2025

Periodic Report

NEWMEDENERGY

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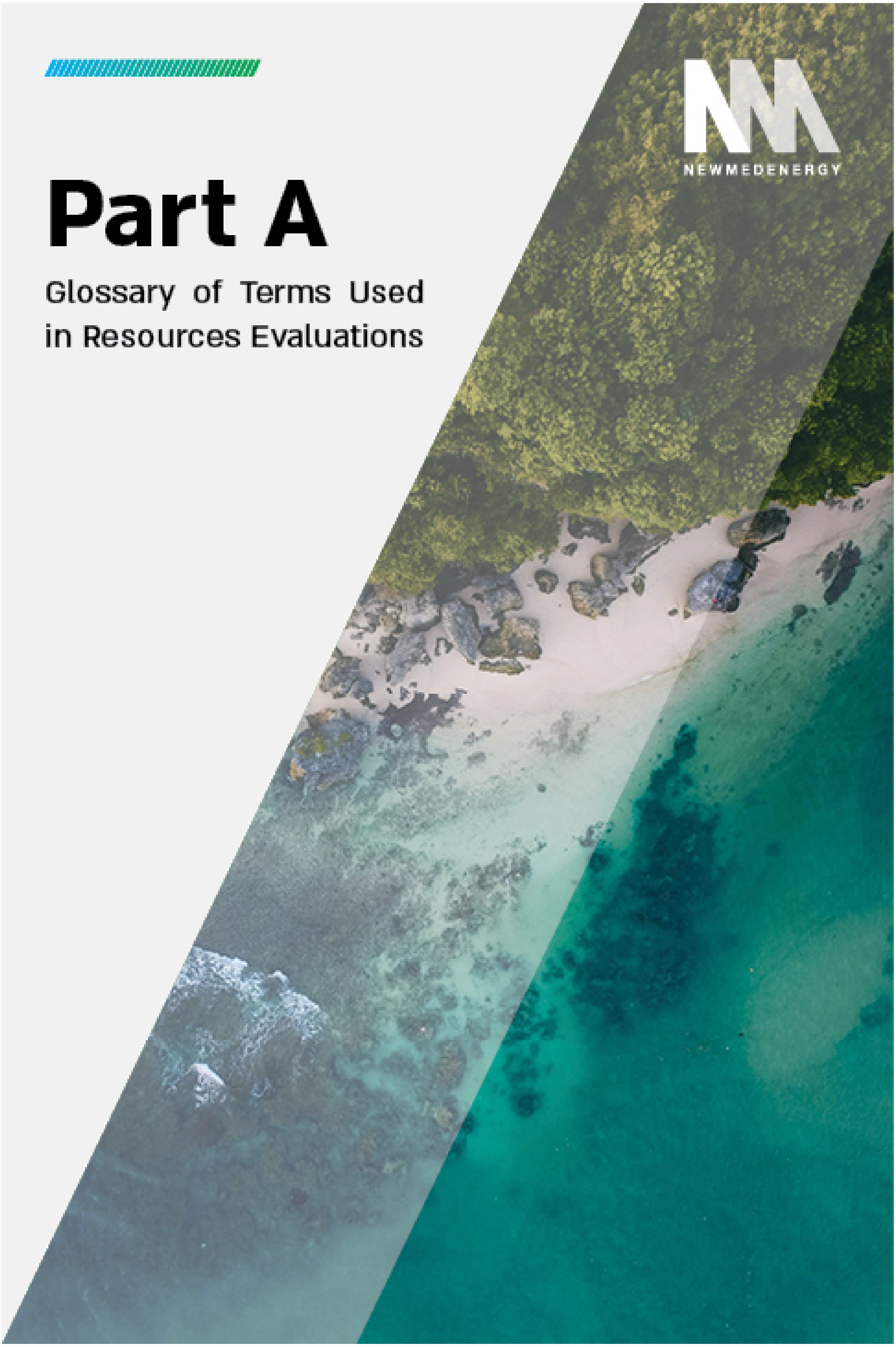


Chapter A – Description of the General Development of the Corporation's Business

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, and over the years, this activity also expanded to Cyprus, Morocco and Bulgaria. The Partnership is also exploring and promoting possibilities for the making 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 "**G**"), and NewMed Energy Trusts Ltd. as limited partner, of the second part (the "**LP**")[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 LP issued participation units to the public which confer a right to participate in the rights of the LP in the Partnership (the "**Participation Units**" or the "**Units**"), which are listed for trade on the Tel Aviv Stock Exchange Ltd. ("**TASE**"). The LP 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 GP 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 LP 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 GP, as well as powers of supervision over the fulfillment of the LP's obligations to the Unit holders.

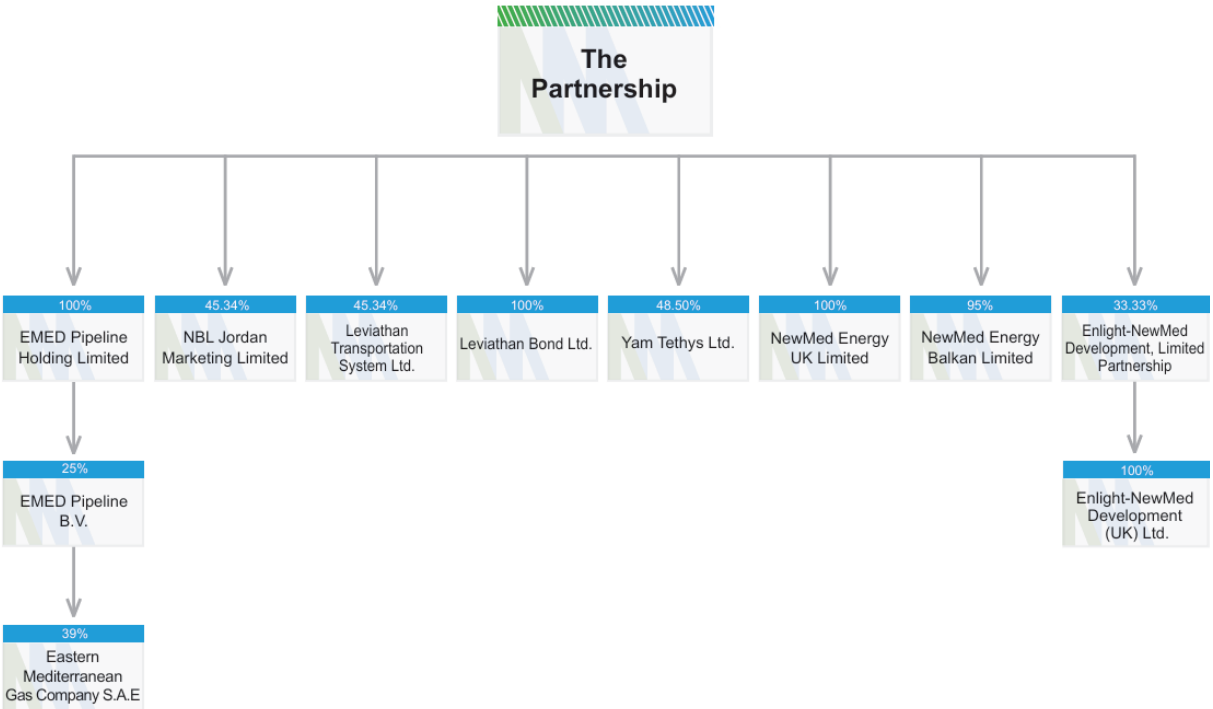
1.5. The GP and the LP are subsidiaries of Delek Energy Systems Ltd. ("**Delek Energy**"), a private company wholly owned by Delek Group Ltd. ("**Delek Group**"), the

[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 GP's previous name was Delek Drilling Management (1993) Ltd. and the LP'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).
[5] As published in the Partnership's immediate report of 7 June 2020 (Ref. 2020-01-058218).

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 GP, and through an indirect holding in Avner Oil & Gas Ltd.) approx. 54.66% of the Partnership's issued unit capital.

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 LP 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**").

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



1.7.1. Yam Tethys Ltd. is a special purpose company 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

[6] As of the report approval date, Mr. Yitzhak Sharon (Tshuva) holds approx. 50.44% of the issued capital and approx. 50.44% of the voting rights in Delek Group.

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 ("**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 Lease and Leviathan North Lease 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 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 NBL Jordan Marketing Limited 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 a special purpose company ("**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[7] – 10%. For further details, see Section 7.26.6 below.

1.7.6. Leviathan Bond Ltd. is a special purpose company ("**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,

[7] An Egyptian state-owned company.

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 was incorporated in England and holds interests in the Boujdour Atlantique exploration licenses located in the Atlantic Ocean offshore Morocco. For further details, see Section 0 below.

1.7.8. NewMed Energy Balkan Limited is a special purpose company ("**NewMed Balkan**"), that holds 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, was incorporated in England and whose shares are held as follows: the Partnership – 95%, Mr. Yossi Abu, CEO of the Partnership ("**Mr. Abu**") – 5%[8]. For further details, see Section 7.8 below.

1.7.9. Enlight-NewMed Development (UK) Ltd. is a special purpose company ("**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.

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 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

[8] On 9 March 2025, notwithstanding the opposition of the general meeting of Unit holders, the compensation committee and the board of directors ("**Board**") of the GP approved the grant to Mr. Abu of equity compensation which includes, *inter alia*, allocation of 5% of the issued share capital of NewMed Balkan.

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**"), in Block 1-21 Han Asparuh, which is located at the EEZ of the Republic of Bulgaria in the Black Sea (the "**Bulgaria License**"), and in additional petroleum assets, as specified in Sections 7.2 to 7.8 below.

