) Maturities by years after the date of the consolidated statement of financial position:

	Amount	Amortized Cost	Interest	Stated Maturity
Leviathan Bond-2025	600.0	485.6[18]	6.125%	June 2025
Leviathan Bond-2027	600.0	596.5	6.500%	June 2027
Leviathan Bond-2030	550.0	543.5	6.750%	June 2030
Total	**1,750.0**	**1,625.6**		

B. Bonds of Leviathan Bond:

On 18 August 2020, the issuance of bonds that were offered by Leviathan Bond (the "**Issuer**"), an SPC that is wholly held by the Partnership, pursuant to which bonds were issued in the total amount of $2.25 billion, was completed (of which $0.5 billion were repaid in 2023).

The bonds were issued in four series. The bond principal and interest are in dollars. The interest on each one of the bond series is paid twice a year, on 30 June and on 30 December.

On 3 August 2020, the Issuer received the approval of the Tel Aviv Stock Exchange Ltd. ("**TASE**") for the listing of the bonds on the TACT-Institutional system of TASE ("**TACT-Institutional**").

The full Issue proceeds were provided by the Issuer as a loan to the Partnership on terms and conditions identical to those of the bonds (back-to-back), and according to a loan agreement that was signed between the Issuer and the Partnership (the "**Loan**").

The Loan funds were used by the Partnership to repay loans from banking corporations in the sum of approx. $2 billion, deposit a safety cushion in the sum of $100 million in accordance with the terms and conditions of the bonds, pay the issue costs in the sum of approx. $33 million, and the balance of the proceeds served other uses according to the terms and conditions of the Commissioner's approval as described below (the "**Commissioner's Approval**").

[20] Net of approx. $113.8 million in respect of buybacks, as specified in Section C below.

Note 10 – Bonds, loans and credit facilities from banking corporations (Cont.):

B. Bonds of Leviathan Bond (Cont.):

To secure the bonds and the Loan, in the context of the indenture for the bonds and the other documents according to which the bonds will be issued (collectively: the "**Financing Documents**"), the Partnership pledged in favor of the trustee for the bonds (the "**Trustee**"), in a first-ranking fixed charge, its interests in the Leviathan project (45.34%), including in the Leviathan Leases, the operating approvals of the production system and the export approvals (collectively: the "**Pledge of the Leases**"), the Partnership's rights and the revenues from agreements for the sale of gas and condensate from the Leviathan project (the "**Gas Agreements**"), the Partnership's rights in the joint operating agreement (JOA) for the Leases, the Partnership's share in the project's assets (including the platform, wells, facilities, and systems for production and transmission to shore), the Partnership's rights in dedicated bank accounts, certain insurance policies and various licenses in connection with the Leviathan project. The Partnership also pledged the shares held thereby in the Issuer, in the Marketing Company and in Leviathan Transportation System.

In addition, the Issuer pledged in favor of the Trustee, in a first-ranking floating charge, its rights in all of its existing and future assets and pledged in favor of the Trustee its rights in the Loan agreement and in its bank accounts (collectively: the "**Pledges**" and the "**Pledged Assets**", as the case may be).

According to the Financing Documents, the Partnership's undertakings to the Trustee and the bondholders are limited to the Pledged Assets, with no guarantee or additional collateral.

The Pledges that the Partnership created in favor of the Trustee are subject, *inter alia*, to the State's royalties according to the Petroleum Law and to the rights of the parties entitled to royalties in respect of the Partnership's revenues from the Leviathan project, including the control holder of the Partnership.

As is standard in financing transactions of this type, in the Financing Documents the Partnership assumed stipulations, restrictions, covenants and there are grounds for acceleration of the bonds and enforcement of the Pledges, including, *inter alia*, the following principal obligations:

The Partnership and the Issuer, as applicable, have undertaken, *inter alia*, to fulfill obligations and conditions specified in government licenses and approvals, including in relation to the operator of the project, and including the conditions of the Commissioner's Approval; to fulfill the terms and conditions of the Leases and the JOA (jointly: the "**Leviathan Agreements**"); to protect their rights in the Pledged Assets and to ensure the validity of the Pledges and the rights of the Trustee and the holders according thereto; not to change or discontinue the Issuer's activity, and not to change the incorporation documents of the Issuer; not to create additional pledges on the Pledged Assets (aside from certain exceptions); to fulfill the provisions of the law that apply to their activity; to pay the taxes that apply thereto; to give the Trustee and the holders certain reports, notices and information that were specified in the Financing Documents; to act to maintain the listing of the bonds on TACT-Institutional; to act for the continued proper operation of the Leviathan project in accordance with the Leviathan Agreements; to take any action possible under the JOA so as to ensure that the operator fulfills its undertakings according to the JOA; to make all of the payments that apply thereto and to bear all of the Trustee's expenses that apply thereto according to the Financing Documents; to purchase and maintain certain insurance policies; to refrain from modifying or amending the Leviathan Agreements or material Gas Agreements, as defined in the Financing Documents ("**Material Gas Agreements**"), or the royalty agreements or engage in a new royalty agreement; to refrain from approval of certain acts in the context of the JOA; etc.

Note 10 – Bonds, loans and credit facilities from banking corporations (Cont.):

B. Bonds of Leviathan Bond (Cont.):

The Issuer has undertaken not to take on additional financial debt, with the exception of the issue of additional bonds or other secured debt *pari passu*, subject to the conditions specified, including (i) the sum of the secured debt of the Issuer (including the bonds) does not exceed, at any time, $2.5 billion; (ii) certain financial ratios specified in the Financing Documents in relation to the issuance of such additional debt are maintained.

In addition, the Partnership has undertaken not to assume any additional financial debt which is secured by the Pledged Assets, with the exception of an additional loan that it shall receive from the Issuer on terms and conditions back-to-back to additional debt that the Issuer shall raise subject to the restrictions set forth therefor in the Financing Documents.

The Partnership has undertaken not to perform any merger transaction or change its business in a manner which would likely cause an material adverse effect ("**MAE**"), or enter dissolution proceedings or other defined restructurings, and not to sell, transfer, pledge or make any other disposition of all or substantially all of its assets, other than Permitted Transactions, as defined in the Financing Documents, including sale of interests in the Leviathan project subject to mandatory early redemption or a tender offer to the bondholders in certain cases, or permitted restructurings, as defined, including a transfer of the Partnership's interests in the Leviathan project to a new subsidiary and/or other actions, including the outline under consideration for a split of the Partnership's assets, provided that the holders' rights are not prejudiced by such actions and additional terms and conditions as defined.

Furthermore, provisions were set out regarding early redemption of the bonds, including (1) early redemption at the Issuer's initiative, subject to payment of a make whole premium, other than a certain period before the specified repayment date, during which prepayment will not be charged with make whole premium and (2) mandatory early redemption in certain cases that were defined, including by way of a buyback of the bonds and/or performance of a tender offer to all the bondholders, including upon a sale of all or some of the interests in the Leviathan project. The Issuer and the Partnership undertook that if a tax withholding duty shall apply to the payments due under the terms and conditions of the bonds to a foreign resident then, subject to certain exceptions as defined, the Issuer and/or the Partnership, as the case may be, shall pay additional amounts as required for the net amounts to be received by the foreign resident to be equal to the amounts such foreign resident would have received, but for the withholding tax duty. In this context, it is noted that on 27 July 2020 the Partnership received a ruling from the Tax Authority stating, *inter alia*, that the bonds to be traded on the TACT-Institutional system of the TASE are bonds traded on a stock exchange in Israel for purposes of Section 9(15D) of the Income Tax Ordinance (for purposes of exemption from tax on interest paid to a foreign resident on bonds traded on the stock exchange), and Section 97(B2) of the Ordinance (for purposes of exemption from tax for a foreign resident on capital gains in the sale of the bonds traded on the stock exchange), all subject to the terms and conditions specified in the Tax Authority's ruling and the provisions of the Income Tax Ordinance and the regulations promulgated thereunder.

Note 10 – Bonds, loans and credit facilities from banking corporations (Cont.):

B. Bonds of Leviathan Bond (Cont.):

The Financing Documents include a payment waterfall mechanism, whereby the Partnership's entire revenues from the Leviathan project is transferred to an account that is pledged in favor of the Trustee (the "**Revenues Account**"), which is used to make various payments in connection with the project and the bonds, including payment of royalties to the State and to the royalty interests owners; payments to the Trustee; taxes and the levy under the Levy Law; capital expenses and operating expenses in connection with the Leviathan project; principal and interest payments; deposits into safety cushions; and balancing payments in connection with tax payments under Section 19 of the Law. The transfer of the amounts remaining in the Revenues Account after the making of the said payments to a non-pledged account of the Partnership is subject to conditions determined, including fulfillment of an NPV Coverage Ratio of at least 1.5[21].

The Financing Documents define Events of Default, upon occurrence of which, subject to certain determined curing periods, exceptions and conditions, the Trustee for the bonds shall be entitled (or required – upon the demand of one quarter of the bondholders) to accelerate the outstanding balance of the bonds and shall be entitled to act to enforce the Pledges. The main events are as follows: (1) Default on payment of principal, interest or other payments mandated by the Financing Documents; (2) Breach of representations; (3) Breach of the Covenants or Negative Covenants determined in the Financing Documents; (4) An event or entry into proceedings for insolvency of the Issuer, and an insolvency event as aforesaid or of a party to a Material Gas Agreement (as defined in the Financing Documents), the operator in the Leviathan project or the Partnership, if likely to cause an MAE (as defined in the agreement), subject to certain conditions and qualifications; (5) premature termination of any of the Leviathan Agreements or Material Gas Agreements, if likely to cause an MAE, subject to certain conditions and qualifications; (6) If a party to a Material Gas Agreement breaches the agreement with a likely MAE, subject to certain conditions and qualifications; (7) In the event of abandonment or cessation of the Leviathan project operations for more than 15 consecutive days, if likely to cause an MAE; (8) If damage is caused to the Leviathan project (including physical damage, revocation of license or transfer of the Partnership's rights therein by a government authority), with a likely MAE, which was not cured; (9) In the event of denial or revocation of a government approval granted in connection with the Leviathan project, with a likely MAE; (10) If any of the Financing Documents to which the Issuer or the Partnership are a party, or pledges provided under the Financing Documents, with an aggregate value of more than $35 million, cease to be in effect; (11) If a non-appealable judgment is issued against the Issuer for payment of an amount in excess of $35 million which was not paid; (12) If there is a breach of an undertaking in an agreement for the provision of other *pari passu* secured debt of the Issuer worth over $35 million; (13) If an undertaking to perform mandatory early redemption is breached; (14) If the provisions regarding expenditures from the Revenues Account are breached; etc. The bonds are rated by international rating agencies and an Israeli rating agency.

[21] The NPV Coverage Ratio was defined as the ratio between the current value of the available cash flow to the debt service (as defined in the Financing Documents) which is expected from proved and probable (2P) reserves, at a cap rate of 10%, from the Partnership's interests in the Leviathan project (the "**Discounted Cash Flow**"), and the debt balance of the issuer which is secured by the Pledged Assets net of cash accrued in certain accounts on the measurement date. According to the Financing Documents, the Discounted Cash Flow shall be calculated according to the same assumptions to be used by the Partnership in the resource reports to be released thereby under the provisions of the Securities Law, other than assumptions on the Brent barrel price, which shall be based on the prices of futures traded on ICE, as defined in the Financing Documents.

Note 10 – Bonds, loans and credit facilities from banking corporations (Cont.):

B. Bonds of Leviathan Bond (Cont.):

On 3 August 2020, the Commissioner's Approval was received for the Pledge of the Leases in favor of the Trustee, for the bondholders. The Commissioner's Approval provides that, *inter alia*, the pledge is given to secure payment of the bonds whose proceeds are intended for the granting of credit to the Partnership in the sum of up to $2.5 billion in total, for payment of loans in the sum of approx. $2 billion (which were mainly used for investments in the development of the Leviathan project), the deposit of a safety cushion in the sum of $100 million, investments in the Leviathan project only and the financing of the construction of a pipeline for the export of gas from the Leviathan and Tamar reservoirs. As of the date of approval of the consolidated financial statements, the Partnership is compliant with its aforesaid obligations. On 1 May 2023 a partial prepayment of the first series of the bonds, as described above, whose original maturity date was 30 June 2023, was made according to the terms and conditions of the bonds, for a total of $280 million (out of a total series of $500 million). The outstanding balance of the first series of the bonds was repaid in full and on schedule on 30 June 2023, according to the terms and conditions of the bonds.

C. On 21 January 2023, the board of directors of the Partnership's General Partner, approved the adoption of a plan for purchase of bonds of Leviathan Bond, whereby the Partnership and/or Leviathan would be able, from time to time, according to the discretion of the Partnership's management and in accordance with the details of the additional purchase plan, make purchases of bonds of Leviathan Bond in an aggregate amount of up to $100 million, by way of an off-exchange purchase, purchase via the TACT-Institutional system on TASE or otherwise for a two-year period, and the Partnership has accordingly executed buybacks of the bonds at the full extent of this plan. On 15 October 2024, the board of directors of the General Partner of the Partnership approved the adoption of another plan for purchase of Series 2025 and Series 2027 Bonds of Leviathan Bond in an aggregate amount of up to $100 million, which plan took effect on 15 October 2024 and will expire at the lapse of two years, i.e., on 15 October 2026. It is clarified that such decision does not obligate the Partnership and/or Leviathan Bond to make bond purchases, and that the Partnership's management is at liberty to decide not to purchase any bonds at all.

Up to the date of approval of the consolidated financial statements, the Partnership has executed buybacks under the said purchase plans totaling approx. $135 million of Series 2025, which includes the interest accrued as of the purchase date.

D. Credit facilities from banking corporations:

On 5 February 2023, the Partnership signed documents with an Israeli bank for the provision of two new bank credit facilities, intended to serve the Partnership in its current business. According to the terms and conditions of the credit facilities, the Partnership may draw down, from time to time, U.S. dollar loans up to a total sum of $150 million under two credit facilities, credit facility A of $100 million ("**Credit Facility A**") and credit facility B of $50 million (in this section: "**Credit Facility B**", and jointly with Credit Facility A, the "**Credit Facilities**") during an availability period commencing on 6 February 2023 and ending on 6 March 2024. For the undrawn part of each one of the Credit Facilities, the Partnership paid a quarterly non-drawdown fee at an annual rate of 0.65%, until it is drawn down by the Partnership or until the end of the availability period, whichever is earlier. Any loan drawn down from Credit Facility A bears interest at the SOFR rate plus a margin of 2.7% per annum, with the principal of the loan so drawn down from Facility A being due and payable by 30 May 2025.

Note 10 – Bonds, loans and credit facilities from banking corporations (Cont.):

D. Credit facilities from banking corporations (Cont.):

According to the terms of Credit Facility B, it was determined that any loan drawn down from such facility bears interest at the SOFR rate plus a margin of 3% per annum, with the principal of the drawn down loan being due and payable in four equal quarterly installments beginning at the end of Q1/2024 and ending at the end of 2024. Additionally, for Credit Facility, on 15 February 2023 the Partnership paid a one-time commitment fee at the rate of 0.75% of Credit Facility B.

On 9 January 2023, at the Partnership's request, Credit Facility B was terminated. The Partnership had neither used nor drawn a loan from Facility B during the availability period. Furthermore, letters were signed for amendment of the facility agreement whereby the availability period of Credit Facility A would be extended until 31 March 2024. The Partnership has drawn down a sum of $80 million from Credit Facility A, which was fully repaid in January 2024.

On 14 March 2024, the Partnership signed an agreement with an Israeli bank for the provision of a bank credit facility, which agreement cancels all aforesaid previous facilities, for use by the Partnership in its operating activities. According to the terms and conditions of the credit facility, the Partnership may draw down, from time to time, loans in U.S. dollars up to an aggregate amount of $100 million during the availability period commencing on 14 March 2024 and ending on 7 March 2025. According to the agreement, the Partnership will pay a quarterly no-use fee at the rate of 0.65% per annum for the unused portion of the credit facility, until its drawdown by the Partnership or the expiration of the availability period, whichever is earlier. Every loan taken out of the credit facility bears SOFR interest plus a margin of 2.5% per annum, with the principal of the loan so drawn due and payable by 15 April 2026.

E. On 8 October 2024, the Partnership signed agreements for the provision of credit facilities by two Israeli banks, in the amount of $200 million each (in this section: the "**Lenders**" and "**Credit Facilities**", respectively). Of note, the new credit facility from one of the banks substitutes for a $100-million credit facility provided to the Partnership by that bank on 14 March 2024, as specified in Section D above. The Credit Facilities are intended to be used by the Partnership in its operating activities, including as relating to Phase 1B of the Leviathan reservoir Development Plan. Under the terms and conditions of the Credit Facilities, during the period beginning on 8 October 2024 and ending on 8 October 2025 (the "**Availability Period**"), the Partnership will be able to draw down, from time to time, U.S. dollar loans up to a total of $200 million from each of the Lenders (the "**Loans**"). Loans to be so drawn shall be partly repaid by 15 April 2027 with their balance repaid by 15 October 2026 (the "**Payment Due Dates**"). As of the date of approval of the consolidated financial statements, the Partnership has not yet drawn down amounts out of such Credit Facilities.

<u>Below is a concise description of the additional key conditions stipulated in the documents of the Credit Facilities</u>:

1. The Loans shall be repaid in one payment on the Payment Due Dates and bear annual interest payable on a quarterly basis, based on the SOFR rate plus a margin ranging between 2.5% and 3.2%. For receipt of the Credit Facilities, the Partnership has paid the Lenders a one-time commitment fee totaling 0.15% of the aggregate amount of the Credit Facilities, and a fee for the undrawn Credit Facilities at an annual rate ranging between 0.4% and 0.55% of the balance of the undrawn Credit Facilities until the end of the Availability Period. Any loan from the Credit Facilities may be drawn again until the end of the Availability Period, and at any time, the Partnership may inform the Lenders of reduction of the Credit Facilities free of charge.

Note 10 – Bonds and credit facilities from banking corporations (Cont.):

E. Credit facilities from banking corporations (Cont.):

2. The Partnership has the right to prepay each of the Loans (in whole or in part) at any time, with no prepayment fee or other payment, except in certain cases as specified in the loan agreement, for which it shall pay negligible amounts.

3. The Partnership has undertaken not to sell and/or transfer and/or encumber and/or pledge its royalty interests in the Karish and Tanin leases without the advance written consent of the Lenders.

4. The documents of the Credit Facilities set out provisions in connection with the sale of the Partnership's holdings in the Leviathan project, including the Partnership's undertaking to reduce the Credit Facilities' total, first by cancelling unused credit facilities (if any) and subsequently by prepayment.

5. If the Partnership issues new short-term bonds in an amount exceeding $200 million, with a maturity date predating 30 June 2027, the Partnership will reduce the Credit Facilities' total, such that after the reduction, the amount of each of the Credit Facilities does not exceed $100 million.

6. The documents of the Credit Facilities specify financial covenants that must be met by the Partnership on a quarterly basis (apart from Section d below, which requires compliance on a semiannual basis) and breach of which gives rise to the Lender's right to immediate repayment, as is standard in agreements of this type, including the ratio between the Value of the Partnership's Assets and its Net Financial Debt[22], minimum liquidity and ratios between surplus sources and the amount of the credit facility in each bank separately. As of the date of the consolidated statement of financial position, the Partnership complies with all the financial covenants set forth in the agreements.

   Below are details regarding the financial covenants with which the Partnership is required to comply and which give rise to the Lender's right to immediate repayment, and the calculated value thereof as of the date of the consolidated statement of financial position:

   a. The ratio between the Value of the Partnership's Assets and the Net Financial Debt shall be no less than 1.5 on two consecutive review dates. As of 31 December 2024, the ratio is 4.48[23] .

[22] For this purpose, "**Value of the Partnership's Assets**" – The total discounted cash flow (at a rate of 10%) after deduction of taxes of the probable and/or contingent reserves (2P and/or 2C) of the Partnership's share in all the projects, based on the last discounted cash flow (DCF) released to the public by the Partnership and adding the value of other assets of the Partnership (which are not included in the definition of projects) based on an independent external valuation by an appraiser whose identity is acceptable to the lender.

"**Financial Debt**" – The Partnership's debts and liabilities to banks and other financial institutions and/or deriving from bonds of all types, including straight bonds and convertible bonds and/or deriving from loans received by the Partnership from affiliates or from any third parties (except loans for which letters of subordination shall have been signed vis-à-vis the lender by the Partnership and by the provider of that loan). For the avoidance of doubt, the term "Financial Debt" does not include guarantee facilities and bank guarantees issued thereunder at the Partnership's request.

"**Net Financial Debt**" – Financial Debt net of: (1) cash and cash equivalents; and (2) deposits in banks and financial institutions; (3) safety cushions and funds provided to secure Financial Debt (to the extent not included in Subsection (1) or (2)), provided that none of the aforementioned assets is encumbered by a fixed charge and/or in respect of which a non-withdrawal undertaking has been given in favor of any party other than the lender other than in respect of the debt or liability included in the definition of the Financial Debt.

[23] Net of buybacks, as specified in Note 10C above.

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 10 – Bonds and credit facilities from banking corporations (Cont.):

E. **Credit facilities from banking corporations (Cont.):**

6. (Cont.)

   b. The Partnership's (standalone) liquidity shall be no less than $20 million. As of 31 December 2024, the Partnership's liquidity is approx. $451 million[24].

   c. Total financial debt, excluding limited-recourse loans other than the bonds of Leviathan Bond, shall not exceed $3 billion. As of 31 December 2024, financial debt totals approx. $1.6 billion.

   d. The ratio between surplus sources and the amount of the Credit Facilities in each bank separately shall be no less than 1. As of 31 December 2024, the ratio is 4.45.

7. The documents of the Credit Facilities specify certain representations by the Partnership as well as additional conditions and obligations as standard in financing agreements of this type, including delineation by the Credit Facilities' documents of certain default events upon occurrence of which the Lender shall have the right to accelerate the Loans or some of them.

Note 11 - Other Short-Term and Long-Term Liabilities:

A. **Other Long-Term Liabilities:**

	31.12.2024	31.12.2023
Oil and gas asset retirement obligation (see Note 2J and Section B)	68.5	71.3
Liability due to lease	2.0	2.3
Other	-	0.1
Total	**70.5**	**73.7**

B. **Transactions in oil and gas asset retirement obligation:**

	2024	2023
Balance as of 1 January	73.5	76.4
Change of cost estimate	(3.8)	3.7
Effect of the lapse of time[25]	3.5	3.2
Effect of update of the cap rate and indexation[21]	(5.1)	(2.1)
Amounts incurred for abandonment of oil and gas assets (see Note 7C3(b) above)	0.4	(7.7)
Balance as of 31 December	**68.5**	**73.5**
Net of short-term oil and gas asset retirement obligation (See Note 7C3(b) above)	-	(2.2)
Total	**68.5**	**71.3**

[24] Including the credit facility provided to the Partnership on 14 March 2024 but excluding balances in accounts pledged in favor of the bonds of Leviathan Bond.

[25] The cap rate for measuring the oil and gas asset retirement obligation as of 31 December 2024 is 7.2% (31 December 2023: 6.9%).

Note 12 – Contingent Liabilities, Engagements and Pledges

A. Under the Partnership Agreement, the General Partner will be entitled to 0.01% of the revenues and shall bear 0.01% of the expenses and losses of the Partnership, and the Limited Partner (the trustee) will be entitled to 99.99% of the revenues and shall bear 99.99% of the expenses and losses of the Partnership.

B. Royalty payment engagements:

1. Following the closing of the merger between the Partnership and Avner Oil Exploration Limited Partnership ("**Avner**" or "**Avner Partnership**") of May 2017, all of the liabilities related to royalties apply with respect to all of the (current and future) gas and petroleum assets of the Partnership. However, the rate of royalties in respect thereof, was reduced by 50% compared with the rate of royalties prior to the Merger (since the Partnership and Avner Partnership held equal parts in the petroleum assets, excluding the Ashkelon and Noa leases, in which the Partnership held 25.5% and Avner Partnership 23%, and in their respect the rate of royalties was reduced by 47.42% with respect to the royalties paid by the Partnership to Delek Group and Delek Energy, as defined below, and by 52.58% with respect to the royalties paid by Avner Partnership before the Merger, as specified below).
2. In the context of the right transfer agreement signed in 1993, the Partnership undertook to pay Delek Energy and Delek Group (the "**Royalty Interest Owners**") royalties at the rates specified below from the entire share of the Partnership in petroleum and/or gas and/or other valuable substances that shall be produced and utilized from the petroleum assets, in which the Partnership has or shall have any interest (prior to deduction of any kind of royalties, but after deduction of the petroleum used for the production itself).
   The royalty rates are as follows: until the date of the Partnership's investment recovery, royalties shall be paid at a rate of 2.5% of onshore petroleum assets and 1.5% of offshore petroleum assets, and after the investment recovery date – 7.5% of onshore petroleum assets and 6.5% of offshore petroleum assets.
3. In addition, the Partnership will pay pursuant to the Avner Partnership Agreement royalties at a rate of 3% of all of the share of the limited partnership in petroleum and/or gas and/or other valuable substances which will be produced and utilized out of the petroleum assets in which the limited partnership has a present or will have a future interest (before deduction of royalties of any type, but after the reduction of the oil to be used for the purpose of the production itself). In an agreement signed on 2 September 1991, it was determined that the said right of the royalties is held by the General Partner in trust, and it is paid to those entitled to royalties under the Limited Partnership Agreement.

C. Engagements for the supply of natural gas and condensate:

1. **Agreements for the sale of natural gas from the Leviathan project:**
   Below are concise details regarding the agreements for the supply of natural gas from the Leviathan project which were signed by the Partnership, together with the other Leviathan Partners, that are valid as of the date of approval of the consolidated financial statements[26]:

[26] The figures in the table do not include agreements for the supply of natural gas from the Leviathan project on an interruptible basis.

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

C. Engagements for the supply of natural gas and condensate (Cont.)

1. Cont.)

Customer	Supply Commencement Date	Term of Agreement[27]	Total Maximum Contractual Supply Quantity (100%) (BCM)	Total Quantity Supplied by 31 December 2024 (100%) (BCM)	Primary Gas Price Linkage Base
Independent power producers[28]	2020, or the date of commencement of the commercial operation of the buyers' power plant (whichever is later).	Long-term agreements for 9-25 years. Some of the agreements grant each of the parties the option to extend the agreement in cases of non-purchase of the total contractual quantity.	~17.1	~3.3	In most of the agreements the gas price linkage formula is based on the electricity price tariff (the Electricity Production Tariff and the TAOZ Tariff) and includes a "price floor". One of the agreements specifies a fixed, non-linked price.
Industrial customers	2020	The agreements are for 2.5-15 year terms. Most of the agreements do not grant the parties an option to extend the term of the agreement.	~4.2	~1.1	The linkage formula in most of the agreements is based partly on linkage to the Brent prices and partly to the Electricity Production Tariff, and includes a "price floor". There is also partial linkage to the Crack Spread Index and to the TAOZ Tariff. Several agreements determine a fixed, non-linked price.
NEPCO export agreement (described in Paragraph 2 below)	2020	15 years. The agreement stipulates that if the buyer does not purchase the total contract quantity, the supply period will be extended by another two years.	~45	~12.7	The linkage formula is based on linkage to the Brent prices and includes a "price floor".
Blue Ocean export agreement (described in Paragraph 3 below)	2020	15 years. The agreement stipulates that if the buyer does not buy the total contract quantity, the supply period will be extended by another two years.	~60	~23.5	The linkage formula is based on linkage to the Brent prices and includes a "price floor". The agreement includes a mechanism for price updates by up to 10% (up or down) after the 5th and 10th years of the agreement, in certain conditions specified in the agreement.
Total			**~126**	**~40.5**[29]	

[27] Under most of the agreements, the gas supply term may end when the maximum contract quantity specified in the agreement shall have been supplied to the customers.

[28] This includes entry into the agreement signed on 23 May 2024 between the Leviathan Partners and Eshkol Power Energies Ltd. for the supply of natural gas in an aggregate annual quantity of ~0.5 BCM; see Note 12E below.

[29] The total quantity supplied from the Leviathan project by 31 December 2024 (100%) (under the agreements listed in the table, under SPOT agreements and agreements that have come to an end) is ~51.5 BCM.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

C. Engagements for the supply of natural gas and condensate (Cont.):

1. Agreements for the sale of natural gas from the Leviathan project (Cont.):

Further details with respect to the agreements for sale of natural gas from the Leviathan reservoir to independent power producers and industrial customers in the domestic market:

a) In 2024 and up to the date of approval of the consolidated financial statements, the Partnership signed several agreements for sale of natural gas from the Leviathan project with various customers in the Israeli market, both on a firm basis and on an interruptible (spot) basis.

b) Under all the natural gas sale agreements, excluding agreements on an interruptible (spot) basis (in this section: the "**Agreements**"), the customers have undertaken to purchase or pay ('Take or Pay') for a minimum annual quantity of natural gas at a scope and according to the mechanism specified in the supply agreement (the "**Minimum Quantity**"). Of note, the Agreements set out provisions and mechanisms that allow each of the said buyers, having paid under the agreement for natural gas not consumed thereby due to the application of the aforesaid billable Minimum Quantity mechanism, to receive gas with no additional payment up to the amount paid for gas not consumed in the years following the year in which the payment was made and subject to consumption of the Minimum Quantity in each of such following years. In addition, the Agreements determine a mechanism for accrual of a balance of surplus quantities (over the 'Take or Pay') consumed by the buyers in any given year and the use thereof to reduce the buyers' obligation to purchase the aforesaid Minimum Quantity in several subsequent years.

c) The Agreements specify additional provisions, *inter alia*, on the following subjects: The right to terminate the agreement in the event of breach of a material obligation, the Leviathan Partners' right to supply gas to the buyers from other natural gas sources, compensation mechanisms in the event of failure to supply the contractual quantities, limitations of the liability of the parties to the agreement, as well as with respect to the relationship among the sellers themselves as relating to the supply of gas to the said buyers.

d) In accordance with the Gas Framework, each of the buyers under Agreements signed by 13 June 2017 and for a term exceeding 8 years, was given the option to reduce the Minimum Quantity down to a quantity equal to 50% of the average annual quantity actually consumed thereby in the three years preceding the date of the notice of exercise of the option, subject to such adjustments as specified in the supply agreement. Upon reduction of the Minimum Quantity, the other quantities specified in the supply agreement will be reduced accordingly. Each one of the said buyers may exercise such option by a notice to be given to the sellers during a 3-year period commencing at the lapse of 5 years from the date of the first piping of gas from Leviathan project to the buyer. If the buyer gives notice of the exercise of such option, the quantity will be reduced at the lapse of 12 months from the date the notice was given.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

C. Engagements for the supply of natural gas and condensate (Cont.):

2. Agreements for the export of natural gas from the Leviathan reservoir to Jordan

a) Agreement for the export of natural gas from the Leviathan project to NEPCO:
In September 2016, an agreement was signed for the supply of natural gas between the Marketing Company and NEPCO (the "**NEPCO Agreement**"). The Marketing Company is a subsidiary wholly owned by the Leviathan Partners, whose holdings therein are *pro rata* to their holding rates in the Leviathan project. According to the NEPCO Agreement, the Marketing Company undertook to supply natural gas to NEPCO for a period of approx. 15 years from the date of commencement of the commercial supply or until the total supply volume will be ~45 BCM. The supply of gas to NEPCO began on 1 January 2020. The gas delivery point according to the NEPCO Agreement is at the connection between the Israeli transmission system and the Jordanian transmission system on the border between Israel and Jordan. In December 2019, INGL completed the construction of the Israeli transmission system up to the border between Israel and Jordan at a cost of approx. $109 million (100%, the Partnership's share being approx. $49.4 million). NEPCO has undertaken to take or pay for a minimum annual quantity of gas, in such amount and in accordance with the mechanism as determined in the NEPCO Agreement. In addition, in connection with NEPCO's 'take or pay' undertaking, the agreement sets forth, *inter alia*, provisions and a mechanism that allow NEPCO, after it has consumed the minimum billable quantity for a certain year, to receive in such year, a supply of gas for no additional payment up to the remaining gas quantity not consumed in previous years and for which it paid consideration to the Marketing Company in the context of the 'take or pay' undertaking (makeup mechanism), as well as provisions and a mechanism that allow NEPCO to accumulate quantities purchased in any year over and above the minimum quantity, and to utilize the same to reduce its undertaking (carry forward mechanism). The price of the gas that was set in the agreement is based on a price that is linked to the Brent oil barrel prices and includes a "price floor" plus a marketing commission and piping fees. In addition, NEPCO will bear the piping payments to INGL. In November 2016, the Leviathan Partners and the Marketing Company signed a back-to-back GSPA ("**Back-to-Back**"), whereby the amounts that shall be received, the liabilities, the risks and the costs relating to the export agreement will be endorsed to the Leviathan Partners under the same terms (back-to-back), as if the Leviathan Partners were a party to the export agreement instead of the Marketing Company. On 3 July 2023, the parties agreed to increase the natural gas quantities that would be supplied to NEPCO on a firm basis, temporarily and in relation to several months in 2023-2024, and that the minimum annual quantity that NEPCO had undertaken to take or pay for during 2023-2024 would increase accordingly. The aforesaid does not change the total supply volume under the Export to Jordan Agreement (~45 BCM), as specified above.

b) In October 2024, an agreement was signed between the Marketing Company and FAJR for the supply of a total volume of ~2.5-3 BCM of natural gas for a period of 10 years. The gas price formula determined in this agreement is based on linkage to the Brent prices and includes a "floor price". The agreement is also contingent on obtaining the required regulatory approvals in Israel, including export approval from the Commissioner, and in Jordan, the signing of a transmission agreement with INGL which will allow transmission of the quantities under the agreement, and obtaining a tax ruling. As of the date of approval of the consolidated financial statements, the export approval for this agreement has not yet been received and supply of the gas thereunder has not yet begun

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

C. Engagements for the supply of natural gas and condensate (Cont.):

3. Agreement for export of natural gas from the Leviathan project to Blue Ocean in Egypt:

In February 2018, an agreement was signed between the Partnership and Chevron and Blue Ocean (in this section: the "**Buyer**") for the export of natural gas from the Leviathan project to Egypt and on 26 September 2019, the signing of an agreement for amendment of the original Leviathan-Blue Ocean agreement between the Leviathan Partners and Blue Ocean was closed (in this section: the "**Leviathan Agreement**"), and an agreement was signed in connection with the allocation of the available capacity in the transmission system from Israel to Egypt between the Leviathan Partners and the Tamar partners. On 15 January 2020, the flow of natural gas began in accordance with the Leviathan Agreement.

<u>Below is a summary of the details and terms and conditions of the Leviathan export agreement</u>:

a) The total contract gas quantity which the Leviathan Partners have undertaken to supply to the Buyer on a firm basis is ~60 BCM (the "**TCQ**").

b) The supply of gas began on 15 January 2020, and will be until 31 December 2034 or until the supply of the full TCQ, whichever is earlier (the "**Term of the Leviathan Agreement**"). In the event that the Buyer does not purchase the TCQ, each party will be entitled to extend the supply period by two additional years.

c) The Leviathan Partners have undertaken to supply the Buyer with annual gas quantities as follows: (i) in the period that commenced on 15 January 2020 and ended on 30 June 2020, ~2.1 BCM per year; (ii) in the period that commenced on 1 July 2020 and ended 30 June 2022, ~3.6 BCM per year; and (iii) in the period commencing 1 July 2022 and ending on the end of the Term of the Leviathan Agreement, ~4.7 BCM per year. Furthermore, the Levithan Agreement includes provisions with respect to the possibility of piping additional gas quantities, over and above the aforesaid daily quantities, on an interruptible (spot) basis. For details with respect to export of the gas to Egypt via the EMG Pipeline and through Jordan via the Jordan North export line and the Jordanian transmission system, see Note 12F2 below. The export agreement provides provisions whereby in a case where the daily gas quantities are undersupplied in a certain month (shortfall), the Buyer is entitled, under certain conditions, to compensation in the form of a discount on the gas supplied thereto the following month, at a rate determined, *inter alia*, as a function of the rate of undersupply in the current month.

d) The Buyer has undertaken to take or pay for quarterly and annual quantities according to mechanisms set forth in the Leviathan Agreement which, *inter alia*, enable the Buyer to reduce the TOP quantity in a year in which the average daily Brent price (as defined in the agreement) is lower than $50 per barrel, such that it shall be 50% of the annual contract quantity. If the contract quantity is reduced in the case of a disagreement about the gas price update, as stated in Paragraph E below, Blue Ocean's right to reduce the take-or-pay quantity as aforesaid will be revoked (see Note 12E6 below regarding a claim and a motion for class certification thereof which was filed against the Partnership in connection with such clause). Also, in connection with the Buyer's undertaking to take or pay, the agreement stipulates, among other things, instructions and a mechanism that allow the Buyer, after having consumed the minimum billable quantity for a certain year, to receive gas supply in that year without additional payment up to the balance of the amount of gas that was not consumed in previous years and for which it paid the sellers as part of the take-or-pay obligation (make up mechanism), as well as instructions and a mechanism that allow the Buyer to accumulate quantities purchased in any year above the minimum quantity, and use them to reduce the Buyer's obligation (carry forward mechanism).

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

C. Engagements for the supply of natural gas and condensate (Cont.):

3. Agreement for the export of natural gas from the Leviathan project to Blue Ocean in Egypt (Cont.):

e) The price of the gas to be supplied to the Buyer will be determined according to a formula based on a Brent oil barrel, and a "price floor". Export to Egypt includes a mechanism for a price update of up to 10% (up or down) after the fifth and tenth years of the agreement, upon certain conditions specified in the agreement. If the parties do not reach an agreement on the price update as aforesaid, the Buyer shall have the right to reduce the contractual quantity by up to 50% on the first adjustment date and 30% on the second adjustment date. The agreement includes an incentives mechanism, subject to quantities and the oil barrel price. The Leviathan Agreement includes accepted provisions relating to conclusion of the agreement, as well as provisions in the case of conclusion of the export agreement, signed between the Tamar partners and Blue Ocean as a result of a breach thereof, and the Leviathan Partners' not agreeing to supply also the quantities according to the said Tamar agreement, and also includes compensation mechanisms in such a case.

f) To facilitate an increase in the export quantities to Egypt, and in view of the delay in completion of the new offshore transmission section between Ashdod and Ashkelon, as specified in Note 12F2(a) below, the Leviathan Partners and Blue Ocean signed an amendment to the agreement for export to Egypt, in which it was agreed, *inter alia*, to define an additional gas delivery point in Aqaba, Jordan, under the agreement for export to Egypt, in which a certain price discount was determined as compensation to Blue Ocean for the additional transmission expenses entailed by transmission of the gas from the additional delivery point, which are borne thereby. The piping of gas to Egypt to the delivery point in Aqaba began in March 2022, and is performed through the Jordan-North Export Pipeline, as specified in Note 12F2(b) below. As of the date of approval of the consolidated financial statements, the Leviathan Partners and Blue Ocean are conducting negotiations regarding additional gas quantities that shall be sold to Blue Ocean in a volume exceeding ~100 BCM.

Concurrently with the signing of the Leviathan Agreement, on 26 September 2019 (as amended on 21 August 2023) an agreement was signed between the Partnership and Chevron and the rest of the Leviathan Partners and the Tamar partners in connection with allocation of the capacity (in this section: the "**Capacity Allocation Agreement**") in the transmission from Israel to Egypt system.

Allocation of the capacity in the transmission system from Israel to Egypt (the EMG Pipeline and the transmission pipeline in Israel) will be on a daily basis, according to the following order of priority:

1) First layer – up to 350 MMCF per day will be allocated to the Leviathan Partners.
2) Second layer – the capacity above the first layer, up to 150 MMCF per day until 30 June 2022 (the "**Capacity Increase Date**"), and 200 MMCF per day after the Capacity Increase Date, will be allocated to the Tamar partners.
3) Third layer – any additional capacity above the second layer will be allocated to the Leviathan Partners.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

C. Engagements for the supply of natural gas and condensate (Cont.):

3. Agreement for the export of natural gas from the Leviathan project to Blue Ocean in Egypt (Cont.):

Pursuant to the Capacity Allocation Agreement, on the date of the closing the EMG transaction, the Leviathan Partners and the Tamar partners paid the Partnership and Chevron the sum of $250 million (80% by the Leviathan Partners and 20% by the Tamar partners), as participation fees, in consideration for the undertaking to allow the piping of natural gas from the Leviathan and Tamar reservoirs and guaranteeing capacity in the EMG Pipeline. Pursuant to the agreement, the amount of the aforesaid payments will be updated according to the formula and dates determined in the agreement, based on the actual use of the EMG Pipeline. In view of the aforesaid, for the period between 1 January 2022 and 30 June 2022, the distribution of payments between the Leviathan Partners and the Tamar partners was approx. 83% and approx. 17%, respectively. The Capacity Allocation Agreement determines further arrangements for bearing the additional costs and investments that will be required for refurbishment of the EMG Pipeline and maximum utilization of the pipeline capacity, which shall be paid by both the Leviathan Partners and the Tamar partners. In this context it is noted that on 30 June 2022 and 30 June 2024, the parties updated the distribution of payments between the Leviathan Partners and the Tamar partners, and held a reconciliation accordingly in non-material amounts, for purposes of adjusting the parties' respective rates of participation in the actual costs of usage of the EMG Pipeline capacity in such period. The Capacity Allocation Agreement further determines that from 30 June 2020 until the Capacity Increase Date, insofar as the Tamar partners shall be unable to supply the quantities which they undertook to supply to Blue Ocean, the Leviathan Partners shall supply the Tamar partners with the required quantities.

The term of the Capacity Allocation Agreement is until the conclusion of the agreement for export to Egypt, unless it shall have ended prior thereto in the following cases: Breach of a payment undertaking which is not remedied by the party in breach; or in a case where the Competition Authority does approve the extension of the capacity and operatorship agreement according to the decision of the Competition Commissioner. In addition, each party shall be entitled to end its part in the Capacity Allocation Agreement insofar as its export agreement shall have been terminated.

4. Agreement for natural gas supply to Eshkol Power Energies Ltd.

on 23 May 2024, the Leviathan Partners entered with Eshkol Power Energies Ltd. (in this section: the "**Buyer**") in an agreement for the supply of natural gas (in this section: the "**Agreement**") to the production units at the Eshkol site in Ashdod, which the Buyer intends to purchase from IEC, pursuant to a sale agreement it has signed with the IEC. Under the Agreement, the Leviathan Partners have undertaken to supply the Buyer, on a firm basis, daily gas quantities in an aggregate annual quantity of ~0.5 BCM, which are intended to serve the two combined cycle production units at the Eshkol site (the "**CCGTs**"), as of the supply commencement date in June 2024, upon transfer of ownership of the power plant from IEC to the Buyer and until the end of the term of the Agreement on 31 December 2031.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

C. Engagements for the supply of natural gas and condensate (Cont.):

4. Agreement for natural gas supply to Eshkol Power Energies Ltd. (Cont.)

The Buyer has undertaken to purchase or pay for (Take or Pay) certain gas quantities calculated as a percentage of the adjusted annual contract quantity (Adjusted ACQ), subject to *force majeure* circumstances and other standard terms and conditions. The parties further agreed that the Leviathan Partners will supply the Buyer, on an interruptible basis, additional gas quantities that will be used for the four steam production units at the Eshkol site (the "**Steam Units**"), which will operate mainly when the electricity reserves in the market are low, starting from the aforesaid supply commencement date and throughout their period of operation (currently expected to continue until 31 December 2026). The Buyer has undertaken to take or pay for certain gas quantities for the Steam Units, subject to the extent of their actual operation, the availability of gas and other standard terms and conditions. The sale prices stipulated in the Agreement are linked to the electricity prices for CCGTs, and to the Brent oil barrel price in relation to the Steam Units, in accordance with such mechanisms and periods as specified in the Agreement. The said sale prices are denominated in dollars and are subject to minimum prices. The Agreement sets forth additional provisions, as is standard in agreements of this type, *inter alia*, with respect to *force majeure* events, default events and indemnification, taxation and fiscal changes, early termination, etc. In June 2024 supply of natural gas to the Buyer began in accordance with the Agreement.

5. Agreement for supply of condensate to ORL:

In December 2019, an agreement was signed (the "**ORL Agreement**") whereby condensate produced from the Leviathan reservoir will be piped to the existing fuel pipeline of EAPC which leads to a container site of Energy Infrastructures Ltd. ("**PEI**") and from there it will be piped to ORL's facilities, *inter alia*, in accordance with regulatory instructions.

The agreement signed with ORL is on an interruptible basis, up to a maximum quantity that was agreed between the parties, as shall be updated from time to time, in accordance with the terms and conditions determined by the authorities in this regard, for a term of 15 years from the date of the first condensate piped (in commercial quantities), with each party having the right to terminate the ORL Agreement by giving prior notice of at least 360 days, to the other party. In addition, each party may terminate the ORL Agreement on shorter notice upon the occurrence of various events, including in the case of a breach by the other party, and upon the occurrence of regulatory and other changes which will not allow the piping of the condensate according to the provisions of the ORL Agreement. According to the agreement, the Leviathan Partners are not entitled to consideration for supplying the condensate to ORL, with the Leviathan Partners being obligated to bear any and all expenses, including tax exposures, relating to the supply of the condensate.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

C. Engagements for the supply of natural gas and condensate (Cont.):

5. Agreement for supply of condensate to ORL (Cont.):

As specified in Paragraph F below, on 7 March 2024, the Leviathan Partners began piping condensate through the PEI pipeline to ARF, following which, as of the said date, the condensate quantities supplied to ORL under the said agreement have been significantly reduced. In the context of correspondence between the Leviathan Partners and ORL in Q1/2022, the Leviathan Partners claimed against ORL that failure to pay for the condensate supplied to ORL as aforesaid constitutes prohibited and unlawful abuse of ORL's power as a monopsony in the purchase of condensate. ORL responded in a letter rejecting the Leviathan Partners' claims. On 4 February 2024, the Leviathan Partners notified ORL that the piping of the condensate to ARF was expected to commence in March 2024, and that from that date the quantities delivered to ORL would be significantly reduced. In response to this notice, ORL sent a letter to the Leviathan Partners, according to which the Leviathan Partners' said notice constitutes a breach of the agreement with ORL. It is the Partnership's position that ORL's said claims and demands are groundless, and accordingly, the Leviathan Partners are considering their next steps vis-à-vis ORL on this matter.

6. Agreement with ARF for sale of condensate from the Leviathan reservoir

On 18 January 2023, the Leviathan Partners, including the Partnership (in this section: the "**Sellers**") engaged with ARF in an agreement for the sale of condensate to ARF (in this section: the "**Agreement**"). Following is a concise description of the main terms of the Agreement:

a) According to the Agreement, the Sellers undertook to supply to ARF, condensate that is produced from the Leviathan reservoir, which will be transported through PEI's pipe.

b) The Agreement stipulates, *inter alia*, provisions regarding limitations on the maximum quantities (on a daily and monthly level) of the condensate to be supplied to ARF, fines in the event of a breach of the provisions of the Agreement, and other standard provisions in agreements of this type.

c) The price to be paid to the Sellers was determined according to the price of a Brent oil barrel less a margin, in a graduated manner, as specified in the Agreement.

d) Condensate piping to ARF will begin on the date of first piping through PEI's pipeline (in this section: the "**First Piping Date**") and continue for a period of 4 years. Condensate piping to ARF under the aforesaid agreement commenced on 7 March 2024.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

C. Engagements for the supply of natural gas and condensate (Cont.):

7. On 3 May 2020, the Partnership, Chevron, the Delek Group and Ratio Energies signed an agreement (in this section: the "**Agreement**") regulating the method of supply of natural gas to customers of the Yam Tethys reservoir, to be performed by Leviathan Partners which are partners in the Yam Tethys project (i.e., the Partnership and Chevron), which carry an obligation under a gas sale agreement in the Yam Tethys project (the "**Yam Tethys Agreement**"), and by another Leviathan partner (i.e., Ratio Energies) which is not a partner in the Yam Tethys project (and which is not so bound by the Yam Tethys Agreement). The consideration determined in the Agreement is the average monthly price of the Leviathan project from sales of natural gas. The consideration was divided such that the consideration to Ratio Energies reflects a natural gas price that is equal to the (current) average monthly price of natural gas that was supplied to the Leviathan customers in that month under agreements signed between the Leviathan Partners and their customers, and the financial balance that remained was divided between the Partnership and Chevron, according to their relative share in the Leviathan project excluding the share of Ratio Energies. Such division allowed for maintaining the balance in the gas quantities in the Leviathan project between the partners therein according to their share. On 30 June 2023 the last agreement for the sale of gas in the Yam Tethys project came to an end and, accordingly, the aforementioned Agreement came to end as well.

8. **Dependence on a customer:**
   As of 31 December 2024, NEPCO and Blue Ocean are the Partnership's largest customers and therefore, termination or non-performance of the agreements signed between them and the Leviathan Partners would materially affect the Partnership's business and future revenues.
   For details regarding sales volumes and trade receivables balance, see Note 21G below.