2.3. The operators of the Leviathan Leases and Block 12 are Chevron Mediterranean Limited ("**Chevron**" or the "**Operator of the Leviathan Project**") and Chevron Cyprus Limited ("**Chevron Cyprus**"), respectively, subsidiaries of a subsidiary wholly-owned by Chevron Corporation ("**Chevron Corp**").[9] The operator of the Bulgaria License is OMV Offshore Bulgaria GmbH ("**OMV Bulgaria**"), a subsidiary of OMV Petrom, which, to the best of 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.

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 of 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 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

[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**").

petroleum assets Leviathan and Block 12 in Cyprus, as of 31 December 2025, and to the Krum prospect in the area of the Bulgaria License as of 30 November 2024[11], as estimated by the 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 (100%) [12]			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%	-	-	-	679.6	1.5	19,526	43.0
Leviathan Deep Prospects	45.34%	378.7	-	368	-	-	-	-
Aphrodite Reservoir	30.00%	79.2	0.1	-	3,665.5	8.1	-	-
Bulgaria License	42.75%	7,505.6	-	-	-	-	-	-

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 licenses located in the area of Atlantic Ocean offshore Morocco, as specified in Section 0 below;

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, as specified in Section 7.7 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.

[11] For details on the results of the Vinekh prospect exploration well, see Section 7.8.8 below.

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

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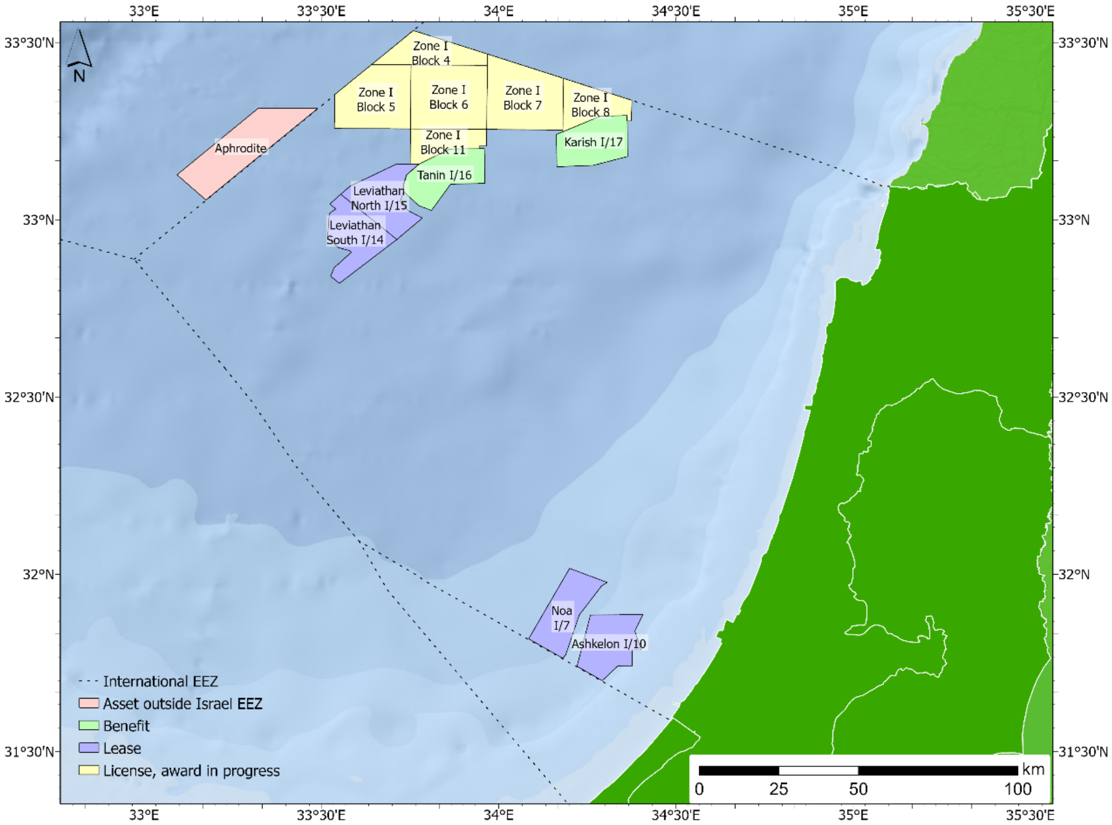
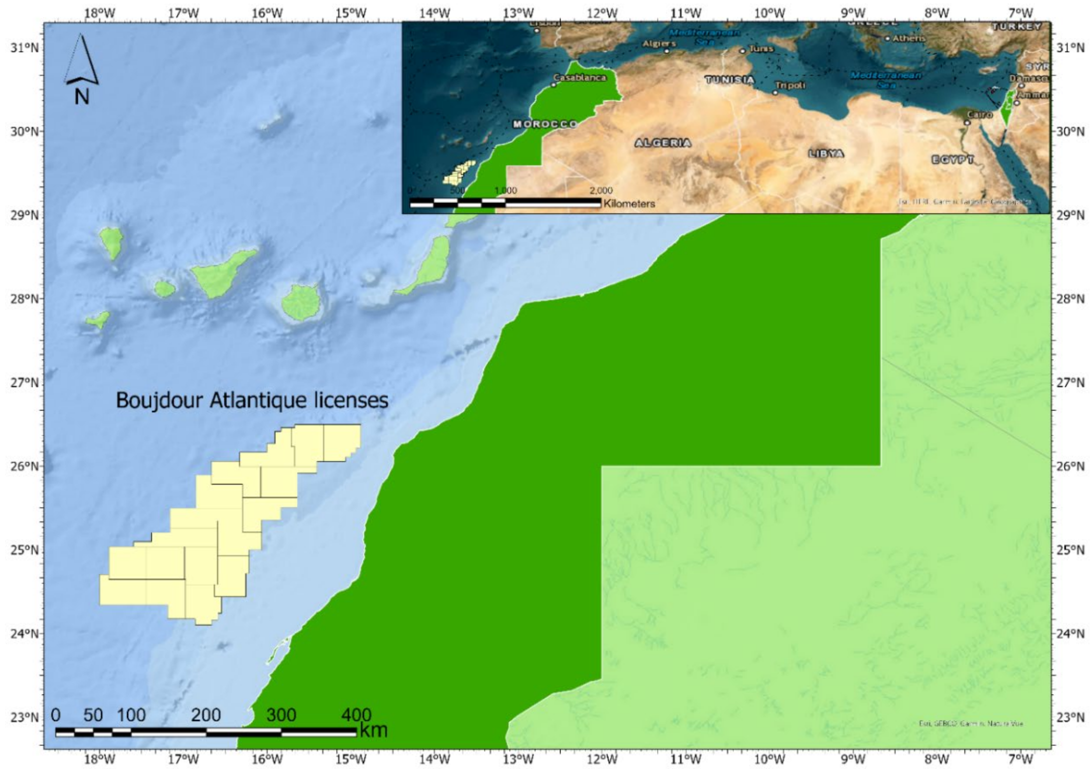
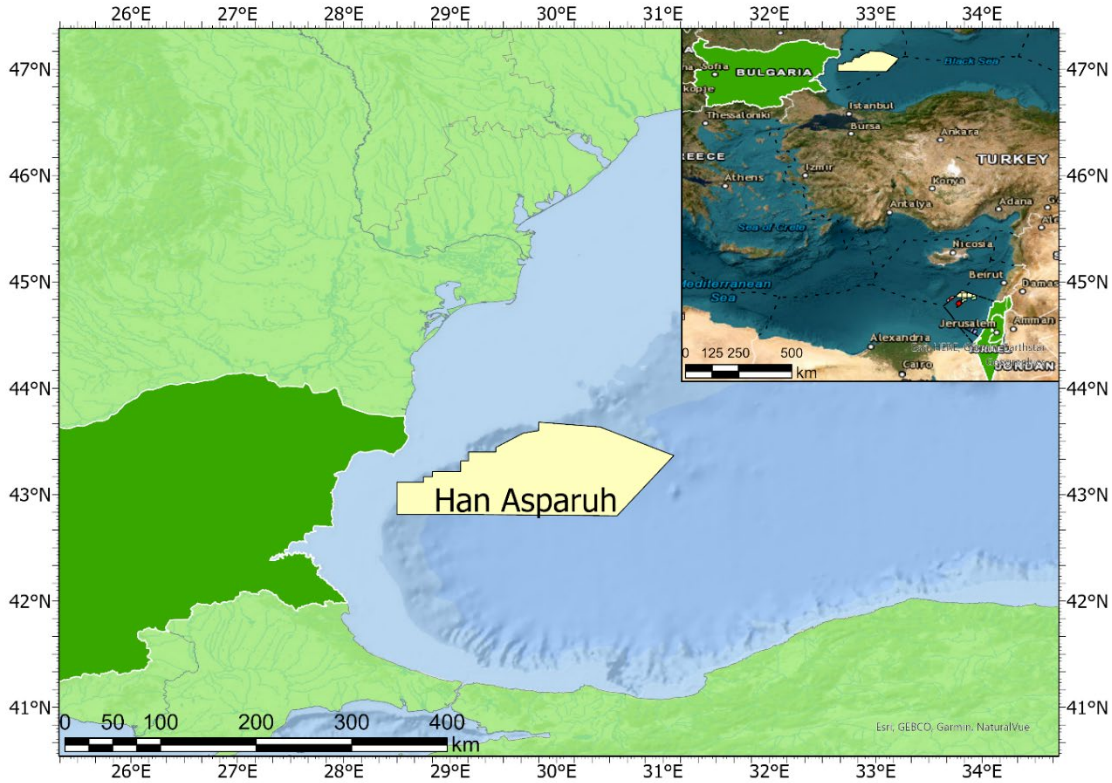
Below are maps showing the location of the Partnership's petroleum assets, as of the report approval date:







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 report approval date, no investments in the Participation Units or off exchange transactions by interested parties have been made.

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

4.1. In the period from 1 January 2024 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	Immediate Report
19.3.2024	11.4.2024	0.05112	60	Ref. 2024-01-027819
24.5.2024	20.6.2024	0.05112	60	Ref. 2024-01-051454
8.8.2024	5.9.2024	0.05538	65	Ref. 2024-01-085054
20.11.2024	12.12.2024	0.05538	65	Ref. 2024-01-617108
10.3.2025	3.4.2025	0.05112	60	Ref. 2025-01-015639
12.5.2025	5.6.2025	0.05112	60	Ref. 2025-01-032989

Declaration Date	Distribution Date	Distribution Amount per Participation Unit (in $)	Total Distribution Amount	Immediate Report
8.8.2025	28.8.2025	0.05112	60	Ref. 2025-01-058657
10.11.2025	4.12.2025	0.05112	60	Ref. 2025-01-085259
16.3.2026	31.3.2026	0.05963	70	-

4.2. For details regarding the tax regime applicable to the Partnership, see Section 0 below.

4.3. As of 31 December 2025, the Partnership has profits available for distribution in the sum of approx. 1,705 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. The provisions of the Partnership Agreement regarding a profit distribution and resolutions of general meetings thereon:

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 GP, 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 GP, 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.

4.5.4 In addition, in the context of this 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 details see Section 7.10 below.

4.5.5 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 licenses 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 licenses and according to their 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).

4.5.6 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 in which is incorporated herein by reference.

4.5.7 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 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 2025 and 31 December 2024, 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 7.24.5, 7.24.6 and 7.22.2 below, respectively.

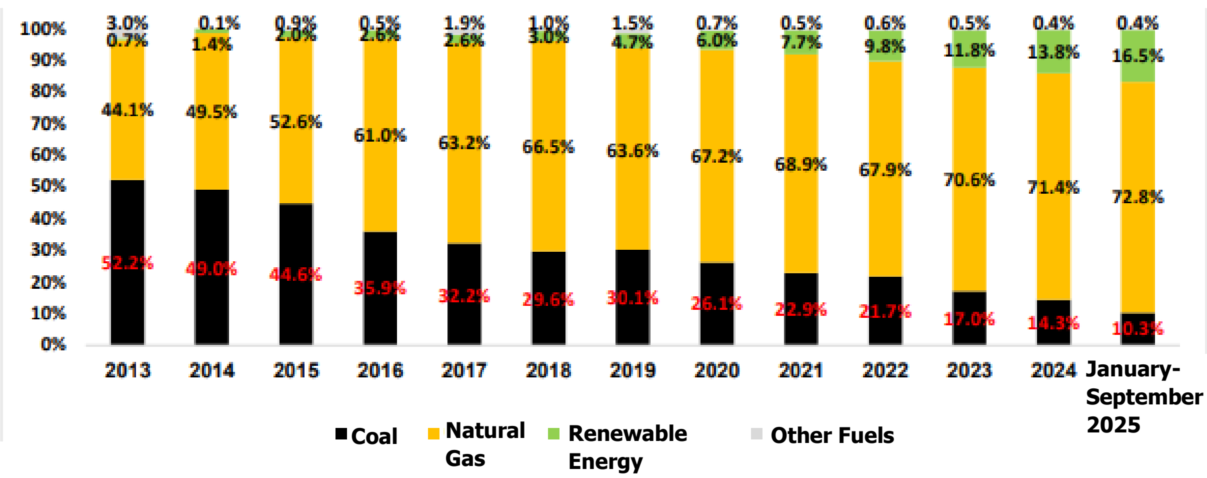
6.2. The economic merit of investments in the exploration for and development of natural gas reservoirs is greatly affected by oil and gas prices in the world, *inter alia* LNG prices, by the demand for natural gas in the global, regional and domestic markets and by the ability to transmit natural gas to consumers (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 Aphrodite reservoir, the vast majority of which is located in the EEZ of Cyprus, was discovered in 2012. 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 layout 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**") notified that the flow of gas from the Karish reservoir had begun.

In addition, since 2022 and until the report approval date, 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 from 2013 through September 2025:

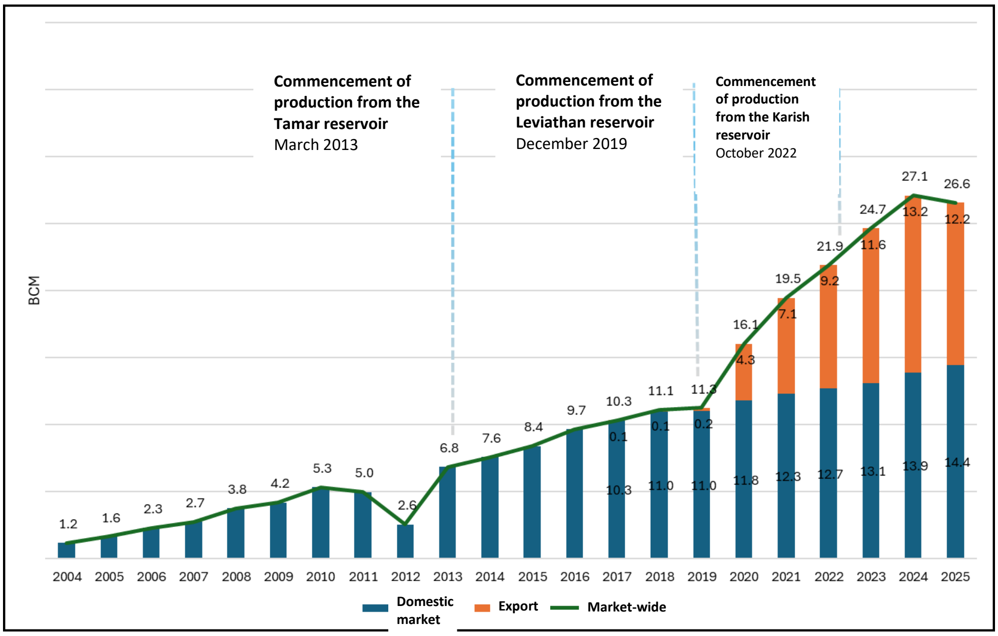


(*) Source: Knesset Research and Information Center – Report on the Phase-out of Coal in Electricity Production, November 2025.[13]

[13] Link (in Hebrew).

6.5. According to the data included in the 2024 review of the natural gas sector of May 2025, which was released by the Natural Gas Authority at the Ministry of Energy (the "**Natural Gas Authority**" and in this section below: the "**Review**")[14], the draft report for public comments by the Inter-Ministerial Committee for the examination of the natural gas policy and the strengthening of energy security, of 9 April 2025[15] and estimates of the Partnership in connection with 2025, (since the Natural Gas Authority's data on such year have not yet been released), the volume of natural gas consumption in Israel increased from approx. 6.8 BCM in 2013 to approx. 14.4 BCM in 2025[16]. 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 approx. 12.15 BCM in 2025.

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:[17]



According to the Review, the upward trend in natural gas demand in the domestic market is expected to continue over the next decade due to the anticipated growth in electricity demand, including the transition to electric transportation, the conversion of coal-fired power plants to natural gas, the ongoing shift of industry to natural gas at the expense of other fossil fuels, and future consumption related to the possibility of the construction of data centers in Israel. Furthermore, the growth trend in natural gas demand is projected to persist even given significant growth in the use of renewable energy, considering the projected growth in overall energy demand. Despite the volatility in global oil and gas prices in the last five

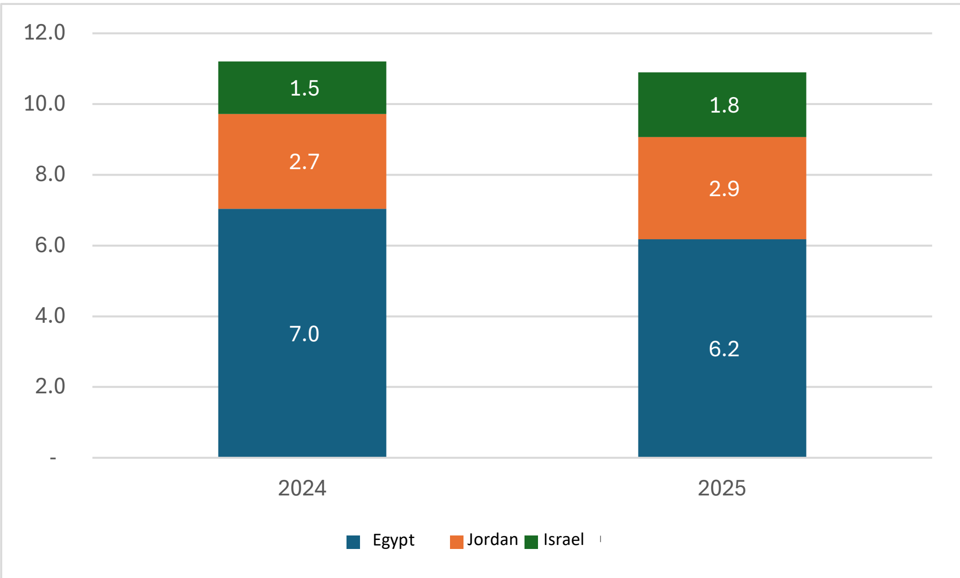
[14] Link (in Hebrew).
[15] Link (in Hebrew).
[16] Natural Gas Sector Report 2025 (Israel's Natural Gas Association, with BDO analysis) (Link) (in Hebrew).
[17] Link (in Hebrew).