9. **Estimates regarding natural gas and condensate quantities, prices and supply dates:**
   The estimates regarding the natural gas and condensate quantities to be purchased by the aforesaid buyers in the Leviathan project, and the supply commencement dates under the supply agreements, constitute information the materialization of which, in whole or in part, is uncertain, and which may materialize in a materially different manner, due to various factors, including non-fulfillment of the conditions precedent under each one of the supply agreements (insofar as not yet fulfilled), non-receipt of regulatory approvals, changes in the volume, pace and timing of natural gas consumption by each of the aforesaid buyers, gas and condensate prices to be determined according to the formulas specified in the supply agreements, the Electricity Production Tariff, the dollar-shekel exchange rate (insofar as relevant to the supply agreement), Brent prices (insofar as relevant to the supply agreement), the TAOZ Tariff published by the Electricity Authority and the Crack Spread Index (insofar as relevant to the supply agreement), construction and operation of the power plants and/or other plants of the buyers (insofar as relevant to the supply agreement), the exercise and exercise date of options granted in each of the supply agreements, etc.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

D. Pledges and guarantees:

1. Short-term (dollar) bank deposits as of 31 December 2024 in the sum of approx. $333.1 million used for debt service and current payments in the context of the issue of the Leviathan Bond bonds (see Note 10 above).
2. Long-term bank deposits as of 31 December 2024 include a deposit of $0.5 million used to secure a guarantee in the sum of $1 million, provided by the Partnership and Chevron (in equal parts) in favor of the Director of the Natural Gas Authority in relation to the license for gas transmission to Egypt.
3. See Note 10B regarding pledges provided by the Partnership on its assets in the context of the bonds.
4. According to the demand of the Government of Cyprus in the framework of the PSC as stated in Note 7C2 above, in 2013, Delek Group provided a performance guarantee in favor of the Republic of Cyprus. In consideration for provision of the guarantee, the Partnership pays Delek Group a guarantee fee in the amount of approx. $368 thousand per year until 25 years after the date of provision of the guarantee.
5. In the context of the Partnership's activity in the Leviathan project, the Partnership provided a personal guarantee in favor of the Israeli Tax Authority (Customs) in connection with equipment imported by the venture operator in the sum of approx. ILS 67.6 million.
6. In the context of the abandonment actions in the Yam Tethys project, the Partnership provided a personal guarantee in connection with equipment imported by the operator of the transaction in the sum of approx. ILS 57.7 million in favor of the Israel Tax Authority (Customs).
7. In July 2018, the Leviathan Partners provided a guarantee in favor of the Israel Land Authority regarding the construction of development infrastructure for the Leviathan project. The share of the Partnership in the said guarantee is approx. ILS 2.3 million.
8. In order to secure payments for rights of use of areas, facilities and infrastructures in connection with the EMG Transaction, the Partnership provided a bank guarantee in the amount of $2 million in favor of EAPC. In the context of the agreement with EAPC, EMED BV provided a company guarantee in the amount of $4 million to EAPC.
9. To secure a transmission agreement for the export of gas to Egypt (see Section F2) in the context of the Partnership's activity in the Leviathan project, the Partnership provided bank guarantees in favor of INGL. As of the date of approval of the consolidated financial statements the total sum is approx. ILS 186.4 million.
10. In the context of the Partnership's operations in Morocco, the Partnership has provided a bank guarantee in the sum of approx. $1.75 million to ONHYM (see Note 7C4 above).
11. As of the date of approval of the consolidated financial statements, the Partnership provided guarantees in the sum of approx. $54.5 million to the Ministry of Energy in connection with its rights in the oil and gas assets, see Section H3 below.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

E. Legal proceedings:

1. On 12 March 2015, the Partnership and Chevron (jointly in this section: the "**Plaintiffs**") filed a complaint with the District Court in Jerusalem against the State of Israel through its representatives from the Ministry of Energy (in this section: the "**Defendant**"), which mainly includes the restitution of royalties paid by the Plaintiffs, in excess and under protest, to the Defendant, for revenues generated to the Plaintiffs from gas supply agreements, which were signed between natural gas consumers and the Yam Tethys Partners, some of which was supplied from the Tamar Project, according to the accounting mechanism designated to maintain a balance of the gas quantities in the Tamar Project between the partners therein according to their share. The restitution remedy sought to be paid by the State is, as of 31 December 2024, approx. $28 million, with the Partnership's share being approx. $13 million. Alternatively, the Plaintiffs' claim that they are at least entitled to a partial restitution amount which as of 31 December 2024 is $19.4 million, with the Partnership's share being approx. $9 million. On 14 November 2022, the court's judgment was received, dismissing the claim, other than in connection with the Plaintiffs' position regarding repayment of interest amounts collected by the Defendant from the Plaintiffs in an immaterial amount, and charging the Plaintiffs with payment of the Defendant's expenses and legal fees. On 6 February 2023, the Plaintiffs filed an appeal from the judgment with the Supreme Court. On 13 August 2023, the Defendant submitted its answer to the appeal, and a hearing on the appeal was scheduled for 27 April 2025. In the Partnership's estimation, based on the opinion of its legal counsel, it is difficult to estimate the chances of acceptance of the Plaintiffs' claims in the appeal, further to the issuance of the judgment since no hearing has yet been held in the appeal.

   In accordance with the foregoing, in 2022, for the period until the sale of its all its holdings in the Tamar Project, the Partnership recorded expenses in the sum of approx. $13.6 million for the Tamar Project and approx. $1.7 million for the Leviathan project, which were included under the 'profit (loss) from discontinued operations' and under the 'royalty expenses in the continued operations', respectively. The expenses include the royalties paid by the Partnership to the State under protest, overriding royalties payables in connection with revenues arising from such gas supply agreements, and an update of the rate of the royalty at the wellhead in the Tamar and Leviathan projects. Note that the decision on this matter, once it is final and non-appealable, shall apply mutatis mutandis also to the overriding royalties paid by the Partnership over the years for the Tamar Project. Accordingly, if the court's said decision of 14 November 2022 stands, the Partnership will bear an additional payment (including interest and linkage) to royalty holders for gas quantities supplied by the Partnership to customers of the Yam Tethys project, in the sum of about $6.7 million (including approx. $1.9 million to related parties).
   According to the agreement for the sale of the Partnership's rights in the Tamar and Dalit Leases, as stated in Note 7C9 above, after the closing of the transaction the Partnership is still liable and entitled, as applicable, in relation to amounts in dispute vis-à-vis the State and royalty interest owners.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

E. Legal proceedings (Cont.):

2. On 25 December 2016, the holders of Avner participation units prior to the merger (the "**Petitioners**"), filed a motion for class certification (in this section: the "**Certification Motion**") claiming that the merger transaction between the Partnership and Avner had been approved by an unfair procedure and the consideration paid to the holders of the minority units in Avner, as determined in the merger agreement, was unfair. The motion was filed against Avner, the general partner of Avner and the board members thereof, Delek Group as the (indirect) control holder of Avner, and against Price Waterhouse Coopers Consulting Ltd. (PWC), as the economic advisors of an independent board committee set up by Avner (in this section: the "**Respondents**"). The motion argues, among other claims, that the committee members, the board of directors of Avner and the general partner had breached the duty of care to Avner, and that Avner had conducted itself in a manner that oppressed the minority. The Petitioners estimate the total damage at ILS 320 million.
   On 7 May 2023, the court issued a judgment denying the Certification Motion. On 6 July 2023, the Petitioners filed an appeal from the judgment with the Supreme Court, requesting the Supreme Court to accept the appeal and order the grant of the Certification Motion.
   On 27 December 2023, PWC filed a counter-appeal on the judgment, which is being heard within the framework of the said appeal, in which it claimed that the District Court erred in not awarding costs in its favor (in this section: the "**Counter-Appeal**"). In accordance with the court's decisions, the parties submitted responses to the appeal and Counter-Appeal on 22 August 2024. A hearing on the appeal and Counter-Appeal is scheduled for 11 September 2025.
   In the Partnership's estimation, based on the opinion of the legal counsel, the probability that the appeal will be denied is greater than the probability that it will be granted.
3. On 4 February 2019, a class action and a motion for class certification thereof (in this section: the "**Certification Motion**") was filed with the Tel Aviv District Court (Economic Department) by a shareholder of Tamar Petroleum and the Public Representatives Association (in this section jointly: the "**Petitioners**"), against Tamar Petroleum, the Partnership, the CEO of the Partnership and the Chairman of the Board of Tamar Petroleum at the time of the IPO, the CEO of Tamar Petroleum, the CFO of Tamar Petroleum and Leader Underwriters (1993) Ltd. (in this section jointly: the "**Respondents**"), in connection with the issue of the Tamar Petroleum shares in July 2017 (in this section: the "**IPO**").
   According to the Petitioners, in essence, the Respondents misled the investing public at the time of the IPO with respect to the ability of Tamar Petroleum to distribute a dividend to its shareholders, for the period commencing on the IPO date and ending at the end of 2021 (in this section: the "**Period**"), and breached duties under various laws, and *inter alia*, the duty of care of the said officers and the Partnership's duties as a shareholder and controlling shareholder of Tamar Petroleum prior to the IPO.
   The remedies sought in the Certification Motion mainly included a financial remedy in the minimum sum of $53 million, which is, according to the Petitioners, the difference between the total dividend which Tamar Petroleum is expected to distribute for the Period, as stated in the offering to institutional investors document of 12 July 2017, and the total dividend which, according to an expert opinion attached to the Certification Motion, Tamar Petroleum is expected to distribute for the Period.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

E. Legal proceedings (Cont.):

3. (Cont.):

   On 13 August 2019, the court ordered the Petitioners to deliver the pleadings in the file to the Attorney General, in order that he gives notice, by 15 September 2019, of whether he wishes to join the proceeding. On 1 November 2020, the Petitioners filed a motion to amend the Certification Motion, in which they sought to join to the Certification Motion another petitioner who had participated in the IPO, unlike the current Petitioners who did not take part therein and to increase the amount of the alleged damage to $153 million.
   On 6 April 2021, the court granted the Petitioners' motion to amend the Certification Motion and ruled that the Petitioners are entitled to file the amended Certification Motion in accordance with the language filed with the court and on 23 January 2022, an amended certification motion was filed. On 23 April 2023, the Petitioners filed a motion for a discovery order, and on 17 July 2023, the court denied the motion for discovery in relation to all the Respondents, except Leader, with respect to which the motion was partly granted. Furthermore, on 16 August 2023, the court approved an agreed procedural arrangement between the parties, whereby the cross-examination of witnesses in the context of the Certification Motion would be conducted in February-April 2024. Accordingly, the trial stage concluded in April 2024, and according to the court's instructions, the Petitioners' summations were filed with the court in March 2025 and the Respondents' summations are required to be filed with the court by October 2025. In the Partnership's estimation, based on the opinion of its legal counsel, the chances of the Certification Motion being granted are lower than 50%.

4. On 27 February 2020, the Partnership learned of the filing of a class action and a motion for class certification (in this section: the "**Certification Motion**") with the Tel Aviv District Court by an electricity consumer (in this section: the "**Petitioner**") against the Partnership and Chevron and against the other holders of the Tamar Project and the Leviathan project (as parties against which no remedy is sought), in connection with the competitive process for the supply of natural gas conducted by the IEC and in connection with a possible amendment to the agreement for the supply of gas from the Tamar Project to the IEC, as agreed by Isramco, Tamar Petroleum, Dor and Everest Infrastructures Limited Partnership (collectively in this section: the "**Other Holders in the Tamar Project**"), with no involvement on the part of the Partnership and Chevron (in this section: the "**Amendment to the Tamar Agreement**").
   The Petitioner's principal arguments are that the bids made by the Other Holders in the Tamar Project and the holders in the Leviathan project in the competitive process amount to abuse of monopoly power and to a restrictive arrangement, as defined in the Economic Competition Law; the Partnership's and Chevron's not signing the Amendment to the Tamar Agreement also amounts to abuse of monopoly power; the price determined in the agreement for the supply of gas from the Leviathan project to the IEC further to the competitive process is an unfair price; and profits made and which shall be made by the Partnership and Chevron under this agreement, while harming competition, amount to unjust enrichment.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

E. Legal proceedings (Cont.):

4. (Cont.):

The Petitioner asserts that such acts by the Partnership and Chevron have caused and are expected to cause damage to the classes he seeks to represent in the sum of approx. ILS 1.16 billion, and the court is moved to award damages and fees accordingly. The main remedy in the Certification Motion is a ruling by the court that the Partnership and Chevron are not entitled to prevent the Other Holders in the Tamar Project from signing the Amendment to the Tamar Agreement. On 6 February 2024, the court granted the Petitioner's motion, with the consent of respondents, to cancel the trial hearings scheduled for March-April 2024, and on 27 June 2024, the court entered a judgment on the parties' agreement, which had been reached per its recommendation, to conduct a reconciliation proceeding toward a withdrawal arrangement. According to the court's decision, on 25 September 2024, a preliminary court hearing was held, during which the court suggested that the parties negotiate to attempt an agreement to defer the proceeding to mediation. On 15 January 2025, the parties filed a joint motion for renumerated withdrawal of the Certification Motion, and on 18 February 2025, the Tel Aviv District Court (Economic Department) handed down its judgment, approving the agreed motion for remunerated withdrawal of the Certification Motion by the Petitioner, whereby, *inter alia*, the respondents are required to pay the Petitioner and his counsel remuneration, fees and expense reimbursement in the amount of ILS 400 thousand (the Partnership's share – ILS 200 thousand), plus V.A.T as required by law. Accordingly, the Partnership has included a provision in its consolidated financial statements.

5. On 15 December 2020, a motion for class action certification was filed with the Tel Aviv District Court against Chevron (in this section: the "**Respondent**") by a resident of Dor Beach on behalf of "anyone who was exposed to the air, sea and coastal environment pollution, due to prohibited emissions from the gas platform operated by the Respondents in the sea, which is located opposite Dor Beach, and treats the natural gas reservoir, Leviathan, in the period from the commencement of the platform's activity in December 2019 until a judgment is issued in the claim" (in this section: the "**Certification Motion**", the "**Petitioner**" and the "**Class Members**"). In essence, the Certification Motion argues that the Respondent exposed the Class Members to air, sea and environmental pollution, due to prohibited emissions deriving from the Leviathan reservoir platform. Such exposure, according to the Petitioner, created various health problems (which were not specified in the Certification Motion) and damage of injury to autonomy due to the concern of health damage as aforesaid. The main remedy sought in the Certification Motion is compensation for the class for the damage it allegedly incurred which is estimated at approx. ILS 50 million. 7 February 2024 saw a judgment handed down, which denied the Certification Motion and imposed costs on the Petitioner.

6. On 23 April 2020, a holder of participation units of the Partnership (in this section: the "**Petitioner**") filed a class action and motion for class certification against the Partnership, the General Partner, Delek Group, Yitzhak Sharon (Tshuva), the directors of the General Partner (including the former chairman of the board) and the CEO of the General Partner (in this section: the "**Certification Motion**" and the "**Respondents**", respectively), with the Economic Department of the Tel Aviv District Court.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

E. Legal proceedings (Cont.):

6. (Cont.):

   The Certification Motion alleges that the Respondents refrained from disclosing, in the Partnership's reports, the existence of a clause in the agreements for the sale of natural gas from the Leviathan and Tamar reservoirs to Blue Ocean (in this section: the "**Sale Agreements**" and the "**Buyer**", respectively), according to which in a year in which the average daily price of a Brent barrel (as defined in the Sale Agreements) is lower than $50 per barrel, the Buyer is entitled to reduce the minimum annual quantity purchased under the Sale Agreements, to 50% of the annual contract quantity. According to the Petitioner, the alleged non-disclosure in the Partnership's reports establishes causes of action by virtue of various sections of the Securities Law, by virtue of the tort of breach of statutory duty, and by virtue of the tort of negligence.

   The main remedy sought in the Certification Motion is compensation of the class which the Petitioner intends to represent, for the alleged damage incurred thereby, which is estimated, according to the opinion attached to the Certification Motion, at approx. ILS 55.5 million. The Petitioner also moved to issue any and all other remedies in favor of the class, as the court will deem fit under the circumstances.

   According to the court's decision, the Respondents and the Petitioner must file summations and responding summations in 2024, and all by April 2025. In the Partnership's estimation, based on the opinion of its legal counsel, the chances of the motion being granted are lower than 50%.

7. On 3 May 2021, Haifa Port Co. Ltd. (in this section: "**Haifa Port**") filed a claim against Chevron, Coral Maritime Services Ltd. (in this section: "**Coral**") and Gold Line Shipping Ltd. (in this section: "**Gold Line**") in the sum of approx. ILS 77 million (the "**Primary Claim**"). According to Haifa Port, direct unloading of cargos in the area of the Leviathan platform, as was done by Chevron, without first unloading such cargos at one of Israel's ports, is unlawful and was done so as to evade making mandatory payments to the port, and financial loss was thus incurred by the port. The complaint claims that from July 2018 forth, Chevron performed direct unloading as aforesaid, while declaring to the tax authorities that Haifa Port was the 'unloading port', even though the cargos that were unloaded did not pass through Haifa Port in practice. The claim against the companies Coral and Gold Line is that they acted, at the relevant times, as the shipping agents for Chevron, which imposes on them, so Haifa Port claims, a duty to pay the handling fees on Chevron's behalf.

   Chevron filed an answer on 31 August 2021, and Haifa Port filed a replication on 1 December 2021. Concurrently therewith, Chevron filed a counterclaim against Haifa Port in the sum of approx. ILS 4.4 million, for a claim in the sum of about ILS 0.7 million for handling fees and infrastructure fees actually and unlawfully charged by Haifa Port, and a claim of some ILS 3.7 million for mooring fees charged to Chevron and unlawfully not reduced by 30%, in cases of self-routing of ships which passed through the port area. On 11 September 2022, a pretrial hearing was held, in which it was determined that the parties will negotiate with the aim of reaching agreement on the completion of the preliminary proceeding, failing which they will file motions accordingly. Despite the attempt to reach agreements, the parties filed mutual motions regarding the preliminary proceedings.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

E. Legal proceedings (Cont.):

7. (Cont.):

On 8 July 2023 and 18 July 2023, the court denied the said motions. On 4 June 2024, a pretrial hearing was held, in which various motions that had been filed by the parties were heard, except for Haifa Port's motion to summon the Customs representative as a witness, and on 28 July 2024, the court denied the motions filed by Haifa Port and granted the motion filed by Chevron to summon witnesses who are beyond its control. On 13 October 2024, Haifa Port filed a motion for leave to appeal the court's decision to deny motions it had filed, as well as a motion to postpone the date for filing of the response affidavits. The court granted the said motion for postponement and ruled that the response affidavits would be filed 30 days after the ruling on the motion for leave to appeal. On 20 November 2024, the court denied the said motion for leave to appeal, and the response affidavits on behalf of the parties to the claim and the counterclaim were filed on 21 January 2025. The last pretrial hearing and the hearing on Haifa Port's motion to summon the Customs representative as a witness are scheduled for 10 March 2025. It is further noted that on 3 April 2023, Haifa Port filed a motion for summary dismissal of the counterclaim, arguing lack of controversy between itself and Chevron, because the invoices and mooring fees had been paid by an agent. On 21 June 2023, the motion was denied, and the court issued an order for costs against Haifa Port.

In the Partnership's estimation, based on the opinion of its legal counsel, the Primary Claim is more likely to be dismissed than granted.

8. On 3 December 2023, a participation unit holder of the Partnership (in this section: the "**Petitioner**") filed a motion against the Partnership, in accordance with Section 65OO of the Partnerships Ordinance and Section 198A of the Companies Law, for the issuance of a pre-derivative suit document discovery and inspection order against the General Partner; Mr. Abu, CEO of the General Partner; and the members of the General Partner's board of directors (including members of the compensation committee) in the relevant period (in this section: the "**Discovery Motion**"). In summary, the Discovery Motion is based on the claim that the approval of the current terms of Mr. Abu's office and employment by the compensation committee and the board of directors, by overruling the position of the general meeting of participation unit holders, was done in violation of the law, breaching the duties of care and the fiduciary duties imposed on the members of the board of directors and breaching Mr. Abu's duty, as CEO of the General Partner, to act in the best interests of the Partnership. As part of the Discovery Motion, it is claimed that the approval of the terms of Mr. Abu's office and employment by overruling was carried out without satisfaction of the conditions required therefor pursuant to the Partnerships Ordinance; the terms of Mr. Abu's office and employment were not sufficiently discussed and the general meeting's objection was not addressed; and the reasons specified by the board of directors did not address to the mere fact that the general meeting had withheld the approval of the terms of Mr. Abu's office and employment. In proximity to the filing of the Discovery Motion, the Petitioner filed a notice with the court with respect to additional pre-derivative suit document discovery and inspection motions filed by him or his counsel, which were based, per his claim, on a "similar factual foundation"; against other respondents: Delek Group Ltd. (D.A. 58205-11-23);

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

E. Legal proceedings (Cont.):

8. (Cont.):

Electra Ltd. (D.A. 50050-11-23), Matrix I.T. Ltd. (D.A. 60805-11-23); and Scope Metals Ltd. (D.A. 47021-11-23) (the "**Additional Proceedings**"). On 6 December 2023, the court ordered that the parties to the Additional Proceedings consider consolidating their hearings by choosing a lead case ("**Locomotive Case**") which shall govern the decisions in all of the Additional Proceedings; or in any other way ("**Consolidation of the Hearing**"). On 8 January 2024, the Petitioner informed the court of his consent to the Consolidation of the Hearing, and on that date the Partnership filed its objection with the court to the Consolidation of the Hearing, since, *inter alia*, these are different and distinct proceedings, which concern other decisions, made by other entities, in relation to the terms of office of other officers and in other corporations; and that under these circumstances the consolidation of the proceedings is not expected to simplify and streamline the hearing thereof, and there is no concern of conflicting decisions between them, as required by law in order to consolidate the hearing in parallel proceedings. To the best of the Partnership's knowledge, the respondents in the Additional Proceedings also opposed the proposal for Consolidation of the Hearing. On 17 July 2024, the court ruled that the hearing would not be consolidated. The Partnership filed its response to the Discovery Motion with the court on 18 April 2024, and the Petitioner's reply to the Partnership's response to the Discovery Motion was filed on 4 June 2024. According to the court's decisions of 31 October 2024 and 7 November 2024, the Partnership's participation unit holders may notify whether they support the Discovery Motion by 5 December 2024, explaining their position. To that end, the court ordered the Petitioner to serve the proceeding pleadings on the Partnership's participation unit holders by 7 November 2024, and on 6 November 2024, the Petitioner filed a motion to extend such date until 14 November 2024. The court did not respond to this motion for extension. It is clarified that the aforesaid court decisions also apply, *mutatis mutandis*, to the Additional Proceedings. On 23 June 2024, a motion was filed on behalf of the Association of Publicly Traded Companies in Israel (the "**Association**"), requesting to join the proceeding as Amicus Curiae, and in accordance with the court's decision, after the parties' responses to such motion were filed, the Association filed its response to the objection of the Petitioner to the motion to join the proceeding as Amicus Curiae. On 19 September 2024, the court granted the Association's said motion to join.

On 5 December 2024, the Attorney General filed her position in relation to this proceeding and the Additional Proceedings, and according to the court's decision, the Attorney General was at liberty to file a supplemental position to such position by 25 February 2025. On 20 January 2025, a trial hearing was held, and according to the court's decision, the Petitioner and the Partnership are required to file summations and responding summations, and all by September 2025, and the Association is required to file summations on its behalf in relation to this proceeding and the Additional Proceedings by June 2025. In the Partnership's estimation, based on the opinion of its legal counsel, the chances of the motion being granted are lower than 50%.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

E. Legal proceedings (Cont.):

9. In view of the enduring delays in completion of the construction work and postponement of commencement of piping under the transmission agreement of 18 January 2021 with INGL, as specified in Note 12F2(a) below, on 24 November 2024, Chevron filed an arbitration claim against INGL in connection with breach of the said transmission agreement. In the complaint, Chevron seeks, *inter alia*, recovery of the difference accrued since 30 April 2023 between the interruptible rate actually paid and the standard transmission rate that should have been paid under the firm-basis transmission agreement of 18 January 2021, which difference amounts to approx. ILS 102 million (100%, the Leviathan Partners' share – approx. ILS 67 million) as of December 2024. The preliminary hearing of the proceeding was scheduled for 2 April 2024. Of note, alongside such arbitration proceedings, the parties have deferred to mediation with the aim of trying to reach an agreement without the arbitration being decided, and this proceeding is still ongoing.

F. Engagement in agreements for natural gas and condensate transmission from the Leviathan reservoir:

1. Condensate transmission agreement

On 1 September 2022, Chevron (on behalf of the Leviathan Partners) and PEI signed an agreement designed to regulate an alternative mechanism for condensate piping from the Leviathan project through an existing PEI 6" pipeline and the systems related thereto (in this section: the "**Agreement**" and the "**Pipeline**", respectively), the principles of which are as follows:

The Agreement will be in effect for 20 years from the date of commencement of piping, subject to provisions that allow the parties to terminate it before the end of the term. Upon certain conditions, under the Agreement, PEI will be responsible for planning and carrying out the work for connection and adjustment of the Pipeline for the purpose of such condensate piping (the "**Connection Work**"), obtaining all the approvals for the transmission of condensate through the Pipeline, and the ongoing operation and maintenance of the Pipeline. Chevron (via the Leviathan Partners, per their share in the Leviathan Leases) has undertaken to bear the costs entailed by the Connection Work per the scope and mechanism set in the Agreement, in amounts the parties shall agree upon in advance. Each of the parties may terminate the Agreement if the closing conditions are not met within 12 months of the signing date or if the piping commencement date does not occur within 12 months of the date on which the Agreement takes effect.

During the piping period, PEI will make the Pipeline available for use by Chevron (except in such emergencies as defined in the Agreement, in which condensate piping through the Pipeline will be temporarily discontinued) and reserve an agreed Pipeline capacity in exchange for such fixed capacity fees as specified in the Agreement. PEI will also transmit the condensate through the Pipeline, in consideration for such transmission fees as agreed in the Agreement. The Connection Work and the Agreement account for the increase in the condensate quantity transmitted through the Pipeline as a result of operation of the Third Pipeline and the commencement of production under Phase 1B. Transmission of the condensate in the PEI Pipeline under the aforesaid agreement began on 7 March 2024.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

F. Engagement in agreements for natural gas and condensate transmission from the Leviathan reservoir (Cont.):

2. Agreements for transmission of natural gas for export to Jordan and Egypt

As of the date of approval of the consolidated financial statements, the pipeline infrastructure for export to the Partnership's customers in Egypt and Jordan includes the main systems specified below. Of note, the capacity of gas supply to Egypt through these systems is divided between the Tamar partners and the Leviathan Partners.

c) **Entry into transmission agreements with INGL in relation to export to Egypt:**

The EMG Pipeline connects the Israeli transmission system in the Ashkelon area with the Egyptian transmission system in the el-Arish area and serves as the main line of export to Egypt since the start of production from the Leviathan reservoir.

January 2025 saw completion of another electricity connection to the compression terminal, allowing for simultaneous operation of the two compressors installed at the entry to the EMG system in Ashkelon. Such simultaneous operation of both compressors, as of the date of approval of the consolidated financial statements, allows for increasing the piping capacity of the EMG Pipeline from ~600 MMCF per day (~6 BCM per year) to ~650 MMCF per day (~6.5 BCM). Maximum utilization of this capacity is contingent on the conditions of INGL's national transmission system, which may change from time to time.

For further increase of the EMG Pipeline's transmission capacity to ~850 MMCF per day (~8.5 BCM per year), INGL is carrying out a project for construction of a new offshore section between Ashdod and Ashkelon stretching across approx. 46 km (the "**Combined Section**"). The estimated date of completion of the project for construction of the Combined Section has been postponed several times.

On 28 May 2019, Chevron and INGL engaged in an agreement for supply of interruptible transmission services in relation to the piping of natural gas from the Leviathan reservoir and Tamar reservoir to EMG's terminal in Ashkelon, for the purpose of export to Egypt (in this section: the "**2019 Agreement**"). The payment pursuant to the 2019 Agreement will be made based on the gas quantity actually piped through the transmission system, subject to Chevron's undertaking to pay for certain minimum quantities.

On 26 December 2024, Chevron and INGL signed an addendum to the 2019 Agreement, whereby the agreement would be extended until the earlier of: (1) The expiration date of the agreement according to its terms and conditions; (b) 1 January 2026; or (c) The Piping Commencement Date as defined in the agreement for transmission on a firm basis, which is described below.

On 18 January 2021, Chevron entered with INGL into an agreement for the provision of transmission services on a firm basis, intended to supersede the 2019 Agreement, for the purpose of piping natural gas from the Leviathan and Tamar reservoirs to the EMG terminal in Ashkelon in order to transmit it to Egypt, which agreement took effect on 14 February 2021 (hereinbefore and hereinafter: the "**Transmission Agreement**" or, in this section: the "**Agreement**").

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

F. Engagement in agreements for natural gas and condensate transmission from the Leviathan reservoir (Cont.):

2. Agreements for transmission of natural gas for export to Jordan and Egypt (Cont.):

a) (Cont.):

Below is a concise description of the principles of the Agreement, as amended from time to time:

1) Under the Transmission Agreement, INGL has undertaken to provide transmission services for the natural gas that shall be supplied from the Leviathan and Tamar reservoirs, including maintaining an annual base capacity in the transmission system of ~5.5 BCM (the "**Base Capacity**"). For the transmission services in relation to the Base Capacity, Chevron will pay capacity fees and a payment for the gas quantity that shall actually be piped (throughput), in accordance with the generally accepted transmission rates in Israel, as updated from time to time. INGL has further undertaken to provide non-continuous transmission services on an interruptible basis of additional gas quantities over and above the Base Capacity, subject to the available capacity of the transmission system. For transmission of such additional quantities, Chevron will pay a transmission rate for non-continuous transmission services in relation to the throughput.
2) Under the Transmission Agreement, Chevron has undertaken to pay for the piping of a gas quantity no lesser than 44 BCM throughout the term of the Agreement. If the parties agree on an increase in the Base Capacity, then such minimum piping quantity will be increased accordingly.
3) The Transmission Agreement specifies undertakings by INGL regarding the date of completion of the construction of the Combined Section and commencement of piping of the gas (in this section: the "**Piping Commencement Date**"). However, from time to time, INGL has notified of delays and postponements in the performance of the construction work due to various constraints, by reason of which the Piping Commencement Date has been postponed, *inter alia*, due to technical malfunctions during the work and due to the foreign construction contractor's departure from the region in view of the security situation.
4) Against this background, on 4 August 2024, Chevron and INGL signed an amendment to the Transmission Agreement, whereby, *inter alia*, for the share of the partners in the Leviathan and Tamar projects, Chevron will bear a sum equal to 56.5% of the additional costs entailed by the return of the foreign contractor to Israel and resumption of the project's construction work, insofar as resumed by October 2024. As of the date of approval of the consolidated financial statements, notice from INGL in connection with the date of the contractor's return and resumption of the work has not been received yet, and accordingly, an assessment as to the increase in costs entailed by the contractor's return and the project's completion has yet to be received.

   In the Operator's estimation, the Piping Commencement Date is not expected to occur before Q1/2026.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

F. Engagement in agreements for natural gas and condensate transmission from the Leviathan reservoir (Cont.):

2. Agreements for transmission of natural gas for export to Jordan and Egypt (Cont.):

a) (Cont.):

5) The Transmission Agreement determines that it will expire upon the earlier of: (1) The date on which the total quantity piped is 44 BCM; (2) the lapse of 8 years from the piping commencement date; or (3) upon expiration of INGL's transmission license.

6) In accordance with the principles determined in the Commission's decision, the share of the partners in Leviathan and Tamar is 56.5% of the total cost of construction of the Ashdod-Ashkelon Combined Section, with the Leviathan Partners and the Tamar partners bearing these costs and the provision of guarantees as specified below at the rate of 69% and 31%, respectively.

7) As of the date of approval of the consolidated financial statements, the costs of construction of the Combined Section, including the costs of pushing forward the doubling of the Dor-Hagit and Sorek-Nesher sections, are estimated at a total of approx. $295 million (the Partnership's share – approx. $52 million), without additional costs that may apply in respect of resumption of the work as set out in Section 4 above.

8) In accordance with the Commission's decision, the Leviathan Partners and the Tamar partners provided a bank guarantee to secure INGL's share in the cost of construction of the aforesaid infrastructure, and to cover Chevron's obligation to pay the capacity and transmission fees. As of the date of approval of the consolidated financial statements, the guarantees in favor of INGL for the Partnership's share in the Leviathan project total approx. ILS 186.4 million.

9) The Transmission Agreement stipulates that in case of cessation of the export of natural gas from the Tamar and Leviathan projects to Egypt, Chevron will be entitled to terminate the Transmission Agreement subject to payment of compensation to INGL due to the early termination, in an amount equal to 120% of the costs of construction of the Combined Section, plus the costs of accelerating the doubling of the Sorek-Nesher and Dor-Hagit sections, net of the amounts Chevron paid until the date of the termination in respect of such construction and acceleration costs and in respect of the piping of the gas under the Transmission Agreement. If, after the termination of the Transmission Agreement, export to Egypt resumes, the Transmission Agreement will be renewed subject to and in accordance with the capacity that shall be available in the transmission system at such time.

10) Due to the delays in completion of the construction work and postponement of the piping commencement date as noted above, Chevron has raised claims of breach of the Transmission Agreement against INGL, following which the parties have agreed to conduct a mediation proceeding and, at the same time, operate according to the arbitration mechanism under the Transmission Agreement. See Note 12E9 above.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

F. Engagement in agreements for natural gas and condensate transmission from the Leviathan reservoir (Cont.):

2. Agreements for transmission of natural gas for export to Jordan and Egypt (Cont.):

a) (Cont.):

11) Concurrently with the signing of the Transmission Agreement, Chevron, the Partnership and the other the Leviathan Partners and Tamar partners have signed a back-to-back services agreement (in this section: the "**Services Agreement**"), which provides that the Leviathan and Tamar partners will be entitled to transmit natural gas (through Chevron) under the Transmission Agreement, and will be responsible for the performance of Chevron's obligations under the Transmission Agreement (back-to-back) as if the Leviathan Partners and the Tamar partners were a party to the Transmission Agreement in Chevron's place, each according to its respective share as determined in the Capacity Allocation Agreement between the Leviathan Partners and the Tamar partners, as specified in Section 12C3 above. The Services Agreement further provides that the Base Capacity of the transmission system reserved for Chevron will be allocated between the Leviathan Partners and the Tamar partners according to the specified rates and according to the order set forth in the Capacity Allocation Agreement. The Leviathan Partners and the Tamar partners will bear capacity fees at a fixed proportion of 69% (Leviathan Partners) and 31% (Tamar partners), except in a case where a party (either the Leviathan Partners or the Tamar partners, as applicable) shall have used the other party's unused capacity.

d) **Export of natural gas to Egypt through the Jordan-North Export Pipeline**

The Jordan-North Export Pipeline, which connects between the Israeli transmission system and the Jordanian transmission system near the Sheikh Hussein Bridge. The construction of this export pipeline was completed in December 2019, *inter alia* through the construction of a natural gas pipeline by INGL from the Tel Kashish station to the border with Jordan, including the construction of a station near the border whose purpose is to measure the gas exported to Jordan. The follow-on pipeline on the Jordanian side was built by FAJR, the (Egyptian-owned) Jordanian transmission company ("**FAJR**"), which connects the Israeli transmission system to the existing transmission pipeline in Jordan and the Arab Gas Pipeline, and connects to the Egyptian transmission system in the area of Aqaba (above and below: the "**Jordan-North Export Pipeline**"). As of the date of approval of the consolidated financial statements, the total maximum gas supply capacity in the Jordan-North Export Pipeline is approx. 7 BCM per annum, around 3.5 BCM of which are set aside for the NEPCO Agreement. The supply of gas to Egypt under the export agreement via the Jordan-North Export Pipeline began in March 2022.

Given the delay in completion of the project for construction of the Ashdod-Ashkelon Combined Section (as aforesaid in Section F2D), the Leviathan Partners have signed a set of agreements intended to allow the piping of quantities of natural gas to Egypt under the agreement for export to Egypt through Jordan, using the Jordan-North Export Pipeline.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

F. Engagement in agreements for natural gas and condensate transmission from the Leviathan reservoir (Cont.):

2. Agreements for transmission of natural gas for export to Jordan and Egypt (Cont.):

b) (Cont.):

In accordance with the said set of agreements, in March 2022, natural gas piping to Egypt through Jordan began, which allows for maximizing the sale of the natural gas produced from the Leviathan reservoir and transmitting natural gas surpluses that are not consumed in Israel and Jordan and/or piped to Egypt via the EMG Pipeline, to the Egyptian market, via the Jordanian transmission system, mainly until the Combined Section is completed by INGL as aforesaid. As of the date of approval of the consolidated financial statements, and as the Partnership was informed by the Operator, using the existing transmission infrastructure and under the current operating conditions, natural gas can be piped to Egypt, via Jordan, in an average daily amount of up to ~350 MMCF (~3.5 BCM per year). It is noted in this context that the Ministry of Energy authorized the Leviathan Partners to add a point of delivery of natural gas to Egypt in Aqaba, Jordan. It is further noted that transmission of the gas to Egypt via the Jordan-North Export Pipeline entails additional transmission costs compared with transmission of the gas via the EMG Pipeline.

The set of agreements so signed includes the following agreements:

1) An agreement between a Chevron affiliate (in this section: the "**Affiliate**") and FAJR, the Jordanian transmission company, for the provision of interruptible transmission services in relation to the piping of natural gas from the Leviathan and Tamar reservoirs via the transmission system in Jordan, from the point of entry at the border between Israel and Jordan to the delivery point at the border between Jordan and Egypt, near Aqaba (the "**FAJR Agreement**"). Payment under the FAJR Agreement will be made based on the gas quantity actually piped through the FAJR transmission system after deduction of own-use gas used for operation of the compressors in Aqaba. It is also stipulated that the term of the FAJR Agreement is 5 years as of the piping date, unless it comes to an end at an earlier time in accordance with the provisions set out therein.

2) A back-to-back services agreement signed between the Affiliate, Chevron and the other Leviathan and Tamar partners, which stipulates, *inter alia*, that the entry of the Affiliate into the FAJR Agreement is done for and in the interest of the holders of interests in the Tamar from and Leviathan reservoirs for the purpose of export of natural gas to Egypt the Tamar and Leviathan reservoirs on a 'back-to-back' basis, as if they were party to such agreement. It is also stipulated that use of the FAJR transmission system will be made in accordance with such mechanism, terms and conditions, and priorities as specified in the aforesaid agreement, which are based, *inter alia*, on the capacity of the EMG Pipeline, the available capacity and the constraints of the FAJR transmission system and the gas orders placed under the agreements for export to Egypt between BOE and the holders of interests in the Leviathan and Tamar reservoirs.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

F. Engagement in agreements for natural gas and condensate transmission from the Leviathan reservoir (Cont.):

2. Agreements for transmission of natural gas for export to Jordan and Egypt (Cont.):

b) (Cont.):

3) Agreement between Chevron and INGL for the provision of interruptible transmission services in relation to the piping of natural gas from the Leviathan reservoir via the Jordan-North Export Pipeline to the point of connection to the FAJR transmission system at the border between Israel and Jordan (the "**Jordan-North INGL Agreement**"). Payment under the Jordan-North INGL Agreement will be made based on the gas quantity actually piped through the INGL transmission system, subject to Chevron's undertaking to pay for a minimum quantity as specified in the agreement. The term of the Jordan-North INGL Agreement has been extended until 1 January 2026, unless it is extended pursuant to the parties' agreement subject to the decisions of the Natural Gas Authority at such time. Concurrently with the signing of the Jordan-North INGL Agreement, Chevron and the other Leviathan Partners entered into a back-to-back services agreement related to the Jordan-North INGL Agreement. Of note, in a letter dated 22 December 2024, the Natural Gas Authority informed, *inter alia*, that the annual available transmission capacity for 2025 through the Jordan-North pipeline was 4.2 BCM. It was also clarified that the agreements for piping through the Jordan-North pipeline will only be signed on an interruptible basis. Further thereto, the partners in the Leviathan project notified INGL of their request that half of such transmission capacity be designated for the transmission of gas from the Leviathan project.
The Leviathan Partners and Blue Ocean signed an amendment to the agreement for export to Egypt as specified in Section 12C3 above.

4) Under the agreement for export to Egypt, the Leviathan Partners have been obligated since July 2022 to supply Blue Ocean with 450 MMCF of natural gas per day. Piping this quantity in full via the EMG Pipeline will only be made possible after completion of the Combined Section, construction of which is delayed, as noted. Despite the fact that up to the date of approval of the consolidated financial statements, the piping of gas through Jordan has been conducted as planned, because the transmission agreements with INGL as effective on the date of approval of the consolidated financial statements are for the provision of interruptible transmission services, there is no certainty on the date of approval of the consolidated financial statements that the full quantities the Leviathan Partners are so obligated to supply to Blue Ocean will be able to be piped through Jordan at any time.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

F. Engagement in agreements for natural gas and condensate transmission from the Leviathan reservoir (Cont.):

2. Agreements for transmission of natural gas for export to Jordan and Egypt (Cont.):

e) **Agreements for contribution to the funding of a project for upgrade of a gas transmission system outside of Israel**

On 19 September 2024, a set of agreements was signed which pertained to participation by the Leviathan Partners and the Tamar partners in the funding of a project for construction of a gas compression terminal outside of Israel in the transmission system mentioned in Section 2 above for the local transmission company (in this section: the "**Project**", "**Transmission System**" and "**Transmission Company**", respectively), as specified below.

1) Under an agreement signed with the Transmission Company, Chevron has undertaken to contribute up to approx. $341 million to the funding of the Project (the "**Funding Contribution Agreement**"), which stipulates, *inter alia*, that the Transmission Company will be in charge of building and operating the Project and Chevron will pay the Transmission Company an annual sum for operating and maintaining the compression terminal and for licensing fees. It is further provided that Chevron will be entitled to receive annual reimbursement payments from the Transmission Company for the contribution to the funding, and additional reimbursement for some of the operation and maintenance fees of the compression terminal, depending on the gas quantities to be piped via the Transmission System, including by third parties, over and above a certain amount and according to such mechanism and for such period as specified in the Funding Contribution Agreement.

   On 31 December 2024, Chevron notified the Leviathan Partners that the conditions precedent to entry of the Funding Contribution Agreement into effect had been satisfied.

2) The partners in the Leviathan and Tamar projects have entered into an agreement with Chevron, back-to-back with the Funding Contribution Agreement, whereby the Leviathan Partners and the Tamar partners will bear, in equal shares, the funding contribution amount plus the costs of management of the Project by Chevron, in an aggregate amount not to exceed approx. $343 million (100% of the Project, the Partnership's share is up to approx. $78 million). Chevron shall exercise the rights, powers and discretion granted thereto under the Funding Contribution Agreement in accordance with the decision-making mechanisms specified in such agreement. The Leviathan Partners and the Tamar partners shall be entitled to the aforementioned reimbursements, in equal shares, regardless of their respective shares in the piping of gas through the Transmission System. In the event that a holder of interest in one of the reservoirs fails to discharge the payment imposed thereon under the Funding Contribution Agreement, the other interest holders in that reservoir will be required to bear the share of the defaulting party, and the defaulting party will be charged with the payment of interest and damages (as agreed under the said agreement) to the other paying interest holders. For details with respect to the manner of allocation of the additional capacity of the Transmission System to be provided by the Project (the "**Additional Capacity**"), see Note 12C3 below.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

F. Engagement in agreements for natural gas and condensate transmission from the Leviathan reservoir (Cont.):

2. Agreements for transmission of natural gas for export to Jordan and Egypt (Cont.):

c) (Cont.):

3) An affiliate of Chevron (in this section: the "**Affiliate**") has entered into an agreement with the Transmission Company for the provision of transmission services for the Additional Capacity (the "**Additional Transmission Agreement**"). The payment of transmission fees under the Additional Transmission Agreement will be made based on the quantity of gas actually piped through the Transmission System. On 31 December 2024, Chevron notified the Leviathan Partners that the conditions precedent to entry of the Additional Transmission Agreement into effect had been satisfied.
The Additional Transmission Agreement is effective until 25 January 2034, unless it comes to an end at an earlier time in accordance with the provisions thereof.
Chevron and the other Leviathan Partners and Tamar partners have signed an amendment to the existing services agreement (the "**Amendment to the Services Agreement**"), which stipulates, *inter alia*, that the entry of the Affiliate into the Additional Transmission Agreement is done for and on behalf of the Leviathan Partners and the Tamar partners on a back-to-back basis, as if they were parties to such agreement. It is further provided, *inter alia*, that the Additional Capacity will be allocated between the Leviathan Partners and the Tamar partners in equal shares. Chevron shall exercise the rights, powers and discretion granted thereto under the Additional Transmission Agreement in accordance with the decision-making mechanisms specified in the Amendment to the Services Agreement.
As of the date of approval of the consolidated financial statements, estimated completion of the Project is expected to occur during H2/2026.

f) The Jordan-South export pipeline, which connects the Israeli transmission system in the Southern Dead Sea are to Jordanian industrial plants.

g) As of the date of approval of the consolidated financial statements, the Operator, on behalf of the Leviathan Partners and the Tamar partners, is considering the possibility of participating in the construction of a project for a new onshore connection between the Israeli transmission system and the Egyptian transmission system in the area of Nitzana (the "**Nitzana Pipeline**" or "**Nitzana Project**"), which includes a pipeline and the construction of a compressor station in the area of Ramat Hovav. The Nitzana Pipeline (if built) will constitute part of INGL's transmission system and is expected to increase the capacity of transmission to Egypt by at least ~6-7 BCM per year. For promotion of the construction of the Nitzana Pipeline, by the date of approval of the consolidated financial statements, the Leviathan Partners approved preliminary budgets prior to an undertaking to participate in the funding of the Nitzana Pipeline, in accordance with the decision of the Natural Gas Commission on the matter, and prior to the adoption of a final investment decision (insofar as adopted) in the aggregate amount of approx. $111.1 million (100%).

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

F. Engagement in agreements for natural gas and condensate transmission from the Leviathan reservoir (Cont.):

2. Agreements for transmission of natural gas for export to Jordan and Egypt (Cont.):

e) (Cont.):

In the Operator's estimation (based on data provided by INGL), the Nitzana Pipeline project's budget is estimated at approx. $585 million (in equal shares between the gas exporters participating in the funding thereof; the Partnership's share – approx. $133 million). As of the date of approval of the consolidated financial statements, the Partnership is examining, together with the other Leviathan Partners, all of the commercial conditions in this project compared to the alternatives of other projects for increase of the capacity for export to Egypt, including the installation of a pipeline that will connect to the platform to the Egyptian transmission system, and accordingly, a decision will be made on whether and how to participate in the Nitzana Project.

G. Engagement for renewable energy collaboration:

1) The Partnership's renewable energy operations are conducted in collaboration with Enlight

a) On 21 September 2022, the general meeting of the Unit holders gave approval to the Partnership to make investments in renewable energy projects, up to the aggregate investment amount (the Partnership's share only) of US $100 million (by capital and/or by shareholder's loan including a capital note or by way of guarantee in respect of loans to be provided), as required by TASE Rules, and in such context, approved the outline of the transaction with Enlight, noting, *inter alia*, the personal interest of Mr. Yossi Abu, CEO of the Partnership.

As of the date of approval of the consolidated financial statements, the Partnership's renewable energy operations are conducted in collaboration with Enlight, as specified below.

On 13 March 2023, the Partnership engaged with Enlight in a detailed agreement regarding exclusive collaboration for a fixed term regarding the initiation, development, financing, construction and operation of renewable energy projects, including the following: Solar projects, wind projects, energy storage, and other renewable energy segments, insofar as relevant in several target countries, including Egypt, Jordan, Morocco, the UAE, Bahrain, Oman and Saudi Arabia (in this section: the "**Collaboration Agreement**" and the "**Target Countries**", respectively). In accordance with the Collaboration Agreement, Enlight and the Partnership incorporated MedLight (a private company incorporated in England and wholly owned by the Enlight Corporation) which is controlled by the Enlight Corporation as specified in Note 1D(8) above. Concurrently with the signing of the Collaboration Agreement, Enlight and Mr. Abu signed an agreement pursuant to which Enlight allotted 30% of the share capital of the Enlight Corporation to Mr. Abu. Under the agreement signed by and between the parties, Mr. Abu's share in the required investments in the Enlight Corporation will be provided on his behalf by Enlight, by way of a non-recourse loan.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

G. Engagement for renewable energy collaboration (Cont.):

1) The Partnership's renewable energy operations are conducted in collaboration with Enlight (Cont.):

a) (Cont.):

The Collaboration Agreement stipulates, *inter alia*, the following provisions:

1. The parties will act together to identify, initiate, develop, finance, build and operate renewable energy projects in the Target Countries (in this section: the "**Joint Venture**"). For the purpose of the Joint Venture, the parties will form corporations that will engage in promotion of the joint operations (the "**Co-Owned Corporations**").
2. As part of the Joint Venture, the Partnership will utilize its business connections in the Target Countries to promote the Joint Venture, with active personal involvement by Mr. Abu. The Enlight Corporation, via Enlight, will provide the joint operations with professional design, development and management services in the interest of promoting the Joint Venture.
3. Enlight will hold control during the projects' construction and operation stages. The agreement stipulates provisions with respect to the parties' rights to appoint members of the boards of Co-Owned Corporations based on their holding rates, and stipulates that Mr. Abu will serve as chairman of the board of Co-Owned Corporations in the first 24 months.
4. In the context of the Joint Venture, one of the Co-Owned Corporations will perform feasibility studies and due diligence reviews for any project it deems suitable for the collaboration and thereafter, each party will notify the other party whether it wishes to participate and promote the proposed project under the Joint Venture. If the Partnership does not confirm its participation in or objects to the promotion of a certain project, the Enlight Corporation may undertake the project independently, without the Partnership, in which case the Partnership will be entitled to reimbursement of its expenses on such project plus interest.
5. Under the Collaboration Agreement, it is agreed that resolutions of Co-Owned Corporations be adopted by a majority vote, subject to the requirement of the Partnership's consent to certain resolutions as long as the Partnership holds 15% or more of the Co-Owned Corporations' capital. Provisions are also set with respect to the manner of financing of the Joint Venture operations and the investments in projects carried out thereunder, based on each party's *pro rata* share.
6. The term of the parties' exclusive collaboration will be 3 years as of the date of signing of the Collaboration Agreement, which may be extended under certain circumstances up to a term of 5 years as of the date of signing of the Collaboration Agreement (the "**Exclusivity Period**"). Following the expiration of the Exclusivity Period, the collaboration will continue on projects that shall have commenced prior to the expiration date, and Enlight may promote projects that are in early stages of development without the Partnership's participation.
7. The Collaboration Agreement specifies additional provisions on other matters, as is standard in transactions of this type, *inter alia*, with respect to resolutions that require the Partnership's consent, as long as the Partnership holds 15% or more of the capital of the Co-Owned Corporations, restrictions applicable to transfers of interests in Co-Owned Corporations to third parties, early termination of the Exclusivity Period, the joining of third parties in the projects and Co-Owned Corporations' profit distribution policy.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

G. Engagement for renewable energy collaboration (Cont.):

1) The Partnership's renewable energy operations are conducted in collaboration with Enlight (Cont.):

b) On 9 March 2025, MedLight entered into a set of agreements with a local partner in Morocco (a third party which is not related to the Partnership or Enlight; in this section: the "**Partner**") for the incorporation of two project companies for the purpose of developing and building two renewable energy projects in Morocco (in this section: the "**Agreements**"): (a) A photovoltaic project for the generation of electricity from solar energy with a capacity of approx. 300 MW; and (b) A project for the generation of electricity from wind power with a capacity of approx. 200 MW (in this section: the "**Projects**").