years, in Israel the natural gas prices have remained stable due, *inter alia*, to the fact that they are based on long-term agreements.[18]

6.6. Below is a table presenting the sales figures in 2024-2025, broken down by the different gas suppliers and by sales to the domestic market and for export. The 2024 figures are based on Ministry of Energy data, and the 2025 figures are based on the Partnership's analyses:[19]

	2025			2024		
	Domestic market	Export	Total	Domestic market	Export	Total
Leviathan	1.8	9.1	10.9	1.5	9.7	11.2
Tamar	7	3.1	10.1	6.7	3.4	10.1
Karish	5.6	-	5.6	6.0	-	6.0

According to the Review, natural gas consumption figures for 2024 were 13.9 BCM in the domestic market and 13.2 BCM in exports. In 2024, approx. 1.5 BCM of natural gas was supplied from the Leviathan reservoir to the domestic market, and approx. 2.7 BCM and approx. 7.0 BCM to Jordan and Egypt respectively, and in 2025 approx. 1.8 BCM of natural gas was supplied from the Leviathan reservoir to the domestic market, and approx. 2.9 BCM and approx. 6.2 BCM to Jordan and Egypt respectively, as specified in the graph below:



According to the Review, export from Israel in 2024 totaled 13.2 BCM, accounting for around 49% of the total domestic production of natural gas, compared with export in 2023 of 11.6 BCM, accounting for around 47% of the total domestic

[18] Link (in Hebrew).
[19] Link (in Hebrew).

production in that year, reflecting growth of around 14% in the export volume between 2023 and 2024[20].

The Review further presented a breakdown of consumption of natural gas produced in 2024 (in BCM) between the domestic market and the export markets, and according to the different uses, as specified below:

Domestic Market									
Industry				Cogeneration	Electricity	Total	Export	Total	
CNG	Distribution	Industry Connected to Transmission Network	Total						
0.051	0.430	1.0	1.5	1.5	10.9	13.9	13.2	27.1	**2024**
0.035	0.393	1.0	1.4	1.6	10.2	13.1	11.6	24.7	**2023**
0.030	0.353	2.2	2.6		10.1	12.7	9.2	21.9	**2022**
0.032	0.299	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	0.194	1.7	1.9		9.1	11.0	0.1	11.1	**2018**

6.7. In the Partnership's estimation, based, *inter alia*, on work performed by independent consulting firms, the natural gas demand forecast for the domestic market in the coming years, upon which the Partnership relied, is as follows: approx. 15.5 BCM in 2026; approx. 17 BCM in 2027; approx. 17.6 BCM during the years 2028-2030, reaching up to approx. 21 BCM in 2040."by 2040. The forecast was provided, *inter alia* given the 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 desalination facilities), increased use of compressed natural gas ("**CNG**") in the industry and in some transportation sectors, accessibility to natural gas for additional industrial enterprises throughout Israel and for the agricultural sector, and government legislative moves for changes in the distribution segment, for the purpose of upgrading the functioning 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).

The increasing use of Artificial Intelligence (AI) and Machine Learning (ML) is leading to a global rise in demand for energy in general, and electricity in particular. This is driven, *inter alia*, by the operational requirements of data centers. For example, global electricity consumption by data centers in 2026 is expected to double that of 2022. Such growth in energy demand is anticipated to bring about significant market shifts and impact the energy sources used for power generation.

The growth factors detailed above are in addition to the 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

[20] Link (in Hebrew).

years against the backdrop of the government policy on reducing greenhouse gas emissions and promoting the use of renewable energies for power production, and given potential technological developments in aspects of energy storage and sequestration. For details see Section 7.24.11 below.

The demand forecast constitutes forward-looking information, within the meaning thereof in the Securities Law, 5728-1968 (the "Securities Law"), the materialization of which, in whole or in part, is not certain, and it may materialize in a materially different manner due to various factors, including, *inter alia*: the growth rate of the Israeli economy, climate conditions in Israel and globally, the pace of discontinuation of use of coal as a source of power generation, the penetration rate of renewable energy as a source for electricity production, the pace of entry of electric vehicles into the Israeli market, and government policy in other areas directly or indirectly affecting the growth in natural gas demand.

6.8. <u>The Swords of Iron war and the security situation</u>

6.8.1. Since 7 October 2023, Israel has been at war on several fronts against the Hamas terrorist organization, and the Islamic Jihad terrorist organization in the Gaza Strip; the Hezbollah terrorist organization in Lebanon, the Houthi terrorist organization in Yemen, Shia militias in Iraq; the Iranian regime; and against terrorist activity originating from Judea and Samaria. At the same time, in most of 2025, the Israeli economy operated under a routine overshadowed by the war. On 13 June 2025, the State of Israel declared operation Rising Lion, involving a direct conflict between Israel and Iran. The operation lasted 12 days. In November 2024, the Israeli government approved an agreement for the cessation of hostilities with the Hezbollah terrorist organization in Lebanon, and in October 2025, the Israeli government approved an agreement for the cessation of hostilities in the Gaza Strip and the return of the hostages. On 28 February 2026, a combined offensive was launched by Israel and the U.S., named Roaring Lion and Epic Fury, respectively, against government targets in Iran, following which a conflict began on the northern front between Israel and the Hezbollah terrorist organization in Lebanon.

6.8.2. As a result of the war and the security escalation, Moody's downgraded Israel's credit rating in two stages: in February 2024, from A1 to A2, and in September 2024, from A2 to Baa1. As of January 2026, Moody's has left the rating (Baa1) unchanged while updating the rating outlook to stable. S&P Global Ratings downgraded Israel's credit rating in two stages: from AA- to A+ with a negative outlook, and later from A+ to A. In November 2025, the agency affirmed the rating and updated the rating outlook to stable. The rating agency Fitch downgraded the rating in August 2024 from A+ to A (with a negative outlook), and as of the report approval date, the rating remains unchanged.

6.8.3. Upon commencement of operation Rising Lion on 13 June 2025, the Operator of the Leviathan Project received an instruction from the Minister of Energy whereby due to the security situation, it is required to cease operations at the Leviathan platform until further notice. Accordingly, the production of natural gas and condensate from the Leviathan reservoir was suspended.

Following the conclusion of the Operation, on 24 June 2025, the Leviathan platform was reactivated, and a return to regular production from the reservoir was achieved on 25 June 2025. For further details, see the Partnership's immediate report of 25 June 2025 (Ref. 2025-01-045146), the information of which is incorporated herein by reference. To the best of the Partnership's knowledge, similar instructions were issued regarding the cessation of operations at the Karish platform. The Partnership estimates that the production halt during this period resulted in a loss of revenue (gross, before royalties) from the sale of natural gas and condensate, as well as a loss of overriding royalty income from the Karish lease, totaling approx. $33 million, and a decrease in net profit of approx. $20 million. However, concurrently, a certain decrease was recorded in transmission, operating, and depreciation expenses during such period.

6.8.4. With the commencement of operation Roaring Lion on 28 February 2026, the operator of the Leviathan project received an instruction from the Minister of Energy, whereby in accordance with a security recommendation delivered to him, the operator is required to suspend the Leviathan platform's operations until further notice. The Minister's notice stated that, in accordance with security requirements, the Petroleum Commissioner may issue additional instructions regarding the platform's activity. Accordingly, the production of natural gas and condensate from the Leviathan reservoir was suspended. On 28 February 2026, the Petroleum Commissioner notified the Leviathan Partners that, in view of developments and the special situation on the home front, Chevron must prepare for a variable operation policy for the platform's activity, which policy may include, *inter alia*, directives for temporary suspensions of production, based on periodic situation assessments and ongoing updates from the security forces. In accordance with the gas sale agreements, the Leviathan Partners issued notices to customers regarding the occurrence of a *force majeure* event in connection with the said suspension of production. For further details, see the Partnership's immediate report of 1 March 2026 (Ref. 2026-01-018843), the information in which is incorporated herein by reference. To the best of the Partnership's knowledge, similar instructions were issued in connection with suspension of the Karish platform's operations.

As of the report approval date, the Operator of the Leviathan Project has not yet received an update from the Minister of Energy on the date of resumption of production from the reservoir. According to the Partnership's initial assessment, suspension of production until the report approval date (16 days of non-production) and the apparent delay in completion of the Combined Section project are not expected to have a material aggregate impact on the total value of the Partnership's discounted cash flow from the Leviathan project. However, a positive aggregate impact is expected on the projected cash flow for 2026, *inter alia*, given an updated Brent forecast[21],

[21] Several entities are working to update the Brent forecast for the remainder of 2026, including the EIA (U.S. Energy Information Administration), which updated the Brent price forecast for 2026 to approx. $79, versus $58 before the outbreak of the war (link).

relative to the Partnership's discounted cash flow figures as of 31 December 2025, as released by the Partnership on 16 January 2026.

6.8.5. The war did not have a material impact on the Partnership's business in 2025. However, there was a delay in the timetables for completion of the Third Pipeline Project (as defined in Section 7.2.5(b)1 below), as well as a delay in the timetables and an increase in costs for the INGL project for the laying of a subsea pipeline in the offshore transmission section between Ashdod and Ashkelon (see Section 7.13.2(c) below). As of the report approval date, there is uncertainty as to the development of the current conflict with Iran, including its potential expansion to additional arenas in the Middle East (including the Persian Gulf states) and the possible implications for regional infrastructures and supply chains, including oil and gas production and export infrastructures and shipping routes.

As a result of operation Roaring Lion and military strikes by Israel and the U.S. against targets in Iran, and conversely, military responses by Iran against targets in the Middle East and the Persian Gulf, a sharp increase has been recorded in geopolitical uncertainty and heightened volatility in global energy markets. In particular, a material impact has been recorded on the liquefied natural gas (LNG) market, due, *inter alia*, to extensive disruptions in the regional supply chain, damage to energy infrastructures, and de facto restrictions on navigation through the Strait of Hormuz, a primary transit route for a significant portion of global trade in LNG and crude oil, as well as the shutdown of manufacturing facilities.

With the commencement of operation Roaring Lion, INGL announced that the foreign contractors working on the Combined Section project had left Israel. As a result, completion of the project has been further postponed, such that as of the report approval date, and in the Partnership's estimation, the Combined Section project is expected to be completed in Q3/2026.

At this stage, the development, duration and impact of operation Roaring Lion are uncertain, as is the date of resumption of production from the Leviathan project. As of the report approval date, and in view of the said developments, it is impossible to predict how the fighting and/or the regional escalation will develop, and in this context whether further disruptions will occur in energy infrastructures and/or shipping routes in the Middle East (including in the Gulf region and the Strait of Hormuz). Accordingly, it is impossible to assess the scope of their potential impact, if any, on global energy prices, including the Brent oil barrel price and/or on the prices of natural gas and/or LNG. Furthermore, it is impossible to predict the impact of the operation and/or the regional escalation on the Partnership, its assets, and its business, including the possibility of the materialization of risk factors arising therefrom and their potential impact, including the risk factors specified in Section 7.30 below, the materialization of which may have a material negative effect on the Partnership, its assets and its business.

The Partnership's estimates regarding the repercussions of suspension of production from the Leviathan project constitute forward-looking

information, as defined in the Securities Law, which is based on information held by the Partnership as of the present time, the Partnership's agreements with its customers, the gas sale prices and quantities, and other factors. There is no certainty that the above estimates will materialize, in whole or in part, and they may materialize in a materially different manner, due to factors that are not dependent on the Partnership, including the risk factors specified in Section 7.30 below.

6.9. **The principal external factors that affect this sector**

6.9.1. Fluctuations in linkage components in the formulas of natural gas prices

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**" and the "**PUA-E**"), 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**")[22]. As of the report approval date, and with the exception of an agreement where 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, marketing, 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.

[22] 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 international markets. For further details, see Section 7.1.4 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.

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 ensuring strict adherence to stringent safety regulations, 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 of piping and facilities, 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 and costs 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 and activation 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 and activation 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 commercially viable when the price of an oil barrel is X dollars, may become commercially viable 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. <u>Restrictions, legislation, standardization, directives and special constraints applicable to the field of business</u>

For details, see Section 7.24 below.

7.1.3. <u>Developments in markets or changes in customer characteristics</u>

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 other 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 7.24.9 below. The Partnership is also exploring the 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**").[23] 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 bid rounds and invest in natural gas exploration and production projects in Israel and Egypt.

Within the framework of such export activities, the Partnership may examine the movement of natural gas between markets through swap transactions. Under such transactions, a party supplying natural gas at a specific delivery point receives an equivalent quantity of natural gas at another delivery point from a third party, while utilizing existing pipeline infrastructures connecting different countries, in a manner so as to enable access to markets that are not directly connected to the source of production, or to consumers with which there are no direct commercial agreements. The performance of such transactions is subject, *inter alia*, to the existence of appropriate commercial agreements, regulatory approvals (insofar as required), and geopolitical conditions that allow for their actual consummation.

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.

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.

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[23] Link.

In addition, Government policies may affect the market share of natural gas in the mix of electricity production sources, through, *inter alia*, encouraging development of energy sources that serve as alternatives to natural gas, such as renewable energies and civilian nuclear energy; energy sequestration 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 the Partnership's properties in the regional markets relevant to the Partnership and adversely affecting the Partnership's revenues from the reservoirs. Accordingly, high LNG prices may reduce the import of LNG into the regional markets, and increase the demand for natural gas produced from the Partnership's assets.

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, mainly liquefaction facilities in the U.S. and Qatar, and acceleration of the construction of liquefaction facilities and regasification facilities for LNG in the target markets 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, approx. 13% 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. 20% by 2040 as a result of a decrease in domestic gas production in certain regions, which will lead to increased use of LNG in order to meet the demand for natural gas[24].

In 2025, the levels of global demand for LNG were slightly reduced, and according to estimates, totaled approx. 407 million tons (approx. 562 BCM), reflecting a decrease of approx. 0.7% compared with the consumption in 2024. 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.

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

At present, the U.S., Qatar and Australia are the world's largest LNG exporters, and in 2025 they provided approx. 60-65% of the global LNG supply.

As a result of operation Roaring Lion and military strikes by Israel and the U.S. against targets in Iran, and conversely, military responses by Iran against targets in the Middle East and the Persian Gulf, a sharp increase has been recorded in geopolitical uncertainty and heightened volatility in global energy markets. In particular, a material impact has been recorded on the LNG market, due, *inter alia*, to extensive disruptions in the regional supply chain, damage to energy infrastructures, and de facto restrictions on navigation through the Strait of Hormuz, a primary transit route for a significant portion of global trade in LNG and crude oil. In the context of the said developments, a temporary shutdown has been reported of LNG liquefaction and production facilities in Qatar, one of the world's largest exporters, including a declaration of *force majeure* regarding shipments. This shutdown removed a material portion of the global LNG supply and exacerbated the shortage in the international market; accordingly, it led to sharp increases in natural gas prices, intensified competition for alternative supply sources – primarily from consumers in Europe and Asia – and the incorporation of a geopolitical risk premium into energy prices.

<u>The volatility in energy prices in recent years and in the period shortly before release of the report</u>

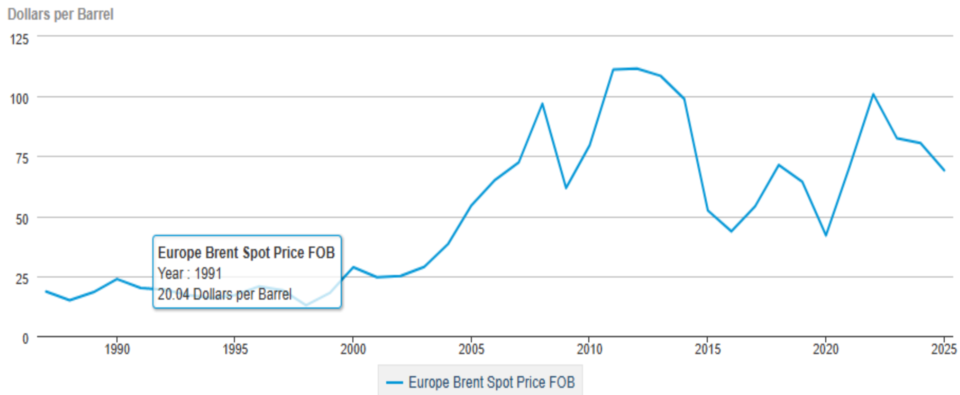
In recent years, energy prices have been characterized by high volatility, primarily as a result of global events and shifts, such as weather conditions affecting the volume of electricity generation from renewable sources, the Covid pandemic and its conclusion, and the Russia-Ukraine war, and as of the report approval date, also in view of geopolitical tensions in the Middle East, including the conflict between Israel and the U.S. with Iran following operation Roaring Lion and expansion of the conflict and its impact on other countries in the region, including the Gulf states, as well as on shipping routes and oil and gas production and export infrastructures. Energy prices are also affected by U.S. sanctions and political intervention regarding Venezuela.

From mid-2022, the growth in natural gas demand moderated, following a previous surge with the conclusion of the Covid pandemic and even more so with the outbreak of the Russia-Ukraine war, along with a certain decline in energy prices in the global markets, *inter alia* against the backdrop of a swift rise in the rate of inflation, leading to the raising of interest rates by central banks. In 2025, energy prices exhibited volatility as a result of global events and shifts in the supply and demand balance and changes in global inventory levels, as well as macroeconomic developments that included the moderation of inflationary trends and the beginning of interest rate cuts by some of the world's central banks.

In 2024, a Brent barrel traded in the range of $69-$90 per barrel, and in 2025, it traded in the range of $63-$79 per barrel. As of the report approval date, the price of a Brent oil barrel is approx. $100[25].

In terms of LNG prices, in 2024, LNG delivered in North-West Europe was traded at an annual average of approx. $10.6 per MMBTU, and in 2025 at an annual average of approx. $11.3 per MMBTU.

Below is a graph showing the monthly Brent prices in dollars in 1985-2025:



(*) Graph source: U.S. Energy Information Administration

The monetary policy and the inflation rate in Israel

The inflation rate in Israel in 2025 was approx. 2.6%26, compared with inflation at a rate of approx. 3.2%27 in 2024 and approx. 3%28 in 2023.

According to a macroeconomic forecast document released by the Research Division at the Bank of Israel in January 2026[29], it is estimated that the rate of inflation in the upcoming four quarters (ending Q4/2026) is expected to be 1.7%, and the rate of inflation in 2027 - 2%, and the interest rate level in Q4/2026 is expected to be, on average, 3.5%. According to a forecast update for 2026, released by the Chief Economist Division at the Ministry of Finance on 10 March 2026, it is estimated that the GDP increased in 2025 by 2.9% and is expected to increase in 2026 by 4.7%[30].