Under the Agreements, MedLight will be allotted 75% of the share capital of the project companies, and the rest of the shares (25%) will be held by the Partner. MedLight has undertaken to inject capital into the project companies, by way of a shareholder loan, according to agreed milestones, in the aggregate amount (for both Projects) of approx. €25 million (subject to certain adjustments). Furthermore, MedLight has been given the option to acquire the remainder of the Partner's holdings by the date of commercial operation of the Projects, and the Partner has been given the option to sell its holdings to MedLight during the period beginning on the commercial operation date and ending at the lapse of five years from that date.

The Agreements stipulate additional provisions, *inter alia*, with respect to services the Partner will provide to the Projects until they reach the commercial operation date, and provisions that determine the parties' rights as shareholders of the project companies, including refusal right, tag-along right, drag-along right and BMBY mechanisms, provisions pertaining to the appointment of board members and corporate governance, certain veto rights to be afforded to the Partner, restrictions on share transfers, and other matters, as is standard in transactions of this type.

According to the timetables agreed between the parties, financial closing of the Projects is intended to take place in 2027-2028, and commercial operation is scheduled for 2029-2030. For the avoidance of doubt, it is clarified that as of the date of approval of the consolidated financial statements, at this preliminary stage, there is no certainty that the Projects will come to fruition or reach the commercial operation stage, *inter alia*, because development of the Projects requires approvals by third parties and local authorities, over which the Partnership has no control. As of the date of approval of the consolidated financial statements, MedLight is examining and advancing additional possible projects in the renewable energy sector.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

G. Engagement for renewable energy collaboration (Cont.):

2) **The Partnership's hydrogen production operations:**

The Partnership is considering a blue hydrogen venture in which natural gas is split into hydrogen and carbon dioxide (CO_2), with the carbon dioxide captured and stored in special underground storage sites or injected by various methods into subterranean or underwater geological formations or used in the manufacture of various products. Of note, hydrogen is considered one of the primary pillars of a sustainable and thriving low-carbon economy, and serves as a key course of coping with the climate crisis. On 9 September 2024, the Partnership entered into agreements with Airovation Technologies, a private Israeli technology company (having no interest in the Partnership), for investment in several stages, the aggregate amount of which is up to $3 million, in a pilot project testing the feasibility of use of a carbon dioxide sequestration technology developed by this company, which, if proved to be efficient economically viable, may, under certain conditions, serve, *inter alia*, as part of the process of producing clean blue hydrogen from the natural gas produced from the Leviathan project.

H. Regulation:

1. **The Gas Framework:**

On 16 August 2015, Government Resolution No. 476 (readopted by the Government Resolution of 22 May 2016) was adopted with respect to a framework for the increase of the natural gas quantity produced from the "Tamar" natural gas field and the expeditious development of the "Leviathan", "Karish" and "Tanin" natural gas fields and other natural gas fields (in this section: the "**Government Resolution**"), which took effect on 17 December 2015, upon the grant of an exemption from certain provisions of the Restrictive Trade Practices Law to the Partnership, Ratio Energies and Chevron (in this section: the "**Parties**") by the former Prime Minister, in his capacity as Minister of Economy, pursuant to the provisions of Section 52 of the Economic Competition Law, 5748-1988 (in this section: the "**Exemption**" or the "**Exemption pursuant to the Restrictive Trade Practices Law**"), the main principles of which are presented below.

a) **The restrictive trade practices in relation to which the Exemption was granted are as follows:**

1) The restrictive trade practice that was ostensibly created, according to the Competition Commissioner's position, as a result of the acquisition of the rights in the Ratio-Yam permit by the Parties; and the restrictive trade practice that was ostensibly created as a result of the Parties' coming together as joint holders of the Ratio-Yam permit and the Leviathan reservoir.
2) The restrictive trade practice that shall ostensibly be created in a case in which the Parties or some of them jointly market the gas that shall be extracted from the Leviathan reservoir to the domestic market until 1 January 2030.
3) The restrictive trade practice that shall ostensibly be created in a case in which the Parties or some of them market the gas that shall be extracted from the Leviathan reservoir jointly for export only.
4) The restrictive trade practice which may be created as a result of a certain agreement for the purchase of natural gas from the Leviathan reservoir, provided that such agreement is signed by 1 January 2025.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

H. Regulation (Cont.):

1. The Gas Framework (Cont.):

a) (Cont.):

5) With respect to their activity in the Tamar and Leviathan reservoirs only, the Partnership and Chevron being the holders of a monopoly according to the Competition Commissioner's declarations.

b) The Exemption from the aforesaid restrictive arrangements had been contingent upon the satisfaction of certain conditions, including the transfer of all the interests of the Partnership and Chevron in the Tanin and Karish leases (see Note 8B above), the transfer of all the interests of the Partnership in the Tamar Project (see Note 7C9 above) and the transfer of some of the interests of Chevron (interests in excess of 25%) in the Tamar Project, all of which were completed in accordance with the framework by December 2021.

c) <u>Satisfaction of specific restrictions that will apply to new natural gas supply agreements</u>

The Gas Framework sets out specific restrictions that will apply to new agreements for the supply of gas from the Leviathan reservoir, that shall be signed with consumers from the date of the Government Resolution. Most of the restrictions are no longer relevant, other than:

1. The consumer shall be subject to no restriction with respect to the purchase of natural gas from any other natural gas supplier.
2. The consumer will have the possibility of selling natural gas that it purchased in a resale, in accordance with the conditions and provisions set forth in the Exemption.
3. The parties shall not apply any restriction to the sale price at which the consumer shall sell the natural gas in a resale.
4. The gas sales agreements shall not include a condition whereby the consumer's notification of shortening of the term of the agreement or reduction of the purchase amount will lead to any change in the terms of the agreement that is detrimental to the consumer. In this context, no change detrimental to the consumer shall be made to the price and terms of payment, the terms, dates and quantities of supply, the addition of restrictions on resale of the gas, etc.

2. Environmental Regulation:

The Partnership acts to prevent and/or minimize the environmental hazards that may occur in the course of its operations, and prepares for the financial, legal and operating implications deriving from such laws, regulations and directives and allocates budgets for compliance therewith in the framework of its annual work plans for its various assets.

a) On 20 May 2020, Chevron received a notice from the MoEP of the intention to impose an administrative monetary penalty, in an immaterial amount, due to alleged violations of the emission permit given to the Leviathan platform as well as the Clean Air Law, and the instruction given thereunder by the Supervisor of the emission permit at the MoEP (in this section: the "**Supervisor**") in connection with the continuous monitoring systems on the Leviathan platform.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

H. Regulation (Cont.):

2. Environmental Regulation (Cont.):

a) (Cont.):

Chevron informed the Partnership that it had submitted to the MoEP an application to receive information under the Freedom of Information Law, 5758-1998, which directly responds to the claims raised in said notice, and that the MoEP approved the postponement of the date for submission of the arguments with regards to said administrative monetary penalty and scheduling thereof for 30 days after receipt of the information. As of the date of approval of the consolidated financial statements, the requested information has not yet been received and therefore the count of days for responding to the aforesaid notice has not yet begun, and on 5 January 2025, the MoEP's issued its decision not to impose such administrative penalty on Chevron.

b) On 6 August 2023, Chevron received a letter of notice and summons to a hearing before the MoEP for alleged violations of the marine discharge permit and the toxins permit of the Leviathan project, and violation of the Prevention of Sea Pollution and the Hazardous Substances Law. The hearing took place on 7 January 2024, and on 21 January 2024, the hearing summary was received, whereby Chevron is required to take all actions to prevent deviations from the marine discharge permit, and the MoEP is considering exercising its powers according to law. At this stage, it is impossible to predict whether an administrative penalty will be imposed due to the violations, and the amount of the administrative penalty to be imposed, if any.

As of the date of approval of the consolidated financial statements, and according to information provided to the Partnership by Chevron, the Partnership is not aware of noncompliance with or deviation from environmental protection requirements in projects in which the Partnership holds interests, which may have a material effect on the Partnership.

3. Directives on the provision of collateral in connection with petroleum rights:

In September 2014, pursuant to Section 57 of the Petroleum Law, the Commissioner published directives for the provision of collateral in connection with petroleum rights. As of the date of approval of the consolidated financial statements, the Partnership has deposited autonomous bank guarantees with the Ministry of Energy, in connection with its rights in the oil and gas assets, against a bank credit facility (see Section D11 above).

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

H. Regulation (Cont.):

4. **Projects for export through the national transmission system:**
On 23 June 2020, the Director General of the Natural Gas Authority announced his determination that the cost of the Combined Section designated for the piping of natural gas from the Leviathan and Tamar reservoirs to EMG's terminal in Ashkelon for purposes of piping gas to Egypt according to the export agreements is estimated (as of the date of signing of the Transmission Agreement) at a sum total of ILS 738 million which will be updated according to an update and accounting mechanism between the parties as set forth in the Transmission Agreement with INGL. On 2 May 2022, INGL updated the project's budget to approx. ILS 796 million. According to the announcement of the Director General of the Gas Authority, 43.5% of the section's cost, as shall be determined in accordance with the aforesaid, will be financed by the holder of the transmission license (INGL) and 56.5% of the section's cost shall be financed by the exporter in accordance with the milestones that shall be determined in the Transmission Agreement. In addition thereto, the exporter shall pay the holder of the transmission license ILS 27 million (the Partnership's share approx. ILS 8.5 million) for its share in the cost deriving from the bringing forward of the doubling of the Dor-Hagit and Sorek-Nesher sections (which is estimated at approx. ILS 48 million) and that the exporter will provide the holder of the transmission license with an independent financial guarantee on behalf of an Israeli bank, in the sum of 110% of the aggregate amount of the cost stated above (the share of the holder of the transmission license in the cost of construction of the Combined Section plus 10% percent), and in the sum of ILS 21 million (the share of the holder of the transmission license in the cost of acceleration of the doubling of the Dor-Hagit and Sorek-Nesher sections), which will decrease in accordance with the provisions of the addendum to the decision.
The announcement of the Director General of the Authority further determines that as long as the exporter exports to Egypt, the quantity of natural gas determined in the Transmission Agreement will be transported via the transmission system of the holder of the transmission license and not via a section outside of the Israeli transmission system and that insofar as the exporter shall have ceased to export to Egypt, it will be required to pay the holder of the transmission license the difference, if any, between 110% of the aggregate total cost of the section plus ILS 48 million (the cost derives from the acceleration of the doubling of the Dor-Hagit and Sorek-Nesher sections), and the aggregate capacity and piping fees that the exporter paid the holder of the transmission license from the date of completion of the Combined Section and of the payments that the exporter paid the license holder in accordance with the aforesaid.
With regards to Chevron's engagement with INGL in an agreement for transmission on a firm basis for the purpose of piping of natural gas from the Tamar reservoir and Leviathan reservoir to the EMG terminal in Ashkelon for transmission thereof to Egypt, see Note 12F2(a) above.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

H. Regulation (Cont.):

5. **Natural Gas Commission resolution on the regulation of criteria and rates relating to the operation of the transmission system:**
   a. From time to time, the Natural Gas Commission adopts resolutions that update the rates of the various transmission services.
   b. According to the Natural Gas Commission's resolution of 3 January 2021 on criteria and rates for the purpose of operation of the transmission system in a flow control regime, the Commission determined that the costs in respect of unaccounted for gas (UFG) in the transmission system that derives from reasons that cannot be attributed to deficient operation of the transmission system, but rather to factors that can be neither prevented nor controlled, such as measurement timing, pressure differences and temperature differences, will be borne by the gas suppliers. The resolution further stipulates that UFG within the range of 0% and 0.5% (either positive or negative) is deemed to be within the reasonable range. The costs in respect of a reasonable UFG-T will be allocated equally between the gas suppliers and the gas consumers.
   c. On 11 April 2024, the Natural Gas Commission released a hearing for public comment on reduction of the natural gas transmission tariff (in this section: the "**Hearing**"). Under the Hearing, it is proposed to reduce the capacity tariff for natural gas transmission on an uninterruptible basis by 12.9% and the natural gas transmission tariff by approx. 7.6% per MMBTU, from May 2024. On 16 May 2024, Chevron submitted its response to the Hearing on behalf of the Leviathan Partners, and on 4 June 2024, the Natural Gas Commission rendered Resolution No. 1/2024 on annual update of the uninterruptible transmission tariffs, which reduced the natural gas transmission capacity tariff by 12.9% and the natural gas piping tariff by ~7.6% per MMBTU, from July 2024.

6. **Natural Gas Commission resolution No. 3/2023 on funding and allocation of capacity in all export lines (in this section: the "Natural Gas Commission Resolution")**

   On 9 August 2023, the Natural Gas Commission Resolution was released, the principles of which are as follows:
   a) Capacity will be allocated to every exporter according to a percentage to be calculated in accordance with certain parameters, such as the exporter's annual production capacity and existing and prospective export volumes. According to the initial allocation, 54% of the total capacity for export will be allocated to the Leviathan reservoir, 33% to the Tamar reservoir and 13% to the Karish reservoir. For the avoidance of doubt, it is clarified that preexisting transmission agreements will not be adversely affected.
   b) In the event that export infrastructure is built other than by the transmission license holder, the share of every exporter in such infrastructure will be taken into account as part of its allotted share for export.
   c) The Commission shall reexamine and redetermine the allocation upon the occurrence of a significant event in the natural gas sector, the discovery of additional significant reserves, the entry of a new exporter, the construction of additional natural gas export infrastructure, or another material change in the natural gas sector as determined by the Commission.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

H. Regulation (Cont.):

7. Natural Gas Commission resolution No. 3/2023 on funding and allocation of capacity in all export lines (in this section: the "Natural Gas Commission Resolution") (Cont.):

d) The Commission may determine that use will be made of some or all of the export lines for the purpose of natural gas import in the event that it finds that there is need to supply domestic market demand.

e) As concerns the Ramat Hovav-Nitzana line, it has been determined as follows:

1) Capacity allocation between the existing exporters shall be on an equal basis, such that every existing exporter may request one third of the line's capacity and choose whether to use its allotted share. The remaining capacity of an exporter that opts not to use all or any of its allotted share will be divided equally between the other exporters, subject to the total allocation limit of every exporter.

2) An exporter that funded the line will be entitled to reimbursement relative to its allotted share in respect of uses of the line by other parties during the term of the transmission agreement.

3) An exporter that does not sign a transmission agreement within two months of receipt of the line allocation or fails to complete its share of the funding in accordance with the provisions of the transmission agreement, will be deemed as having waived its allotted share. Accordingly, the allotted share will be transferred to another exporter, and it will receive reimbursement for the costs it paid.

4) The line construction costs (CAPEX) include the costs of the compressor and are estimated at approx. ILS 2 billion, and the time of construction is estimated at approx. 36 months. Of note, operation of the compressor is expected to impose high annual operating costs as compared with the operation of the rest of the national transmission system, which are estimated at approx. ILS 20 million per year, excluding the electricity costs entailed by operation of the compressors, which are borne by the exporters. For details with respect to the Nitzana line, see Note 12F2E above.

f) As concerns the Jordan-North line, it has been determined that after the transfer of payment to the parties that funded its construction (the Marketing Company and INGL), an exporter may sign a transmission agreement for use thereof, according to the available quantity over and above the existing uninterruptible transmission agreements, as of 1 August 2023.

g) Any exporter's uninterruptible transmission agreements for the Ramat Hovav-Nitzana line and the Jordan-North line shall not exceed 70% of the allotted share of that exporter in that line, with the remaining capacity kept for interruptible piping.

h) The actual cost of funding the line, and the resulting cost of use per MMBTU, will be determined by the Director General of the Natural Gas Authority after construction of the export line is completed.

i) In the event of discovery of a new natural gas reservoir from which it is intended to export natural gas, the new exporter will receive its full allotted share in the Ramat Hovav-Nitzana line and the balance of its allotted share in the Jordan-North line, provided that its allotted share does not exceed 20% of the capacity of each line. Such allocation shall be carried out at the expense of the interruptible transmission agreements and subject to a transmission agreement being signed within 24 months before the commencement of piping through the line.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

H. Regulation (Cont.):

6. Natural Gas Commission resolution No. 3/2023 on funding and allocation of capacity in all export lines (in this section: the "Natural Gas Commission Resolution") (Cont.):

j) An export mechanism by way of secondary trade will be available through interruptible transmission agreements, at up to 5% of the capacity of any export line.

In June 2024 and November 2024, the Leviathan Partners authorized additional preliminary budgets for the Nitzana Project of approx. $4.2 million and approx. $1.3 million (100%), respectively, such that by the date of approval of the consolidated financial statements, a preliminary budget totaling approx. $20 million (100%) has been approved, before the undertaking to contribute to the funding of the project, in accordance with the Natural Gas Commission Resolution, and before the Leviathan partners' signing of the transmission and construction agreement with INGL in connection with the Nitzana Project. As of the date of approval of the consolidated financial statements, the Leviathan Partners are in negotiations with INGL for the signing of an agreement as aforesaid, which, due to the gaps between the parties, have not yet matured into an agreement. In this context, it is noted that according to up-to-date assessments by INGL, as confirmed by the Natural Gas Authority, the total cost of the Nitzana Project is estimated at approx. $585 million (100%, the Leviathan Partners' share – approx. $292.5 million (50% of the project), the Partnership's share – approx. $133 million)[30]. In addition and following the delays in finalization of the negotiations with INGL as aforesaid, the Leviathan Partners have started an initial examination of alternative projects for the construction of transmission infrastructure for export to Egypt.

Further to previous letters by the Natural Gas Commission, in its letter of 15 January 2025 to the Leviathan Partners regarding the allocation of capacity in the Ramat Hovav-Nitzana line, the Natural Gas Commission renotified the Leviathan Partners that their allotted share in the Ramat Hovav-Nitzana export line is 33.33%. The letter also states that, pursuant to the resolution, the Leviathan Partners are required to sign a transmission agreement with INGL by 14 March 2025, on the conditions stipulated by the Gas Authority in its aforesaid letter, and that an exporter that does not sign a transmission agreement with INGL by such date will be deemed as having waived its allotted line capacity and the capacity that will be made available will be offered to the other exporters as set out in the resolution.

Further thereto, on 5 March 2025 INGL delivered an updated draft agreement to the Leviathan partners, but in view of the said gaps, and particularly in reference to the total budget framework for the project, the Partnership estimates that it will not be possible to sign the said agreement at such time. It is clarified that as of the date of approval of the consolidated financial statements, there is no certainty with respect to participation in the Nitzana Project or in such alternative project by the Leviathan Partners.

[30] The allocation rate of the Leviathan project out of the prospective export capacity of the Nitzana Line project is based on the assumption that the capacity will be allocated between the Leviathan Partners and the Tamar partners on an equal basis.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

H. Regulation (Cont.):

7. **Draft policy document with respect to the decommissioning of offshore exploration and production infrastructures:**

   On 2 May 2023, the Ministry of Energy published for public comment a draft policy document that specifies general principles with respect to the decommissioning of offshore oil and natural gas exploration and production infrastructures, without derogating from the provisions of law applicable to this issue and from the provisions of the lease deeds and operation authorizations. The draft policy document specifies, *inter alia*, rules, criteria and timeframes for the decommissioning of wells and production facilities as well as the abandonment of no-longer used subsea infrastructures and pipelines, *inter alia*, according to the location of such installations in the deep sea, on the seabed or under the seabed. According to the Partnership's preliminary assessment, insofar as the stringent requirements of the draft policy document are approved, costs of decommissioning of the Partnership's assets are expected to increase.

8. **Permits and licenses for project facilities:**

   a) In the context of the development of the Yam Tethys project, the Yam Tethys Partners received approval for construction of a permanent natural gas and oil production platform, and approval for operation of a natural gas production system under the Petroleum Law. Furthermore, the Minister of Energy granted Yam Tethys Ltd. (a company owned by the Yam Tethys Partners) a license for construction and operation of a transmission system to be used for transfer of natural gas belonging to the Yam Tethys Partners or to other natural gas suppliers upon the fulfillment of certain conditions, and all subject to the terms and conditions of the license and the Natural Gas Sector Law from the production platform to the terminal (see Note 12J for details on an agreement for the provision of usage rights in the Yam Tethys project facilities).

   b) In the context of the Leviathan project Phase 1A development plan, the Leviathan Partners received approval for the construction of a permanent platform for the production of natural gas and oil, as well as approval for the operation of a system for production of natural gas and condensate from the Leviathan project pursuant to which the Leviathan Partners were required, *inter alia,* to submit guarantees as provided in Note 12D(11) above.

      In February 2017, the Minister of Energy granted Leviathan Transmission System a license for construction and operation of the transmission system, which will serve for the transfer of natural gas of the Leviathan Partners originating from the Leviathan Leases, or other natural gas suppliers upon the fulfillment of certain conditions, all subject to the terms of the license.

I. Reimbursement of indirect expenses to project operators:

The Partnership's operations in the Ratio-Yam and Yam Tethys joint ventures are carried out by Chevron, and the Partnership's operations in the Block 12 joint venture in Cyprus is carried out by Chevron Cyprus. Under the joint operation agreements (in this section: the "**JOAs**") in such joint ventures and licenses, it was agreed that Chevron and Chevron Cyprus, as noted, would serve as operators and be exclusively responsible for the management of the joint operations. According to the rules of accounting specified in the JOAs, Chevron and Chevron Cyprus are entitled to reimbursement of indirect expenses which are calculated as a percentage of the direct expenses, as specified below:

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

I. Reimbursement of indirect expenses to project operators (Cont.):

Ratio-Yam joint venture:
Chevron is entitled to reimbursement of all direct expenses incurred thereby in connection with the discharge of its duties as operator as well as a rate of 1% to 4% in respect of exploration expenses, with the rate of payment to the operator decreasing as exploration expenses increase, and additionally, to a rate of 1% of all the direct development and operating expenses, as defined in the JOA, subject to certain exceptions.

Yam Tethys joint venture:
Chevron is entitled to reimbursement of all direct expenses incurred thereby in connection with the discharge of its duties as operator as well as reimbursement of the indirect expenses deriving from a percentage of the joint venture expenses, at a rate of 1% of the expenses up to an expense amount of $20 million per year, and, over and above this amount – at a rate of 0.85% of the expenses.

Block 12 Cyprus:
Chevron Cyprus is entitled to reimbursement of all direct expenses incurred thereby in connection with the discharge of its duties as operator as well as amounts in respect of payment of indirect expenses of the operator at a rate of 1% to 4% in connection with exploration expenses. Of note, the rate of the payment of indirect expenses to the operator decreases as exploration expenses increase. Furthermore, Chevron Cyprus is entitled to payment of indirect expenses at the rate of 1.5% in respect of the operator's indirect expenses out of the overall direct expenses in connection with development operations, subject to specific exceptions, such as marketing activity. As of the date of approval of the consolidated financial statements, the operator fees in respect of indirect expenses in connection with production operations have not yet been determined.

The Boujdour license in Morocco:
NewMed Morocco is entitled to reimbursement of any and all direct expenses it incurs in connection with its role as operator, as well as amounts for payment of indirect expenses of the operator at the rate of 2%-5% in connection with exploration expenses, as well as in connection with development expenses, subject to certain exceptions. The rate of payment of the indirect expenses to NewMed Morocco as aforesaid decreases with the increase of the exploration or development expenses, as applicable. For any other activity, including operating expenses, NewMed Morocco is entitled to payment of indirect expenses at the rate of 2%.

J. Agreement for the grant of usage rights in the facilities of the Yam Tethys project:

As of the date of approval of the consolidated financial statements, the project assets are primarily used for the provision of infrastructure services to the Tamar reservoir under an agreement signed on 23 July 2012 between the Partnership together with the other Yam Tethys Partners and the Tamar partners on 23 July 2012, whereby the Yam Tethys Partners granted the Tamar partners usage rights in the existing Yam Tethys project facilities in exchange for the payment of $380 million in total (the "**Usage Agreement**"). The term of the Usage Agreement will expire upon the earlier of: (a) expiration or termination of the Tamar lease, and in case the Dalit field is developed such that the Yam Tethys facilities are used – expiration or termination of the Dalit lease; (b) a notice of permanent cessation of commercial gas production from the Tamar Project given by the Tamar partners; (c) abandonment of the Tamar Project. The agreement specifies various provisions with respect to the term of usage and expiration of the term of usage, including an accounting mechanism in respect of

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

J. Agreement for the grant of usage rights in the facilities of the Yam Tethys project (Cont.)

upgrades to be made to the facilities. In the context of the sale of the Partnership's remaining interests in the Tamar Project, the Partnership assigned the buyers its interests in the Usage Agreement as partners in the Tamar Project (see Section 9B below). Ownership of the Yam Tethys facilities and the cost of abandonment of the facilities will continue to be held by the Yam Tethys Partners and the Usage Agreement specifies an accounting mechanism pertaining to the value of the said facilities when the term of the Usage Agreement expires.

Note 13 – Equity:

A. The participation units are issued by the Limited Partner (in this section: the "**Trustee**") and confer upon the holders thereof a working interest in the rights of the Limited Partner in the Partnership. The units are held thereby in trust in favor of the unit holders and under the supervision of the Supervisor.

B. The unit holders' register records, as of 31 December 2024: 1,173,814,691 units of par value ILS 1 which are listed on TASE. In respect of options that are exercisable into participation units of the Partnership which were granted to the Partnership's CEO, see Note 20C4.

C. Distributions of profit:

1. **The Partnership Agreement and the Trust Agreement:**

   a) The limited partnership agreement, as amended, prescribes rules regarding profit distributions in the Partnership, and, *inter alia*, allows the General Partner to refrain from or delay profit distributions, to the extent required, for the purpose of financing the Partnership's operations, in such manner and on such terms and conditions as stipulated in the agreement and by the general meetings. Other than restrictions imposed under the financing agreements, no external limitations which may affect the Partnership's ability to distribute profits in the future, exist on the date of approval of the consolidated financial statements.

   b) The Trust Agreement, as amended, prescribes rules regarding the manner of distribution of profits that shall be received from the partners by the Trustee for the unit holders, and the portion that shall remain with the Trustee as sums required thereby, *inter alia*, for making payments and expenses and for performing the acts set forth in the Trust Agreement, the amount of which will be determined from time to time, by the Trustee with approval from the Supervisor.

2. **Profit distribution amounts:**

Date of Profit Distribution Announcement	Date of Profit Distribution	Total Distribution Amount ($ in millions)	Distribution Amount per Participation Unit ($)
22.5.2022	16.6.2022	50	0.04260
17.8.2022	22.9.2022	50	0.04260
23.11.2022	19.1.2023	50	0.04260
27.3.2023	20.4.2023	60	0.05112
10.5.2023	15.6.2023	50	0.04260
20.8.2023	14.9.2023	50	0.04260
15.11.2023	21.12.2023	50	0.04260
18.3.2024	11.4.2024	60	0.05112
23.5.2024	20.6.2024	60	0.05112
7.8.2024	5.9.2024	65	0.05538
19.11.2024	12.12.2024	65	0.05538
9.3.2025	3.4.2025	60	0.05112

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 13 – Equity (Cont.):

C. Distributions of profit (Cont.):

3. **Distributions to the Limited Partner:**
   a) On 1 March 2023, 20 August 2023 and 15 November 2023, the board of directors of the General Partner approved a distribution to the Limited Partner in the sum of ILS 1 million, ILS 0.5 million and ILS 0.5 million, respectively (approx. $0.3 million, approx. $0.1 million and approx. $0.1 million, respectively).
   b) On 28 March 2024 and 19 November 2024, the board of directors of the General Partner approved a distribution to the Limited Partner in the sum of approx. ILS 0.5 million each (approx. $0.1 million).

   Such distributions are used for payment of the Supervisor' fees and the trustee's fees and expenses, in accordance with the provisions of the Trust Agreement.

D. Advance tax payments, tax payments and balancing payments:

1. In accordance with the provisions of Section 19, the General Partner paid the Income Tax Authority, on account of the tax owed by participation unit holders due to the 2021 tax year (for further details see Notes 19A and 19B), as specified below:

Tax Year	Type of Income	Tax Advances in ILS millions	ILS per Participation Unit
2021	Current	Approx. 217.3	0.1851
2021	Capital gain	Approx. [31]527.9	0.4497

With respect to the change of the tax regime that applies to the Partnership, such that it is taxed as a company for its taxable income commencing on 2022, see Note 19A1.

2. On 26 December 2021, the Partnership declared tax payments to individual holders and balancing payments to non-individual holders in the amount of approx. ILS 268 million that constitute approx. 0.2283281 per participation unit that were distributed on 20 January 2022.

E. Equity composition as of 31 December 2024 is as follows:

	The Limited Partner	The General Partner	Total
The Partnership's equity	154.8	-[32]	154.8
Capital reserves	(28.1)	-[32]	(28.1)
Retained earnings	1,660.4	0.2	1,660.6
Balance as of 31 December 2024	**1,787.1**	**0.2**	**1,787.3**

The Limited Partner's share in the Partnership is 99.99%, and the share of the General Partner is 0.01%. The General Partner of the Partnership has also an indirect holding through participation units that were issued by the Limited Partner (the trustee).

[31] Approx. ILS 477.9 million of which is in respect of the sale of the Tamar and Dalit project.

[32] Less than $0.1 million.

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 13 – Equity (Cont.):

F. On 31 May 2022, the Partnership released a shelf prospectus for the issuance of various securities including, *inter alia*, participation units, bonds and warrants. The shelf prospectus is in effect for 24 months with an option of extension by 12 additional months. This shelf prospectus has been extended by 12 additional months, i.e., until 30 May 2025.

G. With respect to the participation unit-based payment granted to the CEO of the General Partner of the Partnership, see Note 20C4.

Note 14 – Revenues from the Sale of Natural Gas and Condensate:

A. The Partnership's revenues originate from natural gas and condensate sales to its customers, all in accordance with agreements signed therewith, as specified in Note 12C above.

B. The Partnership's revenues in the report period from the sale of natural gas and condensate is affected mainly by the volume of natural gas consumption for the domestic market, Egypt and Jordan (the "**Regional Market**"). Below is the Partnership's share in the income from the sale of natural gas and condensate and in the natural gas quantities sold to the domestic market and to the Regional Market in the report period from the Leviathan project:

	For the year ended		
	31.12.2024[33]	31.12.2023	31.12.2022
Revenues from the sale of natural gas and condensate:			
Domestic market	141.9	168.6	284.7
Regional market	994.4	925.8	859.2
	1,136.3	**1,094.4**	**1,143.9**
Quantities of natural gas (BCM)			
Domestic market	0.67	0.93	1.71
Regional market	4.41	4.05	3.45
	5.08	**4.98**	**5.16**

Note 15 – Royalties:

A. Composition:

	For the year ended		
	31.12.2024	31.12.2023	31.12.2022
Royalties to the State	120.0	117.5	126.4
Royalties to interested parties	14.4	14.1	15.2
Royalties to third parties	28.8	28.2	30.4
Total	**163.2**	**159.8**	**172.0**

(see Note 12B above and Paragraph B below)

[33] Including revenues from the sale of condensate in the amount of $16.8 million, sale of which began in March 2024. For further details, see Note 12C6 above.

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 15 – Royalties (Cont.):

Effective rate of royalties in the Leviathan project:

	For the year ended		
	31.12.2024	31.12.2023	31.12.2022
Effective rate of the royalties in Leviathan project:			
To the State	10.57%	10.73%	10.93%
To interested parties	1.27%	1.29%	1.31%
To a third party	2.54%	2.57%	2.62%

B. **Royalties to the State and overriding royalties (to interested and third parties) as included on the Partnership's books:**

1. The Petroleum Law, 5712-1952 (the "**Petroleum Law**") and the Petroleum Regulations, 5713-1953 prescribe that a lease holder, within the meaning of the term under the Petroleum Law, owes the State Treasury royalties at the rate of one eighth of the amount of petroleum produced from the area of the lease and used, according to the market value at the wellhead, except for petroleum quantities used by the lease holder in operating the area of the lease, but under no circumstances less than such minimum royalties as specified in the law. Under the Petroleum Law, the State is entitled to royalties out of the gas quantity produced. The Commissioner has notified Chevron that the State has decided not to receive the royalties from the gas discoveries to which it is entitled in kind but rather receive the market value of the royalties at the wellhead, in dollars.
2. In May 2020, the Director of Natural Resources at the Ministry of Energy released the final version of the directives on the method of calculation of the royalty value at the wellhead in accordance with Section 32(b) of the Petroleum Law (in this section: the "**Directives**"):
   a) The Directives state that the value of the royalty at the wellhead shall be equal to 12.5% of the sale price for customers at the point of sale, net of essential costs of the treatment, processing and transportation of the petroleum, actually incurred by the lease holder between the wellhead and the point of sale.
   b) The Directives lay down additional provisions, including a list of types of expenses that are or are not deductible for the purposes of the above calculation.
3. In September 2020 and July 2022, specific directives were released (the "**Specific Directives**") regarding the calculation of the royalty value at the wellhead for the Tamar lease and Leviathan lease, respectively, which listed the deductible expenses for the purpose of calculating royalty value at the wellhead.

   Below is a summary of the Specific Directives issued with respect to calculation of the royalty value at the wellhead in the Leviathan Lease:
   a) Capital expenses (CAPEX) recognized for purposes of calculation of the royalty value at the wellhead and the rate of recognition include: (a) Capital cost for the transmission pipeline from the main manifold to the Leviathan platform (in this section: the "**Platform**"), will be recognized at a rate of 100%; (b) Capital costs in respect of the Platform will be recognized at a rate of 82%; and (c) Capital cost in respect of the transmission pipeline from the Platform to the onshore entrance (DVS) will be recognized at a rate of 100%.

Note 15 – Royalties (Cont.):

B. Royalties to the State and overriding royalties (to interested and third parties) as included on the Partnership's books (Cont.):

3. (Cont.)

b) Operating expenses arising directly from the above-listed types of CAPEX will be recognized at a rate of 82%: Platform workers payroll expenses; maintenance and repair expenses; expenses for travel and transportation to the Platform; Platform workers food expenses; Platform protection and security expenses; professional and engineering consulting expenses; insurance expenses and communications expenses on the Platform.

c) In the event that the sale price specified in the contract includes a component of a transmission tariff that is paid to INGL, all of the transmission expenses paid to INGL directly by the lease holders and included in the contractual sale price will be recognized according to the relevant transmission tariff.

d) Abandonment costs will be recognized for calculation of the royalty according to the provisions set forth in the general directives, cumulatively: a. P2 Reserves balance in the Leviathan field according to an updated resources report is less than 125 BCM. b. The abandonment plan has been approved by the Commissioner.

On 1 September 2022, the Leviathan Partners submitted their response to such Specific Directives. As of the date of approval of the consolidated financial statements, the response of the Ministry of Energy has not yet been received.

4. According to demand letters received from the Ministry of Energy, the Leviathan Partners are required to make advance payments to the State on account of the State royalties in respect of the revenues from the Leviathan project in 2023 and 2024 at the rate of 11.06% (2022: 11.26%). According to a letter received from the Ministry of Energy in January 2025, the rate of the advance payments on account of State royalties in respect of the revenues from the Leviathan Project in 2025 will continue to be 11.06%. The rate of the advance payments made to the State is higher than the calculation of the rate of the royalty value at the wellhead in the royalty reports submitted by Chevron to the Ministry of Energy for the years 2020 and 2021, whereby the rate of the royalty value at the wellhead in the Leviathan project is 9.58% and 10.17%, respectively. The royalty rate on which the Partnership based its financial statements for 2024 is approx. 10.6% (2023: 10.7%, 2022: 10.9%).

   It is the position of the Partnership that the calculation of the actual State royalty rate should reflect the complexity of the project, the risks involved therein and the amount of the investments in the project. It is clarified that there are substantial differences between the royalties actually paid to the Ministry of Energy in the aggregate starting from commencement of production from the Leviathan project, and the amounts recorded in the statement of comprehensive income as royalty expenses.

5. The difference between the advance payments in respect of royalties actually paid to the State and the effective royalty rate applied by the Partnership in its financial statements in the Tamar (until the date of sale of the Partnership's interests in the Tamar project, as described in Note 7C9 above) and Leviathan projects amounted to approx. $27.0 million (2023: approx. $34.2 million) and was included in the other short-term and long-term assets items.

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 15 – Royalties (Cont.):

B. Royalties to the State and overriding royalties (to interested and third parties) as included on the Partnership's books (Cont.):

6. The method of calculation of State royalties is also used for calculation of market value at the wellhead of the overriding royalties paid by the Partnership to interested parties and to third parties. The difference between the royalties that were actually paid to related parties and to third parties and the effective royalty rate on which the Partnership relied in its financial statements of the Tamar Project (until the date of sale of the Partnership's interests in the Tamar project, as specified in Note 7C9 above) and of the Leviathan project amounts to approx. $8.3 million (2023: approx. $14.5 million) and is included under the 'trade and other receivables' and 'other long-term assets' items.
7. As of the date of approval of the consolidated financial statements, the Ministry of Energy's audit of the royalty reports submitted for the Tamar Project in respect of the years 2013-2018 has been completed, and such reports are therefore deemed final reports. Accordingly, in the aforesaid years, the Partnership made excess advance payments to the State and accordingly also to the overriding royalty interest owners. As of the date of approval of the consolidated financial statements, the Partnership has received the advance payments paid in excess (including interest and indexation) from the Ministry of Energy and from the overriding royalty interest owners in the amounts of approx. $17.2 million and approx. $8.2 million, respectively.

Note 16 – Cost of Natural Gas and Condensate Production[34]:

Composition:	For the year ended		
	31.12.2024	31.12.2023	31.12.2022
Salaries and social benefits	25.2	19.6	19.5
Guarding and security	1.4	0.9	2.0
Insurance	19.0	17.5	17.4
Delivery, transmission and transportation costs	74.0	69.3	49.9
Operation management and operator fee	22.6	17.6	19.5
Maintenance	19.7	18.1	15.8
Others	6.5	5.6	10.0
Total	**168.4**	**148.6**	**134.1**

[34] Mostly through the joint ventures.

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 17 – G&A Expenses:

Composition:	For the year ended		
	31.12.2024	31.12.2023	31.12.2022
Salaries and social benefits	6.7	6.5	6.3
Cost of participation unit-based payment to the CEO (see Note 20C4 below)	0.5	2.7	1.0
Professional services, net	3.7	7.2	8.7
Other	6.0	4.4	3.7
Total	**16.9**	**20.8**	**19.7**

Note 18 – Financial Expenses and Income:

Composition:

	For the year ended		
	31.12.2024	31.12.2023	31.12.2022
Expenses:			
For bonds (Notes 10B and 10C above)	113.0	126.9	145.9
For liability to banking corporations (Note 10D)	1.7	2.4	0.7
Revaluation of future production-based royalties from the Karish and Tanin leases (see Note 8B above)	-	5.0	-
For a guarantee fee to Delek Group (Notes 12K4 and 20D)	0.4	0.4	0.4
For changes in oil and gas asset retirement obligation due to lapse of time	3.5	3.2	1.5
Other[35]	1.5	1.1	13.5
Net of financing costs capitalized to gas and oil assets[36]	(6.3)	(5.2)	(6.7)
Total expenses	113.8	133.8	155.3
Income:			
From deposits in banks and short-term investments	17.5	13.1	5.4
Revaluation of future production-based royalties from the Karish and Tanin leases (see Note 8B above)	60.9	-	60.9
Revaluation of loan to Energean in the context of the sale of the Karish and Tanin leases (Note 8B above)	1.2	5.9	1.6
Update of amounts receivable from a company accounted for at equity (see Note 21G3 below)	5.5	7.1	3.1
Other	5.8	2.6	0.1
Total income	90.9	28.7	71.1
Total financial expenses, net	(22.9)	(105.1)	(84.2)

[35] In 2022, mostly comprising expenses formed in connection with restructuring.

[36] The cap rate used for determining the borrowing costs capitalized in 2024 is ~6.6% (2023: ~6.7%).

Note 19 – Taxes on Income and Oil and Gas Profit Levy:

A. Information regarding income tax rules and the main arrangements existing as of the date of the consolidated statement of financial position:

1. The Partnership was approved by the Director General of the Tax Authority for the purpose of the Income Tax Regulations (Rules for the Calculation of Tax due to the Holding and Selling of Participation Units in an Oil Exploration Partnership), 5749-1988 (the "**Participation Unit Regulations**" or the "**Regulations**"). In September 2021 an amendment to the Income Tax Regulations as aforesaid was published in the Official Gazette whereby, effective from tax year 2022 a change has occurred in the tax regime that applies to the Partnership, such that it is taxed as a company with respect to its taxable income (while setoff of losses will be possible, subject to the tax laws, on the level of the Partnership itself without the same being attributed to the holders of the participation units). As a result of this change, commencing from tax year 2022, holders of participation units in the Partnership are subject to a tax regime that applies with respect to profit distributions made by the Partnership, which is similar to the tax applying to shareholders of a company for dividend distributions (i.e. pursuant to the two-stage method).

   In view of the aforesaid amendment, up to and including tax year 2021 the accounting with holders of the participation units and the reporting on the Partnership's taxable income will be as being prior to the amendment as explained below.

2. Until 31 December 2021 the Partnership acted as a "transparent" entity for tax purposes according to the provisions of the Income Tax Ordinance (New Version) 5721-1961 (the "**Income Tax Ordinance**") and the Levy Law (in this section: the "**Law**") i.e. the Partnership's taxable income and the losses for tax purposes were attributed to the unit holders who are "eligible holders", as defined in the Participation Unit Regulations, according to the proportion of their holdings in the Partnership. An "eligible holder" was defined in the Participation Unit Regulations as anyone holding participation units at the end of December 31 of the tax year. According to Section 19 of the Law ("**Section 19**"), for the purposes of Section 63(a)(1) of the Ordinance, the share of each partner in the tax year will be calculated from the taxable income of the Partnership or from its losses.

   Because the partners bear the tax consequences of the Partnership's revenues and expenses, the consolidated financial statements did not include current taxes on income.

3. According to the provisions of Section 19, the General Partner is obligated to submit to the Tax Assessor a report on the Partnership's taxable income and pay the tax deriving therefrom (see below in the section), on account of the tax owed by the partners in the Partnership in the tax year for which the report was submitted (i.e., on account of the tax owed by the holders of the participation units, on 31 December of each tax year), according to the rate of the share of the Partnership of the eligible holders which are bodies corporate (according to the corporate tax rate) and the rate of the share of the Partnership of the eligible holders who are individuals (according to a maximum marginal tax rate). The General Partner is liable for advance tax payments calculated according to the tax rates applicable to companies (in 2019 to 2021 – 23%). See Section 1 above as to the change in the tax regulations as of 2022 applicable to the Partnership, according to which the Partnership is taxed at the corporate tax rate of 23%.

Note 19 – Taxes on Income and Oil and Gas Profit Levy (Cont.):

A. Information regarding income tax rules and the main arrangements existing as of the date of the consolidated statement of financial position (Cont.):

4. Implementation of the provisions of Section 19 raised difficulties and questions of interpretation in view of the difference in the tax rates applicable to companies and individuals, which were discussed in the context of several legal proceedings.

On 28 June 2021 the Tel Aviv District Court issued a judgment, the key rulings in which were as follows:

a) With respect to payments for assessment differences made by the Partnership for the tax years 2015 and 2016, the Partnership is required to pay previous corporate holders balancing payments under the "counterbalancing the loss" option specified in the judgment, i.e., supplementation of the "surplus" amount that was paid for the individual holders who are subject to the higher tax rate.

On 1 July 2021, several holders filed a motion for clarification with the court, in which the court was moved to order how the payment should be made under the "counterbalancing the loss" option specified in the judgment as pertains to the payment of interest and indexation, and on 9 August 2021, the court ruled that lawful interest and linkage differentials would be added to the said payment, in accordance with the provisions of the Adjudication of Interest and Linkage Law, 5721-1961.

Accordingly, on 21 July 2022, the Partnership transferred to the account of Reznik Paz Nevo Trusts Ltd., which was appointed by the court as the trustee responsible for executing payment in accordance with the outline determined by the court for payment to body corporate eligible holders in each of the years 2015-2016, a sum of approx. ILS 39.7 million (approx. $11.4 million), including indexation and interest. The distribution was carried out by the trustee in September 2023.

Due to difficulties encountered by the trustee in finding some of the eligible holders, the court allowed the trustee to postpone the deadline for filing the summary report (the "**Summary Report**"). The Summary Report on behalf of the trustee was filed with the court on 30 April 2024. According to the Summary Report, distribution of the funds has been completed, and 99.7% of the total amount of compensation to the eligible holders of the Partnership and Avner have been distributed thereunder. Furthermore, in May 2024, the trustee returned the amounts that remained in the trust accounts to the Partnership. It is clarified that the legal proceeding on the matter concluded upon submission of the Summary Report.

b) With respect to 2017 through 2021 (regarding which the Partnership paid tax advances in accordance with the corporate tax rate and further thereto a "balancing" profit distribution was made considering the different tax rates of companies/individuals – see Section C below), it is the Partnership that will bear payment of the tax assessment differences, if any, but no balancing payments will be made in respect thereof. With regards to the future balancing and assessment differences payments, according to the judgment, the Partnership will continue to act in accordance with the arrangement according to which it has acted since tax year 2017, and the judgment thus grants all of the holders of the Partnership certainty as to the manner of the making of future balancing and assessment differences payments.

Note 19 – Taxes on Income and Oil and Gas Profit Levy (Cont.):

A. **Information regarding income tax rules and the main arrangements existing as of the date of the consolidated statement of financial position (Cont.):**

5. In December 2017, the Partnership and the Tax Assessor for Large Enterprises ("TALE") signed an agreement for collection of tax on account of the tax for which the unit holders are liable due to the estimated taxable income from the Partnership's business for 2017 (the "**2017 Tax Agreement**"). In the context of the 2017 Tax Agreement, the Partnership supplemented additional tax payments in accordance with the maximum tax rate which applies to individuals due to the aforesaid estimated taxable income, by way of deduction of withholding tax from balancing distributions made to participation unit holders (the withholding tax was deducted from the distributions made to participation unit holders who are individuals, and no withholding tax was deducted from distributions made to corporate participation unit holders). In the tax years 2018 to 2021, the Partnership acted similarly to the manner in which it acted pursuant to 2017 Tax Agreement, including with regard to calculation of the estimation of the Partnership's taxable income for the aforesaid tax years and supplementation of payments made by the Partnership in relation thereto in January for the following tax year.

It is clarified that the estimated taxable income calculated toward the end of the tax year for each of the years 2017-2021 was calculated based on estimates and assessments and financial figures that are unaudited.

B. **Income tax assessments and tax certificates:**

1. On 20 October 2021 the Partnership released final tax certificates for eligible holders for holding participation units of the Partnership and of Avner (the Partnership and Avner shall be referred to hereinafter as the "**Partnerships**") for the tax year 2015.

2. On 13 December 2017, the Partnership released temporary tax certificates for eligible holders for holding the Partnerships' participation units as of the tax year 2016. In the context of the disputes that emerged between the Partnership and the Tax Authority and disagreements on the amount of the Partnerships' taxable income for 2016, on 22 November 2018, assessments to the best of judgment were received from the Tax Authority, pursuant to Section 145(a)(2)(b) of the Income Tax Ordinance (in this section: the "**Tax Assessments**"), and on 14 March 2019 the Partnership filed a reasoned administrative objection to the Tax Assessments. Further to the administrative objection to the Tax Assessments filed by the Partnership, on 29 July 2020 the Partnerships received assessment orders under Section 152(b) of the Income Tax Ordinance (the "**Orders**") by the Tax Authority. The disputes, the subject matter of the Orders, primarily pertain to the method of recognition of financial expenses and additional expenses borne by the Partnerships in practice and the method of calculation of the capital gain from the sale of the Karish and Tanin leases. According to such Orders, the taxable business income of the Partnership and the Avner Partnership for 2016 is approx. $125.1 million and approx. $113.4 million, respectively (*in lieu* of approx. $106.6 million and approx. $94.9 million, respectively, as stated in the Partnerships' tax reports filed with the Tax Authority). The Partnerships' capital gain for 2016 is approx. $49.1 million and approx. $66.8 million, respectively (*in lieu* of approx. $7.5 million and approx. $18 million, respectively, as stated in the Partnerships' tax reports filed with the Tax Authority).

Note 19 – Taxes on Income and Oil and Gas Profit Levy (Cont.):

B. Income tax assessments and tax certificates (Cont.):

2. (Cont.):

The said amounts were translated from shekels to dollars according to the dollar exchange rate known as of 31 December 2024. Insofar as all of the Tax Authority's arguments are accepted, the Partnership will be required to make a supplementary tax payment (including interest and linkage differentials) on account of the tax owed by holders of participation units in the Partnerships in the sum of approx. $54.5 million. On 15 September 2020, the Partnership filed an appeal from the Orders with the Tel Aviv District Court. In this appeal, the grounds for the assessment were filed by the Tax Assessor on 9 December 2020, and in accordance with the decision of the court, notice of the grounds for the appeal was filed by the Partnership on 3 May 2021. A pretrial hearing on the appeal was held on 25 November 2021 and an additional pretrial hearing on the appeal is scheduled for 17 March 2025.

3. On 8 November 2018, the Partnership released temporary tax certificates for eligible holders for holding the participation units as of the tax year 2017. In the context of the disputes that emerged between the Partnership and the Tax Authority and disagreements on the amount of the Partnership's taxable income for 2017, the Partnership received a tax assessment to the best of judgment pursuant to Section 145(a)(2)(b) of the Ordinance, 5721-1961 (in this section: the "**Tax Assessment**"). The disputes primarily pertain to the interpretation of the manner of recognition of financial expenses and other expenses actually incurred by the Partnership, attribution of financial income deriving from exchange rate differences to assets under construction, the manner of implementation of Section 20(b) of the Law regarding the deduction of depreciation expenses; and the method of calculation of the capital gain from the sale of 9.25% (out of 100%) of the Partnership's interests in the Tamar and Dalit Leases. On 10 December 2020, the Partnership filed a reasoned administrative objection to the Tax Assessment, and on 21 December 2022, the Partnership received an assessment order for the 2017 tax year under Section 152(b) of the Income Tax Ordinance (the "**Order**"). According to such Order, the Partnership's taxable business income in 2017 is approx. $342.3 million (*in lieu* of approx. $204.3 million, as included in the Partnership's tax report submitted to the Tax Authority) and the Partnership's capital gain including deferred capital gain in 2017 is approx. $726.3 million (*in lieu* of approx. $590.2 million as stated in the Partnership's tax report submitted to the Tax Authority). The said amounts were translated from shekels to dollars according to the dollar exchange rate known as of 31 December 2024. On 22 January 2023, the Partnership filed an appeal from the Order with the Tel Aviv District Court. In this appeal, the grounds for the assessment were filed by the Tax Assessor on 30 May 2023, and according to the court's decision, notice of the grounds for the appeal was filed on 30 January 2024. A pretrial hearing on the appeal is scheduled for 17 March 2025.

As of the date of the consolidated financial statements and according to the said Order, and insofar as all of the Tax Authority's arguments are accepted, the Partnership will be required to make an additional tax payment (including linkage differentials and interest), on account of the holders of participation units of the Partnership, in the amount of approx. $120.8 million.

Note 19 – Taxes on Income and Oil and Gas Profit Levy (Cont.):

B. Income tax assessments and tax certificates (Cont.):

4. On 19 February 2020, the Partnership released temporary tax certificates for eligible holders for holding the participation units as of the tax year 2018. In the context of the disputes that emerged between the Partnership and the Tax Authority and disagreements on the amount of the Partnership's taxable income for 2018, on 24 March 2021, an assessment to the best of judgment was received from the Tax Authority, pursuant to Section 145(a)(2)(b) of the Income Tax Ordinance (in this section: the "**Tax Assessment**"), and on 10 June 2021, the Partnership submitted a reasoned administrative objection to the Tax assessment. On 28 March 2024, the Partnership received an assessment order for the 2018 tax year under Section 152(b) of the Income Tax Ordinance (the "**Order**"). According to such Order, the Partnership's taxable business income for 2018 is approx. $179.6 million (*in lieu* of approx. $137.1 million, as stated in the Partnership's tax report filed with the Tax Authority) and the Partnership's capital gain for 2018 is approx. $15.9 million, as declared in the report so filed thereby. The said amounts were translated from shekels to dollars according to the dollar exchange rate known as of 31 December 2024. On 17 April 2024, the Partnership filed an appeal from the Order with the Tel Aviv District Court. In this appeal, the grounds for the assessment were filed by the Tax Assessor on 30 September 2024, and according to the court's decision, the Partnership filed the notice of the grounds for the appeal on its behalf on 17 February 2025.
   The dispute primarily pertains to the interpretation of the method of recognition of financial expenses and additional expenses borne by the Partnership in practice, similarly to the disputes for which assessments to the best judgment were issued for 2016 and 2017, as specified above. As of the date of the consolidated financial statements and pursuant to the said Order, and insofar as all of the Tax Authority's arguments are accepted, the Partnership will be required to make a supplementary tax payment (including interest and linkage differentials), on account of holders of the Partnership's participation units, in the sum of approx. $15 million.
5. As of the date of approval of the consolidated financial statements, discussions are held and are expected to continue to be held, between the Partnership and the Tax Assessor with respect to the assessments for tax years 2016-2018.
6. In the Partnership's estimation, based on the opinion of its professional advisors, the chances of the Partnership's main arguments being accepted or at least the authorization of deduction of the expenses that are the subject matter of the disputes for tax years 2016-2018 in such years and/or in the following years, are higher than 50%.
7. On 14 July 2021, the Partnership released temporary tax certificates for eligible holders for holding participation units of the Partnership for 2019. According to the tax report filed by the Partnership for 2019, which is subject to audit by the Tax Authority, the taxable income is approx. ILS 573.6 million.
8. On 12 April 2022, the Partnership released temporary tax certificates for eligible holders for holding participation units of the Partnership for 2020. According to the tax report filed by the Partnership for 2020, which is subject to audit by the Tax Authority, the taxable income is approx. ILS 277.6 million.

Note 19 – Taxes on Income and Oil and Gas Profit Levy (Cont.):

B. Income tax assessments and tax certificates (Cont.):

9. On 30 April 2023, the Partnership released temporary tax certificates for eligible holders for holding participation units of the Partnership for 2021. According to the tax report filed by the Partnership for 2021, which is subject to audit by the Tax Authority, the Partnership's taxable business income for tax purposes is approx. ILS 919 million, the net capital gain mainly due to the sale of the Partnership's holdings in the Tamar and Dalit Leases (see Note 7C9B above) is approx. ILS 1,868 million, and the deferred capital gain for the sale of the Partnership's holdings in Tamar Petroleum (see Note 7C9C above) is approx. ILS 203.1 million.

10. It is clarified that in respect of each of the tax years 2016 through 2021, for which the Tax Authority's audit of the Partnership's tax reports has not yet been completed and/or final income tax assessments have not yet been issued, it may transpire, after completion of the Tax Authority's audit and issuance of final tax assessments (including after decisions in the administrative objections and/or appeals) that assessment differences exist, such that the final tax assessment is higher than the tax payments made by the Partnership (net of refunds paid thereto), in which case the Partnership will be required to pay the Tax Authority, on account of the holders, the tax balance that derives from the assessment differences, according to the tax rate calculated pursuant to Section 19.

It is clarified that in accordance with the provisions of the aforementioned judgment of 28 June 2021, no balancing payments will be made due to assessment differences as aforesaid, starting from tax year 2017 (if any). If in the future it transpires that the Partnership made advance payments in amounts exceeding the amounts required pursuant to the Law, the balance will be returned to the Partnership.

11. In view of the aforesaid, the issuance of final tax certificates for eligible holders for holding participation units of the Partnerships for the tax years 2016 through 2021 may be delayed, pending conclusion of the proceedings required to determine the final assessment. Upon determination of the taxable income amount for eligible holders for each tax year, a final certificate will be released for the purpose of calculation of the taxable income of eligible holders in respect of the aforesaid tax years, in accordance with the Income Tax Regulations.

12. It is clarified that according to the Tax Authority directives, participation unit holders will include in their tax reports, for each one of the years 2016 through 2021, their share in the Partnership's taxable income and their share in the tax amount that was paid by the Partnership, including tax that was deducted in the framework of the additional payments that the Partnership made in respect of such tax years, in accordance with the temporary tax certificates.

In addition, such unit holders will be required to amend their tax reports in accordance with the final tax certificates once released by the Partnership, in which case the amount of the refund or the payment to which the eligible holder is entitled or for which it is liable may decrease or increase as a result of the aforesaid, and accordingly, unit holders may also be required to repay the Tax Authority amounts that were received thereby based on the temporary certificate (subject to the relevant tax arrangement, as specified in Section A5 above).

Note 19 – Taxes on Income and Oil and Gas Profit Levy (Cont.):

B. Income tax assessments and tax certificates (Cont.):

13. The tax issues, including the implementation of the Law (as specified in Paragraph C below), which are related to the operations of the limited partnership have not yet been contemplated in case law of the Israeli courts (other than as stated below), and it is difficult to foresee or determine how the courts shall rule if and when said legal questions will be presented for their adjudication. In addition, in respect of some of the legal questions, it is difficult to foresee the position of the tax authorities. Since the Partnership's operations are subject to a unique tax regime, the changes that shall be caused due to an amendment of the law, case law or a change in the position of the Tax Authority, as aforesaid, may have material consequences on the tax regime applying to the Partnership.

14. Taxation in Cyprus:

In the amendment to the 2019 PSC a new mechanism was determined for the distribution of the natural gas output, which is based on a factor of the R-Factor type. According to such mechanism, the partners will be entitled to 55% of the annual revenues to be derived from the natural gas output, up to the coverage of all of their recognized capital and current expenditures (the "**Expenditure Coverage Output**"), whereas the balance (the "**Distributable Output**") will be distributed among the partners and the Government of Cyprus according to the R-Factor, the numerator of which consists of the total of Net Accrued Revenues and the denominator of which consists of the total of Accrued Capital Investments. Under the mechanism, the share of the Government of Cyprus in the Distributable Output linearly increases as a function of the factor and will reach the maximum rate when the R-Factor equals 2.5. For this purpose:

"**Net Accrued Revenues**" shall mean, the partners' share in revenues actually received from the gas output (including the Expenditure Coverage Output), net of the operating expenses borne by the partners in the area of the PSC, from the date of signing of the PSC (28 October 2008) to the end of the quarter preceding the day of the calculation (the "**Calculation Period**").

"**Accrued Capital Investments**" shall mean, the development expenses, production expenses of a capital nature (excluding operating expenses) and all exploration expenses, in respect of the area to which the PSC pertains, which were actually expended during the Calculation Period.

Note 19 – Taxes on Income and Oil and Gas Profit Levy (Cont.):

B. Income tax assessments and tax certificates (Cont.):

14. Taxation in Cyprus (Cont.):

The Partnership has received an approval from the Israel Tax Authority in respect of its operations in Block 12, in which, *inter alia*, the following provisions are specified: The Partnership operations in Block 12 shall not prejudice the Partnership's status as a "partnership" for the purposes of the Participation Unit Regulations; the income that shall be generated in Block 12 shall be considered income that is taxable in Israel and the tax shall be calculated according to Israeli law; insofar as exploration investments prove to be investments which do not justify production (dry well), said investments shall be recognized as an expense that will be spread over a five-year period; should the exploration investments prove to be recoverable investments, the Block 12 operations will be deemed a separate standalone sector for tax purposes, and the exploration investments will be recognized in Israel as an expense, solely against income from Cyprus (thus, expenses incurred by the Partnership in Cyprus for its operations in Block 12 will not be included in its tax reports in the context of expenses which may be deducted in Israel, but rather shall be deducted in the future from income that the Partnership will generate from Block 12), all subject to the law applying in Israel; the recognition method of income, including credit for taxes paid in Cyprus, will be effected according to the instructions of the Tax Authority Director, considering the conditions that will be relevant at the prevailing time and the conditions that were known at the time of issuance of the approval.

The Commissioner gave his approval, in accordance with Section 8 of Income Tax Regulations (Deductions from the Income of Petroleum Right Holders), 5716-1956, for application of the Regulations to the Partnership also in Block 12, subject to conditions prescribed by him.

C. The Levy Law:

In April 2011, the Knesset passed the Taxation of Profits from Natural Resources Law, 5771-2011 (in this section: the "**Law**"). Implementation of the Law has led to a change in the taxation rules applicable to the Partnership's revenues, which include, *inter alia*, the introduction of a oil and gas profits levy according to a mechanism specified in the Law and cancellation of the depletion deduction. The Law includes transitional provisions with respect to producing ventures or ones that commenced production by 2014.

The Law's main provisions are as follows:

1) The introduction of an oil and gas profits levy at a rate to be determined as stated below: The rate of the levy will be calculated according to a proposed R-factor mechanism, according to the ratio between the net aggregate revenues from the project and the aggregate investments as defined in the Law. A minimum levy of 20% will be collected commencing from the point when the R-factor ratio reaches 1.5, and will progressively increase up to a maximum rate when the ratio reaches 2.3. The maximum rate of the levy is 50% minus the product of 0.64 and the difference between the corporate tax rate set forth in Section 126 of the Income Tax Ordinance, 5721-1961 (in respect of each tax year) and a 18% tax rate. According to the corporate tax rate in 2024, the maximum levy rate is 46.8%.

Note 19 – Oil and Gas Profit Levy and Taxes (Cont.):

C. The Levy Law (Cont.):

1) (Cont.)

Additional provisions were also determined, *inter alia*, that the levy will be recognized as an expense for the purpose of calculation of income tax; the levy limits shall not include transmission plants that are used for export; the levy shall be calculated and imposed in relation to each lease separately (ring fencing); the charge of a recipient of payment from a holder of a petroleum interest which is calculated, *inter alia*, as a percentage of the petroleum produced, (the "**Derivative Payment**") in accordance with the amount of the Derivative Payment received thereby, while the amount of the levy attributed to the recipient of the Derivative Payment will concurrently be deducted from the levy amount owed by the holder of the petroleum right. In addition, the Law prescribes rules for consolidation or separation of petroleum ventures for purposes of the Law.

According to the Law, the holder of the petroleum right will be given fixed annual accelerated depreciation on a deductible asset, as defined in the Law, which is owned thereby, at a fixed rate of up to 10% (at the choice of the holder of the petroleum right) or, alternatively, variable current annual depreciation up to the amount of the taxable income in that year (and not more than 10%).

The provisions regarding the imposition of an oil and gas profits levy apply from 10 April 2011 and include transition provisions with respect to ventures that began commercial production by 1 January 2014.

a) A venture, the date of commencement of commercial production from which occurred before the commencement date, will be subject to the provisions of this Law with the following changes:
   (1) If a levy payment duty applies with respect to such venture in the tax year which the commencement date occurs, the rate of the levy in such tax year will be half of the rate of the levy that would have been imposed on the petroleum profits if not for the provisions of this paragraph and no more than 10%;
   (2) In the event that the levy coefficient in the tax year in which the commencement date occurs exceeds 1.5, rules were set for the manner of calculation of the levy coefficient in each tax year thereafter;
   (3) The rate of the levy which will be imposed on the petroleum profits of the venture in each of the tax years 2012 to 2015 will be equal to half the rate of the levy that would have been imposed on the petroleum profits as aforesaid, if not for the provisions of this paragraph.
b) A venture with respect to which the commercial production commencement date occurs in the period between the commencement date and 1 January 2014, will be subject, *inter alia*, to the following provisions:
   (1) The minimal levy coefficient will be at a rate of 2 instead of 1.5 and the maximal rate will be 2.8 instead of 2.3;
   (2) The accelerated annual depreciation rate regarding a deductible asset purchased in the years 2011-2013 will be 15% instead of 10%.

2) The Law includes provisions regarding the taxation of petroleum partnerships as of 2011 - see Paragraph A above.
3) Pursuant to the Law, the reporting partner of the petroleum project files reports that include, *inter alia*, accrued data regarding proceeds and investments for the purpose of calculating the R-factor, as specified in Section 1 above.

Note 19 – Oil and Gas Profit Levy and Taxes (Cont.):

C. The Levy Law (Cont.):

4) On 10 November 2021, the Knesset approved, in the second and third readings, amendment no. 3 to the Taxation of Profits from Natural Resources Law, 5782-2021 (the "**Amendment to the Law**"), according to which, *inter alia*, in the case of a dispute, it will be necessary to bring forward payment of the oil and gas profit levy in the sum of 75% of the amounts in dispute, subject to the decision of the Tax Assessor in the administrative objection (prior to completion of legal hearings on the dispute at the court, if any). In accordance with the said Amendment to the Law, 75% of the amounts in dispute might be brought forward.
5) Disputes have emerged between the TALE and the holders of interests in the Leviathan Leases regarding the levy reports for the Leviathan Leases for the years 2013-2015, which disputes chiefly pertained to the method of classification and quantification of data in the levy reports for the Leviathan Leases for the said years. In October 2018 the parties reached agreements with respect to the said disputes in the framework of a levy assessment agreement for the years 2013-2015, which, in October 2018, was sanctioned as a judgment by the Tel Aviv District Court.

   A levy assessment agreement was signed in December 2019 between the TALE and the holders of the interests in Leviathan, with respect to the levy reports for the years 2016-2017, and in October 2021 an assessment agreement was signed with respect to the Leviathan levy assessment for 2018.

   In December 2021, the Leviathan Partners received an assessment to the best of judgment for the Leviathan levy for 2019, which includes interpretive disputes with regards to the implementation of the provisions of the Law in the levy reports of the Leviathan Leases, including pertaining to recognition of payments borne by the holders of the interests in the leases in order to allow for the feasibility of export of natural gas to Egypt. An administrative objection to the assessment to the best of judgment was submitted to the TALE in March 2022. On 23 October 2022, an appeal was filed with the Tel Aviv District Court in respect of a levy assessment order for 2019, which was served on the Leviathan Partners in September 2022, and on 15 March 2022, the TALE's grounds for the assessment in the said appeal were received. According to the court's decision, notice of the grounds for the appeal was filed on 8 May 2024, and further thereto the court scheduled a pretrial hearing for 17 March 2025. On 6 January 2022, a Leviathan lease levy report for 2020 was submitted to the Tax Authority and on 31 December 2023 an assessment to the best of judgment was received from the Tax Authority pursuant to Section 14(B)(2) of the Law.

   The rate of the levy coefficient in the Leviathan Leases as of the date of the consolidated financial statements is lower than 1.5 and the effect of the above-mentioned assessments and disputes may be reflected in the levy amount calculation. However, even if the Tax Assessor's position is fully accepted, to date it is not expected to result in a coefficient rate higher than 1.5 from which actual collection of the levy begins.

   In addition, the interest holders in the Leviathan venture have reached agreements with the Tax Authority on the consolidation of the Leviathan Leases (north and south) as a single petroleum venture for purposes of the Law and the reports thereunder, according to the provisions of Section 8(a) of the Law.

Note 19 – Oil and Gas Profit Levy and Taxes (Cont.):

C. The Levy Law (Cont.):

5) (Cont.)

Disputes have emerged between the TALE and the holders of interests in the Tamar venture as to the Tamar venture levy reports for the years 2013-2020, pertaining, *inter alia*, to the dispute in connection with the sale of gas from the Tamar reservoir for the supply of gas by virtue of agreements signed between natural gas consumers and the Yam Tethys Partners, where, the Tax Authority's position is that the Tamar venture should be attributed notional revenues for the said supply of natural gas from the Tamar reservoir to customers with which the Yam Tethys Partners engaged, rather than determining the venture's revenues according to the actual proceeds received, in connection with the method of recognition and classification of exploration and construction investments in the Tamar SW reservoir and Tamar SW reservoir construction payments and recognition of various payments borne by the holders of the interests in the venture including costs borne thereby in order to allow for the feasibility of export of natural gas to Egypt (jointly: the "**Disputed Issues**"). It is noted that the disputes as to the levy reports for the years 2013-2020 are litigated between the parties in the context of appeals conducted before the Tel Aviv District Court. On 15 March 2022, TALE's grounds for the assessment were received for the appeal in respect of 2019. According to the court's decision, the notice of the grounds for the appeal was filed on 27 February 2025. It is clarified that insofar as it is determined in a final and binding proceeding that the Tax Authority's position regarding the aforesaid disputes is accepted in full, the Partnership may incur an additional liability of payment of an oil and gas profit levy to the Tax Authority and recording of an expense for the period until the sale of its rights in the Tamar Project (see Note 7C9 above) in an estimated amount, as of 31 December 2024, of approx. $39.2 million (which includes an amount of approx. $25.3 million for 2020).

In May 2022, the TALE issued an assessment to the best of judgment for the tax year 2020, which was mainly in respect of the same disputes that emerged in respect of 2013-2019. In July 2022, the holders of the rights in the Tamar venture filed an administrative objection with the TALE regarding the said assessment.

On 25 January 2023, a levy assessment order for 2020 was received. On 8 February 2023, an appeal was filed with the Tel Aviv District Court regarding the order issued to the Tamar venture for 2020, and on 30 April 2023, the TALE assessment reasoning for the appeal regarding 2020 was received. In accordance with the court's decision, the notice of the grounds for the appeal was filed on 27 February 2025.

On 30 December 2024, TALE issued an assessment to the best of judgment for the tax year 2020, which chiefly pertains to the same disputes as emerged between the years 2013 and 2020.

In this context, 14 November 2022 saw the issuance of the Jerusalem District Court judgment dismissing the claim against the State for restitution of the royalties paid by the Partnership and Chevron in respect of notional proceeds deriving from the supply of natural gas to Yam Tethys customers, as mentioned above (see Note 12E1 above).

On 8 February 2023, 75% of the levy liability was paid, amounting to approx. ILS 62.7 million (including interest and linkage) (approx. $18 million), per the Amendment to the Law as stated in Paragraph 4 above. Such sum was included in the other long-term assets item.

In the Partnership's estimation, based on the opinion of its legal counsel, the chances that the Partnership's arguments with respect to the Disputed Issues (including the issue of notional revenues) will be accepted are higher than the chances that they will be rejected, *inter alia,* taking the above judgement into consideration.

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 19 – Oil and Gas Profit Levy and Taxes (Cont.):

C. The Levy Law (Cont.):

6) Disputes have emerged between the TALE and the holders of interests in the Ashkelon venture and the Noa venture (jointly below, the "**Yam Tethys Ventures**"), in respect of the levy reports of the Yam Tethys Ventures for the years 2018-2019. The disputes in respect of the levy reports for the years 2018-2019 are litigated before the Tel Aviv District Court. The Partnership's share in the disputed amounts is approx. $1.9 million. In the Partnership's estimation, based on the opinion of its professional consultants, the chances that the Partnership's principal arguments will be accepted are higher than 50%.

7) **Taxation of Profits from Natural Resources Regulations:**
On 2 December 2020, the Taxation of Profits from Natural Resources Regulations (Advance Payments toward the Petroleum Profit Levy), 5781-2020 (in this section: the "**Advance Payments Regulations**") were published. The Advance Payments Regulations were promulgated pursuant to Sections 10(b) and 51 of the Levy Law and their purpose is to regulate advance payments to be made by the holders of petroleum rights in a petroleum venture. The Regulations mainly pertain to the determination of the calculation, payment dates of and reports on the advance payments.
As of the date of approval of the consolidated financial statements, for 2020 through 2022, the Partnership paid oil and gas profit levy advances (for revenues from sales of gas until the date of sale of the Tamar project) in the total amount of approx. $63 million, due to its rights in the Tamar Project (including the advance for 2020 in the sum of approx. $18 million as aforesaid). According to the Partnership's estimation and appraisals, based on the existing disputes with the Tax Authority, in 2022, oil and gas profit levy expenses were recorded in the amount of approx. $2.1 million, which are presented under the item of discontinued operations due to sale of Tamar Project as set out in Note 7C9 above.

D. Income taxes included in the statement of comprehensive income

	For the year ended		
	31.12.2024	**31.12.2023**	**31.12.2022**
Current taxes	(109.4)	(97.4)	(50.2)
Current taxes due to previous years	[37]30.4	(1.8)	-
Deferred taxes	(77.6)	(44.1)	(62.0)
Total income taxes	**(156.6)**	**(143.3)**	**(112.2)**
Taxes attributed to discontinued operations	*)	0.5	(3.8)
Total taxes attributed to continuing operations	**(156.6)**	**(142.8)**	**(116.0)**

***) Less than $0.1 million in expenses.**

[37] An update of the tax provision for the tax year 2023 in respect of full utilization of the Partnership's entitlement to deduct expenses according to data and details received from the operator, affecting in turn the update of the deferred taxes.

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 19 – Oil and Gas Profit Levy and Taxes (Cont.):

E. Deferred taxes

1. Composition:

	31.12.2024	31.12.2023
Deferred tax liabilities		
Trade and other receivables	1.4	4.3
Costs of bond issue	0.1	0.2
Oil and gas assets	355.5	296.1
Other long-term assets	35.0	14.6
Total	**392.0**	**315.2**
Deferred tax assets		
Share-based payment and social benefits	(0.5)	(0.8)
Short-term retirement obligation	-	(0.5)
Total	**(0.5)**	**(1.3)**
Deferred tax liabilities, net	**391.5**	**313.9**

2. Deferred taxes are calculated according to a tax rate of 23% (2023 – identical) based on the tax rate expected to apply on the reversal date.

3. Deferred tax liabilities were not recognized in respect of temporary differences totaling approx. $1.4 million (2023: approx. $1.3 million) which relate to investments in investee companies as these investments are not expected to be liquidated in the foreseeable future.

F. Theoretical tax

Below is a reconciliation between the tax amount that would have applied if all revenues and expenses, profits and losses in profit or loss were taxable at the statutory tax rate, and the amount of income taxes recognized in the statement of comprehensive income:

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 19 – Oil and Gas Profit Levy and Taxes (Cont.):

F. Theoretical Tax (Cont.):

	For the year ended		
	31.12.2024	31.12.2023	31.12.2022
Profit before income taxes from continuing operations	**681.2**	**574.3**	**594.6**
Statutory tax rate	23%	23%	23.0%
Tax calculated according to the statutory tax rate	**(156.7)**	**(132.1)**	**(136.8)**
Decrease (increase) in income taxes due to the following factors:			
Change of estimate of the tax basis for other long-term assets [38]	-	-	25.0
Difference between the income measurement basis as reported for tax purposes (ILS) and the income measurement basis as reported in the financial statements ($)	(0.6)	(7.3)	(3.9)
Taxes due to previous years	-	(1.8)	-
Others	0.7	(1.6)	(0.3)
Income taxes	**(156.6)**	**(142.8)**	**(116.0)**

Note 20 – Transactions and Balances vis-à-vis Interested Parties, Related Parties and Control Holders:

A. Balances:

	31 December 2024		31 December 2023	
	Parent Companies	Related Parties and Other Interested Parties	Parent Companies	Related Parties and Other Interested Parties
Trade and other receivables	-	17.6	2.6	10.6
Other long-term assets	0.3	12.0	0.3	21.1
Trade and other payables	2.4	1.5	3.6	1.6
The highest current debt balance this year	0.2	-	0.1	-

[38] As a result of a change in the projected method of recovery of the value of a financial asset.

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 20 – Transactions and Balances vis-à-vis Interested Parties, Related Parties and Control Holders (Cont.):

B. Transactions with related parties and interested parties:

For the year ended 31 December 2024:

	Note	Parent Companies	Related parties and Other Interested Parties
Overriding royalty expenses (continued operations)	15	*)	14.4
Overriding royalty revenues (discontinued operations)	7C9	0.8	-
Directors' remuneration		-	0.3
Delek Group guarantee fee	20D 12N4	0.4	-
Rent	20E2	0.3	-

*) Less than $0.1 million in revenue.

For the year ended 31 December 2023:

	Note	Parent Companies	Related parties and Other Interested Parties
Gas sale revenues	14, 12C7	**)	-
Overriding royalty expenses (continued operations)	15	-	14.1
Overriding royalty revenues (discontinued operations)	7C9	1.1	-
Directors' remuneration		-	0.5
Delek Group guarantee fee	20D, 12D4	0.4	-
Rent	20E2	0.4	-

**) Less than $0.1 million in revenue.

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 20 – Transactions and Balances vis-à-vis Interested Parties, Related Parties and Control Holders (Cont.):

B. Transactions with related parties and interested parties (Cont.)

For the year ended 31 December 2022:

	Note	Parent companies	Related parties and other interested parties
Gas sale revenues	14, 12C7	0.2	-
Overriding royalty expenses (continued operations)	15	0.1	15.1
Overriding royalty revenues (discontinued operations)	7C9	2.6	-
Directors' remuneration		-	0.3
Delek Group guarantee fee	20D 12D4	0.4	-
Rent	20E2	0.4	-

C. Terms of Employment of the CEO of the General Partner, Mr. Yossi Abu ("Mr. Abu" or the "CEO"):

Mr. Yossi Abu has served as CEO of the General Partner in a full-time position (100%) since 1 April 2011.

On 28 September 2022, the compensation committee and the board of directors decided, after reopening the discussion thereon, by way of "overruling", to approve the updated terms of office and employment for the CEO, despite the objection of the meeting of the holders of the Partnership's participation units held on 21 September 2022. In the matter of the issuance of a motion for discovery and inspection order before filing a derivative claim in connection with approval of Mr. Abu's updated terms of office and employment by the compensation committee and the board of directors by way of "overruling", see Note 12E8 above.

Below is a brief description of the main updated terms of office and employment:

1. The CEO's monthly salary as of 31 December 2024 is ILS 215.8 thousand (in gross terms) updated according to changes in the Consumer Price Index (positive only) every 3 months.
2. In addition to his monthly salary, Mr. Abu is entitled to standard social benefits, a study fund, a pension plan, annual leave days (including entitlement to leave cash-in), sick days and recuperation pay. The Partnership provides Mr. Abu with a car, as is standard for his position, and bears any and all expenses entailed by the use of the car. The value of the use of the car is grossed-up and paid by the Partnership. Mr. Abu is also entitled to additional related benefits, such as his inclusion in officer indemnification, exemption and insurance arrangements, communication expenses (mobile telephone, internet, newspapers and payment of expenses in respect of reasonable use of his home phone), executive physicals, private health insurance at the Partnership's expense, participation in professional continuing education, severance pay (since 2016 Mr. Abu has not signed Section 14 of the Severance Pay Law, 5723-1963, and therefore the severance pay to which he is entitled is pursuant to the law as aforesaid), receipt of loans from the Partnership, reimbursement of expenses for the performance of his duties, and reimbursement of per diem expenses during foreign travel on behalf of the Partnership.

Note 20 – Transactions and Balances vis-à-vis Interested Parties, Related Parties and Control Holders (Cont.):

C. **Terms of Employment of the CEO of the General Partner, Mr. Yossi Abu ("Mr. Abu"** or the **"CEO") (Cont.)**

2. (Cont.)

   The Partnership may grant Mr. Abu, each year, an annual bonus for the previous calendar year, provided that he shall be employed by the Partnership at least 3 months in such year, and a special bonus, a retention bonus, and in the case of separation from employment, an adjustment bonus and a retirement bonus, all in accordance with the compensation policy as updated from time to time. The parties may terminate the Employment Agreement at any time by giving prior written notice of 6 months. In addition, the employment agreement includes provisions regarding confidentiality and a non-compete clause for a period of 12 months.

3. The term of Mr. Abu's employment is until 30 April 2027.
4. The CEO was granted on 27 July 2022 (the date of grant), for no consideration, 3,295,599 non-marketable options exercisable for 3,295,599 participation units. The allocation was made in accordance with the compensation policy and the option plan which was submitted to the Income Tax on 4 August 2022 pursuant to Section 102 of the Income Tax Ordinance [New Version], 5721-1961, and which was adopted by the board of directors on 27 July 2022. The options will vest in 3 equal annual installments, commencing from 1 August 2022. The exercise price of the first installment is ILS 8.66, which is equal to the average closing price of the participation units on TASE at the close of the 30 trading days that preceded the date of grant. The exercise price of the remaining two installments will increase by 5% each year relative to the previous year.
   The economic value of the options at the grant date totaled approx. ILS 9.8 million, and the annual economic value, i.e., the economic value of the options at the grant date divided by three, totaled approx. ILS 3,267 thousand.
   The said economic value of the options was calculated according to the binomial model based on the following assumptions: (1) participation unit price of ILS 9.35; (2) exercise price of each option (adjusted to a profit distribution) calculated according to ILS 8.66 for the first installment, ILS 9.1 for the second installment, and ILS 9.55 for the third installment); (3) standard deviation rate of 49.9%; (4) risk-free interest rate of approx. 2.31%; (5) expiration date: 26 July 2027.
5. In 2024, Mr. Abu received an annual bonus of approx. ILS 3,282 thousand for 2023 (in 2023 Mr. Abu received an annual bonus of approx. ILS 2,932 thousand for 2022 and in 2022 Mr. Abu received an annual bonus of approx. ILS 2,090 thousand for 2021, as well as a special bonus equal to one gross monthly salary, in the sum of approx. ILS 160 thousand).
6. On 9 January 2025, the participation unit holders' meeting decided not to approve a grant to Mr. Abu of equity-based compensation at the rate of 5% of the issued share capital of NewMed Balkan, and to fund his proportionate share in the initial investment costs, which include the first two wells to be drilled in the area of the Bulgaria license, up to a sum of $173 million (100%) (the "**Initial Investment**"), according to the conditions specified in the relevant notice of meeting report, in deviation from the Partnership's compensation policy (the "**Equity Compensation**"). Notwithstanding the objection of the unit holders' meeting as aforesaid, on 9 March 2025 the compensation committee and the board of directors unanimously decided to approve the granting of updated Equity Compensation to Mr. Abu, based on the conditions of the Equity Compensation and with certain changes that are favorable to the Partnership, primarily: (a) Reduction of the sum of participation in the

Note 20 – Transactions and Balances vis-à-vis Interested Parties, Related Parties and Control Holders (Cont.):

C. Terms of Employment of the CEO of the General Partner, Mr. Yossi Abu ("Mr. Abu" or the **"CEO") (Cont.)**

funding of Mr. Abu's proportionate share in the Initial Investment cost to a maximum of $100 million (in lieu of $173 million as aforesaid); (b) Addition of mechanisms to secure the Partnership's rights through a trustee and pledge of the shares; and (c) Addition of a right for the Partnership to purchase the shares from Mr. Abu in case of termination of his employment.

Note 20 – Transactions and Balances vis-à-vis Interested Parties, Related Parties and Control Holders (Cont.):

D. Further to Note 7C2 in respect of the Partnership's exploration rights in Block 12 in Cyprus, as a condition for the endorsement, the Cypriot Government requested, in accordance with terms of the PSC, that a performance guarantee, unlimited in amount, shall be provided in favor of the Republic of Cyprus to secure the fulfillment of all of the undertakings under the PSC (the "**Guarantee**"), that was provided on the date of transfer of the rights by Delek Group. Delek Group agreed to provide the Guarantee, against payment of a guarantee fee by the Partnership (see Note 12D4 above), as approved by the general meeting of participation unit holders in the Partnership, and subject to several conditions as summarized below:

1. The purchase of insurance coverage to the satisfaction of Delek Group.
2. In addition, the Partnership undertook that from the date of provision of the Guarantee and for as long as the Guarantee is in effect, the following provisions shall apply:
   a) In the event that the Partnership sells its rights to Block 12, the Partnership will act to release Delek Group from the Guarantee, or from its relative share (in the event of any partial sale of the rights);
   b) Delek Group will be entitled to demand that the Partnership, by written notice, at any time and at its discretion, shall cause the release of Delek Group from the Guarantee, or in the alternative, shall sign an agreement for the sale of the rights in Block 12;
   c) The Partnership will indemnify Delek Group for any damage of any kind whatsoever and/or expenses of any kind whatsoever and/or payments that shall be incurred by Delek Group with no amount limit;
   d) Since the undertakings of the Partnership and Chevron Cyprus under the PSC are jointly and severally, an agreement was signed between Delek Group and Chevron Cyprus, and the parent company of BG Cyprus, regarding division of the responsibilities and mutual indemnification among themselves, in respect of the operations in Block 12, according to the respective holding percentage of the Partnership, Chevron Cyprus and BG Cyprus in the rights in Block 12;
   e) The Partnership shall provide Delek Group with a copy of any resolution and/or notice by the Cypriot authorities in connection with the PSC and/or the Guarantee and will also act to inform Delek Energy of any event that may, to the best of its knowledge, result in the enforcement of the Guarantee. According to the PSC, any change in control of the Delek Group or the Partnership, directly or indirectly, is subject to advance approval by the Republic of Cyprus.

E. Additional information regarding transactions with related parties and interested parties:

1. See Notes 12B and 15 above regarding the payment of royalties by the Partnership to its control holders.
2. The Partnership entered with Delek Group into a lease agreement in connection with the offices used by the General Partner and the Partnership. In 2024, the Partnership recorded approx. $0.3 million in expenses in the statement of comprehensive income for its share in the aforesaid expense.
3. On 24 June 2024, the compensation committee, in accordance with the compensation policy, approved the Partnership's engagement in a D&O insurance policy, which covers the officers of the General Partner, the Partnership and its subsidiaries, including the Partnership's CEO, for a 17-month period from 1 July 2024 until 30 November 2025, with a total liability cap of $270 million per claim and in the aggregate for the insurance period, all under terms and conditions that comply with the compensation policy.

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 20 – Transactions and Balances vis-à-vis Interested Parties, Related Parties and Control Holders (Cont.):

E. **Additional information regarding transactions with related parties and interested parties (Cont.):**

4. For the commercial natural gas supply arrangement between the Yam Tethys Partners and the Leviathan Partners, see Note 12C7 above.
5. On 26 July 2021, the General Partner's board of directors approved the pledge of approx. 4.5% of the Partnership's participation unit capital held by the General Partner to secure bonds issued by Delek Group, which (indirectly) holds all the General Partner's issued share capital. As of the date of approval of the consolidated financial statements, such pledge has been removed.
6. Regarding the renewable energy collaboration with Enlight and the personal interest of Mr. Abu in the engagement, see Note 12G1 above.
7. Regarding NewMed Balkan's engagement in an agreement for the purchase of a 50% interest in a license in Bulgaria, and Mr. Abu's personal interest in NewMed Balkan, see Notes 7C7 and 20C6 above.
8. In the report year, the Partnership had additional engagements in which Delek Group has a personal interest, which are classified as negligible transactions, such as the receipt of "*Dalkan*" services (automatic billing for fueling) from Delek the Israel Fuel Corporation Ltd., an affiliate of Delek Group, receipt of services from the NYX Herzliya Hotel of the Fattal Hotels Chain, an accounting with Delek Group and with Mr. Yitzhak Sharon (Tshuva) in connection with legal costs in the context of a motion for certification of a class action (see Note 12E6).

Note 21 – Financial Instruments:

A. **Method for determining the fair value of the financial instruments:**

Due to their nature, the fair value of financial instruments, such as cash and cash equivalents, trade receivables, trade and other receivables and trade and other payables, is an adequate approximation to their book value.

Short-term non-negotiable assets and liabilities bearing interest with a fixed maturity date	-	Their book value reflects their fair value as of the date of the consolidated statement of financial position, since the average interest rate thereon is not materially different from the interest rate customary in the market for similar items as of the date of the consolidated statement of financial position.
Short-term receivables and payables	-	The book value constitutes an approximation of their fair value.
Assets and liabilities with no maturity date	-	The fair value is determined according to the payable amount per demand on the report date.
Assets and liabilities at variable interest	-	The fair value of assets and liabilities at variable interest, due to which no material changes have occurred, was determined based on the contractual conditions of the instrument.

B. **Fair value hierarchy:**

For disclosure purposes, the Partnership classifies fair value measurements under one of the levels of the fair value hierarchy, which reflects the significance of the data used when making the measurements.

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 21 – Financial Instruments (Cont.):

B. Fair value hierarchy (Cont.):

The following table presents fair value hierarchy figures for the financial instruments measured at fair value that were recognized in the statement of financial position:

	31.12.2024			
	Level 1	Level 2	Level 3	Total
Financial assets at fair value through profit or loss:				
Future production-based royalties from the Karish and Tanin leases (see Note 8B above)	-	-	278.0	278.0

	31.12.2023			
	Level 1	Level 2	Level 3	Total
Financial assets at fair value through profit or loss:				
Future production-based royalties from the Karish and Tanin leases (see Note 8B above)	-	-	273.2	**273.2**
Loan to Energean in the context of the sale of the Karish and Tanin leases (see Note 8B above)	-	46.2	-	**46.2**
Total financial assets at fair value through profit or loss:	-	**46.2**	**273.2**	**319.4**

Adjustment due to fair value measurements classified as Level 3 under the fair value hierarchy of financial instruments:

	For the year ended 31 December	
	2024	2023
Balance as of January 1	**273.2**	**320.8**
Proceeds	(55.0)	(36.7)
Proceeds receivable	(1.1)	(5.9)
Remeasurement recognized in profit or loss	60.9	(5.0)
Balance as of December 31	**278.0**	**273.2**

C. Fair value of financial instruments:

The fair value of the financial instruments presented in the financial statements matches or approximates their book value, with the exception of the issued bonds of Leviathan Bond, as stated in Note 10B:

	Fair Value	Book Value
Bonds:		
As of 31 December 2024	1,589.6	1,625.6
As of 31 December 2023	1,652.1	1,735.1

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 21 – Financial Instruments (Cont.):

D. Groups of financial instruments:

	As of 31 December	
	2024	2023
Financial assets:		
Cash and cash equivalents	51.2	29.1
Deposits	333.8	259.5
Trade receivables	209.6	194.5
Trade and other receivables	127.5	155.7
Other long-term assets	227.2	229.2
Total financial assets	**949.3**	**868.0**
Financial liabilities:		
Trade and other payables	2.0	1.5
Short-term liability to a banking corporation	-	80.0
Bonds (see Note 10B above)	1,625.6	1,735.1
Total financial liabilities	**1,627.6**	**1,816.6**

E. **Risk management policy:**

The Partnership's transactions expose the Partnership to various financial risks, such as: market risk (including foreign currency risk, fair value risk due to interest rate, linkage to the U.S. CPI, price risk, credit risk, liquidity risk and cash flow risk due to the exposure to the SOFR interest rate. The general risk management plan of the Partnership focuses on acts to reduce the possible negative effects on the Partnership's financial performances. The Partnership at time uses derivative financial instruments to hedge certain exposures to risks.

F. **Market risks:**

Market risks derive from the risk that the fair value or future cash flow of a financial instrument will change as a result of changes in market prices. Market risks include three types of risks: currency risk, price risk and fair value risk due to interest rate as follows:

1. **Currency risk**:
   Exchange rate risk mainly stems from assets, liabilities and expenses denominated in ILS. The risk mainly stems from the tax advances which the Partnership pays based on the taxable income for tax purposes in ILS, as well as the liability for deferred taxes, and expenses in ILS which expose the Partnership to cash flow risk and profit or loss risk.
2. **Interest risk**:
   Interest risk stems from the risk that the fair value or the future cash flows of a financial asset will change as a result of changes in the market interest rates. Financial instruments that bear variable interest expose the Partnership to a cash flow and profit and loss risk due to changes in the interest rate. The Partnership's credit facility, as provided in Note 10D above, is based on the SOFR interest.

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 21 – Financial Instruments (Cont.):

F. Market risks (Cont.):

2. Interest risk (Cont.):

The following table presents the balances of financial instruments that bear variable interest according to their book value:

	As of 31 December	
	2024	2023
Financial instruments at variable interest:		
Assets:		
Deposits in banks (including cash and cash equivalents)	373.8	287.0
Trade and other receivables in the context of joint ventures	39.8	27.1
Total	**413.6**	**314.1**
Liabilities:		
Short-term liability to a banking corporation	-	80.0

The following table presents the effect of the change in the event of a 0.5% change in the base interest rate, and with respect to a full year, with the other variables remaining constant:

	Effect on Profit or Loss	
	Increase in Interest Rate	Decrease in Interest Rate
	0.5%	**0.5%**
2024	2.1	(2.1)
2023	1.2	(1.2)

The following table presents tests of sensitivity to a change in capitalized interest, with the other variables remaining constant:

	As of 31 December 2024				
	Profit (Loss) from Change in Capitalized Interest				
	2%	1%	**Fair Value**	-1%	-2%
Future production-based royalties from the Karish and Tanin leases (see Note 8B above)	(20.1)	(10.4)	**278.0**	11.4	23.7

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 21 – Financial Instruments (Cont.):

F. Market risks (Cont.):

2. Interest risk (Cont.):

	As of 31 December 2023				
	Profit (Loss) from Change in Capitalized Interest				
	2%	1%	Fair value	-1%	-2%
Future production-based royalties from the Karish and Tanin leases (see Note 8B above)	(20.7)	(10.8)	**273.2**	11.8	24.6
Loan to Energean in the context of the sale of the Karish and Tanin leases (see Note 8B above)	(0.3)	(0.1)	**46.2**	0.2	0.3
Total	**(21.0)**	**(10.9)**	**319.4**	**12.0**	**24.9**

Further to Note 8B as relating to the sale of the Partnership's interests in the Karish and Tanin leases, the Partnership recorded royalties receivable from the Karish and Tanin leases in the sum of approx. $278.0 million (as of 31 December 2023 – approx. $273.2 million) and amounts receivable in connection with a loan provided to Energean in the context of the sale of the Karish and Tanin leases in the sum of approx. $46.2 million as of 31 December 2023.

3. **Price risk**:

Natural gas and condensate price risk:

Agreements for the supply of natural gas determine the gas price according to price formulas that include various linkage components, primarily including linkage to the Brent barrel price, to the Electricity Production Tariff, to the shekel-dollar exchange rate, to the TAOZ Tariff, and in one of the agreements also to the Crack Spread Index. All the natural gas supply agreements into which the Partnership has entered, except contracts that include a non-linked fixed price, also specify, along with the price formulas, price floors that somewhat limit the exposure to fluctuations in the linkage components. Nevertheless, there is no certainty that the Partnership will be able to keep stipulating such price floors in new agreements signed thereby in the future.

Furthermore, a drop in the Brent prices and/or electricity tariffs and/or a change in the shekel-dollar exchange rate, may have an adverse effect on the Partnership's revenues from present and future gas sale agreements.

The frequent methodological changes made by the Electricity Authority to the method of calculation of the Electricity Production Tariff make it difficult to predict the same, and may lead to disputes between the gas suppliers and the customers in connection with the method of calculation thereof. In this context it is noted that with respect to some of the private power plants (including plants that were sold by the IEC)), the Electricity Authority introduced regulation by the name of SMP (system marginal price), whereby every 30 minutes, the wholesale electricity price is determined according to the marginal cost for production of one additional kilowatt-hour in the economy, based on half-hour tenders conducted by the manager of the electricity system between the various power producers each day. The said pricing method may have an effect on the prices of the natural gas that shall be sold by the Partnership to power producers in the domestic market in a case where the gas prices in future contracts are linked to the said pricing.

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 21 – Financial Instruments (Cont.):

F. Market risks (Cont.):

3. Price risk (Cont.):

Natural gas and condensate price risk (Cont.):

The following table presents extended sensitivity tests of future production-based royalties from the Karish and Tanin leases (see Note 8B above) in relation to a change in natural gas and condensate prices, all the other variables being constant:

As of 31 December 2024								
Profit (Loss) from Change in the Natural Gas Price[39]								
30%	20%	10%	5%	Fair Value	-5%	-10%	-20%	-30%
2.1	(16.3)	(28.4)	(35.2)	**278.0**	(7.8)	(15.7)	(28.2)	(46.8)

As of 31 December 2024								
Profit (Loss) from Change in the Condensate Price								
30%	20%	10%	5%	Fair Value	-5%	-10%	-20%	-30%
(20.7)	(25.7)	(31.5)	3.5	**278.0**	(3.5)	(7.1)	(14.1)	(21.1)

As of 31 December 2023								
Profit (Loss) from Change in the Natural Gas Price[41]								
30%	20%	10%	5%	Fair Value	-5%	-10%	-20%	-30%
39.5	25.3	14.3	7.1	**273.2**	(10.9)	(14.5)	(30.4)	(15.8)

As of 31 December 2023								
Profit (Loss) from Change in the Condensate Price								
30%	20%	10%	5%	Fair Value	-5%	-10%	-20%	-30%
20.4	13.6	6.7	3.4	**273.2**	(3.6)	(10.7)	(17.7)	(24.7)

[39] The negative effect deriving from an increase in the natural gas price and/or the condensate price affects the date of recovery of the investment in the project, and consequently leads to a reduction of the royalties payable to the Partnership, as set out it Note 8B above.

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 21 – Financial Instruments (Cont.):

G. Credit risks:

Credit risk is the risk that one party to financial instruments will cause the other party a financial loss by failing to comply with its obligations. A credit risk derives mainly from trade accounts receivable and deposits in banks. The trade receivables balance as of 31 December 2024 is a current balance. The Partnership's principal customers in the report period are Blue Ocean which accounted for ~62% of the sales in the report period, and NEPCO which accounted for ~26% of the sales in the report period (58% and 27% of the sales in 2023, respectively). In light of past experience and since their current balances are partly backed by the collateral they have provided, the Partnership estimates that the credit risk deriving from natural gas sales supplied to Blue Ocean and NEPCO is low. However, in view of the security and economic situation in the countries of the region, this risk has increased.