The Ministry of Finance's forecast of 10 March 2026 reflects a change in the growth estimate for 2026, *inter alia* in view of operation Roaring Lion. According to the said forecast, operation Roaring Lion is expected to reduce the GDP growth forecast for 2026 by approx. 0.5 percentage points. The

[25] Several entities are working to update the Brent forecast for the remainder of 2026, including the EIA (U.S. Energy Information Administration), which updated the Brent price forecast for 2026 to approx. $79, versus $58 before the outbreak of the war (link).
[26] Link to the Bank of Israel's desk presenting inflation data for the year 2025.
[27] Link to CBS data for 2024 (in Hebrew).
[28] Link to CBS data for 2023 (in Hebrew).
[29] The Macroeconomic Forecast of the Research Division, January 2026.
[30] Link to State Revenues and Macroeconomic Review – 2026 Forecast Update, Chief Economist Division, Ministry of Finance, 10 March 2026 (in Hebrew).

base scenario underlying the forecast includes continued short-term fighting on the northern front and against Iran for a period of several weeks, alongside economic shutdowns, the burden of military reserve duty, global impacts, and data updates.

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 inflation, interest rates, growth rates and the impact of the macroeconomic environment 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 characterization 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 in a manner so as to allow, *inter alia*, 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, including the transition to use of Ocean Bottom Nodes (OBN) technology, as distinguished from traditional technologies involving the towing of sensors behind vessels, in order to obtain more accurate and comprehensive seismic imaging of geological layers, *inter alia* in areas requiring the characterization of deep targets or the imaging of producing layers, to optimize 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 in the Partnership's projects, including the Leviathan project in order to streamline the production system, enhance the facilities' safety and reduce their impact on the environment.

7.1.6. 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 in view of the adoption of a final investment decision (FID) for the development of the First Stage of the Expansion Project, the Leviathan Partners are no longer exploring the possibility of building an FLNG facility as a development alternative.

In recent years, 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 data, operation of the production systems, maintenance, environmental monitoring, 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.

7.1.7. <u>Critical success factors in the field of business</u>

(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.

7.1.8. Changes in suppliers and raw materials

For details, see Section 0 below.

7.1.9. 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 (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.

7.1.10. 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 sequestration 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 7.24.11 below, respectively. 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.

7.1.11. 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 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.
1. The name of the operator:	Chevron
2. 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, Ratio Energies Management Ltd., the control holder of Ratio Energies General Partner Ltd., which is the general partner of Ratio, 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.[31]

[31] 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) is approx. 23.73%.

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 asset attributable to the holders of the equity interests of the partnership:	Before investment recovery – 37.63%. 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. $518,285 thousand[32].

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,

[32] 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), the construction of the Israeli transmission system up to the border between Israel and Jordan (as specified in Section 7.12.3(b) below, the construction of the Nitzana Pipeline (as specified in Section 7.13.2(b)(5) below), the project specified in Section 7.13.2(b)(3) below and conversion of the PEI pipeline for the transmission of condensate.

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.

(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 requires written approval from the Petroleum Commissioner with the approval of the Minister of Energy (the "**Export Approval**"). The Export Approval was granted in accordance with the applicable regulation, including changes thereto, and subject to any law.[33] 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 natural gas shortage in Israel, the lease holder will prioritize the needs of the local economy, subject to the applicable regulation. The quantity to be supplied, as noted, to the local economy will be considered part of the quantity designated for the local economy according to the aforementioned government resolution and will not detract from the quantity permitted for export according to the Export Approval, to the extent granted.

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

[33] For details regarding government resolutions on export, see Section 7.24.9 below.

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) Supervision companies

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) Development plan

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 7.24.10 below.

(n) Guarantees[34]

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 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

[34] 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.

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 of the Guarantee up to the amount thereof, as 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, *inter alia*, 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 2023 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)[35,36]	Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)
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 bid round between international groups specializing in the design and construction of FLNG facilities, in the context of promoting the options for development of the Expansion Project (as defined in Section 7.2.5(b)2 below).	Approx. 36,165	Approx. 16,397
	• 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 the Expansion Project.	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 activities, including continued production from the Leviathan reservoir, ongoing operation and	Approx. 102	Approx. 46

[35] The amounts for the years 2023-2025 are amounts actually expended and audited in the framework of the financial statements.

[36] The costs, budgets and activities specified in the table until 2025 (inclusive) do not include costs for: (a) 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) construction of the Combined Section (as specified in Section 7.13.2(b) below) in the sum of approx. $175.5 million (100%; the Leviathan Partners' share – approx. $126.4 million, the Partnership's share – approx. $57.3 million); (c) construction of the Nitzana Pipeline (as specified in Section 7.13.2(b)(5) below) in the sum of approx. $375 million (100%; the Leviathan Partners' share – approx. $163 million, the Partnership's share – approx. $73.9 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. $18.5 million (100%; the Partnership's share – approx. $8.4 million); (e) the project specified in Section 7.13.2(b)(3) below, in the sum of approx. $272.8 million (100%; the Leviathan Partners' share – approx. $136.4 million, the Partnership's share – $61.9 million); and (f) costs of decommissioning of the reservoir and insurance and administrative 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)[35,36]	Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)
	maintenance,[37] performance of monitoring actions, surveys, tests and review of options for specification, drilling and development of the deep exploration targets.		
2024[38]	• 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 in the field 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
	• 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 the development of the Expansion Project, 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 activities, including continued production from the Leviathan reservoir, ongoing operation and maintenance[39], performance of monitoring actions, surveys, tests and review of options for specification, drilling and development of the deep exploration targets.	Approx. 114	Approx. 52
	• Continued improvement of the production system on the Leviathan platform and the onshore facilities, and improvement of	Approx. 7,197	Approx. 3,263

[37] For details regarding the Leviathan project's operating costs attributed to the Partnership, see the 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.

[38] 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.

[39] For details regarding the Leviathan project's operating costs attributed to the Partnership, see the 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)[35,36]	Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)
2025[40]	support systems and environmental systems, in accordance with operational and regulatory requirements.		
	• Execution of the Third Pipeline Project (as defined in Section 7.2.5(b) below).	Approx. 154,744	Approx. 70,161
	• Completion of the FEED in the context of promoting the development of the Expansion Project, and early commitments for receipt of services and procurement of long-lead items.	Approx. 253,116	Approx. 114,763
	• Various additional activities, including continued production from the Leviathan reservoir, ongoing operation and maintenance[41], performance of monitoring actions, surveys and tests.	Approx. 24	Approx. 11
	• Performance of a baseline gravity survey in the field to optimize production forecasts and assist in the making of development decisions in the project.	Approx. 5,042	Approx. 2,286
2026 forth[42]	• Adoption of a final investment decision (FID) by the Leviathan Partners for the First Stage of the Expansion Project (for further details, see Section 7.2.5(h) below), construction of the project, which includes, *inter alia*, the drilling and completion of additional production wells, expansion of the subsea systems, and expansion of the systems on the production platform.	Approx. 2,066,026	Approx. 936,736
	• Completion of the Third Pipeline Project (as defined in Section 7.2.5(b)1 below).	Approx. 16,656	Approx. 7,552
	• Exploration of possibilities for expansion of the Leviathan reservoir production system beyond the First Stage of the Expansion Project, including the possibility of laying a fourth pipeline between the field and the	Approx. 796,165	Approx. 360,981

[40] The costs specified for 2025 do not include a budget update (reduction) in the sum of approx. $20,402 thousand (100%; the Partnership's share: approx. $9,250 thousand), mainly deriving from the sale of equipment and from returns on investments made in the context of Phase 1A of the Leviathan project Development Plan.

[41] For details regarding the Leviathan project's operating costs attributed to the Partnership, see the 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.

[42] The costs, budgets and actions specified in the table for 2026 forth do not include estimated costs for: (a) the construction of the Combined Section (as specified in Section 7.13.2(b) below) in the sum of approx. $21.2 million (100%; the Leviathan Partners' share: approx. $15.3 million, the Partnership's share: approx. $6.9 million); (b) the construction of the Nitzana Pipeline (as specified in Section 7.13.2(b)(5) below) in the sum of approx. $332.5 million (100%; the Leviathan Partners' share: approx. $159.6 million, the Partnership's share: approx. $72.3 million); (c) the project specified in Section 7.13.2(b)(3) below, in the sum of approx. $44.6 million (100%; the Leviathan Partners' share: approx. $22.3 million, the Partnership's share: $10.1 million); and (d) costs of decommissioning the reservoir and insurance and administrative 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)[35,36]	Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)
	platform and expanding the subsea system (the Second Stage of the Expansion Project)[43].		
	• Performance of a 3D seismic survey in H2/2026, *inter alia* for the characterization of the deep exploration targets.	Approx. 62,701[44]	Approx. 28,428
	• Continued performance of a baseline gravity survey in the field to optimize production forecasts and assist in the making of development decisions in the project[45].	Approx. 10,320	Approx. 4,679
	• Various other activities, continued improvement of the Leviathan platform and the coastal facilities, and improvement of supporting and environmental systems, in accordance with operational and regulatory requirements[46].	Approx. 1,910	Approx. 866

[43] As of the report approval date, this budget has not yet been approved by the Leviathan Partners.
[44] The Leviathan Partners have approved a budget of approx. $25.2 million (100%) out of this budget.
[45] As of the report approval date, this budget has not yet been approved by the Leviathan Partners.
[46] For details regarding the Leviathan project's operating costs attributed to the Partnership, see the 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(b) below).

7.2.5. Plan for development of the Leviathan reservoir

(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 approx. 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 Development Plan also includes the construction of a site for temporary storage and temporary 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 7.24.15 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. Phase 1A – the current stage, in which 5 subsea production wells were drilled (4 wells at production commencement, and an additional well in 2023), 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 approx. 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 2025 (including investments in the Third Pipeline Project), is approx. $4.4 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 approx. 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). In 2025 and in the course of Q1/2026, current maintenance work was conducted at the Leviathan reservoir, including work planned for the purpose of completion of the Third Pipeline Project, during which the production of natural gas from the Leviathan reservoir was reduced and even suspended. On 1 March 2026, the Operator notified the Partnership that the Third Pipeline Project has been completed. As of the report approval date, the total cost of the Third Pipeline Project is approx. $480 million (100%, the Partnership's share is approx. $217 million).