The following table presents the turnover and trade receivables, the value of which has not been impaired:

	Revenues for the Year	Trade Receivables as of 31 December 2024		
	Ended 31 December 2024	Total	Current Balance	Disputed Balance
NEPCO	291.2	55.4	55.4	-
Blue Ocean	703.2	142.2	142.2	-
Other customers	141.9	12.0	12.0	-
Total	**1,136.3**	**209.6**	**209.6**	-

	Revenues for the Year	Trade Receivables as of 31 December 2023		
	Ended 31 December 2023	Total	Current Balance	Disputed Balance
NEPCO	296.3	45.8	45.8	-
Blue Ocean	629.5	128.6	128.6	-
Other customers	168.6	20.1	20.1	-
Total	**1,094.4**	**194.5**	**194.5**	-

1) The Partnership has cash and cash equivalents and deposits that are mostly held with large banking corporations in Israel. The Partnership expects no material losses due to the credit risk deriving from these balances.
2) The balance of the financial assets presented in the statement of financial position, Paragraph D above, reflects the maximal exposure deriving from the credit risk as of the date of approval of the consolidated financial statements.

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 21 – Financial Instruments (Cont.):

G. Credit risks (Cont.):

3) The Partnership has amounts receivable from a company accounted for at equity in the sum of approx. $27.3 million (2023: approx. $30.1 million), which were included under trade and other receivables and other long-term assets items. Amounts receivable are measured at amortized cost and discounted at an interest[40] reflecting the credit risk that reflects the business environment of the company accounted for at equity, based on the Partnership's evaluations on the date of recovery thereof.

H. Liquidity risk:

Liquidity risks result from the management of the Partnership's working capital, from the financial expenses and from principal repayments of the debt instruments. A liquidity risk is the risk that the Partnership will have difficulties in fulfilling undertakings related to its financial liabilities.
The management of the General Partner reviews the expected cash flows on a monthly basis for a 12-month period at least, as well as information regarding the cash balances and the deposits.
The Partnership strives to ensure that the cash and the deposits, together with the forecasted income, shall ensure the fulfillment of its obligations on the respective maturity dates thereof and to further maintain their real value according to the Partnership Agreement. The foregoing does not take into account the effects of extreme scenarios that cannot be foreseen.

The following table presents the contractual maturities of the financial liabilities subsequent to the date of the consolidated statement of financial position (according to the various denominated settlement values, which are different from their book value), based on the interest rates and exchange rates as of the date of the consolidated statement of financial position:

2024	Up to 3 Months	More than 3 Months and up to 1 Year	1-3 Years	3-5 Years	More than 5 Years	Total
Trade and other payables	2.0	-	-	-	-	**2.0**
Bonds	-	694.5	693.8	-	605.7	**1,993.9**
Total	**2.0**	**694.5**	**693.8**	-	**605.7**	**1,995.9**

[40] The cap rate used in determining the fair value of the receivables was estimated at 22.0% as of 31 December 2024 (31 December 2023: 22.8%).

Notes to the Consolidated Financial Statements as of 31 December 2024 (Dollars in millions)

Note 21 – Financial Instruments (Cont.):

H. Liquidity risk (Cont.):

2023	Up to 3 Months	More than 3 Months and up to 1 Year	1-3 Years	3-5 Years	More than 5 Years	Total
Trade and other payables	1.5	-	-	-	-	**1.5**
Short-term liability to a banking corporation	80.0	-	-	-	-	**80.0**
Bonds	-	112.9	770.6	693.8	605.7	**2,182.9**
Total	**81.5**	**112.9**	**770.6**	**693.8**	**605.7**	**2,264.4**

Changes in liabilities deriving from financing activity:

	Balance as of 31 Dec. 2023	Cash Flow	Effect of Changes in Amortized Cost	Other Changes	Balance as of 31 Dec. 2024
Bonds	**1,735.1**	(113.8)	4.3	-	**1,625.6**
Distributable profit declared	-	(250.3)		250.3	-
Short-term liability to a banking corporation	**80.0**	(80.0)	-	-	-
Total liabilities deriving from financing activity	**1,815.1**	**(444.1)**	**4.3**	**250.3**	**1,625.6**

	Balance as of 31 Dec. 2022	Cash Flow	Effect of Changes in Amortized Cost	Other Changes	Balance as of 31 Dec. 2023
Bonds	**2,155.8**	(425.4)	4.5	-	**1,735.1**
Distributable profit declared	**50.0**	(260.0)	-	210.0	-
Short-term liability to a banking corporation	-	80.0	-	-	**80.0**
Total liabilities deriving from financing activity	**2,205.8**	**(605.5)**	**4.5**	**210.0**	**1,815.1**

Note 22 – Material Subsequent Events:

A. For details about a report on reserves and contingent resources in the Leviathan Leases, see Note 7C1(d).

B. For details about the submission of an updated development plan for the Leviathan reservoir at an annual scale of ~23 BCM, see Note 7C1(c)(1).

C. For details about approval of an updated development plan, amendment of a product sharing agreement (PSC) and signing of a non-binding memorandum of understandings for the export of natural gas from the Aphrodite reservoir, see Note 7C3.

D. For details about approval by the general meeting of entry into a contingent agreement for acquisition of interests in a Petroleum Asset in Bulgaria, see Note 7C8.

E. For details about the court's approval of the agreed motion for remunerated withdrawal from a motion for class action certification, see Note 12E4.

F. For details about the entry into effect of agreements in connection with contribution to the funding of an upgrade of the system for transmission to Egypt and the gas transmission, see Note 12F2(c).

G. For details about the decision of the General Partner's compensation committee and board of directors to approve the grant of updated equity compensation to Mr. Abu, see Note 20C6.

H. For details about the approval of profit distribution by the board of directors of the General Partner of the Partnership in the sum of $60 million, see Note 13C2.

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Part D

Additional details about the corporation

Name of the Corporation:	NewMed Energy – Limited Partnership[1]	**Corporation No. at the Registrar:**	550013098
Address:	19 Abba Eban Blvd., Herzliya, 4672537		
Telephone:	09-9712424	**Facsimile:**	09-9712425
Balance Sheet Date:	31 December 2024	**Report Date:**	9 March 2025

Below are additional details regarding the Partnership, according to the Securities Regulations (Periodic and Immediate Reports), 5730-1970 (the "**Reports Regulations**"):

Regulation 8B: **Valuations**

For details regarding a very material valuation on receipt of royalties from the I/16 Tanin and I/17 Karish leases which are owned by Energean Israel Ltd., see Annex B to the Board of Directors' Report (Chapter B of this Report) and Note 8B to the financial statements (Chapter C of this Report). The said valuation is attached at the end of this Report.

Regulation 9D: **Status of liabilities report according to payment dates**

Concurrently with the release of this report, the Partnership is releasing an immediate report regarding the status of the liabilities of the Partnership and the companies consolidated in its financial statements, according to payment dates, which constitutes an integral part of this Report.

Regulation 10A: **Summary of the Partnership's statements of comprehensive income for each one of the quarters in 2024 and for 2024 in its entirety**

See Section 2B of Part One of the Board of Directors' Report (Chapter B of this Report).

Regulation 10B: **Use of the proceeds from securities with reference to the purposes of the proceeds according to the prospectus**

On 30 May 2022, the Partnership released a shelf prospectus and on 29 May 2024 the period for offering securities thereunder was extended until 30 May 2025. For further details, see the Partnership's immediate reports of 30 May 2022 and 29 May 2024 (Ref.: 2022-01-055113 and 2024-01-053836, respectively), the information appearing in which is incorporated herein by reference.

[1] The Partnership's previous name was Delek Drilling – Limited Partnership. On 21 February 2022, the Partnership's name was changed to its current name.

It is noted that the Partnership made no public offering under a prospectus in recent years.

<u>Regulation 11</u>: <u>List of the Partnership's investments in subsidiaries and companies accounted for at equity thereof[2]</u>

Name of the company	Type of security	No. of shares	Total par value	Share value in the Partnership's separate financial statement as of 31 December 2024	Price of the shares listed on TASE as of 31 December 2024 (in Agorot)	% of the holding in the capital, in voting and in the authority to appoint directors	Balance of loans to subsidiaries and to companies accounted for at equity as of 31 December 2024 (U.S. Dollars ("$") in thousands)	Main terms of the loans		
								Final maturity date	Linkage terms	Additional details
Yam Tethys Ltd.[3]	Ordinary shares	48,500	ILS 48,500	-	-	48.5	-	-	-	-
Leviathan Bond Ltd. ("Levithan Bond") [4]	Ordinary shares	100	ILS 100	-	-	100	100,000	June 2030	Dollar	[5]-
Leviathan Transmission System Ltd.[6]	Ordinary shares	45,340	ILS 4,534	-	-	45.34	-	-	-	-
NBL Jordan Marketing Limited[7]	Ordinary shares	4,534	$4,534	-	-	45.34	-	-	-	-

[2] For further details regarding the Partnership's subsidiaries and companies accounted for at equity, see Section 1.7 of Chapter A of this Report.

[3] A special purpose company (SPC) established by the partners in the Yam Tethys project for purposes of receiving a gas transmission license. For further details, see Section 1.7.1 of Chapter A of this Report.

[4] An SPC wholly owned by the Partnership which was established for the offering of bonds to the institutional market in Israel and overseas, which are secured by the Partnership's interests in the Leviathan leases. For further details, see Sections 1.7.6 and 7.21.2 of Chapter A of this Report and Note 10B to the financial statements (Chapter C of this Report).

[5] The loan funds were deposited with the bank and are used as a safety cushion for the repayment of the principal of the bonds issued by Leviathan Bond. For further details, see Notes 4 and 10B to the financial statements (Chapter C of this Report) and Part Five of the Board of Directors' Report (Chapter B of this Report). The loan principal does not include accrued interest in the sum of approx. $6.3 million, as of 31 December 2024.

[6] An SPC which was established for the purpose of obtaining a license for the transmission of natural gas from the Leviathan project. For further details, see Section 1.7.2 of Chapter A of this Report.

[7] An SPC incorporated in the Cayman Islands for the purpose of engagement in the gas supply agreement with the Jordan National Electric Power Company. For further details, see Sections 1.7.3 and 7.12.3(b) of Chapter A of this Report.

Name of the company	Type of security	No. of shares	Total par value	Share value in the Partnership's separate financial statement as of 31 December 2024	Price of the shares listed on TASE as of 31 December 2024 (in Agorot)	% of the holding in the capital, in voting and in the authority to appoint directors	Balance of loans to subsidiaries and to companies accounted for at equity as of 31 December 2024 (U.S. Dollars ("$") in thousands)	Main terms of the loans		
								Final maturity date	Linkage terms	Additional details
EMED Pipeline B.V. ("EMED B.V.")[8]	Ordinary shares	5,000	$5,000	$75,005,000	-	25	27,347	[9] -	Dollar	-
EMED Pipeline[10]	Ordinary shares	5,000	€5,000	-	-	100	-	-	-	-
Eastern Mediterranean Gas Company S.A.E ("EMG")[11]	Ordinary shares	57,330,000	$57,330,000	-	-	9.75	-	-	-	-
NewMed Energy UK Limited ("NewMed Morocco")[12]	Ordinary shares	1	£1	-	-	100	Approx. 2,000	September 2029	ILS	-[13]
NewMed Energy Balkan Limited ("NewMed	Ordinary shares	1	£1	-	-	100[15]	-	-	-	-

[8] Holland in connection with the EMG transaction (as defined in Section 7.26.6(a) of Chapter A of this Report). For further details, see Section 1.7.4 of Chapter A of this Report.

[9] The loan is for the Partnership's investments in refurbishment of the EMG pipeline, which were made through EMED B.V. The loan agreement between EMED Pipeline Holding Limited ("**EMED Pipeline**") and EMED B.V. was signed on 7 September 2022.

[10] An SPC wholly owned by the Partnership which was incorporated in Cyprus in connection with the EMG transaction (as defined in Section 7.26.6(a) of Chapter A of this Report). For further details see Section 1.7.4 of Chapter A of this Report.

[11] A private company incorporated in Egypt which owns the EMG pipeline. For further details see Sections 1.7.5 and 7.26.6 of Chapter A of this Report.

[12] An SPC wholly owned by the Partnership which was incorporated in England and holds interests in the exploration license Boujdour Atlantique in Morocco (formerly Delek Energy Limited). For further details, see Sections 1.7.7 and 7.6 of Chapter A of this Report. The Partnership undertook to keep in escrow for New Med Energy Plc. ("**NewMed England**"), a wholly-owned subsidiary of NewMed Morocco, the sum of £50 thousand, which was transferred thereto for the establishment thereof by NewMed Morocco and which shall be paid to NewMed England upon its request.

[13] The financing is provided through capital notes.

[15] As of the report approval date, the Partnership holds 100% of its shares. It is noted that on 9 March 2025, the compensation committee and board of NewMed Energy Management Ltd., the Partnership's General Partner (the "**Board**" and "**GP**", respectively) approved, notwithstanding the dissent by the meeting of the Partnership's Participation Unit holders (the "**Participation Units**"), the granting of equity compensation to Mr. Yossi Abu, the Partnership's CEO ("**Mr. Abu**" or the "**CEO**") which includes, *inter alia*, the allotment of 5% of the issued share capital of NewMed Balkan, such that following the said allotment the Partnership will hold 95% of the issued share capital of NewMed Balkan. For further details see Regulation 21(b)(2) below.

Name of the company	Type of security	No. of shares	Total par value	Share value in the Partnership's separate financial statement as of 31 December 2024	Price of the shares listed on TASE as of 31 December 2024 (in Agorot)	% of the holding in the capital, in voting and in the authority to appoint directors	Balance of loans to subsidiaries and to companies accounted for at equity as of 31 December 2024 (U.S. Dollars ("$") in thousands)	Main terms of the loans		
								Final maturity date	Linkage terms	Additional details
Balkan")[14]										
Enlight-NewMed Development, Limited Partnership[16]	Participation units	-	-	-	-	33.33%	Approx. 414	_[17]	_	_
Enlight-NewMed Development (UK) Ltd.[18]	Ordinary shares	100	£100	-	-	33.33	-	-	-	-

[14] An SPC which was incorporated in England and is expected to hold interests in the exploration license in Block 1-21 Han Asparuh in Bulgaria. For further details, see Sections 1.7.8 and 7.8 of Chapter A of this Report.

[16] A partnership which was incorporated as part of the collaboration with Enlight Renewable Energy Ltd. ("**Enlight**"), and whose participation units are held as follows: the Partnership – 33.33%, Yes-Enlight Holdings, Limited Partnership – 66.66% (whose participation units are held by Enlight – 70%, and by Mr. Abu – 30%).

[17] The collaboration agreement with Enlight (as specified in Section 7.10 of Chapter A of this report) determined provisions in connection with the method of financing of the operations in the context of the said collaboration, including provisions regarding the method of provision of shareholder loans, the order of repayment thereof, and the interest rate borne thereby (SOFR+4%).

[18] An SPC incorporated in England as part of the collaboration with Enlight. For further details, see Sections 1.7.9 and 7.10 of Chapter A of this Report.

Regulation 12: **Changes in investments in subsidiaries and in companies accounted for at equity in the report period**

In the report period, no changes were made to investments in subsidiaries and in companies accounted for at equity.

Regulation 13: **Revenues of and from the Partnership's subsidiaries and companies accounted for at equity (Dollars in thousands)**

Name of the company	Profit (loss) before tax	Other comprehensive income (loss)	Profit (loss) after tax	Dividends received as of 31 December 2024	Dividends received (or receivable by the Partnership) after 31 December 2024	Dividend payment dates after 31 December 2024	Management fees received as of 31 December 2023	Management fees received (or receivable by the Partnership) after 31 December 2024	Management fee payment dates after 31 December 2024	Interest	Interest payment dates
Leviathan Bond	624	-	624	-	-	-	-	-	-	-	-
EMED Pipeline	(138)	-	(138)	-	-	-	-	-	-	-	-
EMED B.V.	(8,617)	-	(8,617)	-	-	-	-	-	-	-	-
EMG	57,861	-	44,790	-	-	-	-	-	-	-	-

Regulation 20: **Securities listed for trading**

In 2024, until the report approval date, no new securities of the Partnership were listed for trading on the Tel Aviv Stock Exchange ("**TASE**").
To the best of the Partnership's knowledge, there were no trading halts in the Partnership's securities in 2024, apart from brief trading halts by TASE.

Regulation 21: **Compensation of interested parties and senior officers**[19]

(a) Below is a specification regarding the compensation given, in the report year, to the highest-paid senior officers of the Partnership and/or a corporation controlled thereby in connection with their term of office at the Partnership

[19] For further details regarding the terms of employment of the officers and the interested parties stated in the table, see Regulation 21(b) below.

and/or a corporation controlled thereby, as well as regarding the compensation given to interested parties of the Partnership in connection with services provided by them as office holders at the Partnership in the Report Year (Dollars in thousands), as recognized in the financial statements as of 31 December 2024[20]:

[20] For details regarding the decision of the meeting of Participation Unit holders in connection with the Partnership's management expenses, according to which from 1 January 2022, the Partnership bears all of its management expenses, which until such date were borne by the General Partner, including the cost of employment of officers and employees, including the CEO and the Active Chairman of the Board, see Regulation 22(a) below.

Senior officers and interested parties of the Partnership														
Details of Compensation Recipient				Compensation for Services (in Dollars)							Other Compensation (in Dollars)			Total (in Dollars)
Name	Title	Position percentage	% of holding in participation units	Salary	Bonus	Share-based payment	Manage-ment fees	Consult-ing fees	Comm-ission	Other	Interest	Rent	Other	
Senior officers of the Partnership														
Yossi Abu	CEO	100%	0.05%	914,453	885,168	531,883[21]	-	-	-	-	-	-	83,809	**2,415,313**
Gabi Last	Active Chairman of the Board	100%	[22]0.00%	541,141	125,692								75,212	**742,045**
Zvi Karcz	VP Exploration	100%	-	421,660	132,576	-	-	-	-	-	-	-	69,574	**623,809**
Sari Singer Kaufman	General Counsel, EVP	100%	-	425,984	117,600	-	-	-	-	-	-	-	69,654	**613,238**
Tzachi Habusha	VP Finance	100%	-	417,288	117,600	-	-	-	-	-	-	-	46,087	**580,975**
Interested parties of the Partnership and/or the General Partner														
External directors and an independent director[23]	-	-	-	326.7	-	-	-	-	-	-	-	-	-	**326.7**

[21] For details regarding Mr. Abu's holdings in options that are exercisable for the Partnership's Participation Units, see Regulation 21(b)(2) below.
[22] Mr. Last holds 12,109.60 Participation Units.
[23] For details on the salary of directors of the General Partner, see Regulation 21(b)(7) below.

(b) Below is a specification regarding the terms of office and employment of officers who are the highest-paid senior officers of the Partnership:

(1) Compensation policy

On 21 September 2022, the meeting of the Participation Unit holders decided not to approve an updated compensation policy for officers of the Partnership and the General Partner. For further details, see the Partnership's immediate reports of 6 September 2022 and 21 September 2022 (Ref.: 2022-01-092520 and 2022-01-120358, respectively), the information appearing in which is incorporated herein by reference.

Consequently, on 28 September 2022, the Compensation Committee and the Board decided, after reopening the discussion thereon, to approve the said updated compensation policy, with a change to the cap on the annual bonus for the Partnership's CEO and other officers, for a period of 3 years from that date, despite the objection of the meeting of the Participation Unit holders (the "**Compensation Policy**"). For further details, see the Partnership's immediate report of 29 September 2022 (Ref.: 2022-01-121942), the information appearing in which is incorporated herein by reference.

(2) Yossi Abu

Mr. Abu has served as CEO of the Partnership since 1 April 2011.

As specified in Regulation 22(a) below, since 1 January 2022, the Partnership has borne the full cost of Mr. Abu's employment (100%), in lieu of the General Partner.

On 21 September 2022, the meeting of the Participation Unit holders decided not to approve the updated terms of office and employment for Mr. Abu. For further details, see the Partnership's immediate reports of 6 September 2022 and 21 September 2022 (Ref.: 2022-01-092520 and 2022-01-120358, respectively), the information appearing in which is incorporated herein by reference.

Consequently, on 28 September 2022, the compensation committee and the Board decided, after reopening the discussion thereon, to approve the updated terms of office and employment for Mr. Abu, despite the objection of the meeting of the Participation Unit holders. For further details, see the Partnership's immediate report of 29 September 2022 (Ref.: 2022-01-121942), the information appearing in which is incorporated herein by reference.

For details regarding a motion filed according to Section 65-41 of the Partnerships Ordinance [New Version], 5735-1975 (the "**Partnerships Ordinance**") and Section 198A of the Companies Law, 5759-1999 (the "**Companies Law**") for an order for the discovery and inspection of documents prior to the filing of a derivative suit in connection with approval of the updated terms of office and employment for Mr. Abu by the compensation committee and the Board by way of an "overruling", see Section 7.27.7 of Chapter A of this Report.

Accordingly, Mr. Abu's terms of office and employment are as follows (the "**Terms of Office and Employment**"):

Mr. Abu's monthly salary is approx. ILS 215.8 thousand gross (100%)[24] (the salary is updated every 3 months in accordance with the CPI). According to the terms of his employment (in this section: the "**Employment Agreement**"), Mr. Abu is entitled to standard social benefits, a study fund, a pension plan, annual leave days (including entitlement to leave cash-in), sick days and recuperation pay. The Partnership provides Mr. Abu with a car, as is standard for his position, and bears any and all expenses entailed by the use of the car. The value of the use of the car is grossed-up and paid by the Partnership. Mr. Abu is also entitled to additional related benefits, such as his inclusion in officer indemnity, exemption and insurance arrangements, communication expenses (mobile telephone, internet, newspapers and payment of expenses in respect of reasonable use of his home phone), executive physicals, private health insurance at the Partnership's expense, participation in professional continuing education, severance pay (since 2016 Mr. Abu has not signed Section 14 of the Severance Pay Law, 5723-1963, and therefore the severance pay to which he is entitled is pursuant to law), receipt of loans from the Partnership, reimbursement of expenses for the performance of his duties, and reimbursement of per diem expenses during foreign travel on behalf of the Partnership. The Partnership may grant Mr. Abu, each year, an annual bonus for the previous calendar year, provided that he shall be employed by the Partnership at least 3 months in such year, and a special bonus, a retention bonus, and in the case of separation from employment, an adjustment bonus and a retirement bonus, all in accordance with the Compensation Policy as updated from time to time.

The parties may terminate the Employment Agreement at any time by giving prior written notice of 6 months. In addition, the

[24] As of 31 December 2024.

Employment Agreement includes provisions regarding confidentiality and a non-compete clause for a period of 12 months.

In addition, on 3 October 2022, Mr. Abu was allotted, for no consideration, 3,295,599 non-marketable options exercisable for 3,295,599 Participation Units, which constitute approx. 0.28% of the Partnership's issued and paid-up Participation Unit capital (on a fully diluted basis)[25]. The allotment was performed in accordance with the Compensation Policy and the option plan which was submitted to Income Tax on 4 August 2022 pursuant to Section 102 of the Income Tax Ordinance [New Version], and was adopted by the Board on 27 July 2022 (the "**Options**" and the "**Grant Date**", respectively).

The Options will vest in 3 equal annual installments, commencing from the Grant Date, with the exercise price of the first installment being 866 Agorot, which is equal to the average closing price of the Participation Units on the Tel Aviv Stock Exchange Ltd. ("**TASE**") at the close of the 30 trading days that preceded the Grant Date. The exercise price of the remaining two installments will increase by 5% each year relative to the previous year.

For further details, see the Partnership's immediate reports of 3 October 2022 and 12 October 2022 (Ref.: 2022-01-100665, 2022-01-100692 and 2022-01-125926, respectively), the information appearing in which is incorporated herein by reference.

According to a valuation received by the Partnership, the economic value of the Options on the Grant Date totaled approx. ILS 9.8 million and the annual economic value (i.e. the economic value of the Options on the Grant Date, divided by 3) totaled approx. ILS 3,267 thousand. The economic value of the Options as aforesaid, was calculated using the Binomial model, based on the following assumptions: (a) Participation Unit price, as of the Grant Date, of ILS 9.35; (b) the exercise price of each option (adjusted to a profit distribution) was calculated according to ILS 8.66 for the first installment, ILS 9.10 for the second installment, and ILS 9.55 for the third installment; (c) expiration date – 26 July 2027; (d) vesting date – as specified in this section above; (e) standard deviation rate of 49.9%; and (f) risk-free interest rate of approx. 2.31%.

For further details regarding the Terms of Office and Employment, see the Partnership's immediate report of 6

[25] For details regarding the rate of Mr. Abu's holdings (on a fully diluted basis) as of the report approval date, see Regulation 24 below.

September 2022 (Ref.: 2022-01-092520), the information appearing in which is incorporated herein by reference.

According to the Terms of Office and Employment, Mr. Abu received an annual bonus for 2023, which was approved in May 2024, in the sum of approx. ILS 3,281.7 thousand, in accordance with the Compensation Policy and based on the following components:

(a) A business target-dependent component (40%) – Mr. Abu met the business targets specified below, and was therefore entitled, in respect of this component, to the sum of approx. ILS 1,804,957 thousand: (1) the ability to perform a profit distribution of no less than $150 million; and (2) natural gas nominations from the Leviathan project by Dolphinus in an annual amount of no less than 90% of the annual quantity in accordance with the export to Egypt agreement; (b) A component dependent on the quantitative tests specified below (20%): (1) change in adjusted net profit[26]. Mr. Abu met this criterion since the ratio received from a division of the adjusted net profit by the average adjusted net profit in the 3 years preceding the year for which the annual bonus is paid was 121%; (2) the making of investments or adoption of an investment decision: the actual making of investments by the Partnership in a petroleum asset in an amount of no less than $50 million or the adoption of a decision to invest in a petroleum asset in an amount exceeding $300 million (100%), all excluding investments in exploration wells. Mr. Abu met this criterion due to the actual making of investments by the Partnership in a petroleum asset in an amount of no less than $50 million and the adoption of a final decision to invest in a petroleum asset a sum exceeding $300 million (100%); (3) the raising of money or signing of natural gas sale agreements or signing of export agreements: raising of money with the Partnership's share not falling below $200 million, or the signing of binding agreements for the sale of gas in a volume exceeding 25 BCM, or the signing of export agreements. As aforesaid, Mr. Abu met Sections (b)(1) and (b)(2) above, and therefore was entitled in respect of that criterion to an annual bonus of approx. ILS 656,348; and (c) The Board's discretionary component (25%): approx. ILS 820,435 thousand.

On 9 January 2025, the general meeting of Participation Unit holders resolved not to approve the granting of equity compensation to Mr. Abu at a rate of 5% of the issued share capital of NewMed Balkan and the financing of his relative share

[26] The rate received from division of the adjusted net profit in the year for which the bonus is paid, by the average adjusted net profit of the Partnership in the 3 years preceding the year for which the bonus is paid.

of the costs of the initial investment that includes the first two wells to be drilled in the Bulgaria License area, up to $173 million (100%) (the "**Initial Investment**") according to the terms and conditions specified in the respective Notice of Meeting, in deviation from the Partnership's compensation policy (the "**Equity Compensation**"). For further details, see the Partnership's immediate reports of 2 January 2025 and 9 January 2025 (Ref.: 2025-01-000782 and 2025-01-003240, respectively), the information appearing in which is incorporated herein by reference. Notwithstanding the aforesaid dissent of the meeting of Participation Unit holders, on 9 March 2025, the compensation committee and the board resolved, unanimously, to approve the granting of an updated Equity Compensation to Mr. Abu, based on the terms and conditions of the Equity Compensation with certain changes in favor of the Partnership, mainly: (a) lowering the amount of participation in the financing of Mr. Abu's relative share in the cost of the Initial Investment to a maximum of $100 million (instead of $173 million as aforesaid); (b) adding mechanisms to secure the Partnership's rights through a trustee and pledge of the shares; and (c) adding the Partnership's right to purchase the shares from Mr. Abu should his employment be terminated.

(3) Gabi Last

Mr. Gabi Last ("**Mr. Last**") has served as Active Chairman of the Board at the General Partner in a full-time position since April 2022 (prior to which, from May 2001, he held office as a director of the General Partner, and from January 2020, he held office as Chairman of the Board at the General Partner).

Since 1 November 2022, the Partnership has borne the full cost of Mr. Last's employment (100%).

Mr. Last's gross monthly salary is approx. ILS 129.5 thousand[27] (the salary is updated every 3 months in accordance with the CPI). In accordance with the terms of his employment (in this section: the "**Employment Agreement**"), Mr. Last is entitled to standard social benefits, a study fund, a pension plan, annual leave days, sick days and recuperation pay. The Partnership provides Mr. Last with a car, as is standard for his position, and bears any and all expenses entailed by the use of the car. The value of the use of the car is grossed-up and paid by the Partnership. Mr. Last is also entitled to additional related benefits, such as his inclusion in officer indemnity, exemption and insurance arrangements, communication expenses (mobile telephone, internet, newspapers and payment of expenses in

[27] As of 31 December 2024.

respect of reasonable use of his home phone), executive physicals and private health insurance at the Partnership's expense, participation in professional continuing education, reimbursement of expenses for the performance of his duties, and reimbursement of *per diem* expenses during foreign travel on behalf of the Partnership. The Partnership may grant Mr. Last, each year, an annual bonus for the previous calendar year, in the sum of up to 4 gross monthly salaries, provided that he shall be employed by the Partnership at least 3 months in such year, and in the case of separation from employment, an adjustment bonus, all in accordance with the Compensation Policy and as shall be updated from time to time.

The parties may terminate the Employment Agreement at any time by giving prior written notice of 3 months. In addition, the Employment Agreement includes provisions regarding confidentiality and a non-compete clause for a period of 12 months.

Mr. Last received from the Partnership an annual bonus for 2023, which was approved in May 2024, in the sum of approx. ILS 466 thousand, in accordance with the Compensation Policy.

(4) Zvi Karcz

Mr. Zvi Karcz ("**Mr. Karcz**") has served as VP Exploration in a full-time position since August 2014 (prior to which, from September 2011, he was employed as the Partnership's Chief Geologist).

Mr. Karcz's gross monthly salary is approx. ILS 96.4 thousand[28] (the salary is updated every 3 months in accordance with the CPI). In accordance with the terms of his employment (in this section: the "**Employment Agreement**"), Mr. Karcz is entitled to standard social benefits, a study fund, a pension plan, annual leave days (including entitlement to leave cash-in), sick days and recuperation pay. The Partnership provides Mr. Karcz with a car, as is standard for his position, and bears any and all expenses entailed by the use of the car. The value of the use of the car is grossed-up and paid by the Partnership. Mr. Karcz is also entitled to additional related benefits, such as his inclusion in officer indemnity, exemption and insurance arrangements, communication expenses (mobile telephone, internet, newspapers and payment of expenses in respect of reasonable use of his home phone), executive physicals, participation in professional continuing education, reimbursement of expenses for the performance of his duties, and reimbursement of *per diem* expenses during foreign travel on behalf of the

[28] As of 31 December 2024.

Partnership. The Partnership may grant Mr. Karcz, each year, an annual bonus for the previous calendar year, provided that he shall be employed by the Partnership at least 3 months in such year, all in accordance with the Compensation Policy and as shall be updated from time to time.

The parties may terminate the Employment Agreement at any time by giving prior written notice of 3 months. In addition, the Employment Agreement includes provisions regarding confidentiality and a non-compete clause for a period of 9 months. Mr. Karcz is entitled to an adjustment bonus in the sum of 50% of his gross salary for the entire non-competition period, i.e., a bonus in a total amount of up to 4.5 gross monthly salaries. In that period, the Partnership shall make the car and the mobile telephone available to Mr. Karcz.

In February 2024, the Compensation Committee and the Board approved the granting to Mr. Karcz of a one-time retention bonus in the sum total of ILS 270 thousand. The retention bonus will be paid in 3 equal installments, as follows: two monthly salaries were paid together with the February 2024 and February 2025 salaries; and one monthly salary will be paid together with the February 2026 salary, provided that he is employed by the Partnership on 28 February 2026.

Mr. Karcz received from the Partnership an annual bonus for 2023, which was approved in May 2024, in the sum total of ILS 400 thousand.

(5) Sari Singer Kaufman

Ms. Sari Singer Kaufman ("**Ms. Singer**") has served as EVP and General Counsel on a full-time basis since May 2018 and August 2017 respectively (prior to which, from March 2012, she was employed as a legal counsel at the Partnership).

Ms. Singer's gross monthly salary is approx. ILS 94.9 thousand[29] (the salary is updated every 3 months according to the CPI). In accordance with the terms of her employment (in this section: the "**Employment Agreement**"), Ms. Singer is entitled to standard social benefits, a study fund, a pension plan, annual leave days (including entitlement to leave cash-in), sick days and recuperation pay. The Partnership provides Ms. Singer with a car, as is standard for her position, and bears any and all expenses entailed by use of the car. The value of the use of the car is grossed-up and paid by the Partnership. Ms. Singer is further entitled to additional related benefits, such as her

[29] As of 31 December 2024.

inclusion in officer indemnity, exemption and insurance arrangements, communication expenses (mobile phone, internet, newspapers and payment of expenses in respect of reasonable use of her home phone), executive physicals, private health insurance at the Partnership's expense, participation in professional continuing education, reimbursement of expenses for performance of her duties and reimbursement of *per diem* expenses during foreign travel on behalf of the Partnership. The Partnership may grant Ms. Singer, each year, an annual bonus for the previous calendar year, provided that she shall be employed by the Partnership at least 3 months in such year, all in accordance with the Compensation Policy and as shall be updated from time to time.

The parties may terminate the Employment Agreement at any time by giving prior written notice of 3 months. In addition, the Employment Agreement includes provisions regarding confidentiality and a non-compete clause for a period of 3 months.

Ms. Singer received from the Partnership an annual bonus for 2023, which was approved in May 2024, in the sum of ILS 436 thousand.

(6) Tzachi Habusha

Mr. Tzachi Habusha ("**Mr. Habusha**") has served as VP Finance at the Partnership in a full-time position since January 2022.

Mr. Habusha's gross monthly salary is approx. ILS 94.9 thousand[30] (the salary is updated every 3 months in accordance with the CPI). In accordance with the terms of his employment (in this section: the "**Employment Agreement**"), Mr. Habusha is entitled to standard social benefits, a study fund, a pension plan, annual leave days (including entitlement to leave encashment), sick days and recuperation pay. The Partnership provides Mr. Habusha with a car, as is standard for his position, and bears any and all expenses entailed by use of the car. The value of the use of the car is grossed-up and paid by the Partnership. Mr. Habusha is also entitled to additional related benefits, such as his inclusion in officer indemnity, exemption and insurance arrangements, communication expenses (mobile phone, internet, newspapers and payment of expenses in respect of reasonable use of his home phone), executive physicals, participation in professional continuing education, reimbursement of expenses for the performance of his duties, and reimbursement of *per diem* expenses during foreign travel

[30] As of 31 December 2024.

on behalf of the Partnership. The Partnership may grant Mr. Habusha, each year, an annual bonus for the previous calendar year, provided that he shall be employed by the Partnership at least 3 months in such year, all in accordance with the Compensation Policy and as shall be updated from time to time.

The parties may terminate the Employment Agreement at any time by giving prior written notice of 3 months. In addition, the Employment Agreement includes provisions regarding confidentiality and a non-compete clause for a period of 3 months.

Mr. Habusha received from the Partnership an annual bonus for 2023, which was approved in May 2024, in the sum of ILS 436 thousand.

(7) Salary of directors of the General Partner

The two external directors and the independent director on the General Partner's board, who are classified as expert directors, as defined in the Compensation Regulations (Conditions and Tests for a Director having Accounting and Financial Expertise and a Director with Professional Skills), 5766-2005, are entitled to participation compensation and annual compensation in the maximum amounts set forth in the Fourth Schedule to the Compensation Regulations (Rules Regarding Compensation and Expenses for External Directors), 5760-2000 (the "**Compensation Regulations**") and according to the Partnership's rank, as being from time to time.

The terms of office and employment of the Active Chairman of the Board are specified in Regulation 21(b)(3) above. The remaining directors on the General Partner's board are officers in Delek Group Ltd. ("**Delek Group**") or other companies controlled thereby, and the Partnership does not bear the costs of their compensation, as specified in Regulation 22 below.

(8) The Supervisors

1. Fahn Kanne & Co., CPAs, together with Keidar Supervision and Management (collectively: the "**Supervisors**" or the "**Supervisor**") are entitled to receive from NewMed Energy Trusts Ltd. (the "**Limited Partner**" or the "**Trustee**"), out of the trust assets, a fee of approx. ILS 65 thousand per month[31] (plus VAT). The monthly fee is updated every 3 months in accordance with changes in the CPI relative to the April 2020 CPI rate.

[31] As of 31 December 2024.

In addition, in the event of the publication of a prospectus, including a shelf prospectus, the Supervisor will be entitled to additional compensation for its additional work that is entailed by the publication of the prospectus, in an amount in ILS equal to $40 thousand (plus VAT, if applicable), irrespective of the actual working hours (in this section: the "**Additional Compensation**"). It is clarified that in the case of a shelf prospectus, the Additional Compensation shall also include compensation in respect of all of the work that shall be required of the Supervisor after publication of the shelf prospectus, in connection with the shelf prospectus in respect of which the Supervisor received the Additional Compensation, insofar as required, including shelf offering reports that shall be published under the shelf prospectus and/or any offering performed under the shelf prospectus and/or any financing round performed under the shelf prospectus (in this section: "**Work After the Publication of the Shelf Prospectus**"). It is further clarified that after the Supervisor is paid the Additional Compensation, the Supervisor will not be entitled to any additional payment for his work in connection with the publication of the prospectus as aforesaid, in respect of which the Additional Compensation was paid to the Supervisor, as well as in connection with the Work After the Publication of the Shelf Prospectus.

The Supervisor is further entitled to a payment in ILS equal to $40 thousand (plus VAT), irrespective of actual working hours, for his work, insofar as required, in connection with the closing of financing agreements made against a pledge of a petroleum asset of the Partnership.

In addition, the Supervisor is entitled to reimbursement of additional expenses lawfully incurred thereby for the purposes of its role, provided that it received therefor the approval of the meeting of the participation unit holders or that the expenses are within the amount and type approved for such purpose by the meeting of the participation unit holders. It is noted that on 22 December 2016, the meeting of the participation unit holders confirmed, without derogating from the provisions of the Partnership Agreement signed on 1 July 1993, as amended from time to time, between the General Partner and the Limited Partner (the "**Partnership Agreement**"), and the trust agreement of 1 July 1993, which was signed between the Trustee and the Supervisors, as amended from time to time (the "**Trust Agreement**"), that the types of expenses for which the Supervisor will be entitled to reimbursement of expenses out of the trust assets will include expenses of traveling to meetings of the Partnership's organs, to meetings with the General Partner's management and to meetings with the representatives of the General Partner vis-à-vis various regulators, courier services, and parking expenses in respect of all of the above, and that the sum of the expense reimbursement as aforesaid shall not exceed ILS 1,000 (plus VAT) per month.

2. For details regarding the decision of the meeting of the Participation Unit holders of 29 May 2023, to approve the appointment of the Supervisors, beginning on the date of approval by the meeting as aforesaid, for a period of 18 months or until the closing date of the transaction to purchase all publicly held Participation Units and some Participations Units held by Delek Group, if closed, as specified in Section 1.8 of Chapter A of this Report (the **"BP-ADNOC Transaction**"), whichever is earlier, and regarding the decision of the meeting of the Participation Unit holders of 30 December 2024 to approve the appointment of the Supervisors for a period of 3 years beginning on such date, and to approve their terms of office and employment, see the Partnership's immediate reports of 24 April 2023, 29 May 2023, 24 November 2024, 3 December 2024 and 30 December 2024 (Ref.: 2023-01-044772, 2023-01-057420, 2024-01-618247, 2024-01-621633 and 2024-01-628464, respectively), the information appearing in which is incorporated herein by reference.

3. On 24 July 2023, the meeting of the Participation Unit holders decided to approve for the Supervisor a fee in addition to its monthly fee in connection with supervising the BP-ADNOC Transaction and overseeing the independent committee that was appointed by the Board in connection with this transaction, as specified in Section 1.8 of Chapter A of this Report. For further details, see the Partnership's immediate reports of 15 June 2023 and 24 July 2023 (Ref.: 2023-01-066222 and 2023-01-084408, respectively), the information in which is incorporated herein by reference.

4. Below are the sums paid to the Supervisors in the Report Year, according to the above specification (ILS in thousands):

Salary	Additional Salary	Salary for the closing of financing agreements made against a pledge of a petroleum asset	Expense reimbursement	Salary for supervision of the BP-ADNOC transaction and overseeing the independent committee	Total
792	-	-	2	81	875

(9) The Trustee

The Trustee is entitled to receive, out of the trust assets, a fee equal to $1,000 (plus VAT) for every year in which it serves as trustee according to the Trust Agreement (or a proportionate share of such amount in respect of part of a year). This amount will be paid to the Trustee on the last day of the year for which it is being paid. In addition, the Trustee is entitled to receive payment for expenses explicitly permitted in the Trust Agreement or which were approved in advance and in writing by the Supervisor.

Regulation 21A: The Partnership's controlling interest holder

As of the report approval date, the controlling interest holder (indirectly) of the Partnership is Mr. Yitzhak Sharon (Tshuva).

To the best of the Partnership's knowledge, Delek Group, which is controlled by Mr. Yitzhak Sharon (Tshuva), holds, directly and indirectly (through Delek Energy Systems Ltd. ("**Delek Energy**") and the General Partner, and through an indirect holding in Avner Oil & Gas Ltd. approx. 54.66% of the issued unit capital of the Partnership[32].

Regulation 22: Transactions of the Partnership with the General Partner or transactions in which the General Partner's controlling shareholder has a personal interest

Below are details, to the best of the Partnership's knowledge, regarding any transaction with the General Partner or the General Partner's controlling shareholder, or in the approval of

[32] To the best of the Partnership's knowledge, and according to Delek Group's reports, as of the report approval date, a majority of the Participation Units held by Delek Group is pledged in favor of the holders of the bonds issued by Delek Group.

which the General Partner's controlling shareholder has a personal interest, in which the Partnership or a corporation controlled thereby or an affiliate of the Partnership engaged during or after the report year until the report approval date, or which is still in effect on the report approval date, with the exception of negligible transactions, as defined in Section 6 of Part Three of the Board of Directors' Report (Chapter B of this Report):

(a) According to the Partnership Agreement, the General Partner is entitled to 0.01% of the Partnership's income and bears 0.01% of the expenses and losses of the Partnership, as well as the expenses and losses of the Partnership which, due to the limitation on the Limited Partner's liability for obligations of the Partnership, were not borne by the Limited Partner.

According to the decision of the meeting of the Participation Unit holders of 21 September 2022 in connection with the bearing of costs of management of the Partnership and the General Partner, from 1 January 2022, the Partnership directly bears any and all expenses required for the management of its business and assets, including the management expenses of the General Partner, which according to the provisions of Section 65B(a) of the Partnerships Ordinance, has no other activity aside from management of the Partnership. Accordingly, the Partnership does not pay the General Partner or Delek Group any management fees or operator fees.

Furthermore, according to this decision, the Partnership bears the costs of the compensation of all of the directors on the General Partner's board and the fees of the Active Chairman of the Board, with the exception of directors who serve as officers of Delek Group or other companies controlled thereby.

In addition, the Partnership bears the cost of the rent for the Partnership's offices which, as of the report approval date, are leased by the Partnership from Delek Group, as specified in Regulation 22(f) below.

Since, according to the said decision, the General Partner does not bear the Partnership's management expenses, insofar as the General Partner shall pay, out of pocket, any part of the Partnership's management expenses, it will reimbursed in respect of the said expenses, but in any event the General Partner will not be reimbursed with expenses paid thereby, directly or indirectly, to Delek Group or expenses in which Delek Group has a personal interest (within the meaning thereof in the Partnerships Ordinance), unless all of the approvals required by law are received in connection therewith. For this purpose, "**personal interest**" – except a personal interest deriving from Delek Group's mere holding in the General Partner, and with respect to an engagement with an officer or with an employee – except a personal interest deriving from the mere office or employment at the General Partner.

For further details regarding the said decision and its approval, see the Partnership's immediate reports of 6 September 2022 and 21 September 2022 (Ref.: 2022-01-092520 and 2022-01-120358, respectively), the information appearing in which is incorporated herein by reference.

(b) According to a 1993 agreement, Delek Group and Delek Energy are entitled to receive royalties from the Partnership, as specified in Section 7.25.8(c)(2) of Chapter A of this Report. As of the report approval date, the holder of the right to the royalties of Delek Group and Delek Energy in the Leviathan project is Delek Leviathan Overriding Royalty Ltd. ("**Delek Overriding Royalty**"), a wholly owned subsidiary of Delek Energy[33].

In 2024, the Partnership recorded expenses in respect of royalties to Delek Overriding Royalty for the Leviathan project in the sum total of approx. $14.4 million.

(c) According to the terms and conditions of the Production Sharing Contract (PSC) in Block 12, the Partnership is required by the Republic of Cyprus to provide a performance guarantee for its undertakings by the Partnership's parent company. Accordingly, on 18 April 2013, Delek Group provided a performance guarantee in an unlimited amount in favor of the Republic of Cyprus to secure fulfillment of all of the Partnership's undertakings under the PSC (the "**Guarantee**"), as specified below:

1. For provision of the Guarantee by Delek Group, the Partnership pays a fee, on an annual basis, from the date of provision of the Guarantee and so long as the Guarantee is in effect. If the holding rate of the

[33] To the best of the Partnership's knowledge, and according to Delek Group's reports, in October 2020, Delek Group and Delek Energy transferred their right to receive Delek Group's royalties from the Partnership's share (45.34%) in the oil and/or gas and/or other valuable substances that shall be produced and exploited from the Leviathan leases to Delek Overriding Royalty.

Partnership in Block 12 decreases, the amount of the fee will decrease *pro rata* to the decrease in the holding in the asset. In addition, in a case where Delek Group is absolutely released from the Guarantee, whether due to the finding of an alternative guarantor or due to the sale of the interests in Block 12 by the Partnership, the Partnership and Delek Group agreed that payment of the fee will be discontinued immediately. The sum of the Guarantee fee that the Partnership paid Delek Group in 2024 totaled approx. $368 thousand.[34]

2. From the date of provision of the Guarantee and so long as the Guarantee is in effect, the Partnership will not approve a new work plan/s in Block 12 and/or in relation to any other activity in Block 12 by virtue of the Joint Operating Agreement ("**Block 12 Work Plan**"[35]), in the absence of: (a) insurance that covers expenses of taking control of a well, control of which was lost, including coverage for bodily injuries and property damage and cleaning expenses deriving from the risks of accidental contamination in respect of the Partnership's activity in Block 12, to the satisfaction of Delek Group (insurance policies for loss of control of a well and third party liability)[36]; and (b) approval pursuant to the law by the Partnership's competent organs of the terms of the engagement with Delek Group, as specified above and below, and of the arrangements regarding payment of a Guarantee fee by the Partnership to Delek Group.

3. In addition, the Partnership undertook that from the date of provision of the Guarantee and so long as the Guarantee is in effect, the following provisions will apply:

    a. In a case where the Partnership sells its interests in Block 12, the Partnership will act to

[34] The engagement was approved on 14 April 2013 by the Board and on 18 April 2013 by the meeting of the Participation Unit holders. For further details, see the Partnership's immediate reports of 14 April 2013 and 18 April 2013 (Ref.: 2013-01-036844 and 2013-01-039418, respectively). Furthermore, on 8 July 2018, the audit committee confirmed that fixing the payment in respect of the Guarantee for a guarantee period of 25 years, as determined on the date of approval of the Guarantee transaction for the first time, is a reasonable period.

[35] The Partnership will deliver to Delek Group prior notice of any intention to approve a Block 12 Work Plan.

[36] The Partnership has entered into insurance policies that provide it with coverage in respect of accidental and unexpected damage related to expenses due to loss of control of well and third-party liability insurance in relation to the activity in Block 12.

release Delek Group from the Guarantee, or from its proportionate share (in the case of a partial sale of the interests) in the context of such sale, all subject to the provisions of the PSC and the decisions of the authorities in Cyprus on the matter. It is noted that the sale of some of the interests in Block 12 will be possible only subject to reaching arrangements on division of liability and mutual indemnity with the potential buyer of some of the interests as aforesaid, in respect of its proportionate share.

b. Delek Group will have the right to demand, in a written notice, at any time and at its discretion, that the Partnership act for its release from the Guarantee. In the case of such a demand, the Partnership undertakes to perform the actions required for the release of Delek Group from the Guarantee, including, if and insofar as required for the release of Delek Group from the Guarantee as aforesaid, the sale of its interests, in whole or in part, in Block 12 and/or waiver thereof, with no need for additional approvals at the Partnership. In the case of such a demand, the Partnership undertakes that within 12 months from the date of the giving of the written demand, it will cause the release of Delek Group from the Guarantee or will alternatively sign an agreement for the sale of the interests in Block 12. In the case of such a sale, the Partnership undertakes to close the sale within 6 months from the date of the signing of the sale agreement.

c. The Partnership will indemnify Delek Group for damage of any type whatsoever and/or any type of expenses and/or payments borne by Delek Group (including expenses and/or legal fees and/or experts' fees) in respect of enforcement of the Guarantee and/or a claim and/or demand, whose cause is related to the Guarantee and/or enforcement thereof, with no limitation on amount. Without derogating from the aforesaid, Delek Group will deliver to the Partnership, without delay, a notice regarding the filing of the said claim and/or demand upon its receipt thereby, and will allow the

Partnership and/or another on its behalf to conduct a proper legal defense as is deemed necessary by the Partnership in the circumstances against any such demand and/or claim, and/or negotiations for a settlement as aforesaid and/or to mitigate the damage insofar as it is able to do so.

4. Since the undertakings of the Partnership and Chevron Cyprus Limited ("**Chevron Cyprus**"[37]) according to the PSC are joint and several, an agreement was signed between Delek Group and Chevron Corp., and the parent company of BG Cyprus, regarding division of liability and mutual indemnity between them, with respect to the activity in Block 12, according to the holding rates of the Partnership, Chevron Cyprus and BG Cyprus in the interests in Block 12 (in this section: the "**Agreement**"). The Agreement determines, *inter alia*, that:

   a. Each party to the Agreement will be liable for damage or liability relating to the activity in Block 12 according to the rate of the corporation's participation in respect of which it provided a guarantee in favor of the Republic of Cyprus as aforesaid in Block 12 (i.e., Delek Group at a rate of 30%, Chevron Corp. at a rate of 35%, and the parent company of BG Cyprus at a rate of 35%).

   b. Therefore, each party to the Agreement undertook to indemnify or release the other party from liability for damage and/or liability relating to activity in Block 12 over and above the rate of the corporation's participation in respect of which it provided a guarantee in favor of the Republic of Cyprus, as aforesaid, in Block 12.

   c. The parties' undertaking as aforesaid is not limited in amount or by the scope of the insurance coverage of the Partnership, Chevron Cyprus and BG Cyprus in the context of their activity in Block 12.

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[37] To the best of the Partnership's knowledge, Chevron Cyprus is a wholly owned subsidiary of Chevron Corporation ("**Chevron Corp.**").

d. Each party to the Agreement undertook to obtain from its insurer a waiver of a right of subrogation against the other party to the Agreement in respect of damage or liability relating to its activity in Block 12.

e. The Agreement determines a binding arbitration mechanism for resolution of disputes between the parties.

f. The Agreement will be in effect until conclusion of the joint operating agreement that applies to Block 12, subject to a final accounting between the parties with respect to the Agreement.

(d) For details regarding exercise of an option for the purchase of a policy for an extended run-off period in the context of the D&O liability insurance policy that was approved in the context of a previous policy of the Partnership and in the context of a group insurance policy that was purchased by Delek Group, see Regulation 22(k) of the 2020 periodic report, as released on 17 March 2021 (Ref.: 2021-01-036588) (the "**2020 Periodic Report**").

(e) For details regarding the BP-ADNOC Transaction and regarding the activity of the committee that was set up in the context thereof, during the report year, see Section 1.8 of Chapter A of this Report.

(f) The Partnership pays rent to Delek Group for the Partnership's offices in Herzliya. The audit committee and the Board approved the said engagement at arm's length, in accordance with an opinion of an independent appraiser. The term of the lease, which includes an option period, is expected to end on 14 October 2026, with an option to extend it until 14 October 2031, and the monthly rent is ILS 80 per sqm for the office space and the public spaces, linked to the CPI. In addition, the Partnership pays monthly management fees and a payment for the lease of parking spaces. In 2024, the Partnership paid Delek Group, in respect of the said engagement, the sum of approx. $341 thousand.

<u>Negligible transactions</u> – Over and above the transactions specified above, the Partnership has other engagements in which the Partnership's controlling interest holder has a personal interest, which are classified as negligible transactions,

as defined in Section 6 of Part Three of the Board of Directors' Report (Chapter B of this Report), such as: receipt of "*dalkan*" [automatic billing for fueling services] from "Delek" The Israel Fuel Corporation Ltd., an affiliate of Delek Group ("**Delek**"), receipt of services from NYX Hotel Herzliya of the Fattal hotel chain, and an accounting with Delek Group and with Mr. Yitzhak Sharon (Tshuva) in relation to legal costs in the context of a class certification motion.

Regulation 24: **Holdings of interested parties and senior officers**

For details regarding holdings of interested parties and senior officers of the Partnership and/or the General Partner as of 31 December 2024, see the Partnership's immediate report of 7 January 2025 (Ref.: 2025-01-002285), the information appearing in which is incorporated herein by reference.

It is noted that on 12 January 2025, Harel Investments in Insurance and Financial Services Ltd. ceased being an interest holder in the Partnership. For further details, see the Partnership's immediate report of 14 January 2025 (Ref.: 2025-01-004168), the information appearing in which is incorporated herein by reference.

Regulation 24A: **Authorized capital, issued capital and convertible securities**

For details, see the Partnership's immediate report of 3 October 2022 (Ref.: 2022-01-100665), the information appearing in which is incorporated herein by reference.

Regulation 24B: **Register of the Partnership's participation unit holders**

For details, see the Partnership's immediate report of 3 October 2022 (Ref.: 2022-01-100665), the information appearing in which is incorporated herein by reference.

Regulation 25A: **Registered address**

Address:	19 Abba Eban Blvd., Herzliya, 4672537
Telephone:	09-9712424
Facsimile:	09-9712425
E-mail address:	info@newmedenergy.com

Regulation 26: The directors of the General Partner[38]

Details	Gabi Last	Leora Pratt Levin	Idan Wallace	Tamir Polikar
I.D. number:	004787933	057906919	033658246	059749408
Position at the General Partner:	Active Chairman of the Board	Director	Director	Director
Date of birth:	9 September 1946	12 October 1962	8 January 1977	14 August 1965
Address for service of process:	19 Abba Eban Blvd., Herzliya	19 Abba Eban Blvd., Herzliya	19 Abba Eban Blvd., Herzliya	19 Abba Eban Blvd., Herzliya
Nationality:	Israeli	Israeli	Israeli	Israeli and Portuguese
Membership of board committees:	No	No	No	No
Independent director?	No	No	No	No
External director?	No	No	No	No
(a) If so, accounting and financial expertise or professional qualifications?	-	-	-	-
(b) If so, an expert external director?[39]	-	-	-	-
Employee of the General Partner, a subsidiary, an affiliate or of an interested party?	Active Chairman of the Board, member of the Partnership's donations committee (the "**Donations Committee**"), a director of a private subsidiary (SPC) of the Partnership and a director of Med-Enlight General Partner (2023) Ltd. (which was established as part of the Partnership's collaboration with Enlight, as specified in Section 7.9 of Chapter A of this Report) ("**Med-Enlight**")	Senior VP, Chief Legal Counsel and Secretary of Delek Group and director of subsidiaries of Delek Group	CEO of Delek Group and director of subsidiaries of Delek Group	Deputy CEO and CFO of Delek Group and director of subsidiaries of Delek Group
Date of commencement of office as director:	17 May 2001, from 8 January 2020 as Board Chairman, and from 1 April 2022 as Active Chairman of the Board	26 August 2015	7 January 2020	10 September 2020
Education:	LL.B from Tel Aviv University, M.A. in Social Sciences and Mathematics from the University of Haifa and A.M.P (a management program for senior officers) from Harvard University, U.S.	LLB from the University of Reading, England, B.A. in Political Science from Tel Aviv University, attorney, member of the Israel Bar	LL.B from Tel Aviv University, attorney, member of the Israel Bar	B.A. in Accounting from the College of Management, MBA from Heriot-Watt University, CPA

[38] The specification of this regulation presents the directors who serve on the Board as of the report approval date.
[39] Within the meaning of the term in Section 1 of the Compensation Regulations.

Details	Gabi Last	Leora Pratt Levin	Idan Wallace	Tamir Polikar
Occupation in the last five years:	Active Chairman of the Board of the General Partner, member of the Donations Committee, a director of Med-Enlight, Chairman of the Board of Delek Group and the Delek Foundation for Education, Culture and Science (CIC), a director of subsidiaries of Delek Group, a director of a private subsidiary (SPC) of the Partnership and a member of management of various NPOs	A director of the General Partner, EVP, Chief Legal Counsel and Corporate Secretary of Delek Group and director of subsidiaries of Delek Group	A director of the General Partner, CEO of Delek Group, Deputy CEO of Delek Group, CEO of the Tshuva Group private companies and a director of News Co. Ltd. and Keshet Broadcasting Ltd.	A director of the General Partner, deputy CEO and CFO at Delek Group, a director of subsidiaries of Delek Group, real estate developer in Israel and overseas, business consultant and a director of Polikar Holdings Ltd.
Other directorships:	A private subsidiary (SPC) of the Partnership and Med-Enlight	Delek Energy, Delek Sea Maagan (2011) Ltd., Delek Israel Holdings Group Ltd., Delek Infrastructures Ltd., Delek Power Plant Management Ltd., Delek Petroleum Ltd., Delek Property Development Ltd., Delek Overriding Royalty, Leviathan Ltd., Mehadrin Ltd., DKL Investments Limited, DKL Energy Limited and an observer on the board of Ithaca Energy Plc	Delek Energy, Ithaca Energy Plc, Mehadrin Ltd., Wallace Consulting Ltd. and Wallace Investments (2018) Ltd.	Delek Energy, Delek Sea Maagan 2011 Ltd., Delek Israel Holdings Group Ltd., Delek Infrastructures Ltd., Delek Power Plant Management Ltd., Delek Petroleum Ltd., Delek Property Development Ltd., Delek Overriding Royalty, Delek Israel Properties (D.P.) Ltd., Delek, Delek Hungary Limited, Mehadrin Ltd., Polikar Holdings Ltd., Gallipoli Real Estate Investments Ltd., Briza Lgyrp Ltd., and subsidiaries thereof, Elysee Downtown Ltd. and Ithaca Energy Plc
Relative of another interested party of the General Partner?	No	No	No	No
Deemed by the General Partner as having accounting and financial expertise for purposes of compliance with the minimum number determined by the board of directors pursuant to Section 92(a)(12) of the Companies Law?	No	No	No	Yes

Details	Yair Neumann	Eli Zamir	Yoram Cohen	Efraim Sadka
I.D. number:	038127833	024570582	022107098	046002747
Position at the General Partner:	Director	Independent director	External director	External director
Date of birth:	17 January 1986	8 January 1970	7 November 1965	10 July 1946
Address for service of process:	19 Abba Eban Blvd., Herzliya	5 Aharon David Gordon St., Tel Aviv	48 Medinat Hayehudim St., Herzliya	5 Dulchin Arieh St., Tel Aviv
Nationality:	Israeli	Israeli	Israeli	Israeli
Membership of board committees:	No	Audit Committee member Compensation Committee member Financial Statements Review Committee member ("**Finance Committee**") Investment Committee member	Audit Committee member, Chairman Finance Committee member Compensation Committee member, Chairman Investment Committee member	Audit Committee member Finance Committee member, Chairman Compensation Committee member Investment Committee member, Chairman
Independent director?	No	Yes	Yes	Yes
External director?	No	No	Yes	Yes
(a) If so, accounting and financial expertise or professional qualifications?	-	-	Accounting and financial expertise	Accounting and financial expertise
(b) If so, an expert external director?[40]	-	-	Yes	Yes
Employee of the General Partner, a subsidiary, an affiliate or of an interested party?	VP Business Development at Delek Group, CEO of private companies at Tshuva Group, and a director of subsidiaries of the Delek Group	No	No	No
Date of commencement of office as director:	3 September 2024	17 November 2024	31 October2024	1 April 2019
Education:	B.A. in Computer Science and Economics from Tel Aviv University, M.B.A. in Business Administration, specializing in Finance from Reichman University	B.A. in Business Administration from the College of Management, M.B.A. in Business Administration, specializing in Finance from Ben-Gurion University	B.A. in Economics and Geography from the Hebrew University of Jerusalem, M.A. in Business Administration from the Hebrew University of Jerusalem, Directors Course at Tel Aviv University	B.A. in Economics and Statistics from Tel Aviv University, Ph.D. in Economics from the Massachusetts Institute of Technology (MIT)
Occupation in the last five years:	Director at the General Partner, VP Business Development at Delek Group, CEO of private companies at Tshuva Group, Consultant in the field	Director at the General Partner, CEO of Invest-Pro – Shukai Hon Ltd., Independent Director and member of the Audit Committee at Al Systems	Director at the General Partner, CEO of Noga – Electricity System Management Ltd., CEO of Rani Zim Renewable Energy (2022) Ltd., and	External director of the General Partner, independent director of Ravad Ltd., and a director of other companies and NPOs

[40] Within the meaning of the term in Section 1 of the Compensation Regulations.

Details	Yair Neumann	Eli Zamir	Yoram Cohen	Efraim Sadka
	of capital raising and mergers at Delek Group, VP Finance at private companies of Tshuva Group, VP Finance and Head of Finance and Treasury at Discount Investment Corp. Ltd., VP Finance and Head of Finance and Treasury Department at IDB Development Corporation Ltd., Director at Ithaca Energy Plc, Director at Mehadrin Ltd., Director at El-Ad National (2023) U.S. Holdings Ltd., Director at Epsilon Investment House, and Director at Brinks Israel Ltd.	Communications Ltd., and External Director at Formula Systems (1985) Ltd.	Director at Trans Israel Ltd.	
<u>Other</u> directorships:	Ithaca Energy Plc, Mehadrin Ltd., and El-Ad National (2023) U.S. Holdings Ltd.	-	Trans Israel Ltd.	Artzdka Ltd. (Chairman), Babylonian Jewry Heritage Center (Chairman), The Pinhas Sapir Center for Development (Chairman) and Atidim High Tech Industries Co. Ltd.
Relative of another interested party of the General Partner?	No	No	No	No
Deemed by the General Partner as having accounting and financial expertise for purposes of compliance with the minimum number determined by the board of directors pursuant to Section 92(a)(12) of the Companies Law?	Yes	Yes	Yes	Yes

Regulation 26A: Senior officers of the Partnership and/or the General Partner[41]

Officer	I.D. number	Date of Birth	Date of commencement of office	Position at the Partnership, the General Partner, a subsidiary, affiliate or interested party	Interested party of the Partnership and/or the General Partner?	Relative of another senior officer or of an interested party of the Partnership and/or the General Partner?	Education	Experience in the last 5 years
Yossi Abu	033840372	7 December 1977	1 April 2011	CEO of the Partnership, member of the Donations Committee, a director of private subsidiaries (SPCs) of the Partnership, a director of Med-Enlight, Yes-Enlight General Partner Ltd. and at Enlight-NewMed Development (UK) Ltd., and the limited partner of Yes-Enlight Holdings, Limited Partnership (which were established as part of the Partnership's collaboration with Enlight, as specified in Section 7.10 of Chapter A of this Report)	Yes	No	LL.B from the Hebrew University of Jerusalem, attorney, member of the Israel Bar Association.	CEO of the Partnership, member of the Donations Committee, a director of Med-Enlight, Yes-Enlight General Partner Ltd. and at Enlight-NewMed Development (UK) Ltd., and the limited partner of Yes-Enlight Holdings, Limited Partnership, CEO of Delek Energy, and a director of private subsidiaries (SPCs) of the Partnership and private companies owned by him and a director of Techsomed Medical Technologies Ltd..
Sari Singer Kaufman	037485174	22 February 1980	14 May 2018 – EVP, 1 August 2017 – General Counsel 10 March 2012 – attorney	EVP and General Counsel of the Partnership, member of the Donations Committee and a director of a private subsidiary (SPC) of the Partnership	No	No	LL.B from Tel Aviv University, attorney, member of the Israel Bar Association	EVP and General Counsel of the Partnership, member of the Donations Committee, a director of a private subsidiary (SPC) of the Partnership, and an independent director of Steakholder Foods Ltd.
Zvi Karcz	059784355	24 February 1967	12 August 2014 - VP Exploration, 7 September 2011 - Chief Geologist	VP Exploration of the Partnership	No	No	B.Sc. in Geology from the Hebrew University of Jerusalem, M.Sc. in Geology from the Hebrew University of Jerusalem, Ph.D. in Geology and Geophysics from Columbia University, New York, U.S.	VP Exploration of the Partnership

[41] The specification of this regulation presents the officers who hold office at the Partnership as of the report approval date.

Officer	I.D. number	Date of Birth	Date of commencement of office	Position at the Partnership, the General Partner, a subsidiary, affiliate or interested party	Interested party of the Partnership and/or the General Partner?	Relative of another senior officer or of an interested party of the Partnership and/or the General Partner?	Education	Experience in the last 5 years
Tzachi Habusha	027268317	23 March 1974	1 January 2022	CFO of the Partnership, member of the Donations Committee, a director of a private subsidiary (SPC) of the Partnership. A director of Emed Pipeline Reporting Ltd. and a director of Med-Enlight	No	No	B.A. in Economics from Bar-Ilan University, LL.M from Bar-Ilan University, MBA from the College of Management, CPA	CFO of the Partnership, member of the Donations Committee, a director of a private subsidiary (SPC) of the Partnership, a director of Emed Pipeline Reporting Ltd., a director of Med-Enlight and CFO of Israel Airports Authority.
Ronen Edward	024652745	13 October 1969	1 January 2022 - VP Leviathan Project 1 August 2017 – CFO 17 May 2017 – CFO of Avner Oil & Gas Exploration - Limited Partnership	VP Leviathan Project at the Partnership	No	No	B.A. in Accounting and Business Administration from the College of Management, CPA	VP Leviathan Project at the Partnership and CFO of the Partnership and the General Partner
Tal Levi	034837245	19 April 1979	23 May 2022 – VP Budget & Control 1 June 2018 – Head of Control & Investments 10 February 2013 – Controller	VP Budget & Control at the Partnership	No	No	B.A. in Economics and Accounting from Haifa University, MBA from the Technion – Israel Institute of Technology, CPA	VP Budget & Control of the Partnership and Head of Control & Investments of the Partnership
Nadav Perry	040365447	24 April 1980	14 May 2018 - VP Regulatory & Public Affairs 14 June 2015 - Head of Media & Public Affairs	VP Regulatory & Public Affairs at the Partnership and Chairman of the Donations Committee	No	No	B.A. in Government, Diplomacy and Strategy from Reichman University, MBA from Bar-Ilan University	VP Regulatory & Public Affairs at the Partnership, and Chairman of the Donations Committee
Saar Prag	037693942	17 October 1975	3 June 2021 – VP Natural Gas Trade 1 August 2017 – Head of Natural Gas Trade	VP Natural Gas Trade at the Partnership and a director of private subsidiaries (SPCs) of the Partnership	No	No	LL.B from the Hebrew University of Jerusalem, attorney, member of the Israel Bar Association	VP Natural Gas Trade at the Partnership, a director of private subsidiaries (SPCs) of the Partnership and Head of Natural Gas Trade at the Partnership
Lior Cohen	303014237	3 April 1989	25 July 2021	Financial Controller at the Partnership	No	No	B.A. in Accounting and Economics from Tel Aviv University, CPA	Controller at the Partnership, controller at Gottex Retail Brands, and auditor at Kost Forer Gabbay & Kasierer

Officer	I.D. number	Date of Birth	Date of commencement of office	Position at the Partnership, the General Partner, a subsidiary, affiliate or interested party	Interested party of the Partnership and/or the General Partner?	Relative of another senior officer or of an interested party of the Partnership and/or the General Partner?	Education	Experience in the last 5 years
Gali Gana	059674770	2 June 1965	1 February 2016	Internal auditor of the Partnership and the General Partner, and internal auditor of Delek Group	No	No	B.A. in Accounting from the College of Management, M.A. in Internal Audit and Public Administration from Bar-Ilan University, certified information system auditor (CISA), certified internal auditor (CIA), certification in risk management assurance (CRMA), certified in Risk and Information Systems Control (CRISC), CPA	Internal auditor of the Partnership and the General Partner, internal auditor of Delek Group, and partner at Rosenblum-Holtzman, CPAs. Mr. Gana has information security and/or cyber expertise.

Regulation 26B: **Independent authorized signatories**

As of 31 December 2024, and as of the report approval date, there are no independent authorized signatories at the Partnership or the General Partner.

Regulation 27: **The Partnership's CPAs**

Ziv Haft CPAs, of 46-48 Menachem Begin Rd., Tel Aviv, and the accounting firm Kost, Forrer, Gabbay & Kasierer of 144 Menachem Begin Rd., Tel Aviv, jointly serve as the auditors of the Partnership.

Regulation 28: **Modification of the Partnership Agreement**

On 9 January 2025, the meeting of the Participation Unit holders decided to approve an amendment to Section 5.1 of the Partnership Agreement, such that the petroleum asset known as Block 1-21 Han Asparuh and located within the economic water of the Republic of Bulgaria in the Black Sea (the "**Bulgaria License**") be added to the list of petroleum assets mentioned in this section. For further details, see Regulation 29(c)(b) below and the Partnership's immediate report of 9 January 2025 (Ref.: 2025-01-003243), the information appearing in which is incorporated herein by reference.

Regulation 29: **Recommendations and decisions of the directors**

Regulation 29(a):

(a) For details on the Board's decision to approve a plan to purchase the bonds that were issued by Leviathan Bond (the "**Leviathan Bond Bonds**"), see the Partnership's immediate report of 20 October 2024 (Ref.: 2024-01-611345), the information appearing in which is incorporated herein by reference. For further details, see Section (e) of Part 1 of the Board of Directors' Report (Chapter B of this Report).

(b) On 18 March 2024 and 23 May 2024, the Board decided, after receiving the recommendation of the Finance Committee, to approve profit distributions in the sum of $60 million each, and on 7 August 2024 and 19 November 2024 the Board decided, after receiving the recommendation of the Finance Committee, to approve profit distributions in the sum of $65 million each with the record dates for the said distributions being 28 March 2024, 3 June 2024, 25 August 2024 and 28 November 2024, respectively, and the dates of the said distribution being 11

April 2024, 20 June 2024, 5 September 2024 and 12 December 2024, respectively. For further details, see the Partnership's immediate reports of 19 March 2024, 24 March 2024, 8 August 2024 and 20 November 2024 (Ref.: 2024-01-027819, 2024-01-051454, 2024-01-085054 and 2024-01-617108, respectively), the information appearing in which is incorporated herein by reference. In addition, on 9 March 2025, the Board decided, after receiving the recommendation of the Finance Committee, to approve a $60 million profit distribution, with the record date for the said distribution being 20 March 2025, and the date of the said distribution being 3 April 2025.

(c) For details on amendments to the Partnership Agreement that were made in the Report year or thereafter and until the report approval date, see Regulation 28 above.

Regulation 29(c):

(a) For details on the decision of the meeting of the Participation Unit holders of 31 October 2024 to approve the appointment of Mr. Yoram Cohen as an external director of the board of directors of the General Partner, for a term of office of 3 years beginning on the date of the said decision, and to approve his terms of office, see the Partnership's immediate reports of 25 September 2024 and 31 October 2024 (Ref.: 2024-01-605729, 2024-01-613078, 2024-01-613086 and 2024-01-613089, respectively, the information appearing in which is incorporated herein by reference.

(b) For details on the decision of the meeting of the Participation Unit holders of 30 December 2024 to approve the appointment of Fahn Kanne & Co., CPAs, together with Keidar Supervision and Management, to serve together as supervisor at the Partnership, and to approve the terms of office and employment of the Supervisor, see Regulation 21(b)(8) above.

(c) For details on the decision of the meeting of the Participation Unit holders of 9 January 2025 to approve the engagement of the Partnership in an agreement for the purchase of the interests in the Bulgaria License and participation in oil and/or natural gas exploration, development and production activities in the area of the Bulgaria license, to amend for such purpose Section 5.1 of the Partnership Agreement, and to authorize the General Partner, in accordance with the provisions of Section 9.4 of the Partnership Agreement, to refrain from profit distributions for the performance of the actions as per the work plan and budget to be approved by the partners in the Bulgaria License, and not to approve the granting of equity compensation to Mr. Abu at a rate of 5% of the of the issued share capital of NewMed Balkan and the financing of his relative share of the costs of the Initial Investment see the Partnership's immediate reports of 2 January 2025 and 9 January 2025 (Ref.: 2025-01-000782 and 2025-01-003240, respectively), the information appearing in which is incorporated herein by reference.

Regulation 29A: **Decisions of the Partnership**

(a) The outline for the collaboration between the Partnership and Enlight (as specified in Section 7.10 of Chapter A of this report) was approved by the meeting of Participation Unit holders on 21 September 2022 in consideration of, *inter alia*, the personal interest of Mr. Abu in this transaction, as specified in the Partnership's immediate reports of 6 September 2022 and 21 September 2022 (Ref.: 2022-01-092520 and 2022-01-120358, respectively) the information appearing in which is incorporated herein by reference.

(b) The engagement in the agreement to purchase the interests in the Bulgaria License was approved on 27 November 2024 by the audit committee and the board, as a transaction in which Mr. Abu has a personal interest, in consideration of the Equity Compensation granted to him on the same date. For further details see the Partnership's immediate reports of 2 January 2025 and 9 January 2025 (Ref.: 2025-01-000782 and 2025-01-003240, respectively).

Regulation 29A(4): **Exemption, insurance or undertaking to indemnify an officer**

(a) For details regarding indemnity undertakings and exemptions from liability that were granted to directors and officers of the Partnership, the General Partner and Leviathan Bond, see Regulation 29A(4) of Chapter D of the 2020 Periodic Report.

(b) For details regarding engagement in a D&O insurance policy by way of exercise of an option for a run-off period, see Regulation 22(k) of Chapter D of the 2020 Periodic Report.

(c) For details regarding an engagement in a D&O insurance policy for a period of one year from 1 July 2023, see Regulation 29A(4)(c) of Chapter D of the 2023 Periodic Report as released on 19 March 2024 (Ref.: 2024-01-027798).

(d) On 24 June 2024, the Compensation Committee and the Board, in accordance with the recommendation of the Partnership's insurance consultant, approved the Partnership's engagement in a D&O insurance policy, which covers the officers of the General Partner, the Partnership and its subsidiaries, including the Partnership's CEO, for a period of 17 months from 1 July 2024, with a total limit of liability of $270 million per claim and in the aggregate, all under terms and conditions which comply with the Compensation Policy, as specified in Regulation 21(b)(1) above. For further details, see the Partnership's immediate report of 24 June 2024 (Ref.: 2024-01-063934), the information in which is incorporated herein by reference.

(e) On 25 September 2024, the Compensation Committee and the Board approved the granting of letters of exemption and indemnification to the directors Messrs. Yoram Cohen and Yair Neumann, and the inclusion of the said directors in the D&O insurance policy of the General Partner and the Partnership, as it shall be from time to time.

Furthermore, on that date the Compensation Committee and the Board approved the granting of letters of exemption and indemnification to the other directors and officers of the General Partner and the Partnership, as follows: the directors Messrs. Gabi Last, Idan Wallace, Leora Pratt Levin, Tamir Polikar, Amos Yaron, Jacob Zack and Efraim Sadka, and the officers Messrs. Sari Singer Kaufman, Tzachi Habusha, Ronen Edward, Zvi Karcz, Nadav Perry, Saar Prag and Tal Levi and the inclusion of the said directors and officers in the D&O insurance policy of the General Partner and the Partnership, as it shall be from time to time.

(f) On 17 November 2024, the Compensation Committee and the Board approved the granting of letters of exemption and indemnification to the director Mr. Eli Zamir, and the inclusion of the said director in the D&O insurance policy of the General Partner and the Partnership, as it shall be from time to time.

NewMed Energy - Limited Partnership

by the General Partner, NewMed Energy Management Ltd.

<u>Names and positions of signatories</u>: Gabi Last, Chairman of the Board
Yossi Abu, CEO

<u>Date</u>: 9 March 2025

Part E

Report on the effectiveness of internal control over financial reporting and disclosure

This report is a convenience translation of NewMed Energy – Limited Partnership's Hebrew-language Report on the Effectiveness of Internal Control over Financial Reporting and Disclosure. The original Hebrew-language version is the only binding version and shall prevail in any event of discrepancy.

NewMed Energy – Limited Partnership

2024 Annual Report on the Effectiveness of Internal Control over Financial Reporting and Disclosure pursuant to Regulation 9B(a) of the Securities Regulations (Immediate and Periodic Reports), 5730-1970:

The management of NewMed Energy-Limited Partnership (the "**Partnership**"), under the supervision of the board of directors of NewMed Energy Management Ltd., the general partner of the Partnership (the "**GP**"), is responsible for setting and maintaining proper internal control over financial reporting and disclosure at the Partnership.

For this purpose, the members of management are:

1. Gabi Last, Chairman of the Board of the GP;
2. Yossi Abu, CEO of the Partnership;
3. Tzachi Habusha, VP Finance and Market Risk Manager of the Partnership.

Internal control over financial reporting and disclosure consists of controls and procedures existing at the Partnership, designed by, or under the supervision of, the CEO and the most senior financial officer, or by anyone actually performing such functions, under the supervision of the board of directors of the GP, which are designed to provide a reasonable level of assurance regarding the reliability of the financial reporting and the preparation of the reports according to the provisions of the law, and to ensure that information which the Partnership is required to disclose in reports released thereby according to the law is gathered, processed, summarized and reported within the time frames and in the format set forth by the law.

Internal control includes, *inter alia*, controls and procedures designed to ensure that information which the Partnership is thus required to disclose, is gathered and transferred to the management of the Partnership, including the CEO and the most senior financial officer or anyone actually performing such functions, in order to enable the timely decision making in reference to the disclosure requirement.

Due to its inherent limitations, internal control over financial reporting and disclosure is not designed to provide absolute assurance that misrepresentation or omission of information in the reports will be avoided or discovered.

The management of the Partnership, under the supervision of the board of directors of the GP, performed an examination and evaluation of the internal control over the financial reporting and disclosure at the Partnership and the effectiveness thereof.

The evaluation of the effectiveness of the internal control over the financial reporting and disclosure performed by the management of the Partnership and under the supervision of the board of directors of the GP, included: entity-level controls, including controls over the process of preparation and closing of financial reports and general controls over IT systems, controls over the process of settling of accounts vis-à-vis the operators of the joint ventures, and controls over the cash management process, including investments and the process of raising and management of bonds and loans.

Based on the evaluation of the effectiveness performed by the management of the Partnership, under the supervision of the board of directors of the GP, as provided above, the board of directors of the GP and the management of the Partnership have reached the conclusion that the internal control over the financial reporting and disclosure at the Partnership as of 31 December 2024 is effective.

Statement of CEO pursuant to Regulation 9B(d)(1):

Statement of Managers

Statement of CEO

I, Yossi Abu, state that:

(1) I have reviewed the periodic report of NewMed Energy - Limited Partnership (the "**Partnership**") for 2024 (the "**Reports**");

(2) To my knowledge, the Reports do not contain any misrepresentation nor an omission of a material fact required for the representations included therein, given the circumstances under which such representations were included, not to be misleading with regard to the period of the Reports;

(3) To my knowledge, the financial statements and other financial information included in the Reports adequately reflect, in all material respects, the financial position, operating results and cash flows of the Partnership for the periods and as of the dates covered by the Reports;

(4) I have disclosed to the Partnership's auditors, the board of directors and the audit and financial statements review committees of the GP in the Partnership, based on my most current evaluation of internal control over financial reporting and disclosure:

  a. any and all significant flaws and material weaknesses in the setting or maintaining internal control over financial reporting and disclosure which may reasonably adversely affect the Partnership's ability to gather, process, summarize or report financial information in a manner which casts a doubt on the reliability of the financial reporting and preparation of the financial statements in conformity with the provisions of the law; and-

  b. any fraud, either material or immaterial, which involves the CEO or anyone reporting to him directly or which involves other employees who play a significant role in internal control over financial reporting and disclosure;

(5) I, myself or jointly with others in the Partnership:

  a. have set controls and procedures, or confirmed the setting and maintaining of controls and procedures under my supervision, which are designed to ensure that material information in reference to the Partnership, including its consolidated companies as defined in the Securities Regulations (Annual Financial Statements), 5770-2010, is brought to my knowledge by others in the Partnership and in the consolidated companies, particularly during the preparation of the Reports; and-

  b. have set controls and procedures, or confirmed the setting and maintaining of controls and procedures under my supervision, which are designed to reasonably ensure reliability of financial reporting and preparation of the financial statements in conformity with the provisions of the law, including in conformity with GAAP;

  c. have evaluated the effectiveness of the internal control over the financial reporting and disclosure and presented, in this report, the conclusions of the board of directors of the GP in the Partnership and management of the Partnership with regard to the effectiveness of the internal control as aforesaid as of the date of the Reports.

The aforesaid does not derogate from my responsibility or from the responsibility of any other person, pursuant to any law.

9 March 2025	Yossi Abu	CEO	
Date	Full name	Title	Signature

Statement of the most senior financial officer pursuant to Regulation 9B(d)(2):

Statement of Managers

Statement of the most senior financial officer

I, Tzachi Habusha, state that:

(1) I have reviewed the financial statements and other financial information included in the reports of NewMed Energy - Limited Partnership (the "**Partnership**") for 2024 (the "**Reports**");

(2) To my knowledge, the financial statements and the other financial information included in the Reports do not contain any misrepresentation nor omission of a material fact required for the representations included therein, given the circumstances under which such representations were included, not to be misleading with regard to the period of the Reports;

(3) To my knowledge, the financial statements and other financial information included in the Reports adequately reflect, in all material respects, the financial position, operating results of operations and cash flows of the Partnership for the periods and as of the dates covered by the Reports;

(4) I have disclosed to the Partnership's auditors and to the board of directors and the audit and financial statement review committees of the GP in the Partnership, based on my most current evaluation of internal control over financial reporting and disclosure:

   a. any and all significant flaws and material weaknesses in the setting or maintaining internal control over financial reporting and disclosure, insofar as it relates to the financial statements and the other financial information included in the Reports, which may reasonably adversely affect the Partnership's ability to gather, process, summarize or report financial information in a manner which casts doubt on the reliability of the financial reporting and preparation of the financial statements in conformity with the provisions of the law; and-

   b. any fraud, either material or immaterial, which involves the CEO or anyone reporting to him directly or which involves other employees who play a significant role in internal control over financial reporting and disclosure;

(5) I, myself or jointly with others in the Partnership:

   a. have set controls and procedures, or confirmed the setting and maintaining of controls and procedures under my supervision, which are designed to ensure that material information in reference to the Partnership, including its consolidated companies as defined in the Securities Regulations (Annual Financial Statements), 5770-2010, insofar as the same is relevant to the financial statements and other financial information included in the Reports, is brought to my knowledge by others at the Partnership and in the consolidated companies, particularly during the preparation of the Reports; and-

   b. have set controls and procedures, or confirmed the setting and maintaining of controls and procedures under our supervision, which are designed to reasonably ensure reliability of financial reporting and preparation of the financial statements in conformity with the provisions of the law, including in conformity with GAAP;

c. have evaluated the effectiveness of the internal control over the financial reporting and disclosure, insofar as it pertains to the financial statements and other financial information included in the Reports, as of the date of the Reports; my conclusions regarding my evaluation as aforesaid were presented to the board of directors of the GP in the Partnership and management of the Partnership and are integrated into this report.

The aforesaid does not derogate from my responsibility or from the responsibility of any other person, pursuant to any law.

9 March 2025	Tzachi Habusha, CPA	VP Finance	
Date	Full name	Title	Signature

Valuation

GIZA SINGER EVEN

NewMed Energy - Limited Partnership

Valuation of Royalties From the Sale of the I/16 "Tanin" and I/17 "Karish" Leases

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March 2025

This document is a translation of the original Hebrew-language document by Giza Singer Even Ltd. It is prepared solely for convenience purposes. Please note that the Hebrew version is the binding version, and in any event of discrepancy – the Hebrew version shall prevail.

GIZA SINGER EVEN

Table of Contents

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Fax: 03-3730088
www.gse.co.il

1. Introduction and Disclaimer

1.1 General

This paper (the "**Paper**" and/or the "**Valuation**") was prepared by Giza Singer Even Financial Advisory Ltd. ("**GSE**") for the purpose of valuation of the royalties to which the limited partnership NewMed Energy[1] ("**NewMed Energy**" and/or the "**Partnership**") is entitled for the sale of its interests in the I/16 "Tanin" and I/17 "Karish" leases (the "**Tanin Royalties**" and the "**Karish Royalties**", respectively, and collectively: the "**Royalties**") as of 31 December 2024 (the "**Valuation Date**"). We are aware that the Paper is intended to be used by NewMed Energy, *inter alia*¸ for periodic financial statements, and therefore we agree that the Paper will be referred to and/or included in any report released by the Partnership and the interested parties therein, according to the Securities Law, 5728-1968 and the regulations thereunder.

For the preparation of the Paper we relied, *inter alia*, on representations, forecasts and explanations (the "**Information**") which we received from the Partnership and/or anyone on its behalf. GSE assumes that this Information is reliable, and it does not carry out an independent examination of the Information, nor have we become aware of anything which could indicate it being unreasonable. The Information was not examined independently, and therefore the Paper furnished to you does not constitute verification to the correctness, integrity and accuracy of this Information. An economic valuation is supposed to reflect in a reasonable and fair manner a given situation at a certain time, based on known data and while referring to basic assumptions and forecasts which were evaluated.

This Valuation includes a description of the methodology and the main assumptions and analyses which were used for the determination of the fair value of the Royalties to which the Partnership is entitled. However, the description does not purport to be a full and detailed description of all of the procedures which we implemented upon the formulation of the Valuation.

This Paper does not constitute a due diligence inspection and does not replace it. Furthermore, the Paper is also not intended to determine the value of the Royalties for the specific investor, and it does not constitute legal advice or opinion.

[1] On 17 May 2017, NewMed Energy merged with the partnership Avner Oil Exploration – Limited Partnership ("**Avner**") and as a result, the Avner partnership was struck off without dissolution.

The Paper does not include accounting auditing regarding the compliance with the accounting principles. Giza Singer Even Financial Advisory is not responsible for the manner of accounting presentation of the financial statements of the Partnership including the accuracy and integrity of the data and implications of such accounting presentation, if any.

Should the Information and data on which GSE relied, be incomplete, inaccurate or unreliable, the results of this Paper may change. We reserve the right for ourselves, to re-update the Paper in view of new data which were not presented to us. For the avoidance of doubt, this Paper is valid as of the date of signing hereof only.

It is emphasized that the Information specified in this Paper, including with respect to forecasts and the primary commercial terms in the agreement for the sale of the reservoirs, its total financial scope, the rights transferred thereunder, and the Royalties agreed therein, constitute forward-looking information within the meaning thereof in the Securities Law, 5728-1968, of which there is no certainty that it will materialize, in whole or in part, in the said manner or otherwise. The actual performance of the said Information may differ materially due to various factors such as delays in the timetables for the development of the reservoirs, etc.

We hereby confirm that we have no personal interest and/or dependence on the Partnership and/or on the general partner in the Partnership, apart from the fact that we are receiving a fee for this Paper. Furthermore, we confirm that our fee is not dependent on the results of the Paper.

Neither GSE nor any company controlled thereby directly and/or indirectly as well as any controlling shareholder, officer and employee therein, are responsible for any damage, loss or expense whatsoever, including direct and/or indirect, which will be incurred by anyone relying on the contents of this Paper in whole or in part.

1.2 Sources of Information

<u>The main sources of Information used in the preparation of the Valuation are specified below:</u>

- Information regarding the terms of the transaction for the sale of the Partnership's interests in the I/16 Tanin and I/17 Karish leases (the "**Leases**").
- Reports and publications released by Energean plc[2] (the parent company of Energean Israel Limited[3]), including a resources and reserves report as of 31 December 2023 prepared by DeGolyer and MacNaughton and released on 21 March 2024 ("**D&M CPR**").
- Immediate reports of publicly traded companies and public information released on websites (including Energean's website), journalistic articles or other public sources.

[2] Formerly, Energean Oil & Gas plc.

[3] Formerly, Ocean Energean Oil and Gas Ltd.

- Internal sources and databases of GSE.
- Meetings and/or phone calls with office holders at the Partnership.

1.3 Details of the valuating company

GSE is a subsidiary of Giza Singer Even Ltd., which is a leading financial advisory and investment banking firm in Israel. The firm has extensive experience in the advising of the large companies, the prominent privatizations and the important transactions in the Israeli market, which it accrued over its thirty years of operation. Giza Singer Even operates in three fields, through independent business divisions: financial advisory; investment banking; analytical research and corporate governance.

The Paper was prepared by a team headed by Gadi Beeri, Head of the Economic Department and Corporate Finance and a senior partner at Giza Singer Even. Gadi Beeri has expertise and vast experience in corporate finance and financial and financing advice. He holds a BA in Economics and an MBA from Tel Aviv University.

Sincerely,

גיזה זינגר אבן ייעוץ כלכלי ומימוני בע"מ

Giza Singer Even Financial Advisory Ltd.
16 February 2025

2. Executive Summary

9 March 2025

2.1 Background

NewMed Energy is a limited partnership (within the meaning thereof in the Partnerships Ordinance) listed on the Tel Aviv Stock Exchange (TASE). The Partnership engages mainly in exploration, development, production and marketing of natural gas, condensate and petroleum in Israel, Cyprus, Bulgaria and Morocco, and examines and advances options for the performance of investments in projects in the field of renewable energies.

During the years 2012 and 2013 the Partnership reported to TASE that the Karish and Tanin gas reservoirs constitute natural gas discoveries.

Following the decision of the Israeli government on a framework for the increasing of the amount of natural gas produced from the Tamar natural gas field and the quick development of the Leviathan, Karish and Tanin natural gas fields and other natural gas fields (the "**Gas Framework**"), NewMed Energy and Avner (jointly, the "**Partnerships**") and Chevron Mediterranean Ltd.[4] ("**Chevron**") were required, *inter alia*, to sell their holdings in the Leases within 14 months of the signing date of the exemption resolutions related to the Gas Framework (17 December 2015) in order to comply with the conditions which would entitle them to an exemption from several provisions of the Restrictive Trade Practices Law, 5748-1988 (the "**Restrictive Trade Practices Law**"). From 1 January 2025, this exemption has expired.

On 16 August 2016, an agreement was executed between the Partnerships and Energean Israel Limited ("**Energean**") for the sale of all of the Partnerships' interests in the Leases. The Partnership's share in the transaction was in the sum of for approx. $148.5 million, of which approx. $40 million were paid on the date of the transaction closing and $108.5 million will be paid divided into 10 equal annual installments plus interest, according to the mechanism set in the agreement (the "**Debt Component**"). As of the Valuation Date, the Debt Component has been paid in full. Furthermore, the Partnership is entitled to royalties from the revenues generated for the Buyer from the sale of natural gas and condensate produced from the Leases, at the following rates: approx. 5.12% before the payment of petroleum profit levy from the Leases and before the investment recovery date (as these are defined in the Partnership's publications) approx. 2.47% before the payment of the petroleum profit levy from the Leases and after the investment recovery date, and approx. 3.22% upon commencement of payment of the petroleum profit levy and after the investment recovery date.

[4] As of the decision date, NewMed Energy and Avner jointly held 52.941% of the reservoirs (in equal shares) and Chevron Mediterranean held 47.059% of the reservoirs.

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Following are the quantities of natural gas and hydrocarbon liquids (condensate and natural gas liquids) at the Karish and Tanin reservoirs (100%) as released in the D&M CPR[5] as of 31 December 2023:

Reservoir	Reserves and Resources	
	Natural Gas (BCM)	Hydrocarbon Liquids (MMBBL)
	2P	2P
Karish	33.4	53.2
Karish North	37.0	40.7
Tanin	25.9	4.4
Total	**96.3**	**98.3**

2.2 Result of the valuation

The value of the Royalties in the transaction for the sale of the Karish and Tanin leases was estimated through the Discounted free Cash Flow method, while adjusting the cap rate to Energean's weighted average cost of capital (WACC), as specified below in Section 5.2.8. According to the assumptions specified in the Paper itself, the total value of the Royalties as of 31 December 2024 was estimated at approx. $278.0 million (the value of the Karish Royalties (including Karish North) and the Tanin Royalties was estimated at approx. $227.2 million and approx. $50.8 million, respectively).

Below is the sensitivity analysis for the value of the Royalties in relation to changes in the cap rate and the changes in the natural gas prices (U.S. $ in millions):

		Change in the Natural Gas Price Vector (U.S. $ per MMBTU)						
		-1.50	-1.00	-0.50	-	0.50	1.00	1.50
Change in Cap Rate (in Base Points)	+250 bp	203.0	219.3	237.0	253.4	226.9	239.1	259.4
	+150 bp	210.6	227.5	245.6	262.7	236.1	248.9	270.0
	+50 bp	218.9	236.4	255.0	272.7	246.1	259.5	281.5
	-	223.4	241.1	260.0	**278.0**	251.5	265.2	287.6
	-50 bp	228.0	246.0	265.2	283.6	257.0	271.0	293.9
	-150 bp	237.8	256.5	276.3	295.4	268.9	283.6	307.6
	-250 bp	2485	268.0	288.4	308.4	281.9	297.4	322.4

[5] https://www.energean.com/media/5770/energean-israel-cpr.pdf

3. Description of Transaction for the Sale of the Interests in the Karish and Tanin Leases

3.1 Description of the Partnership

NewMed Energy is a public limited partnership (within the meaning thereof in the Partnerships Ordinance) listed on TASE. Since its establishment, the Partnership engages mainly in the exploration, development, production and sale of natural gas, condensate and petroleum in Israel, Egypt, Jordan, Cyprus, Bulgaria and Morocco, and examines and advances options for the performance of investments in projects in the field of renewal energies.

3.2 The sold interests

On 7 February 2012, and on 22 May 2013, the Partnerships reported to TASE that significant quantities of natural gas were discovered in the Tanin-1 and Karish-1 wells in the area of the exploration licenses Alon A and Alon C, respectively. In December 2015, the Petroleum Commissioner at the Ministry of Energy award the holders of interests in the exploration licenses, NewMed Energy (26.4705%), Avner (26.4705%) and Chevron (47.059%), the lease deeds of "Tanin" and "Karish", respectively. Note that in May 2017, Avner merged with and into NewMed Energy and consequently Avner was struck off, without dissolution.

On 16 August 2015, a government resolution was made regarding a framework for the regulation of the natural gas market in Israel including with respect to the interests of the Partnership in the natural gas reservoirs Tamar, Leviathan, Karish and Tanin. Under the Framework the gas and petroleum corporations operating in the gas market in Israel, including the Partnerships, were granted an exemption from several provisions of the Restrictive Trade Practices Law given compliance with several conditions, including the sale of Karish and Tanin leases within 14 months.

On 14 November 2015, the Partnerships announced that they purchased from Chevron the right to sell the share of Chevron in the Karish and Tanin leases, in equal parts, in consideration for a total amount of approx. $67 million. According to the agreement between the Partnerships and Chevron, the latter will not be entitled to any further consideration for the sale of the rights to a third party.

On 17 December 2015, the then Prime Minister (in his capacity as Minister of Economic Affairs) signed several exemptions from the Antitrust Law which were adopted in the context of the government resolution on the Gas Framework.

On 16 August 2016, an agreement for the sale of all of the interests in the Leases was signed between the Partnerships and Energean Israel Ltd. (formerly Ocean Energean Oil and Gas Ltd.), a company registered in Cyprus which is a subsidiary of Energean Plc. The buyer's principal business is exploration, development and production of gas and petroleum reservoirs in Greece and other countries in the Balkan and Middle East area.

On 27 December 2016, the Partnerships announced that the closing conditions for the transaction were fulfilled. On 27 March 2018, Energean notified the Partnerships of the adoption of an investment decision for the development of the Karish reservoir. In addition, on 14 January 2021, Energean reported the adoption of a Final Investment Decision (FID) in the "Karish North" reservoir.

On 25 October 2022, the Ministry of Energy approved for Energean commencement of production of gas from the Karish reservoir, and the following day Energean reported on initial gas production from the reservoir.

In November 2022, Energean transferred to the Partnership the first payment due to overriding royalties from its revenues in the Karish reservoir.

3.3 The consideration

Following is a description of the consideration components in the purchase agreement:

a. The Buyer will purchase from the Partnerships all of their interests and Chevron's interests in the Leases (the "**Sold Interests**").

b. In consideration for the Sold Interests, the Buyer will pay the Partnerships the amount of approx. $148.5 million which will be received in the following manner:

   i. Cash payment of $40 million which was paid to the Partnerships on the transaction closing date;
   ii. The consideration balance, in an amount of $108.5 million, will be paid to the Partnerships divided into ten equal annual installments plus interest according to the mechanism set in the agreement. These payments will be made immediately after the date on which a Final Investment Decision (FID) will be adopted regarding the development of the Leases, or on the date which the total expenses of the Buyer in relation to the development of the Leases will exceed $150 million, whichever is earlier[6]. As of the report release date, these payments have been made in full;
   iii. The Buyer will transfer to the Partnerships royalties for natural gas and condensate which will be produced from the Leases at a rate of 7.5% before payment of a petroleum profits levy by virtue of the Natural Resources Taxation Law (the "**Levy**") and 8.25% after the commencement of payment of the Levy,

[6] On 27 March 2018, Energean notified the Partnerships of the adoption of an investment decision for the development of the Karish reservoir, and from March 2018, Energean began to make the annual payments as aforesaid. For more information, see Section 4.6.2.

net of the rate of the existing royalties[7] borne by the Partnerships in respect of their original share in the Leases. Such rates are in 'wellhead' terms, while the effective payment rate is expected to be adjusted to hydrocarbon sales at the point of entry to the Israeli transmission system.

4. Description of the Business Environment

4.1 General

The natural resources exploration, development and production activity in Israel is subject to the provision of approvals under the Petroleum Law, 5712-1952 (the "**Petroleum Law**") which controls the regulation in the field and defines the type of approvals given to defined field blocks and subject to the approval of a work plan for the performance of exploration and production work.