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 implementation of Phase 1B (the "**Updated Development Plan for the Leviathan Reservoir**"), including with respect to the platform processing facilities, the location and timing of well drilling, and the possibility of performing the second stage of Phase 1B, as specified below (the "**Expansion Project**").

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

   (a) First stage – includes the drilling and completion of 3 additional production wells, installation of additional subsea systems and expansion of the platform processing facilities , with the aim of increasing the total gas production capacity of the system up to approx. 21 BCM per year (the "**First Stage of the Expansion Project**").

   (b) Second stage – mainly includes the receipt of regulatory approvals and the making of additional investments, including investments in the installation of a fourth pipeline between the field and the platform (the "**Fourth Pipeline**") and in the installation of additional subsea systems, with the aim of increasing the maximum daily production capacity to a total quantity of up to approx. 23 BCM per year (the "**Second Stage of the Expansion Project**").

   On 21 August 2025, the Petroleum Commissioner approved the updated development plan for execution of the Expansion Project. Such approval by the Commissioner was granted subject to several conditions that primarily pertain to the provision and presentation of additional technical information to the Ministry of Energy, the implementation of which conditions shall be carried out in coordination with and under the instructions of the professional staff of the Natural Resources Administration at the Ministry of Energy. In his approval, the Commissioner noted that, in order to increase production capacity over and above 2,100 MMSCFD, upon the execution of the Second Stage of the Expansion Project, the submission of supporting documents shall be required in accordance with the instructions of the professional staff of the Natural Resources Administration at the Ministry of Energy, which documents shall constitute an update to the Updated Development Plan and their approval by the Commissioner.

(c) As specified in Section 7.24.9 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, *inter alia*, with the assistance of international professional consultants with respect to the estimated total recoverable quantity of natural gas in the reservoir. On 21 August 2025, the Petroleum Commissioner noted (in his approval of the Updated Development Plan, as stated in Section 7.2.5(b)2 above), that the current position of the Ministry of Energy is that the total quantity of natural gas recoverable from the reservoir (i.e., the quantity of gas produced from the date of commencement of production, plus the recoverable quantity of gas remaining in the reservoir) is approx. 551 BCM (approx. 19.4 TCF), compared with the Ministry of Energy's previous estimate, which was approx. 500 BCM (approx. 17.6 TCF), and that the Ministry will continue to review these figures over the coming years. For details on the total quantity of recoverable natural gas (which includes the reserves, contingent resources and total quantity of gas produced from the reservoir), as of 31 December 2025, see Section 7.2.10 below. As of the report approval date, the Leviathan Partners received the Commissioner's approval to increase the Total Contract Quantity for the export of additional gas quantities to Egypt in a volume of approx. 130 BCM, in accordance with the Petroleum Commissioner's letter, as detailed in Section 7.12.3(c)6 below.

(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. 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 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.

(e) After the signing of an amendment to the export agreement between the Leviathan Partners and Blue Ocean on 7 August 2025, as detailed in Section 7.12.3(c)5 below, the Leviathan Partners applied to the Commissioner for an export permit.

(f) On 17 December 2025, the Leviathan Partners received the Petroleum Commissioner's approval to export the Additional Quantities under the amendment to the Export to Egypt Agreement (as defined in Section 7.12.3(c)5 below, in this section the "**New Approval**"). The Partnership estimates that the New Approval enables fulfillment of the provisions of the amendment to the Export to Egypt Agreement, including the supply of the Additional Quantities to Blue Ocean. The New Approval was issued in addition to the export approval issued to the lease holders on 16 December 2019, and states that it supersedes any conflicting provision in any other document, including the amendment to the Export to Egypt Agreement. For further details, see Section 7.12.3(c)6 below.

(g) In the context of promoting the Expansion Project, the Leviathan Partners approved, in 2024, in accordance with the Joint Operating Agreement, budgets in the sum total of approx. $504 million (100%) for the performance of FEED, which include, *inter alia*, the procurement of long-lead items.

(h) On 15 January 2026, the Leviathan Partners adopted a final investment decision (FID) for development of the First Stage of the Expansion Project, with a total budget of approx. $2.36 billion (100%). This budget includes the FEED budget, as specified above. On the same date, all the conditions precedent were satisfied for the taking effect of the amendment to the agreement for the export to Egypt of natural gas produced from the Leviathan reservoir, in which it was agreed to increase the Total Contract Quantity by approx. 130 BCM (the "**Additional Quantities**"). For further details, see Section 7.17.2 below.

The estimated timetable for production of first gas from the First Stage of the Expansion Project is expected to occur 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 level is defined, from time to time, by the Leviathan Partners. Furthermore, as part of the work for preparation toward the connection and operation of the Expansion Project, subsea work shall be carried out on the platform, which shall occasionally cause a temporary reduction in the production capacity and even a temporary suspension of production.

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, the estimated cost of the activities carried out within the Expansion Project, and the potential date of operation of the First Stage of the Expansion Project, 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 of the Leviathan reservoir, based on a range of factors which are beyond the Partnership's control or which may change, including the costs of the Third Pipeline 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, based on past experience, on geological, geophysical, technical-engineering and other information accumulated, and on various market surveys. 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 specified above, and if the estimates and assessments received change, *inter alia*, as a result of geological and/or operational and technical conditions and/or regulatory changes, changes in market conditions and/or due to a gamut of regulatory and/or 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%	104%-101%	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

Item	Percentage pre investment-Recovery	Percentage post investment-Recovery	Concise explanation as to how royalties or payments are calculated
			onshore gas delivery point. For further details, including with respect to the publication of directives on the method of calculation of the royalty value at the wellhead with respect to offshore petroleum interests, see section 7.24.8(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[47]. The said rate was

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

Item	Percentage pre investment-Recovery	Percentage post investment-Recovery	Concise explanation as to how royalties or payments are calculated
			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%	
Specification of the payments (derived from the expenses) at the petroleum asset level:		
The operator	1%-4%	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 GP	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 2023	Approx. 248,111	-	Approx. 1,744
Budget actually invested in 2024	Approx. 244,948	-	Approx. 1,715
Budget actually invested in 2025	Approx. 310,917	-	Approx. 2,485

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

(a) Upon adoption of a final investment decision (FID) for the First Stage of the Expansion Project, as specified in Section 7.2.5(h) above, the Partnership released, on 16 January 2026 (Ref. 2026-01-006999), a report on updated reserves, contingent resources and DCF figures for the Leviathan Leases (the "**Leviathan Project Resource Report**"). For details regarding the reserves, the contingent resources and the DCF figures for the Leviathan Leases, see the report on the resources in the Leviathan project, the information in which is incorporated herein by reference. Attached as **Annex B** to this report are NSAI's consent to the inclusion of the said report herein, including by reference, and NSAI's letter of no material changes in the Leviathan Leases.

(b) Prospective resources in the Leviathan Leases

Following and based on an analysis of reprocessing of seismic surveys carried out in 2019, the Partnership released, in Chapter A of the 2024 periodic report, released on 10 March 2025 (Ref. 2025-01-015633) (the "**2024 Periodic Report**"), a report on prospective resources in the Leviathan Leases prepared by NSAI according to SPE-PRMS guidelines (in this section: the "**Resource Report**"). For details about the prospective resources in the Leviathan Leases, see the Resource Report, the information in which is incorporated herein by reference. Attached as **Annex B** to this report are NSAI's consent to the inclusion of the said report herein, including by reference, and NSAI's letter of no material changes in relation to the aforesaid resources.

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 foregoing, 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 said amendments to the PSC 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[48].
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

[48] The Aphrodite reservoir is situated almost entirely in the EEZ of Cyprus, with merely a few percent in the area of the 370/Ishai lease (the "**Ishai Lease**"), which is situated in the EEZ of Israel. It is further noted that the partners in the Aphrodite reservoir were previously contacted by the partners in the Ishai Lease, 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 said parties prior to the adoption of a decision on the 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 industry practices. On 11 April 2022, the Israeli Ministry of Energy announced 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 between the EEZs of Israel and Cyprus. For details, see this link (in Hebrew).
On 20 January 2026, a professional delegation on behalf of the Ministry of Energy, together with Ministry of Justice representatives, left for Cyprus in order to continue the negotiations for implementation of the in-principle understandings on the Aphrodite-Ishai natural gas reservoir and to establish the same in an agreement between the countries. Under such understandings, the reservoir's development shall be carried out by the interest holders on the Cypriot side, whereas the holders of the Ishai Lease and the State of Israel shall receive one-time compensation for their share in the reservoir, the amount of which shall be determined by an international expert. For further details, see the Ministry of Energy's announcement of 20 January 2026 (link (in Hebrew)). Furthermore, on 17 February 2026, a similar delegation left for Cyprus to continue these discussions. It is clarified that as of the report approval date, Cyprus and Israel have not reached in-principle agreements on the issue of the Aphrodite-Ishai natural gas reservoir, and no intergovernmental agreement has been signed, and the aforesaid is forward-looking information, as defined in the Securities Law, which may not materialize or may materialize in a manner that differs from the projections due to factors beyond the Partnership's control, including the continued negotiations between the parties and the agreements between the countries.
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 situated.

General details about the petroleum asset	
	the gas and oil industry, which is active in more than 70 countries worldwide[49]. ▪ 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. $65,607 thousand.

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

(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).

On 22 December 2025, a decision was adopted to prepare the FEED (for details, see Section 7.3.11 below).