The natural gas sector in Israel began developing upon the discoveries of the natural gas reservoirs Noa and Mari B in the years 1999 and 2000, respectively. These discoveries allowed companies in the market, headed by the Israel Electric Corporation Ltd. ("**IEC**"), to transition to more extensive use of natural gas instead of the use of more expensive contaminating fuels such as coal, diesel oil and fuel oil. The development of the sector was accelerated upon the discovery of the Tamar and Leviathan reservoirs in the years 2009 and 2010 respectively. These discoveries materially affect the energy independence of Israel, the development and expansion of uses of natural gas in the Israeli market and its status in the region.

Pursuant to the development of the industry, the natural gas sector in Israel is undergoing significant changes that include, *inter alia*, regulatory, economic and environmental changes. Within a few years, the natural gas in the Israeli economy has become the central component in the power production fuel basket, and a significant source of energy for the Israeli industry. The natural gas resources discovered in Israel are able to provide all of the gas needs of the domestic market in the coming decades and the majority of its energy needs and thus, significantly reduce the dependence of the State of Israel on foreign energy sources.

The economic merit of investments in exploration and development of natural gas reservoirs is largely influenced by the oil and gas prices worldwide, the demand for natural gas in the domestic, regional and global market, and the ability to export natural gas which requires, *inter alia*, the discovery of gas resources in significant scopes and the engagement in long-term agreements for the sale of natural gas in significant quantities, that will justify the high cost of construction of such infrastructures.

The use of natural gas holds many benefits for the Israeli market, including:

- **Reduced energy costs in the industry and in electricity production** – The low price of natural gas compared with currently common alternative fuels such as diesel oil and fuel

[7] As defined in the reports of NewMed Energy and Avner to TASE on 25 December 2016.

oil, leads to significant saving of production costs, and thereby also to a decrease in the final product prices, whose production costs mainly consist of the costs of electricity. Most of the power plants constructed in recent years in Israel generate electricity through turbines which are operated by natural gas combustion and are characterized by low construction costs,[8] shorter construction time, smaller areas of land[9] and many operational advantages. In addition to the relatively low price, power plants operated by natural gas are more efficient than plants which are operated by other fuels and therefore power plants and enterprises operate with a high energetic efficiency level which is also ultimately reflected in cost saving[10]. According to the estimates of the Natural Gas Authority for 2023[11], most of the domestic demand for natural gas derived from the electricity sector, total consumption by which in 2023 amounted to ~10.4 BCM, which represents ~80% of the demand for natural gas. The rest of the demand for natural gas is attributed to the industrial sector, total consumption by which in 2023 amounted to ~2.7 BCM.

- **Clean energy** – The main substances emitted from the burning of natural gas are carbon dioxide and water vapor. Coal and petroleum are more complex fuels, *inter alia*, because they have higher carbon ratios, and nitrogen and sulfur components. Therefore, when they burn, more contaminants are released, including ash particles of substances which are not burned and are consequently emitted into the atmosphere and add to the air pollution. Natural gas combustion, on the other hand, releases a relatively small quantity of contaminants, and therefore the use thereof reduces air pollution. In such context it is noted that thanks to the conversion of most of the electricity production in Israel from coal, fuel oil and diesel oil to use of natural gas, air pollution levels caused by electricity production in Israel have been reduced by tens of percentage points.

- **Energy independence** – The geopolitical characteristics of Israel make it an energetic island with limited ability to import fuels from neighboring countries, which forced it to rely for many years on costly fuels import from Europe. Israel's energetic isolation was somewhat reduced between the years 2008 and 2012 upon the commencement of import of natural gas from Egypt, however, the sudden cut of supply illustrated the importance of the development of local energy sources. The development of the natural gas market in Israel provides the Israeli industry with energetic security in the long term and will reduce its dependence on international energy prices.

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[8] About one half of the cost of a coal power plant, about one third of the cost of a nuclear power plant and ~15% of a wind energy operated plant.

[9] The natural gas is transported by an underground pipe and unlike other fuels, requires no storage areas. Furthermore, power plants which are based on natural gas need a considerably smaller area compared to plants which are based on coal or solar energy.

[10] A combined cycle power plant combining gas and steam turbines is characterized by an efficiency rate of 55%, significantly higher than power plants which are operated by other fuels. Cogeneration plants utilizing the thermal energy produced in the production process reach an efficiency rate of ~80%.

[11] Review of Developments in the Natural Gas Sector, Summary as of 2023 – the Natural Gas Authority

- **Natural gas as a governmental source of income through taxation** - The Israeli natural gas market is directly benefiting and is expected to continue to directly benefit the domestic economy through governmental revenues from the taxation of the companies and from the VAT from the sales to the ultimate consumer. Moreover, the Israeli market has a few unique taxation systems which apply to the natural gas sector, in addition to excise tax, which apply to natural gas, similarly to all of the other fuel products[12]. Furthermore, according to the Petroleum Law, the State charges royalties at a rate of up to. 12.5% of the market value of natural gas at the wellhead. Moreover, following the conclusions of the Sheshinski Committee, the State is entitled to proceeds of petroleum and gas profits levy at a rate of up to ~47% (deriving, *inter alia*, from the corporate tax rate) of the revenues of the holders of the petroleum rights, net of royalties, operation costs and development costs.

- **Upgrade of Israel's geostrategic position** – Thanks to the development of the gas reservoirs in Israel's exclusive economic zone (EEZ), the State has at its disposal gas resources at a scope that exceeds the existing and expected needs of the domestic market. Thus, and further to Government Resolution 442 of 13 June 2014 regarding the policy on the export of natural gas, commercial quantities of natural gas are being exported from Israel to the countries in the region. In such context, export from the Tamar reservoir to industrial enterprises located on the Jordanian side of the Dead Sea commenced in 2017, and from 2020, with the beginning of production from the Leviathan reservoir, very significant quantities of natural gas are being exported to Jordan and Egypt.[13]

4.1.1 Iron Swords War

On 7 October 2023, the terrorist organization "Hamas" launched a murderous attack on Israel, targeting in particular communities and military bases in the south of the State of Israel. Further to the attack, the Israeli government declared the Iron Swords war against the terrorist organization as aforesaid (the "**War**").

Since the outbreak of the War, the IDF has also been engaged in ongoing conflicts with the Hezbollah terrorist organization along Israel's northern border and south Lebanon. As a result of these confrontations, since the beginning of the War, northern Israel has been suffering from attacks by rocket, UAVs, and anti-tank missiles near the border.

As of the Valuation Date, the War is in full swing, and it is impossible to predict how long it will last and what its implications will be on the Partnership, its business and its assets.

Shortly after the outbreak of the War, natural gas production from the Tamar reservoir was halted according to the government's order. No such order was given for the Leviathan and

[12] Other than the electricity and industrial sectors in which consumers do not pay excise tax for the gas.
[13] For more information on the export of gas from Israel, see Section 4.5.3.

Karish reservoirs. As a result of the halting of production from the Tamar reservoir as aforesaid, the Leviathan partners supplied natural gas also to some of the customers of the Tamar reservoir in the domestic market, primarily the Israel Electric Corp. Ltd. (IEC), and consequently, the quantity of natural gas directed for export to Egypt was reduced during the shutdown period. On 9 November 2023, the Ministry of Energy notified the Tamar reservoir operator that the Tamar reservoir may be reactivated. During October 2024, the operator of the Leviathan project sent the customers a notice regarding the occurrence of a *force majeure* event, which releases the partners in the Leviathan project from their obligations under the gas agreements due to non-supply of gas as a result of the War. As of the Valuation Date, the production activity from the Leviathan, Tamar and Karish reservoirs continues as usual.

In the last two years, the credit rating agencies have updated Israel's credit rating and their rating outlooks, the latest being S&P's decision to downgrade the credit rating from A+ to A. Below is a summary of the changes to the State of Israel's credit rating in 2024:

Date of Change to Rating	Rating Agency	Previous Rating	Updated Rating
9 February 2024	Moody's	A1	A2
27 September 2024	Moody's	A2	Baa1
18 April 2024	S&P	AA-	A+
12 August 2024	Fitch	A+	A
1 October 2024	S&P	A+	A

4.2 Consumers

The natural gas market in Israel comprises several groups of consumers differentiated from each other in the nature of their activity and the characteristics of the natural gas consumption:

- **Israel Electric Corporation Ltd. ("IEC")** – a governmental company supervised by the Electricity Authority ("**PUA-E**"), *inter alia*, regarding the costs of inputs for electricity production, and in particular, the costs of natural gas. In 2023, the IEC purchased ~4.73 BCM of natural gas from the Tamar and Leviathan partners and from the Karish reservoir, compared to 2022 in which it purchased ~4.82 BCM of natural gas from the Tamar and Leviathan partners and also imported and consumed another ~0.1 BCM of natural gas. In such context it is noted that according to the decision of the Minister of Energy the IEC was required to end the engagement with the regasification vessel used for reception and regasification of imported LNG by the end of 2022. Accordingly, on 8 December 2022, the IEC ended its engagement with the regasification vessel and the remaining LNG that was then on the vessel was sold to Hadera Gateway[14]. The IEC is currently working on the construction of two more natural gas-fired power plants, which will replace units 1 and 4 of the Orot Rabin Power Plant, with a total capacity of ~1,200 MW/h. As of the date of this

[14] Source: IEC's financial statements for 2023.

report, one of such power plants is under commercial operation[15], while the second plant is also scheduled to launch operation in the coming weeks (initially in running-in format). These plants are expected to increase the demand for gas in the Israeli market, in parallel with the discontinuation of coal use scheduled by 2026. As part of the IEC's preparations for the discontinuation of coal usage, the IEC is working on the conversion to gas of the 4 production units at the Rutenberg Station in Ashkelon. However, the conversion of the first of such four units has been completed and that unit has been gas-fired (for pre-commercial-operation running-in purposes) since July 2023. On 9 August 2023, fire was ignited using gas for the first time in the first unit on the Rutenberg site as part of the quality assurance of the systems, in preparation for completing its conversion to gas. However, the IEC reported that in its estimation this phase is expected to take longer in view of the War.

In accordance with the IEC's financial statements, as of 31 December 2023, and 30 September 2024, ~62.9% and ~66.1% of the IEC's total power production for 2023 and for the first three quarters of 2024 (respectively) is through natural gas.

- **Independent power producers** – The independent power producers ("**IPPs**") are divided into several types, according to the production technologies which they use: conventional IPP, cogeneration facilities, renewable energies IPPs, pumped energy[16], and large enterprises that constructed power plants for themselves for which they received a self-production license. Section 93 of the Natural Gas Sector Law defines that natural gas sold to an independent power producer is a product subject to control under the Control of Prices of Commodities and Services Law, 5756-1996. In 2023, the natural gas consumption of IPPs and cogeneration facilities amounted to ~5.6 BCM, which represents ~43% of the overall consumption of natural gas in that year in the entire market. The IPPs' natural gas-fired production in 2022 amounted to ~6.4 GW, which constitutes ~59% of the total power produced using natural gas.

- **Large industry consumers** – This tier of consumers comprises several significant consumers, which are essential to the development of the Israeli gas sector. Consumers with significant power and reputation in the Israeli market, having extensive experience and knowledge pertaining to the operations of Israeli industry in general and the operations of the natural gas sector in Israel in particular. Most of the large industrial enterprises in the market executed agreements for the purchase of natural gas within the construction of private power plants at the enterprise's premises, for the supply of the enterprise's needs of electricity and heat (by generating steam from the residual heat of the power plants or through gas-heated boilers for the production of steam), constituting only part of the production capacity of the power plant, and the sale of the produced electricity to external consumers or to the IEC. Accordingly, the natural gas purchase

[15] https://maya.tase.co.il/he/reports/1642126

[16] In this technology, power is not produced but the energy is stored for use during peak hours or hours where it is not possible to produce power from renewable energies.

agreements signed by most of the large industrial enterprises thus far also have the characteristics of agreements with private power plants. In 2023, natural gas consumption by the industrial sector amounted to ~2.7 BCM, an increase of ~0.1 BCM compared to gas consumption in 2022.

- **Medium and small consumers** – The distribution networks' consumers sector which includes mainly medium and small enterprises and businesses, is a relatively new sector in the natural gas sector which began executing agreements for purchase and infrastructure conversion performance only in recent years. These consumers typically consume low gas pressure, at a relatively small amount, non-continuous over a whole day (24 hours), some of which not yet connected to the onshore transmission systems, or the distribution, and therefore consuming Compressed Natural Gas (CNG) – a temporary and not optimal solution, since the cost of consumption can reach twice the cost of the natural gas which is transmitted through the distribution network. According to the regulation in this respect, some of these consumers are building or planning to build small scale, natural gas-fired power plants, which are intended to provide electricity and heat to the enterprise on the premises of which such power plants are built.

- **Additional markets and consumers** – In addition to the electricity and industrial sectors, several other sectors are expected to develop in the coming years and increase the demand for natural gas, including the transportation sector which is expected to significantly increase the scope of use of natural gas, in view of a forecast for entry into the market of electric vehicles and steps promoting use of CNG-fueled heavy vehicles and construction of CNG fueling stations, as well as enterprises using natural gas as a feedstock. In addition, the government is promoting measures designed to enable the integration of natural gas in the housing sector for purposes of various household uses.

4.3 Regulatory environment

The production and sale of natural gas from reservoirs in the territorial waters of the State of Israel are subject to regulatory restrictions pertaining to the amount of gas produced, restrictions on the export of the gas outside of Israel, and others. In addition, the production and sale of natural resources in Israel, including oil and natural gas, are subject to further regulatory restrictions, as specified below:

- **Royalties to the State of Israel** – Under the Petroleum Law, a lease holder is liable for a royalty of 12.5% of the amount of natural gas or petroleum produced in the lease and the lease holder will pay the State the market value of the royalty at the wellhead. On 14 May 2020, the Natural Resources Administration at the Ministry of Energy published directives regarding the method of calculation of the royalty value at the wellhead pursuant to Section 32(B) of the Petroleum Law. The directives state that the value of the royalty at the wellhead shall be equal to 12.5% of the price of sale to customers at the point of sale, net of essential costs for treatment, processing and transportation of the petroleum, actually incurred by the lease holder between the wellhead and the point of sale. The directives further determine that the Commissioner will prescribe for each lease holder, from time to time, specific instructions for each lease, which will specify the deductible expenses, for purposes of calculating the royalty, according to the specific characteristics of the lease. Further to the aforesaid, on 6 September 2020, the Ministry of Energy published specific instructions for the Tamar reservoir and on 24 July 2022, the Ministry of Energy published specific instructions for the Leviathan reservoir.

The Tamar partners paid advances on account of royalties to the State at the rate of 11.65% in the years 2017-2018, 11.3% in the years 2019-2022 and 11.06% in the years 2023-2024. In the Leviathan reservoir, the partners paid advances on account of royalties to the State of Israel at the rate of ~11.26% in the years 2020-2022, and ~11.06% in the years 2023-2024.

According to the 2024 (unaudited) Revenues Report of the Natural Resources Administration at the Ministry of Energy[17], revenues of about ILS 2.3 billion from the natural gas royalties were recorded, reflecting an increase of ~10.9% compared with the revenues in 2023. The increase in total royalties was due to an increase in the amount of natural gas production from the reservoirs in Israel, and an increase in the amount of production for export.

In 2024, ~27.4 BCM (14.3 BCM for the domestic market and 13.1 BCM for export) were produced from the Tamar, Leviathan and Karish reservoirs, compared with ~25.3 BCM (13.7 BCM for the domestic market and 11.6 BCM for export) produced in 2023, an increase of ~8.3%.

The rate of increase in total royalties in 2024 was higher than the total rate of increase in production mainly due to an increase in production amounts and sales for export.

Production from the Karish reservoir began at the end of October 2022. The total royalties that were collected from the Karish leases in 2024 totaled approx. ILS 507.1 million from the production of ~5.96 BCM and ~5.35 million barrels of petroleum[18]. Revenues from royalties from the Karish reservoir that originate from the production of natural gas for the domestic market totaled approx. ILS 343 million (about 67.7% of the total production), while the remaining revenues from royalties originate from petroleum exports.

- **Taxation of Profits from Natural Resources Law** – The Resources Taxation Law prescribes a levy on petroleum and gas profits according to a mechanism which relates the rate of the levy and the ratio of the net accrued revenues and the total accrued investments, net, as the same are defined in the law (the "**Investment Coverage Ratio**"). The minimal levy at a rate of 20% will be charged when the Investment Coverage Ratio will reach 1.5 and will increase gradually to a rate of ~47% (depending, *inter alia*, on the Corporate Tax rate) when the Investment Coverage Ratio will reach 2.3. The levy will be calculated and imposed on each reservoir separately. On 10 November 2021, the Knesset

[17] Revenues Report of the Natural Resources Administration– Royalties, Accounting and Economics Division, the Ministry of Energy and Infrastructures

[18] The gas volume released by the State in the Revenues Report of the Natural Resources Administration is different than the gas volume released by Energean.

approved in the second and third reading a bill which prescribes, *inter alia*, rules on payment of disputed assessments.[19]

- **Antitrust**– In August 2015, a government resolution was made regarding a framework for the regulation of the natural gas market in Israel including with respect to the rights of the Partnership in the natural gas reservoirs Tamar, Leviathan, Karish and Tanin which took effect on 17 December 2015 upon the grant of an exemption from several provisions of the Economic Competition Law, 5748-1988.
The Gas Framework granted an exemption to the Partnership, Chevron and Ratio Energies - Limited Partnership ("**Ratio Energies**", and collectively: the "**Parties**"), from the restrictive arrangements pertaining to the Leviathan reservoir. Furthermore, The Gas Framework granted an exemption with respect to specific powers of the Commissioner (power to regulate acts of a monopoly through directives, power to order a holder of a monopoly to sell an asset, and power to order the separation of a monopoly), in connection with the Partnership and Chevron being holders of a monopoly by virtue of the declaration thereon by the Commissioner in 2012 (the "**Exemption**")[20].

  On 1 January 2025 the exemption expired. From such date, any agreement for the purchase of natural gas from the reservoirs shall be subject to the provisions of Chapter B of the Competition Law (regarding restrictive trade practices), as well as the provisions of Section 43(a)(1), Section 47(a)(1) and Section 50A with respect to the provisions of Chapter B and Section 50D(a)(1) of the Competition Law.

- **Stable regulatory environment** – In the original framework, the Israeli government undertook to maintain "regulatory stability" in the context of natural gas exploration and production for a period of 10 years. In March 2016, HCJ ruled that the issue of regulatory stability in the Gas Framework in the existing version was illegal. In May 2016, the government re-adopted its resolution on the Gas Framework while setting an alternative arrangement pertaining to a "regulatory stable environment" in order to ensure a regulatory environment which encourages investments in the natural gas exploration and production sector.

- **Price regulation** – In the period between the taking effect of the Gas Framework, and until the date of fulfilment of all of the conditions of the Exemption, upon completion of the sale of the Partnership's holdings in the Tamar reservoir in December 2021, the price control in

[19] Taxation of Profits from Natural Resources Law (Amendment no. 3), 5782-2021. https://main.knesset.gov.il/Activity/Legislation/Laws/Pages/LawBill.aspx?t=lawsuggestionssearch&lawitemid=2155633

[20] Declaration on holders of a monopoly under Section 26(a) of the Restrictive Trade Practices Law, 5748-1988: Delek Drilling Limited Partnership together with Avner Oil & Gas Exploration, Limited Partnership, Noble Energy Mediterranean Ltd., Isramco Negev 2, Limited Partnership, and Dor Gas Exploration, Limited Partnership – holders of a monopoly in the supply of natural gas to Israel starting from H2/2013 (13 November 2012) Restrictive Trade Practices 500249.

the natural gas sector by virtue of the Restrictive Trade Practices Law was limited to the imposition of reporting requirements regarding profitability and the gas price. Therefore, starting from Q3/2016, the Natural Gas Authority released, each quarter, the weighted price of natural gas and the price of natural gas for IPPs. Starting from the completion of the sale of the Partnership's holdings in Tamar, as aforesaid, the Gas Authority ceased to release the natural gas prices as aforesaid, and the partners in the gas reservoirs are no longer required to offer such prices to their customers. However, starting from Q1/2023, the Gas Authority resumed publication of the weighted price of natural gas in the Israeli market, without thereby imposing a duty on the partners in the gas reservoirs to offer such price to their customers.

On 1 June 2020, the decision of the Competition Commissioner was released, pursuant to Section 14 of the Economic Competition Law, 5748-1988, regarding amendment of the conditions for granting certain exemptions from approval of restrictive arrangements for several arrangements between the Tamar partners and their customers, cancelling the requirement for pre-approval of any agreement for the supply of gas from the Tamar project, in lieu of which the agreements will be subjected to a self-assessment regime, i.e. the burden of examining the lawfulness thereof will be imposed on the Tamar partners and their customers, while the Competition Commissioner will be able to examine the agreements retroactively and even not in proximity to the date of the signing thereof, and to take enforcement measures insofar as it is found that arrangements were performed that harm competition.

4.4 Risk factors

The exploration and findings development operations of oil and natural gas involve significant monetary expenses in conditions of uncertainty resulting in a very high financial risk level. Following are risk and uncertainty factors with significant effect on the operations of the Buyer and the proceeds expected therefrom:

- **Changes in the Electricity Production Tariff, price indices, alternative energy sources prices** – The prices paid by the consumers for the natural gas derive, *inter alia*, from the Electricity Production Tariff as updated by the PUA-E on an annual basis, from the Shekel/US Dollar exchange rate, the US consumer price index and the prices of fuels alternative to gas such as fuel oil, diesel oil and Brent. Furthermore, a significant change in alternative energy sources could lead to a change in the use model of the IEC such that priority shall be granted to power plants operated by gas alternatives. A decline in tariffs can also adversely affect the prices which will be obtained from the Tanin reservoir and the economic merit in the development thereof. At the same time, according to Energean's reports, the sale price in the agreements includes a "floor price".

  On 4 September 2024, PUA-E announced a hearing in the matter of determining the controlled tariff for the supplementary tariffs for the producers who are connected or combined in the transmission system according to Title C1 and E1 of the Standards. In the context of the explanations to the hearing, it was noted that PUA-E had made an examination and found out that the electricity producers are operating in a non-competitive manners, their proposals to the system manager are high, and the actual payments to them are not based on the market competitive price. On 17 November 2024, Shikun & Binui Energy Ltd.[21] Published its estimates on the damage to the power plants owned thereby (Ramat Hovav and Hagit East) according to the hearing, and noted that in the event that the hearing is approved as published, the ability of Hagit East Plant to meet the financial covenants according to its financing agreement. On 24 November 2024, Dalia Energy Companies Ltd. ("**Dalia**") published, in the context of the quarterly report[22], that there will be no material effect on the Dalia Power Plant (which is entitled to act in a bilateral manner). However, there is a concern that if the hearing is accepted as-is, the Eshkol Power Plant will not be able to meet its covenants according to its financing agreement. On 17 February 2025, PUA-E published a post-hearing decision which is "softer" than the published hearing. As a result, Dalia announced on 18 February 2025[23] that, considering the final decision, it does not anticipate any material effect on its activity nor that there is any concern to non-meeting the various financial covenants.

On 6 November 2026, in view of the changes in the Israeli electricity market, PUA-E announced[24] a call regarding changes in the structure of the electricity tariff. PUA-E suggests in the call that the production component will split into a fixed component and a variable component, include the costs of polluting greenhouse gas emissions, a more frequent and automatic update and other issues. No final decision on the matter has yet been made.

- **Growth of the renewable energy sector** – Recent years have seen a rise in the share of renewable energies in the mix of fuels used to produce electricity in Israel. Renewable energy is defined as energy produced from heat and solar radiation, wind, bio-gas and bio-mass, or any other non-depletable source that is not fossil fuel. Approx. 10.1% and ~12.5% of actual power production in the State of Israel in 2022 and 2023, respectively, came from renewable sources, but this figure is expected to rise following the addition of the quotas initiated by the government with the aim of reaching the target of electricity production from renewable sources of ~20% of the total demand for energy in 2025, and 30% by 2030[25]. The rates of renewable energies have been gradually reduced by the Authority since 2008 due to the decrease in the construction and financing costs and the holding

[21] https://mayafiles.tase.co.il/rpdf/1627001-1628000/P1627312-00.pdf
[22] https://mayafiles.tase.co.il/rpdf/1628001-1629000/P1628376-00.pdf
[23] https://mayafiles.tase.co.il/rpdf/1646001-1647000/P1646639-00.pdf
[24] https://www.gov.il/BlobFolder/rfp/kk_shinuyim_tariff/he/Files_Kol_Kore_kk_mivne_tar_06112024.pdf
[25] "Status Report – Renewable Energy Targets in the Electricity Sector" – PUA-E, 2023: https://www.gov.il/BlobFolder/generalpage/doch_pv_27022024_2023/he/Files_Pirsumei_Hareshurt_old_doch_pv_2023_27022024.pdf

of competitive processes. These trends indicate that renewable energies may account for a larger share of future power production in Israel.

- **Geopolitical risk** - The security and economic situation in Israel as well as the political situation in the Middle East may affect the willingness of states and foreign bodies, including in the Middle East, to engage in business relations with Israeli bodies and/or international bodies acting in Israel. Therefore, any deterioration in the geopolitical situation in the Middle East and/or deterioration in the relations between Israel and its neighbors, for security and/or political and/or economic reasons, may undermine the ability of the companies in the Israeli gas and oil market to promote their business with such states and bodies and export gas to neighboring states.

- **Competition in gas supply** – Over the last two decades, several significant gas reservoirs were discovered both in Israel and in other countries in the Eastern Mediterranean Basin, the development of which reservoirs may lead to the entry of additional natural gas supply competitors into the domestic market and into neighboring countries, thus increasing the competition in the sector. 2017 saw the commencement of substantial production from the Egyptian "Zohr" reservoir, which supplies gas to the domestic Egyptian market and in recent years, significant reservoirs were discovered in the EEZ of Cyprus, for which reservoirs development decisions have yet to be made.
  In Israel, exploration licenses in the EEZ were granted following two competitive processes (in 2017 and 2019), and in 2022, the Ministry of Energy published another competitive process for receipt of exploration licenses (in this section below, the "**Process**")[26]. In the context of the Process, four zones of exploration licenses were offered. In some of the zones, exploration licenses have already been given in the past, and seismic surveys and other exploration activities have already been performed in them, attesting to a possible potential for discovery of hydrocarbon reservoirs. According to the Process principles, the exploration license will be given for a 3-year period, after which the license holder may request an extension of two additional years and thereafter, of two more years (7 years in total), when specific conditions are met. In addition, in the context of the Process, exploration licenses will only be given in areas that are far from the coast, at a distance greater than at least 40 km. On 16 July 2023, the bidding phase of the Process ended, during which 6 gas exploration bids were received. The bids were submitted by 4 different groups comprised of 9 companies in total, 5 of which are new companies operating in Israel. According to the terms and conditions of the Process, the new companies will be given priority over the existing companies in receiving the exploration licenses. On 29 October 2023, the Ministry of Energy and Infrastructure announced the winners in two of the four zones that were offered. According to the announcement, 12 exploration licenses will be granted to 6 companies, of which 4 are new companies in the Israeli energy sector. In the first zone, licenses will be granted to the Partnership, to the British energy company BP, and to Azerbaijan's national petroleum company SOCAR (as an

[26] https://www.gov.il/he/departments/news/press_131222

operator). In the second zone, licenses will be granted to the Italian energy company ENI (as an operator), to Dana Petroleum (a Korean-owned Scottish company) and to Ratio Energies.

- **Restrictions on export** – Limiting the amount of exportable gas may have adverse effects in the form of surplus supply in the domestic market and reduced tariffs which may also adversely affect the prices obtained from the Tanin reservoir and the economic merit in the development thereof. In this context, it is noted that, according to the Adiri Committee's draft recommendations of July 2018, the gas export quotas as determined in Government Resolution 442 shall remain unchanged. However, according to the Committee's recommendations, the formula for calculating the export quota shall be changed, such that it will be higher relative to the formula determined by Government Resolution 442, solely for gas reservoirs that have not yet been discovered. On 25 October 2020, the government decided to form a professional team that will periodically examine the recommendations of the committee for the examination of the Government's policy regarding the natural gas sector in Israel. On 6 January 2019, the Government approved the recommendations of the Adiri Committee in Government Resolution 4442[27]. On 13 October 2021, the Adiri II Committee recommended to keep the natural gas export restrictions for existing reservoirs as determined in Government Resolution 4442, but to cancel the export restriction on new reservoirs that shall be discovered[28]. On 23 August 2023, the Minister of Energy, Israel Katz, approved expansion of natural gas export from the Tamar reservoir by 3.5 BCM per year, up around 60% from production for the same period[29]. On 16 February 2024, the Tamar partners signed an agreement for expansion of the export to Egypt by 4 BCM per year for 11 years[30]. On 26 June 2024, NewMed Energy reported that the Petroleum Commissioner at the Ministry of Energy granted the partners in the Leviathan reservoir an in-principle approval, as of now, to export additional natural gas from the Leviathan reservoir in a total quantity of up to 118 BCM, which may increase to up to 145 BCM under certain conditions.

- **Dependence on the proper function of the national transmission system** – The ability to supply the gas produced from the reservoirs to potential consumers is dependent, *inter alia*, on the development of the systems to meet market demands according to the schedules, as well as on maintaining the proper function of the national gas transmission system and the regional distribution networks.

- **Dependence on contractors and on professional service and equipment providers** – As of the Valuation Date, there are no contractors in Israel that perform most of the work required for the construction and operation of natural gas and oil reservoirs. Therefore,

[27] Website of the Ministry of Energy, Spokesman's Notice of 10 January 2019: https://www.gov.il/he/departments/news/ng_060119
[28] For more information about the existing demand and regulation on the export side, see Section 4.5.3.
[29] https://www.calcalist.co.il/local_news/article/rktertmph
[30] https://www.calcalist.co.il/market/article/hjltxxaia

the companies operating in the sector depend on foreign contractors for the performance of such work, especially during wartime. Furthermore, the number of facilities that are capable of drilling and performing development activities offshore, in general, and in deep-water, in particular, is relatively small and there is a chance that no suitable facility will be found for performing the aforesaid actions on the dates to be scheduled therefor. Consequently, the aforesaid actions may entail high costs and/or considerable delays may be caused in the schedule determined for the performance of the work.

- **Operational risks and lack of sufficient insurance coverage** – Oil and gas exploration and production activities are exposed to a variety of technical and operational risks, such as loss of control over a drilling or a well and/or a malfunction in subsea facilities or facilities above sea level, which could damage the functioning of the production and transmission system, to the point of short or long-term shutdown. There is also a risk of liability for damage deriving from contamination due to the eruption and/or leakage of liquid and/or a gas leak. Despite the insurance existing in the market, not all of the possible risks are covered or are coverable.

- **Solely estimated costs and timetables and the option of lack of means** – Estimated costs for the performance of exploration and development activities and estimated timetables for the performance thereof are based solely on general estimates and could deviate significantly. The exploration plans could significantly change, *inter alia*, following failures and/or findings which will be obtained during the performance of such actions and lead to significant gaps in the timetables and the estimated costs of such activities. In certain cases, the holder of the lease may waive the performance of certain activities required according to the work plan of the reservoirs and lose the rights therein as a result.

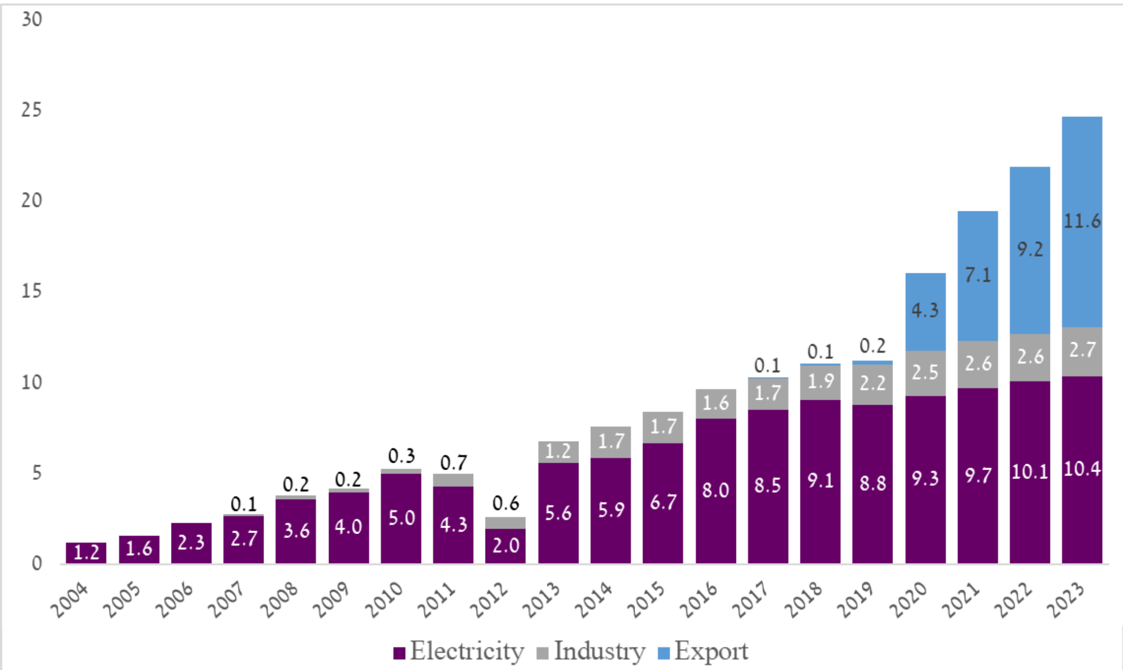
- **Regulatory changes** – The operating segment requires many regulatory approvals, mainly by the entities authorized under the Petroleum Law and the Natural Gas Sector Law, as well as related approvals of the State's authorities (including the Ministry of Energy, the Ministry of Defense, the Ministry of Environmental Protection, the tax authorities, the Competition Authority and the various planning authorities). In recent years several proposals were made for amendments of laws and/or regulations and/or directives relevant to the operating segment and several resolutions, laws and directives were released, the implementation of which could have a negative effect on the companies operating in the field.

- **Applicable environmental regulation** – The companies that operate in the natural gas sector are subject to a range of laws, regulations and directives on the issue of environmental protection, which relate to various matters such as: leaking of oil, natural gas or of other pollutants into the marine environment, the release into the sea of polluting substances and waste of various types (wastewater, residues of drilling equipment, drilling mud, slurry, etc.), chemical substances used at the various work stages, emission of pollutants into the air, light and noise nuisances, construction of piping infrastructures on the seabed and related facilities. In addition, the companies are required, through the operators of the projects, to obtain approvals from entities authorized under the Petroleum Law, the Natural Gas Sector Law and other laws (such as environmental protection laws) for the purpose of their activity.

Additional risk factors – There are other factors which contribute to the uncertainty prevailing in the operating segment including difficulties in obtaining financing, information security risks, dependence on material customers, dependence on weather and sea conditions, cancellation or expiration of rights and petroleum assets and more.

4.5 Demand

Chart 1 – Natural gas consumption in the domestic market in 2004-2023 in BCM per year[31]



The production of natural gas in the Israeli market in 2023 (including export of Israeli gas to neighboring countries) amounted to ~24.7 BCM, reflecting an increase of ~12.8% compared with the consumption in 2022. Approx. 45% of the amount was supplied from the Leviathan reservoir, ~37% of the amount was supplied from the Tamar reservoir and ~18% of the amount was supplied from the Karish-Tanin reservoir. The consumption in the domestic market (which consumption is comprised of industry and electricity) increased to 13.1 BCM, reflecting an annual increase of 3%, and the export increased to 11.6 BCM, reflecting an annual increase of 26% compared with 2022. From 2004 until the end of 2023, a total quantity of ~176 BCM of

[31] Source: Review of the developments in the natural gas sector, 2023 summary, Natural Gas Authority https://www.gov.il/BlobFolder/reports/ng-2023/he/ng-2023.pdf

natural gas was produced. The Natural Gas Authority estimates that the upward trend in natural gas consumption will also continue in the coming years, both as a result of domestic demand and as a result of demand for export.

Below are the main factors expected to motivate growth in the demand for natural gas:

4.5.1 The electricity sector

In recent years, a trend is apparent of a significant reduction of use of petroleum and coal distillates in power production and transition to use of natural gas and renewable energies. This trend is led by the Ministry of Energy and government decisions determining goals for the reduction of use of polluting fuels, *inter alia*, by shutting down IEC power plants and conversion thereof to production with natural gas, in parallel with the privatization of some of the IEC production plants, the construction of two gas plants and granting licenses for the construction of new plants by private producers. As of 31 December 2023, the IEC has nine units of gas turbines in a combined cycle ("**CCGT**"), sixteen units of jet gas turbines and nine units of industrial gas turbines[32]. Government decisions adopted in such regard are specified below:

- In August 2016, the Minister of Energy announced his decision to shut down four coal production units of IEC upon the connection of three gas reservoirs to the shore and the construction of new natural gas operated power plants within six years. Following that, in September 2016, emission permits were received by the IEC under the Clean Air Law 5768-2008, with respect to its coal power plant sites, which included, *inter alia*, the shutdown of units 1-4 in the coal power plant at the Orot Rabin site, no later than 1 June 2022.

- In November 2017, the Minister of Energy decided of principles of policy on the issue of minimal operation of coal production units, according to which natural gas electricity production shall be granted preference at any time to electricity production with coal, while operating the coal units at a minimal load which allows flexibility and reliability of the supply to the market.

- In March 2018, the Finance Committee of the Knesset, followed by the plenum of the Knesset, approved the orders, which prescribed, *inter alia*, that the excise tax on coal will be increased as of 15 March 2019 by ~125% in view of the government's policy to internalize external costs of fuels and encourage a broader use of natural gas. On 12 December 2024, the Tax Authority announced that effective from 1 January 2025, excise tax will be ILS 152.04 per ton of coal[33].

[32] A turbine operated by industrial jet engines, powered by diesel fuel with the option of converting to work with natural gas.
[33] Website of the Tax Authority – https://www.gov.il/he/departments/general/heshavon31819

- In June 2018, a government decision was adopted to implement a reform in the electricity market and a restructuring of the IEC (Resolution No. 3859). According to the reform, a plan was formulated under which the IEC would sell various power plants and build and operate two new natural gas-fired power plants, to replace units 1-4 of the Orot Rabin Power Plant. Aside from these, the IEC would not be permitted to build new power plants or upgrade existing plants. The reform also established principles for maintaining the IEC's activities in the transmission and distribution segments, and principles for gradually opening up the supply segment to competition.

- In October 2018, the Minister of Energy presented a plan whose purpose is to lead to a reduction in the use of polluting energy, the principle of which is to decrease the use of polluting fuel products by 2030. According to the plan, targets have been set for the following sectors:

  a. The electricity sector – Electricity production using 80% natural gas and 20% renewable energies as of 2030, with a final shutdown of the coal-fired power plants in Hadera and in Ashkelon in 2028.

  b. The industrial sector – Production of 95% of the energy and steam required by the industry by means of natural gas as of 2030.

  c. The transportation sector – A gradual transition to electric cars and natural gas trucks and the imposition of an absolute ban on the import of cars that operate on polluting fuels as of 2030.

- In November 2019, the Minister of Energy announced that it is possible to shorten the timetables for the conversion of the coal power plants in Hadera and in Ashkelon to natural gas to 2025. Consequently, in that year, the coal age in the State of Israel is expected to end. The aforesaid decision shortens the timetables that were previously determined by 4 years.

- On 24 June 2020, the Minister of Energy[34] announced his decision to further reduce ~20% of the use of coal in IEC's power plants, as compared with 2019. Therefore, the use of coal in 2020 will not exceed 24.9% (compared with 30% in 2019).

- On 25 October 2020, a government resolution was adopted on the subject of promotion of renewable energy in the electricity market, a resolution which was based *inter alia* on the policy principles set forth by the Minister of Energy in July 2020, according to which, electricity production from renewable energies in 2030 shall be 30% of the total electricity consumption, and electricity production from natural gas shall be 70% of the total electricity consumption. In addition, the interim goal was updated such that electricity

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[34] Website of the Ministry of Energy, Spokesman's Notice of 24 June 2020: https://www.gov.il/he/departments/news/press_240620

production from renewable energies shall be 20% by the end of 2025. The implementation of such policy may affect the demand for natural gas in the domestic market.

- On 8 February 2021, it was reported that the Minister of Energy had instructed the IEC to reduce the use of coal such that it shall not exceed 22.5% of the total electricity production in 2021, as part of the policy to end the coal era in Israel by 2025.[35]

- On 18 April 2021, the Ministry of Energy released a Road Map[36] until 2050 for the low carbon energy sector, which continues the program to reduce the use of polluting energy which was presented in 2018. In accordance with the program, the following targets for the sectors were determined:

  a. Electricity sector – The production of electricity by using 70% natural gas and 30% renewable energies beginning in 2030, while ending the use of coal for electricity production in Israel by 2025.

  b. The transportation sector – A gradual shift to electric cars and natural gas trucks, so that by 2030 the number of electric cars sold will be 50% of the total cars sold in Israel. Furthermore, Israel will adopt the common regulation worldwide and beginning in 2030 it will impose a total prohibition on the import of cars which run on polluting fuels.

- According to the PUA-E's Electricity Sector Status Report for 2023, the total installed capacity of the IEC's natural gas-fired production facilities in 2023 was ~46%. This figure is expected to increase significantly to ~84% of the IEC's total capacity in 2025.[37]

- On 13 August 2023, following the policy to discontinue the use of coal, the Ministry of Energy and Infrastructure announced that the Natural Gas Authority at the Ministry of Energy and Infrastructure approved the conversion to gas of the two new electricity production units at the Orot Rabin Power Plant (CCGT 70 and CCGT 80) which are expected to be the first two units to be powered by gas at the Plant.[38]

- According to the IEC's quarterly report for the period ended 30 September 2024, in August 2023, CCGT unit 70 was synchronized with the grid, and according to reports in the media from 21 January 2025 – the certification of completion for CCGT unit 70 was received from the city. With respect to CCGT 80, there has been a delay in the project due to a lack of foreign experts in view of the War. In addition, there has been a delay due to additional discrepancies under the responsibility of General Electric, and due to a delay in the supply

[35] https://www.calcalist.co.il/local/articles/0,7340,L-3892470,00.html
[36] https://www.gov.il/he/departments/publications/reports/energy_180421
[37] https://www.gov.il/he/pages/dochmeshek
https://www.gov.il/BlobFolder/generalpage/dochmeshek/he/Files_Netunei_hashmal_doch_s_2022_nnn.pdf
[38] https://www.gov.il/he/departments/news/news-130823

of equipment under the responsibility of General Electric. The IEC estimates that the operation of this unit for running-in purposes in expected in the coming days. The commercial operation of CCGT 80 will most likely be delayed to June 2025.[39]

- According to IEC's annual report for the period ended 31 December 2023, ~53.5% of IEC's total installed production capacity is through units that can be operated with natural gas.[40]

4.5.2 Transition to use of natural gas in industry

- Natural gas is a central component of the industry's energy consumption (~32.5% of the total use of fuels in Israeli industry in 2020)[41]. The enterprises are connected to natural gas through transmission and distribution networks, with the transmission and distribution fees supervised by the Natural Gas Authority.

- According to a summary review of the developments in the natural gas market by the Natural Gas Authority at the Ministry of Energy for 2023, ~660 km of distribution pipelines have been laid out to date throughout Israel (~32 km of which in 2022) and ~900 km of transmission pipelines. An expansion of the natural gas distribution network may enable the connection to the network, by 2030, of hundreds of potential industrial consumers whose consumption may amount to ~0.72 BCM per year, representing ~80% of the light industrial consumption potential.

- According to the Natural Gas Authority's estimations, without additional policy steps, until 2025, ~150 consumers with a total consumption of ~0.45 BCM, which represents approx. one half of the overall connection potential of the light industry consumers are expected to connect to the distribution network. Further potential consumption of ~0.27 BCM which derives from the connection of ~300 additional, smaller, plants, is expected to materialize following the implementation of additional policy steps (such as budgetary support in the layout of the distribution network, encouragement of consumers to use natural gas etc.).

- According to the Natural Gas Authority's estimations, in 2030, the total demand for natural gas in the industrial sector is expected to exceed 3 BCM, of which ~2.25 BCM are from consumption of natural gas in the industry for consumers that are connected to the transmission system, and ~0.84 BCM are from consumption of natural gas for consumers that are connected to the distribution network.

- On 10 July 2020, the Ministry of Energy released a legislative memorandum for the amendment of the Natural Gas Sector Law, whereby the Minister of Energy may grant a license for the construction of a particular distribution network to Israel Natural Gas Lines

[39] Israel Electric Corp. Ltd., quarterly report for the period ended 30 September 2024 (tase.co.il)
[40] https://ieccontent.iec.co.il/media/b5pohgzs/meshulav1223_isa.pdf
[41] Source: 2020 Israeli Energy Sector Review – the Ministry of Energy: energy_sector_review_2020.pdf (www.gov.il)

Ltd. ("**INGL**"), should he find that there is an urgent need therefor, and no private-sector body is able and willing to build the system. The purpose of the said legislative memorandum is to enable the acceleration of the connection of industry enterprises to the natural gas infrastructure.

4.5.3 Export

The business relations between the countries in the region have led to the signing of agreements for export of natural gas from Israel to its neighbors, as specified below:

- On 26 September 2016, an agreement was signed between the Leviathan partners and the Jordanian electric power company (NEPCO) for the supply of up to ~45 BCM of natural gas for a period of ~15 years. According to a report of NewMed Energy dated 31 December 2019, flow of natural gas has begun from the Leviathan reservoir to the customers with which gas agreements were signed, and from 1 January 2020 also to NEPCO.

- On 19 February 2018, agreements were signed between NewMed Energy and Chevron, and Dolphinus, an Egyptian company, which were assigned on 26 September 2018 to the Tamar partners and the Leviathan partners. On 26 September 2019, amendments were signed to the said export agreements for the supply of natural gas from the Tamar reservoir and the Leviathan reservoir in quantities of ~25.3 BCM and ~60 BCM, respectively, for a period of ~15 years. The Take-or-Pay mechanism in the amended export agreements includes a reduction of the minimal annual consumption commitment to 50% for a calendar year in which the average Brent price is lower than 50 dollars. On 15 January 2020 the Leviathan partners reported the commencement of the flow of gas to Egypt, and gas flow from the Tamar reservoir to Egypt began in July 2020.

- On 15 February 2021, the partners in the Tamar and Leviathan reservoirs reported the fulfillment of the closing conditions in the transmission agreement that was signed with INGL for the export of gas to Egypt in a manner that will allow flow on a regular basis and increased sale quantities to Egypt according to the supply conditions in the gas sale agreements of the various partnerships.

- On 16 February 2022, the Ministry of Energy approved[42], in view of the increasing demand for natural gas in Egypt, piping of natural gas through the Kingdom of Jordan. The actual piping of the natural gas began on 1 March 2022[43] and increased the volume of natural gas exported to neighboring countries in a manner that secured supply of the annual contract quantity required under the export agreements and beyond in 2022-2023.

[42] "New route for the export of natural gas to Egypt – Jordan North!" – Ministry of Energy, 16 February 2022 https://www.gov.il/he/departments/news/ng_160222

[43] https://mayafiles.tase.co.il/rpdf/1433001-1434000/P1433795-00.pdf

- On 8 May 2023, the Government of Israel, led by the Ministry of Energy and Infrastructure and INGL, approved a plan to increase the infrastructure for the export of natural gas to Egypt. The approved plan includes the establishment of an integrated infrastructure strip and infrastructure facilities in the route between Ramat Hovav and the border with Egypt in the Nitzana area, in addition to the existing maritime pipeline (EMG), and it is expected to increase the potential quantities of natural gas export to Egypt. The length of the segment (Ramat Hovav-Ashalim-Nitzana) is ~65 km, and it will allow the piping of another ~6 BCM per annum to Egypt. The value of the State revenues from exports on this scale is estimated at hundreds of millions of shekels per year from taxes and royalties. Further to the aforesaid, the Ministry of Energy published designated regulation for the allocation of the capacity and the costs associated with the construction of this pipeline among the various gas exporters. As of the report release date, the partners in the Leviathan, Tamar and Energean reservoirs are conducting negotiations with INGL with respect to the terms and conditions of the agreement for the construction and transport at the Nitzana line.

- On 23 August 2023, the Minister of Energy and Infrastructure announced the approval of the increase of the gas export quota from the Tamar reservoir to Egypt. According to the approval outline, the volume of the gas production will increase by 6 BCM per year (an increase of ~60% compared to the current production volume) starting in 2026, 3.5 BCM of which will be earmarked for Egypt. Further to the aforesaid report, on 14 December 2023, the Tamar reservoir partners announced that the Ministry of Energy authorized them to increase the export permit of the reservoir, from 38.7 BCM (approved in August) to 43 BCM. This quantity will enable to increase the additional maximum gas quantity permitted to be exported to Egypt from 3.5 BCM per year to 4 BCM per year. On 15 February 2024, an amendment to the Tamar reservoir export agreement to Egypt was signed. As part of the amendment, the sellers undertook to supply the buyer with an additional quantity of ~4 BCM per year (a quantity that varies between 350 and 450 MMCF per day), which amounts to a total of ~43 BCM, over and above the existing amount in the agreement prior to its amendment, starting in July 2025, and subject to conditions precedent, mainly the completion of the expansion work of the Tamar reservoir and the completion of the expansion of the transmission system so as to allow the transfer of such additional gas quantities.[44]

- On 27 December 2023, the Minister of Energy and Infrastructure announced the formation of an inter-ministerial committee for the periodic examination of the policy of the natural gas sector. They chairperson of the committee will be the director general of the Ministry of Energy and its members will be representatives on behalf of the PUA-E, the Ministry of Environmental Protection, the National Economic Council, the Ministry of Finance, the Competition Authority, the Ministry of Justice, The Ministry of Foreign Affairs, and the National Security Council. One of the duties of the committee, which convenes once every 5 years, will be to examine the policy on gas exports in new gas reservoirs. The committee

[44] https://maya.tase.co.il/reports/details/1574898

is expected to complete its work within several months, and to submit its conclusions to the government in 2024.

- On 26 June 2024, NewMed Energy reported that the Petroleum Commissioner at the Ministry of Energy granted the partners in the Leviathan reservoir an in-principle approval, as of now, to export additional natural gas from the Leviathan reservoir in a total quantity of up to 118 BCM, which may increase to up to 145 BCM under certain conditions.

4.5.4 Energy prices globally and in Israel

- As a result of the global decrease in coal prices in the years 2023-2024 (as of 31 December 2024, a ton of coal is traded for approx. $113.95 compared with approx. $190.5 on 31 December 2022[45]), the PUA-E decreased the electricity tariff for the domestic consumer starting from February and April for 2023 by ~1.5% and 2.4%, respectively, after it increased it by ~8.2% in January of that year. In 2025 the tariff raised by ~3.8% (these changes include the weighting of the payment for the energy consumed from the grid (kWh), the payment for capacity according to the size of the consumer's connection to the grid, and the cost of the consumerism services (fixed payment)).[46] Following the outbreak of the war between Russia and Ukraine at the beginning of 2022, global energy prices skyrocketed, further to the increases in energy prices in 2021 (compared with the Covid period). Despite the slight downward trend in energy prices in H2/2022, the current global oil prices also continue to be higher than on the eve of the war's outbreak. For example, the average price of a Brent barrel in August 2024 was approx. $83.56, compared with an average price of approx. $70.86 per Brent barrel in 2021[47].

- 2022 saw a drastic increase in gas prices, created because of a combination of several unique factors, and causing great difficulty throughout the world in the allocation of the limited gas supply. This increase occurred against the backdrop of the vast volatility in the global gas market at the end of 2021 and the resulting reduction in trade volumes. In addition, the eruption of the war between Russia and Ukraine in 2022 and the explosion of the Nord Stream pipeline in September 2022, caused gas prices to increase several more times, and to break new records each time. A record gas price was reached at the end of August 2022, when the natural gas price index reached the level of ~454 points (100 = 2010 average), compared with an average level of ~130.67 points in 2021.

- As of December 2024, the gas price index is ~111.2 points[48]. The decrease in gas prices was caused mainly due to adjustments on the part of the demand in Europe and Asia, growth of the global gas supply and elimination of infrastructural bottlenecks. However, the

[45] https://markets.businessinsider.com/commodities/coal-price
[46] Decision No. 65203 – Update of the Electricity Tariff for IEC Consumers
[47] Brent crude oil price annually 1976-2024 | Statista
[48] A World Bank Monthly Commodity Price Data (The Pink Sheet): CMO-Pink-Sheet-Januar-2025.pdf (worldbank.org)

shortage in the global supply, which was among the causes for the increase in prices still exists, and the market is still in a state of a fragile and unstable equilibrium.

- On 23 April 2024, the global gas association released the 2023 annual price report.[49] According to the report, in 2023 the gas price in Israel was among the lowest in the world from among the countries that do not subsidize the natural gas price, except Canada, the U.S. and Mexico. In 2023, the gas prices in Israel were less than $5 per MMBTU on average. The State of Israel does not depend on the import of natural gas, and it supplies the principal part of the demand itself. Furthermore, the gas prices in Israel are fixed in long-term agreements and are therefore not directly impacted by changes in global energy prices. Nevertheless, natural gas prices in Israel are indirectly affected due to the linkage components under the contracts for the purchase of natural gas in Israel, mainly to the dollar and to the production component in the electricity tariff.

- According to a forecast prepared for the Partnership by an outside consultant, the domestic demand for natural gas is expected to gradually increase to ~15 and ~20 BCM in 2025 and 2035, respectively. The increase in the domestic demand between 2024-2035 is expected to derive mainly from an addition of ~3.7 BCM as a result of the transportation electrification, an addition of ~2.6% BCM as a result of discontinuance of the use of coal for electricity production, and of an addition of ~4.3 BCM as a result of natural growth in the demand for electricity (population growth, improvement in the standard of living and in disposable income). Conversely, the demand forecast includes a decline in domestic demand for natural gas of ~4.3 BCM due to renewable energies penetrating the domestic market, and in reference to the current target of the Ministry of Energy for electricity production from renewable energies to account for 30% of all power consumption in 2030.

4.6 Market developments

4.6.1 The "Tamar" and "Leviathan" leases

- On 31 December 2019, the Leviathan partners reported the commencement of natural gas flow from the Leviathan reservoir to customers according to the agreements signed with them for the supply of natural gas from the reservoir. Further thereto, it was reported that on 1 January 2020 and on 15 January 2020, the gas flow from the Leviathan reservoir began to Jordan and to Egypt, respectively.

- On 19 January 2021, the Partnership and INGL reported that INGL had entered into an agreement with Chevron for the provision of transmission services on a firm basis for the purpose of piping natural gas from the Leviathan reservoir and from the Tamar reservoir to EMG's terminal in Ashkelon for export to Egypt. According to the agreement, Chevron undertakes to purchase ~5.5 BCM of the piping capacity of the transmission system per year, and at least 44 BCM throughout the term of the agreement. Conversely, INGL

[49] Wholesale Gas Price Survey 2024 Edition – IGU

undertook to transmit no less than the aforesaid gas quantity on a firm basis, while the remaining required quantity will be piped on an interruptible basis. It was further clarified that, in the Partnership's estimation, the transmission system was planned in a manner enabling the piping of the full quantities of gas required under the agreement. In the Partnership's estimation, INGL's expected income under the agreement is expected to total approx. ILS 170 million per year. The transmission agreement will end on the earlier of: (1) the date on which the total quantity piped is 44 BCM; (2) 8 years after the date of commencement of the flow (between July 2022 and April 2023); or (3) upon expiration of the company's transmission license. The report further clarified that the Partnership does not expect any difficulty extending the agreement upon its expiry. On 15 February 2021, INGL reported the fulfillment of the closing conditions determined in the agreement. However, due to the fact that INGL has not yet completed the pipeline section between Ashdod and Ashkelon, the agreement has not yet taken effect. In addition to the aforesaid, on 27 February 2023, INGL informed Chevron that due to a malfunction in a ship carrying out infrastructure work for the laying of a subsea pipeline for INGL in the Ashdod-Ashkelon subsea transmission system segment, a delay of at least 6 months in the completion of the project is expected, such that the window of time during which commencement of the gas flow is possible has been postponed to the period from 1 October 2023 to 1 April 2024. According to the said INGL notice, the said event constitutes *force majeure* as defined in the transmission agreement between the parties. In response to the notice, Chevron approached INGL with a request for additional details and stated that according to the details held thereby, the said event should not be deemed as *force majeure*. With the outbreak of the Iron Swords War, INGL informed Chevron of suspension of the work for the laying of the offshore pipeline and the departure of the vessel that was engaged in the laying thereof. As of the Valuation Date, this vessel has not resumed operations, and the Partnership estimates that this vessel is expected to resume operations toward mid-2025, and the laying of the said pipeline is expected to be completed toward the end of 2025.

- On 4 July 2021, The IEC entered into a SPOT agreement with the Leviathan partners for the purchase of natural gas from the Leviathan reservoir, which is valid for one year, in which framework it was agreed that the gas price will be determined every month and the parties have no commitment regarding the quantities purchased. On 28 June 2023, the SPOT agreement for the purchase of natural gas from the Leviathan reservoir was extended by another year until 4 July 2024.

- On 24 January 2022, the partners in the Tamar reservoir reported the signing of an amendment to the 2012 IEC-Tamar Agreement[50], whereby the gas price by which the IEC is bound in 2021 under the IEC-Tamar agreement of 2012 will be reduced by a rate several percent higher than the rate of the maximum reduction determined in the reduction mechanisms in this agreement for that year and for subsequent years. It was also

[50] https://maya.tase.co.il/reports/details/1427402/2/0

determined that the parties to the agreement will reserve the right to a price adjustment (10% up or down) on 1 January 2025 (instead of 1 July 2024 in the 2012 IEC-Tamar Agreement)[51]. In addition, the term of the 2012 IEC-Tamar Agreement was extended by another 2.5 years, such that this agreement will end on 31 December 2030 (the "**Date of Conclusion of the Amended Agreement**"). The gas price in the 2012 IEC-Tamar Agreement after the reduction determined in 2021 will be linked to the U.S. Consumer Price Index (the "**U.S. CPI**"), as follows:

- An increase of up to 2.25% will be taken into account in full.
- An increase of between 2.25% and 3.75% will not be taken into account in the relevant year, and may accrue and be taken into account in subsequent years only insofar as the rate of the rise in the U.S. CPI therein is less than 2.25%, and in any event the linkage in such years shall not exceed 2.25%.
- An increase of over 3.75% will be taken into account in full (the portion exceeding 3.75%).
- 1% per annum will be deducted from the above weighted linkage rate.

The IEC also undertook to purchase an additional 16 BCM (over and above the quantity to which it committed in the 2012 IEC-Tamar Agreement) until the Date of Conclusion of the Amended Agreement (in accordance with its operational needs). Insofar as the IEC does not consume the total natural gas quantity to which it committed until such date, the agreement will automatically be extended until consumption of the full natural gas quantity. The price per unit of heat (MMBTU) for this additional quantity was determined in the agreement at approx. $4, without linkage and without rights to adjustments in the future. On 24 July 2022, the agreement took effect after the satisfaction of all conditions precedent.

- On 31 December 2024, according to NewMed Energy's reports, the agreement for contribution to funding the building of a compression terminal outside of Israel in the transmission system to Egypt for the local transmission company and the agreement for the provision of transmission services, took effect. Under the agreement, it was determined that the amount of contribution in funding shall be limited to approx. $331 million, and the transmission company shall be responsible for the construction and operation of the project, for which it shall receive payment from Chevron. Chevron shall be entitled to receive annual reimbursements from the transmission company for the contribution to the funding, as well as reimbursements for some of the plant's operating and maintenance fees. The holders of interests in the Tamar and Leviathan reservoirs signed an agreement with Chevron back-to-back with the agreement for participation in financing, as well as for supplemental management fees for Chevron.

[51] In the IEC-Tamar agreement of 2012, the Parties determined two dates on which each party may request adjustment of the purchase price, 1 July 2021 and 31 December 2024. According to the mechanism determined, the IEC may request a price adjustment of up to 25% on the first date and up to 10% on the second date.

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- On 23 February 2025, NewMed Energy reported that the partners in the Leviathan reservoir submitted an updated plan for the development of the Leviathan reservoir to the Petroleum Commissioner at the Ministry of Energy. The updated plan includes two phases:
  a. The drilling of 3 additional production wells, addition of subsea systems, and expansion of the treatment facilities on the platform. Such actions will increase the volume of gas production from the reservoir by ~21 BCM per year. The cost of this phase is estimated at approx. $2.4 billion.
  b. The drilling of additional production wells and subsea systems and also, as required, the construction of a fourth pipeline between the field and the platform. This phase is expected to increase the volume of the production of gas from the reservoir by ~2 BCM per year.

4.6.2 "Karish" and "Tanin" leases

- **Adoption of an investment decision** – On 27 March 2018, Energean notified the Partnership of the adoption of an investment decision for the development of the Karish reservoir. Further thereto, starting from March 2018 and until 31 December 2023, Energean paid the Partnership approx. $81.35 million (6 of 10 installments, including interest) and the balance of the debt component to the Partnership was paid in 2024.

- **Listing of Energean on the Israeli stock exchange** – On 29 October 2018, trading of Energean Israel's parent company, Energean plc, was launched on the Tel Aviv Stock Exchange as a cross-listed company whose shares are additionally also premium-listed on the London Stock Exchange.

- **Commencement of manufacture of Energean's floating production facility** – On 27 November 2018, Energean announced commencement of manufacture, in China, of the floating production facility (FPSO) that is currently used by the Karish and Karish North reservoirs. The facility treats the natural gas produced at the projects and is located in Israel's EEZ at a distance of ~90 km from the shore.

- **Signing of an agreement for the construction and delivery of the eastern section of the infrastructure for gas transmission from the Leases** – On 25 June 2019, Energean announced that it signed an agreement with INGL, whereby it would build and transfer to INGL the eastern section of the gas infrastructure, which includes an offshore section ~10 km off the coast and an onshore section. In consideration therefor, INGL will pay Energean approx. ILS 369 million.

- **Signing of agreements for the sale of natural gas to the Alon Tavor power plant**– On 21 November 2019, Rapac Energy Ltd. reported that MRC Group, the winner of IEC's tender for the purchase of the Alon Tavor power plant, engaged in an agreement with Energean for the supply of natural gas in an annual amount of ~0.5 BCM for a period of 15 yeas (and in total up to 8 BCM). On 17 December 2020, Energean reported that it had engaged with Rapac Energy Ltd. in an additional agreement for supply of natural gas at an average annual amount of ~0.4 BCM for a period of 6 to 15 years, in addition to the existing signed agreements between Energean and Rapac Energy.

- **The signing of an MOU between Energean and Greece's gas transmission corporation (DEPA) for the sale of natural gas** – Ahead of the expected signing of the East Med Pipeline agreement by the governments and Energy Ministers of Cyprus, Greece and Israel, on 2 January 2020, Energean signed an MOU with DEPA for the possible sale of up to 2 BCM of natural gas per year from the reservoirs held by the company in Israel, the gas from which will be produced through the floating production facility (FPSO).

- **The dispute between Energean and NewMed Energy in connection with the right to receive royalties from the reservoirs** – Further to Energean's report of 9 April 2020, regarding an update of the scope of the resources in the "Karish North" well, in April 2020, Energean and the Partnership exchanged letters in connection with claims raised by Energean with respect to the Partnership's rights to receive royalties from the Leases. Energean claims that (a) the Partnership's overriding royalty does not apply to the Karish North reservoir (as opposed to the Karish reservoir), and (b) not all the hydrocarbon liquids to be produced from the Karish lease constitute condensate under the sale agreement which is subject to the obligation to pay royalties. It is the Partnership's position, based on its legal counsel, that Energean's obligation to pay royalties applies with respect to natural gas and condensate to be produced from the Leases, including from the Karish North reservoir, and that all of the hydrocarbon liquids to be produced from the reservoirs in the area of the Leases constitute Condensate, as defined in the agreement which is subject to royalties. Up to the date of approval of the Valuation, Energean paid the Partnership – under protest – royalties for all of the condensate produced from the Karish lease and for the natural gas and all of the condensate from the Karish North reservoir.

- **Signing of an agreement for the sale of natural gas with Ramat Hovav partnership** – On 16 September 2020, Energean reported its engagement in agreements for the supply of natural gas from the Karish reservoir with the Ramat Hovav partnership (Edeltech and Shikun & Binui). According to the agreements, Energean will sell the Ramat Hovav partnership natural gas from the date of commencement of natural gas flow from the Karish field, at an annual quantity of ~1.4 BCM. The agreements include provisions on a floor price and a Take-or-Pay mechanism and are expected to generate for Energean approx. $2.5 billion throughout the life of the contracts. According to the first agreement, which will be valid until expiration of 20 years from the date of the engagement therein, the main quantity sold in the context of the agreements is for the Ramat Hovav power station. Under another agreement, the rest of the gas will be supplied to other power stations held by the owners of the Ramat Hovav partnership – for a period of up to 15 years.

- **Agreement for the acquisition of all of the holdings in Energean Israel** – On 30 December 2020, Energean reported that it had signed an agreement for the acquisition of the remaining 30% of the issued and paid-up share capital of Energean Israel Ltd. ("**Energean Israel**") from Kerogen Investments No. 38 Ltd. ("**Kerogen Fund**"). In consideration for the holdings of Kerogen Fund in Energean Israel, Energean paid an amount ranging between $380 million and $405 million. On 25 February 2021, Energean reported the closing of the transaction, and commencing from such date, Energean holds 100% of the issued and paid-up share capital of Energean Israel.

- **Final investment decision (FID) in the "Karish North" reservoir** – On 14 January 2021, Energean reported on the adoption of a final investment decision (FID) in the 'Karish North' reservoir in the sum of approx. $150 million. Natural gas was produced from this reservoir for the first time in Q1/2024 and Energean estimates that the IRR of the project will be ~40%.

- On 13 December 2021, Energean reported that it had signed an agreement with Kanfa as for the construction of a second Oil Train Module (OTM) for the Karish reservoir. The construction of the additional OTM will allow for an increase of the hydrocarbon liquid output of the floating platform (FPSO) from 18 KBO per day to 32 KBO per day. Due to the Iron Swords War, there is a delay in the installation of the OTM. On 29 October 2024, Energean reported that the OTM had been hoisted onto the FPSO and that its installation and the running-in of the systems therein are expected to take around 6 months. Energean estimates that upon completion of the running-in, the liquid output is expected to increase to around 20-25 thousand barrels per day already in H1/2025.

- **A natural gas sale SPOT agreement signed with IEC** – On 14 March 2022, Energean reported that it had entered into a SPOT agreement with IEC for supply of natural gas from the Karish reservoir (in this section below, the "**SPOT Agreement**"). Under the SPOT Agreement, IEC has the right to purchase natural gas at a variable monthly price in quantities to be determined on a daily basis (without a commitment). The SPOT Agreement shall apply for one year from the date of production of the first gas from the Karish reservoir, with extension options subject to both parties' consent. Further to the aforesaid, IEC reported in the context of its quarterly report for the period ended 30 September 2023, that on 15 October 2023, the SPOT Agreement was extended for one more year, until 17 October 2024.

- **Signing of an agreement for the sale of natural gas with Hagit East Power Plant partnership** – On 3 May 2022, Energean reported its engagement in agreements for the supply of natural gas from the Karish reservoir with the Hagit East Power Plant partnership (Edeltech and Shikun & Binui Energy). According to the agreements, Energean will sell the Hagit East Power Plant partnership natural gas from the date of commencement of first gas production from the Karish field, in an annual quantity of up to ~0.8 BCM. The agreements include provisions on a floor price, Take-or-Pay mechanism and linkages (with no linkage to the Brent price), and are expected to generate for Energean up to approx. $2.0 billion throughout the life of the contracts. The total natural gas sold under the agreement is expected to be up to ~12 BCM over a period of about 15 years. The agreement is subject to the closing of the acquisition of the plant by Edeltech and Shikun & Binui Energy. On 1 June 2022, IEC reported that the process for sale of the plant to Edeltech and Shikun & Binui Energy had been closed.

- On 9 October 2022, Energean reported the piping of natural gas from the shore to the floating production facility (FPSO) via the gas transmission systems as part of the tests and the trial run of the systems conducted by the company in preparation for the commencement of natural gas production from the Karish reservoir.

- On 26 October 2022, Energean reported initial natural gas production from the Karish reservoir and on 28 October 2022, it began selling natural gas to its customers.

- On 17 November 2022, Energean reported that it had signed a sale agreement with Vitol SA for initial marketing of deliveries of hydrocarbon liquids. On 14 February 2023, the company supplied the first delivery of hydrocarbon liquids from the Karish reservoir according to the aforementioned agreement.

- On 18 June 2023, Energean announced that Energean Israel Finance Ltd.[52] intends to issue a secured senior bond series in the total amount of $750 million which is due to mature on 30 September 2033. The annual interest rate of this series is 8.50% and it will be paid in semi-annual installments on 30 March and 30 September of each year. According to the report, the bond is expected to be issued in July 2023 and traded on TASE-UP[53]. Energean intends to use the aforesaid amount, to: (1) pay the company's bonds that are due to mature in 2024; (2) pay the final deferred consideration to Kerogen Fund for the acquisition of Energean Israel; (3) finance interest expenses; and (4) pay fees, accrued interest and other expenses due to the payment of the bonds mentioned in Section 1 above and the issuance of the bond. On 11 July 2023 such bond was issued on TACT-Institutional and on 26 July 2023 the S&P Maalot rating agency assigned an il.A rating to the issuance of the secured senior bond, with a stable outlook.[54] On 18 November 2024, Maalot rating agency affirmed the ilA rating with a negative outlook for Energean's secured senior bonds[55].

[52] An Israel-based SPV. The SPV is held by Energean Israel.

[53] TASE-UP is a platform for raising of capital or debt for private entities from institutional investors and/or other (including private) qualified clients from Israel and overseas. In addition, the private entities may use the platform for trade without being obligated to release a prospectus and without being subject to current reporting obligations or disclosure requirements.

[54] Source: https://mayafiles.tase.co.il/rpdf/1537001-1538000/P1537511-00.pdf

[55] https://www.maalot.co.il/Publications/4795/FAREne20241118161048.pdf

- On 29 February 2024, Energean reported that it had started to produce gas from the Karish North reservoir on 22 February 2024. In addition, the flow of gas has commenced, by means of the second gas export pipeline (Export Riser), installation of which was completed in December 2023.

- Further to the previous paragraph, Energean further informed in the said report that it had entered into a natural gas supply agreement with Eshkol Energies Generation Ltd. ("**Eshkol**"), a company controlled by Dalia. According to the agreement, starting in June 2024, Energean will sell Eshkol an annual amount of ~0.6 BCM of natural gas until 2031 and subsequently an annual amount of 1 BCM until expiration of the term of the contract. The agreement includes clauses that address minimum and maximum prices, a 'take or pay' mechanism and a linkage mechanism. According to the report, the aggregate amount of the contract will be ~12 BCM for a 15-year term, and it is expected to generate Energean revenues of approx. $2 billion.

- **Update of the volume of resources attributable to the Karish, Karish North and Tanin reservoirs** – On 21 March 2024, Energean released a resource and reserve report as of 31 December 2023, prepared by the resource estimation firm DeGolyer and MacNaughton, whereby the Karish, Karish North and Tanin reservoirs (in this section: the "**Reservoirs**") have reserves of natural gas and hydrocarbon liquids (2P) of ~96.3 BCM and ~98.3 million barrels, respectively[56]. Energean has brought forward the date of commencement of production from the Tanin reservoir to 2029 (rather than 2030). Furthermore, Energean released its forecasts with respect to the rate of production of natural gas and hydrocarbon liquids from each one of the Reservoirs, as well as forecasts pertaining to the amounts of the capital investments, royalties, taxes and operating costs of the Reservoirs.

- **Signing of a binding MOU for the purchase of gas between Dalia Energy Companies Ltd. and Energean Israel** – On 23 January 2025, Dalia[57] reported its signing of a binding MOU with Energean Israel for the purchase of natural gas for the "Dalia 2" and "Eshkol Avshal" H Class plants. The MOU specifies the various contractual periods and corresponding quantities until 31 December 2043. Dalia estimates that the gas volume may amount to ~12 BCM for a sum total of approx. $2 billion until the end of the term of the agreement.

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[56] Source: https://www.energean.com/media/5770/energean-israel-cpr.pdf
[57] https://mayafiles.tase.co.il/rpdf/1641001-1642000/P1641823-00.pdf

5. Valuation of Royalties

5.1 Various valuation methodologies

There are three commonly accepted approaches for estimation of the economic value of businesses and companies:

- Market Approach: According to this approach, the fair value of the company is estimated by comparing the accounting and operational parameters of the company under valuation, with the same parameters of comparable publicly traded companies, as well as analyzing similar transactions in the industry. The comparison is made using multiples, which represent the ratio between the value of the comparable companies, and a selected accounting or operational parameter, while making adjustments, as necessary, based on the differences between the company being valued and the comparable companies.

- Cost Approach: According to this approach, the fair value of the company is estimated based on the cost of replacement of the asset with a new one. The key assumption underlying this approach is that a rational investor would not purchase an existing asset for a price higher than the cost involved in creating a comparable asset.

- Income Approach: According to this approach, the fair value of the company is estimated by discounting the cash flows (DCF) that the company is expected to generate in the future. In order to apply such method, it is necessary to estimate the forecasted sales and expenses (cost of goods sold, G&A, marketing and sales, other income/expenses, taxes, etc.) expected to derive from the business/asset, including the forecast of investments and additional adjustments to the cash flow (such as depreciation, setoff of income in advance and changes in working capital). The unleveraged income approach is the standard method in finance for valuation of a "going concern" business. Such cash flows are capitalized at a capital price reflecting the risk inherent in the company's activity.

5.2 Selected methodology

According to IFRS 3, contingent consideration is defined as: "...*an obligation of the acquirer to transfer additional assets or equity interests to the former owners of an acquiree as part of the exchange for control of the acquiree if specified future events occur or conditions are met.*"

As specified in Chapter 3 above, the consideration to which the Partnership is entitled includes a possibility of receiving future proceeds, in addition to the amounts to be received in cash (approx. $148.5 million), which are contingent upon the occurrence of future events.

According to the characteristics of the consideration components, the value of the Royalties in the transaction for the sale of Karish and Tanin leases is assessed through the Discounted Cash Flow method, while adjusting the cap rates to the risks involved in the cash flow.

5.3 Working assumptions

5.3.1 General

The main working assumptions as specified below are based primarily on the D&M CPR together with adjustments to publications regarding operational, technical and financial updates that were performed by Energean (as specified below), and on the analysis of market data and releases of public companies in the oil and gas sector in Israel. **It is emphasized that the assumptions and information specified below, including with respect to forecasts and the main commercial conditions in the agreement for the sale of the reservoirs, as well as regarding the types of the hydrocarbon liquids which will be produced from the reservoirs and in respect of which royalties will be paid to the Partnership, constitute forward-looking information within the meaning thereof in the Securities Law, 5728-1968, which there is no certainty of the materialization thereof, in whole or in part, in the said manner or in any other manner.**

5.3.2 Timetable

According to Energean's aforementioned reports, first gas production from Karish reservoir began in Q4/2022. It was further reported that the production well in the Karish North reservoir was drilled and completed during Q3/2022, and that first gas production from the reservoir began in Q1/2024. According to these reports, production from the Tanin lease is expected to begin in 2029.

In the context of the valuation, it was assumed that the production of gas from the Tanin reservoir will be during 2029. It was further assumed that the production of the natural gas in the Karish, Karish North and Tanin reservoirs will end in 2040, 2044 and 2041, respectively, based on the assumptions presented in the D&M CPR.

5.3.3 Quantity forecast and annual production rate

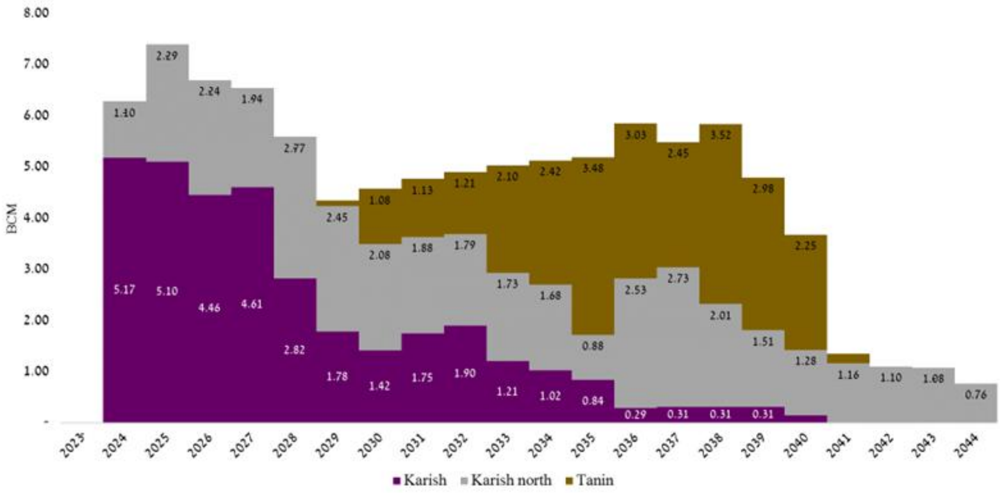
Below is a specification of the quantities of natural gas and hydrocarbon liquids (condensate and natural gas liquids) in the Karish and Tanin leases (100%) as published in the D&M CPR, as of 31 December 2023:

Reservoir	Reserves and Resources	
	Natural Gas (BCM)	Hydrocarbon Liquids (MMBBL)
	2P	2P
Karish	33.4	53.2
Karish North	37.0	40.7
Tanin	25.9	4.4
Total	**96.3**	**98.3**

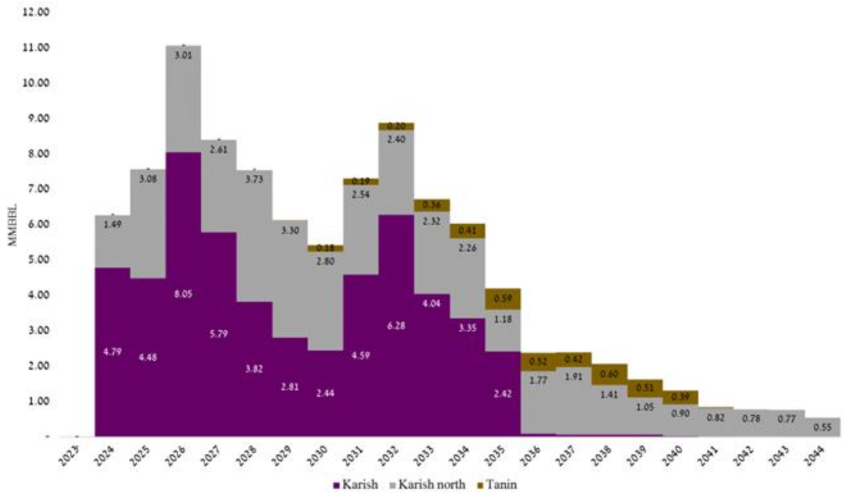
Based on Energean's financial statements as of 31 March 2024, the Partnership's reports regarding the value of the royalties received from Energean, and the conversion ratio derived from the above table between the quantity of natural gas and the quantity of the hydrocarbon liquids in the Karish and Karish North reservoirs, the amount of natural gas and hydrocarbon liquids produced by Energean in 2023, is estimated at ~4.4 BCM and ~3.5 million barrels, respectively.

According to the D&M CPR, the scope of production from the Karish and Karish North reservoirs in 2024 was estimated at ~6.28 BCM of natural gas and ~6.27 million of hydrocarbon liquids. Based on Energean's financial statements as of 30 September 2024, on the Royalties actually received from Energean, on the conversion ratio between the amount of natural gas and hydrocarbon liquids in the reservoirs, and on Energean's notification of 23 January 2025, it was assumed that the amount of natural gas and hydrocarbon liquids produced by Energean in 2024 is estimated at ~4.45 BCM and ~5.3 MMBBL, respectively. Therefore, it was assumed that the 2024 production differences between the D&M CPR and the actual production estimated, will be produced at the end of the lifespan of the Karish North reservoir in the years 2040-2044.

The chart below describes the production rate of natural gas from the reservoirs according to the D&M CPR (2P reserves):



The chart below describes the production rate of the hydrocarbon liquids from the reservoirs according to the D&M CPR (2P reserves):



The forecasted annual rate of production of natural gas and condensate used in the valuation was based on the rate of production specified in the D&M CPR, which in our estimation reflects the likely scenario considering the public information available in relation to the contracts that have been signed, the extent of the demand and the expected competition in the domestic market (for a detailed forecast of the annual production rate of natural gas and condensate, see Annex A).
In addition, according to the D&M CPR, a factor of ~37.2 million was taken into account for the conversion from an MMBTU unit to a BCM unit.

5.3.4 Natural gas prices forecast

The natural gas prices forecast relied on the following assumptions:

- The base price in the contracts on which the valuation is based was estimated using the formulas specified in the price mechanism between Energean and ICL and ORL, and between Energean and OPC, as well as the gas price in the Ramat Hovav power station contract, and the parameters specified below:
  i. **The Production component tariff**: as of the Valuation Date, the production component tariff is 29.39 Agorot (according to PUA-E's publication as of 29 December 2024[58]). Throughout the other forecast years, it was assumed that the production component tariff would change according to the IEC's expected expenses in respect of electricity production, which are affected, *inter alia*, by the prices of natural gas, coal, changes in exchange rate (ILS/$), conversion of the coal-fired power plants to use of natural gas, construction of additional natural gas-fired power plants by the IEC, the sale of power plants to IPPs and other production costs. According to our forecasts, the production component tariff is expected to range between approx. 30.31-35.15 Agorot throughout 2026-2037. As aforesaid in Section 4.4, PUA-E announced a call regarding changes in the calculation of the production component. No final decision on the matter has yet been made, and therefore the suggestions made therein are not expressed in this Paper.
  ii. **ICL and ORL** – floor price of U.S. $3.975 per MMBTU according to an agreement between the company and ICL and ORL.
  iii. **OPC** – floor price of U.S. $3.975 per MMBTU when the production component is larger or equal to 26.4 Agorot, and a floor price of U.S. $3.8 per MMBTU when the production component is lower than 26.4 according to an agreement between the company and OPC.
  iv. **Ramat Hovav** – fixed price of U.S. $3.95 per MMBTU.

- It was assumed that a gas amount of 1.0 BCM shall be regularly supplied to the Ramat Hovav power plant and that the remaining gas amount which will be sold will be equally distributed between IPPs (such as the contract with OPC) and industrial producers (such as the contracts with ICL and ORL).

The base scenario and the low scenario in the D&M CPR assumed that the natural gas price will be approx. U.S. $4.25 and 4.30 per MMBTU in 2025-2027 and from 2028 forth, respectively.

[58] https://www.gov.il/he/pages/70004

5.3.5 Condensate price forecast

The condensate price forecast was estimated based on the average short-term petroleum price forecasts by the World Bank[59], the EIA[60], and the Brent long-term forward prices according to Bloomberg as of the Valuation Date. Since the published forward prices are up to 2032, from 2033 it was assumed that the annual rate of change in the forecast will be the same as the rate of change between 2031 and 2032.

5.3.6 Royalty rate

The effective royalty rate paid to the Partnership is derived from the effective royalty rate paid to the State. The royalty rate paid to the State is determined according to the Petroleum Law and stands at 12.5% of the value of the gas at the wellhead[61]. However, the royalty rate paid in practice is lower as a result of deduction of expenses for the transmission systems and the treatment of the gas up to the gas onshore delivery point. As determined by the Ministry of Energy, the rate of advances paid to the State in the years 2023-2025 for the sales of natural gas and condensate from the Karish lease is 11.06%. This rate constitutes an advance payment only, and the market value of the royalties at the wellhead will be calculated in the future according to the expense deduction rate and method to be agreed with the Ministry of Energy. This rate is used for the calculation of the value of the royalties at the wellhead for the purpose of the Valuation and is identical to the royalty rate as reflected from Energean's public financial statements.

5.3.7 Petroleum profit levy

The Petroleum Profits Levy is a progressive levy which is set according to a mechanism which connects the rate of the levy to the ratio of the net accrued revenues from the petroleum and gas production project and the total accrued investments for the exploration and initial development of the reservoir (the "**Investment Coverage Ratio**"). The minimal levy at a rate of 20% will be charged when the Investment Coverage Ratio will reach 1.5 and rise gradually to a rate of ~47% (according to the corporate tax rate[62]) with the Investment Coverage Ratio reaching 2.3. The levy will be calculated and imposed for every lease separately.

Within the cash flow forecast for the Royalties, we deducted the levy from the net royalties (after offsetting the existing royalties) which will be received by the Partnership from each lease, based on the rate of the levy calculated in the financial model of each of the leases.

[59] A World Bank Semi-Annual Report: Short-term Energy Outlook, October 2024

[60] U.S Energy Information Administration: Analysis & Projections, December 2024

[61] On 14 May 2020, the Ministry of Energy released for public comment directives on the method of calculation of the value of the royalty at the wellhead in connection with offshore petroleum rights. For further details see: https://www.gov.il/BlobFolder/policy/oil_search_publications/he/royalty_sea.pdf

[62] Corporate tax of 23% was assumed according to the statutory tax rate known as of the Valuation Date.

5.3.8 Royalties cap rate

The cap rate (before tax) was estimated at ~11.4% based on a weighted average of the required return on equity which was estimated using the CAPM model, the normative debt price and net of the operational risk, as specified in the table below:

Parameter	Value	Note
Risk-free interest	4.34%	A
Leveraged beta	2.06	B
Market premium	6.46%	C
Specific risk premium	4.24%	D
The company's equity price	**21.9%**	
The debt price	7.25%	E
Tax rate	0%	F
Leverage ratio	60.0%	G
Weighted equity price	**13.1%**	
Net of operational risk	(1.7%)	H
Weighted equity price net of operational risk	**11.4%**	

<u>Below are the working assumptions that were used in the calculation of the cap rate:</u>

c. U.S. government bond yield for the average duration of the cash flow (~4.36 years).

d. Based on an average of unleveraged betas of benchmark companies, as specified in the table below:

Company	Unleveraged Beta
Isramco Negev 2 Limited Partnership	0.93
Ratio Energies Limited Partnership	1.11
Tamar Petroleum Ltd.	0.66
Tomer Energy Royalties (2012) Ltd.	0.29
NewMed Energy Limited Partnership	1.13
Benchmark company average	**0.82**

The leveraged beta was estimated based on the average beta of the benchmark companies above and the normative leverage ratio, without tax (see Note F).

e. The market risk premium in Israel (Damodaran January 2025).

f. Size risk premium according to Duff & Phelps International Valuation Handbook 2023 in addition to a specific risk premium due to the volatility in the oil prices and the competition in the domestic market.

g. The debt price was estimated based on the yield rate derived from the bond issuance carried out by Energean in July 2023[63] and based on "fair value" figures as of the date of the valuation.

h. The valuation model is a pre-tax model and therefore no tax was taken into account in the cap rate.

i. The average leverage ratio of the benchmark companies (in Section (b) above), as of 31 December 2024, was estimated at ~32%. In our estimation, the normative leverage ratio for the long-term is 60.0%.

j. The cap rate of 13.1%, which was estimated using the CAPM model (the "**Operating Cap Rate**"), includes many operational risks to which the recipient of the overriding royalties is not exposed. In our experience, the Operating Cap Rate is 1.5% to 2.0% higher than the cap rate for the royalties. Consequently, a reduction was made at the rate of ~1.7% from the risk rate produced by the model.

5.4 Results of the valuation

According to the assumptions specified in the Paper itself, the value of the Royalties as of 31 December 2024 was estimated at approx. $278.0 million (the value of the Karish Royalties (including Karish North) and the Tanin Royalties were estimated at approx. $227.2 million and approx. $50.8 million, respectively). **To clarify, the valuation does not address the disputes, if any, between Energean and the Partnership, and the implications thereof** (for further details, see Section 4.6.2 above), **and the value reflects the Partnership's position regarding the dispute.**

[63] For more information, see Section 4.6.2.

GIZA SINGER EVEN

5.5 Sensitivity analyses

Following is an analysis of the sensitivity of the Royalties' value to changes in the cap rate and to changes in the natural gas prices, in millions of U.S. $:

		Change in the Natural Gas Price Vector (U.S. $ per MMBTU)						
		-1.50	-1.00	-0.50	-	0.50	1.00	1.50
Change in Cap Rates (in Base Points)	+250 bp	203.0	219.3	237.0	253.4	226.9	239.1	259.4
	+150 bp	210.6	227.5	245.6	262.7	236.1	248.9	270.0
	+50 bp	218.9	236.4	**255.0**	**272.7**	**246.1**	259.5	281.5
	-	223.4	241.1	**260.0**	**278.0**	**251.5**	265.2	287.6
	-50 bp	228.0	246.0	**265.2**	**283.6**	**257.0**	271.0	293.9
	-150 bp	237.8	256.5	276.3	295.4	268.9	283.6	307.6
	-250 bp	248.5	268.0	288.4	308.4	281.9	297.4	322.4

Following is an analysis of the sensitivity of the Royalties' value to changes in the cap rate and to changes in the annual production quantity, in millions of U.S. $:

		Change in the Annual Production Rate of Natural Gas (BCM)						
		-1.00	-0.50	-0.25	-	0.25	0.50	1.00
Change in Cap Rates (in Base Points)	+250 bp	235.1	243.0	248.3	253.4	254.8	221.4	228.3
	+150 bp	244.3	252.1	257.5	262.7	263.8	230.2	237.2
	+50 bp	254.3	262.0	**267.4**	**272.7**	**273.5**	239.7	246.7
	-	259.7	267.2	**272.7**	**278.0**	**278.6**	244.8	251.8
	-50 bp	265.3	272.7	**278.3**	**283.6**	**284.0**	250.0	257.0
	-150 bp	277.3	284.5	290.1	295.4	295.4	261.2	268.2
	-250 bp	290.6	297.4	303.0	308.3	307.8	273.4	280.3

Following is an analysis of the sensitivity of the Royalties' value to changes in the cap rate and to changes in the condensate prices, in millions of U.S. $:

		Change in the Condensate Price Vector (U.S. $ per BBL)						
		-30.00	-20.00	-10.00	-	10.00	20.00	30.00
Change in Cap Rates (in Base Points)	+250 bp	222.3	234.6	244.0	253.4	224.4	232.2	238.8
	+150 bp	230.8	243.4	253.0	262.7	233.7	241.7	248.6
	+50 bp	239.9	252.9	**262.7**	**272.7**	**243.7**	252.0	259.1
	-	244.8	257.9	**267.9**	**278.0**	**249.1**	257.5	264.8
	-50 bp	249.9	263.2	**273.3**	**283.6**	**254.6**	263.3	270.6
	-150 bp	260.7	274.4	284.8	295.4	266.5	275.5	283.2
	-250 bp	272.6	286.6	297.4	308.3	279.5	288.8	296.9

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Annex A – Cash Flow Forecast

Year	Unit	2025	2026	2027	2028	2029	2030	2031	2032	2033
Production										
*Gas production - Karish**	*bcm/y*	*7.39*	*6.70*	*6.54*	*5.59*	*4.24*	*3.49*	*3.63*	*3.69*	*2.93*
Gas production - Tanin	*bcm/y*	-	-	-	-	*0.11*	*1.08*	*1.13*	*1.21*	*2.10*
*Condensate production - Karish**	*bbl/y m*	*7.56*	*11.06*	*8.39*	*7.55*	*6.11*	*5.24*	*7.12*	*8.68*	*6.37*
Condensate production - Tanin	*bbl/y m*	-	-	-	-	*0.02*	*0.18*	*0.19*	*0.20*	*0.36*
Prices										
Natural gas price	*US$*	*4.09*	*4.28*	*4.33*	*4.19*	*4.19*	*4.69*	*4.72*	*4.71*	*4.70*
Condensate Price	*US$*	*73.24*	*71.29*	*69.17*	*68.47*	*68.05*	*67.77*	*67.55*	*67.46*	*67.37*
Revenues										
*Karish - Revenues**										
Natural Gas Revenues	*US$ MM*	*1,124.8*	*1,064.3*	*1,053.4*	*870.4*	*660.4*	*609.5*	*636.6*	*645.9*	*512.3*
Condensate Revenues	*US$ MM*	*554.0*	*788.4*	*580.6*	*516.8*	*415.6*	*355.1*	*481.0*	*585.4*	*429.0*
Total Gross Revenues	*US$ MM*	*1,678.8*	*1,852.7*	*1,633.9*	*1,387.2*	*1,076.0*	*964.5*	*1,117.6*	*1,231.2*	*941.2*
Tanin - Revenues										
Natural Gas Revenues	*US$ MM*	-	-	-	-	*16.7*	*187.9*	*198.7*	*211.8*	*366.2*
Condensate Revenues	*US$ MM*	-	-	-	-	*1.3*	*12.4*	*13.0*	*13.8*	*24.3*
Total Gross Revenues	*US$ MM*	-	-	-	-	*18.0*	*200.3*	*211.7*	*225.6*	*390.4*
K&T - Total Gross Revenues	*US$ MM*	*1,678.8*	*1,852.7*	*1,633.9*	*1,387.2*	*1,093.9*	*1,164.8*	*1,329.4*	*1,456.8*	*1,331.6*
New-Med Energy - Transaction Revenues										
*Karish ORRI, Net**	*US$ MM*	*76.0*	*51.3*	*40.4*	*27.5*	*19.2*	*15.9*	*17.4*	*18.7*	*14.3*
Tanin ORRI Net	*US$ MM*	-	-	-	-	*0.8*	*9.1*	*9.6*	*10.2*	*17.7*
Transaction ORRI, Net*	*US$ MM*	***76.0***	***51.3***	***40.4***	***27.5***	***20.0***	***24.9***	***27.0***	***28.9***	***31.9***
*Karish Discounted Transaction Revenues**	*US$ MM*	*72.1*	*44.1*	*30.9*	*18.9*	*11.8*	*8.8*	*8.6*	*8.3*	*5.7*
Tanin Discounted Transaction Revenues	*US$ MM*	-	-	-	-	*0.5*	*5.0*	*4.8*	*4.5*	*7.1*
Total Discounted Transaction Revenues	*US$ MM*	***72.1***	***44.1***	***30.9***	***18.9***	***12.3***	***13.8***	***13.4***	***12.8***	***12.8***

*Including Karish North
**Net of Existing ORRI net of Petroleum Tax

Year	Unit	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Production												
*Gas production - Karish**	bcm/y	2.70	1.72	2.82	3.04	2.32	1.81	1.60	1.34	1.28	1.25	0.94
Gas production - Tanin	bcm/y	2.42	3.48	3.03	2.45	3.52	2.98	2.25	0.19	-	-	-
*Condensate production - Karish**	bbl/y m	5.62	3.60	1.86	1.97	1.47	1.12	1.12	1.01	0.98	0.96	0.74
Condensate production - Tanin	bbl/y m	0.41	0.59	0.52	0.42	0.60	0.51	0.39	0.03	-	-	-
Prices												
Natural gas price	US$	4.68	4.52	4.30	4.28	4.28	4.35	4.35	4.35	4.35	4.35	4.35
Condensate Price	US$	67.29	67.20	67.11	67.02	66.94	66.85	66.76	66.68	66.59	66.50	66.42
Revenues												
*Karish - Revenues**												
Natural Gas Revenues	US$ MM	469.4	288.7	450.7	483.4	369.1	293.1	259.1	216.2	206.6	202.9	152.0
Condensate Revenues	US$ MM	377.8	242.0	125.0	132.2	98.3	74.7	74.9	67.6	65.2	64.1	49.2
Total Gross Revenues	US$ MM	847.2	530.7	575.7	615.7	467.5	367.8	333.9	283.8	271.8	267.0	201.2
Tanin - Revenues												
Natural Gas Revenues	US$ MM	421.4	584.2	484.1	389.3	561.2	482.1	363.7	29.9	-	-	-
Condensate Revenues	US$ MM	27.9	39.9	34.6	28.0	40.2	34.0	25.7	2.1	-	-	-
Total Gross Revenues	US$ MM	449.3	624.1	518.8	417.3	601.4	516.1	389.4	32.1	-	-	-
K&T - Total Gross Revenues	US$ MM	1,296.5	1,154.8	1,094.5	1,033.0	1,068.8	883.9	723.3	315.9	271.8	267.0	201.2
New-Med Energy - Transaction Revenues												
*Karish ORRI, Net**	US$ MM	12.8	8.0	8.7	9.3	7.1	5.6	5.1	4.3	4.1	4.0	3.1
Tanin ORRI Net	US$ MM	20.3	28.3	14.4	10.4	11.7	8.5	5.9	0.5	-	-	-
Transaction ORRI, Net*	US$ MM	**33.2**	**36.3**	**23.1**	**19.7**	**18.8**	**14.0**	**11.0**	**4.8**	**4.1**	**4.0**	**3.1**
*Karish Discounted Transaction Revenues**	US$ MM	4.6	2.6	2.5	2.4	1.6	1.2	0.9	0.7	0.6	0.5	0.4
Tanin Discounted Transaction Revenues	US$ MM	7.3	9.1	4.2	2.7	2.7	1.8	1.1	0.1	-	-	-
Total Discounted Transaction Revenues	US$ MM	**11.9**	**11.7**	**6.7**	**5.1**	**4.4**	**2.9**	**2.1**	**0.8**	**0.6**	**0.5**	**0.4**

*Including Karish North
**Net of Existing ORRI net of Petroleum Tax

Annex B – Definitions

NewMed Energy/the Partnership	NewMed Energy Limited Partnership
Avner	Avner Oil Exploration - Limited Partnership
Natural Gas	A gas mixture containing mainly Methane, used mainly for the production of electricity and as a source of energy for industry
The Buyer/Energean	Energean Plc. through Energean Israel Limited (Formerly Ocean Energean Oil and Gas Ltd.)
The Partnerships/Sellers	NewMed Energy and Avner
The Petroleum Law	The Petroleum Law, 5712-1952
The Gas Framework or **the Framework**	The resolution of the Israeli Government to create a framework for increasing the amount of natural gas produced from the Tamar natural gas field and the quick development of the Leviathan, Karish and Tanin natural gas fields as well as other gas fields
Chevron	Chevron Mediterranean Ltd.
Condensate	Hydrocarbon liquid created during the production of natural gas, used as raw material for the production of fuels and constitutes a petroleum substitute
Petroleum Asset	A preliminary permit, license or lease by virtue of the Petroleum Law in Israel or a right of similar meaning granted by the entity authorized therefor outside Israel
BCM	Billion Cubic Meters
DCF	Discounted Cash Flows
FID	The adoption of a decision to invest in the development of the Karish and Tanin natural gas reservoirs. Final Investment Decision
LNG	Liquid Natural Gas
MMBTU	A Million BTU – an energy unit used as a basis for the determination of natural gas prices