[49] Further details about Shell are available at the website: (link).

(b) The A-3 Well

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 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) Payments to the Republic of Cyprus

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[50]:

Average daily production (in barrels)[51]	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	77%	80%	83%

[50] The oil sharing mechanism was not amended as part of the amendments to the PSC.
[51] The calculation is made progressively according to the brackets specified in the table.

Average daily production (in barrels)[51]	Price per barrel ($)		
(inclusive)			
For the share in the average daily production higher than 200,000	83%	85%	85%

(e) Distribution of natural gas

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 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**")[52] 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

[52] Block 12 Expenses are recognized on a yearly basis according to reports filed by the operator of the project, and it 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.

("**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.

(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) <u>Grant of a performance guarantee to the Republic of Cyprus</u>

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[53].	-

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 2023 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)[54]**	**Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)**
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 activities, including geological data analysis and geological model update, technical and economic analysis of the prospects in the license area and alternatives for commercialization of the natural gas produced from the reservoir.	Approx. 200	Approx. 60

[53] The drilling of the Aphrodite A-2 appraisal well, which began on 7 June 2013, was completed on 2 October 2013.

[54] The amounts for the years 2023-2025 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)[54]	Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)
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 activities, including geological data analysis and geological model update, technical and economic analysis of the prospects in the license area.	-	-
	• Continued analysis of the findings of the A-3 Well.	Approx. 1,525	Approx. 458
2025	• Update and approval of the development plan, performance of pre-FEED and FEED ahead of adoption of a final investment decision (FID).	Approx. 36,932	Approx. 11,800
	• Various additional activities, including geological data analysis and geological model update, conduct of surveys and technical and economic analysis of the prospects in the license area.	Approx. 268	Approx. 80
	• Conduct of seabed surveys for the purpose of planning the location of the floating production facility and the pipeline route.	Approx. 10,313	Approx. 3,094
2026 forth[55]	• Various additional activities, including geological data analysis and geological model update, conduct of surveys and technical and economic analysis of the prospects in the license area.	Approx. 700	Approx. 210
	• Continued conduct of seabed surveys for the purpose of planning the location of the floating production facility and the pipeline route	Approx. 1,000	Approx. 300
	• Performance and completion of FEED ahead of adoption of a Final Investment Decision (FID).	Approx. 105,700	Approx. 31,710
	• Adoption of a Final Investment Decision (FID) for development of the Aphrodite reservoir and implementation thereof, including well drilling, and construction of subsea systems, a floating production facility and an Onshore Receiving Facility.	Approx. 4,100,000	Approx. 1,230,000

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

[55] As of the report approval date, the Aphrodite partners have approved the budgets designated for the FEED and subsea surveys only.

in the Securities Law, based on estimates of the GP 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

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%	104%-101%	104%-101%	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%	35.19%	54.53%	63.74%	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%	64.81%	45.47%	36.26%	
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%	19.44%	13.64%	10.88%	
Payment of overriding royalties to various entities	1.14%	1.85%	1.30%	1.03%	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 respect of block 12 apply to the partnership's share in the natural gas output, i.e.,

	R-factor 1	R-factor 1.5	R-factor 2	R-factor 2.5	Notes
					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%	17.60%	12.35%	9.84%	

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 asset (without the said royalties)	100%	
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

Item	Percentage	Summary explanation of how the royalties or payments are calculated
		operator out of all of the direct expenses in connection with development actions,[56] 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%	

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

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[57]	Out of which, the share of the holders of the equity interests of the Partnership in payments to the GP	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 2023	Approx. 30,370	-	Approx. 448
Budget actually invested in 2024	Approx. 3,579	-	Approx. 78
Budget actually invested in 2025	Approx. 21,351	-	Approx. 287

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 of 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 thereto, 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 approx. 800 MMCF, through 4 production wells, from which the natural gas will be transmitted via a subsea pipeline to the Egyptian transmission system (the "**Updated Development Plan**").

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

On 26 March 2025 the GP's Board approved a budget for consideration of construction of a transmission infrastructure from the Aphrodite reservoir, as part of the Updated Development Plan for the reservoir, in the sum of approx. $20 million (100%, the Partnership's share – approx. $6 million), which consists mainly of infrastructure and seabed surveys.

In addition, on 18 September 2025 the GP's Board approved the 2026 budget for the Aphrodite reservoir, in the sum of approx. $111.5 million (100%, the Partnership's share – approx. $33.5 million). The FEED item in the budget (in the sum of approx. $105.7 million (100%, the Partnership's share – approx. $31.7 million)) is subject to a decision by the partners in the Aphrodite reservoir to carry out FEED.

Further thereto, on 22 December 2025 the partners in the reservoir adopted a decision to commence FEED for the production systems and the transmission infrastructure with a budget of approx. $105.7 million (100%, the Partnership's share – approx. $31.7 million)

According to the reservoir operator's current estimate, before completion of the FEED, the estimated cost of the Updated Development Plan is approx. $4.1 billion (100%). It is emphasized that carrying out the Updated Development Plan and reaching the adoption of a final investment decision (FID) are contingent, *inter alia*, on the results of the FEED, the 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, the receipt of regulatory approvals, and the 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 reservoir operator, Chevron Cyprus Limited (in this section: 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 the Egyptian national gas company (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 the approval of the Updated Development Plan and amendment of the PSC of 14 February 2025, on 17 February 2025, the holders of the interests in the Aphrodite 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 through the construction of a direct pipeline to Egypt and the sale arrangements. As of the report approval date, the said parties are continuing to conduct negotiations for the signing of a detailed MOU for the sale to Egypt (to EGAS) of all of the natural gas quantities that shall be produced from the reservoir to Egypt, with EGAS acting as the exclusive buyer of the natural gas produced from the reservoir. In addition, the holders of the interests in the Aphrodite reservoir are negotiating with the Egyptian government for the signing of an agreement aimed at regulating the primary elements of the midstream activity, which includes the laying of a subsea pipeline and connection of the Aphrodite reservoir from the Cyprus-Egypt border to the Egyptian transmission system.

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

Following approval of the Updated Development Plan and adoption of a decision regarding the performance of FEED, on 9 March 2026, the Partnership released (Ref. 2026-01-020656) a contingent and prospective resources evaluation report, prepared by NSAI in accordance with the SPE-PRMS rules (in this section: the "**Resource Report**"). For details regarding the resources attributed to the Block 12 petroleum asset, see the Resource Report, the information in which is incorporated herein by reference. Attached to this chapter as **Annex B** is NSAI's consent to the inclusion of the said report herein, including by 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.

To the best of the Partnership's knowledge, 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. [58]

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

[58] 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.

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 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. In his letter of 21 September 2025, the Petroleum Commissioner invited the partners in the Yam Tethys project and in the Tamar project to present their position in connection with the decommissioning of the platform, by 30 November 2025. Further thereto, the Operator informed the Partnership that in coordination with the Petroleum Commissioner, the date for presentation of the partners' position as aforesaid has been deferred to a date yet to be determined.

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 7.24.10 below.

In view of the project's classification 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.

General Details with respect to the Petroleum Asset	
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 best of the Partnership's knowledge, the names of the control holders of such partners:	▪ The Partnership (48.50%). ▪ Chevron (47.059%). ▪ 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 2023 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)[59]	Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)
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 activities, including examination of the potential 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 and environmental surveys in accordance with instructions of the Petroleum Commissioner by 2029.	Approx. 1,500	Approx. 728
	• Various additional activities, including examination of the potential 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 and environmental surveys in accordance with instructions of the Petroleum		

[59] The amounts for the years 2023-2025 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)[59]	Amount of Actual Participation in the Budget by the Holders of the Equity Interests of the Partnership ($ in thousands)
	Commissioner by 2029.		
	• Decommissioning of the platform and the subsea pipeline upon termination of use thereof, in accordance with standards and instructions 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 instructions of the Petroleum Commissioner.	Approx. 8,843	Approx. 4,288
	• Various additional activities, including examination of the potential uses of existing project infrastructures.		
2026 forth	• Conduct of asset integrity and environmental surveys in accordance with the instructions of the Petroleum Commissioner by 2029.		
	• Various additional activities, including examination of the potential 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 2026 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 corroborate the veracity of the details presented in these reports.

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 2025, 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.[60] 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.

[60] 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	
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 – 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 determines that the Karish reservoir will be developed first and the Tanin reservoir will be developed further down the line.[61]

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 published by the Ministry of Energy, Energean marketed 4.4 BCM of natural gas produced from the Karish field in 2023. During 2024, the Karish and Karish North reservoir produced approx. 5.8 BCM, which followed Energean's report of 29 February 2024 on the production of first gas from the Karish North reservoir. According to Energean's reports, in 2025 the Karish and Karish North reservoir produced approx. 5.6 BCM.

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 2025[62]. According to this report, the said reservoirs contain approx. 88.8 BCM of natural gas reserves (2P) and approx. 86.5 million barrels of hydrocarbon liquids.

For details with respect to a 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 to the Board of Directors' Report (Chapter B of this report).

It is emphasized that the Partnership, being a royalty interest owner, 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

[61] Link (in Hebrew).
[62] Link.

commencement of production and the report approval date, Energean paid the Partnership royalties for the condensate produced from the Karish Lease (including from the Karish North reservoir), "under protest".

7.5.5 Below is a concise description of the main activities actually carried out in the Tanin and Karish Leases between 1 January 2023 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)
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.		
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	• Continued operating activities and production from the Karish Lease.		
2026 forth	• 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 2032.		

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.

7.6 **The Boujdour Atlantique exploration licenses[63] 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[64] ("**Adarco**"), signed agreements concerning oil and natural gas exploration and production activities in the Boujdour Atlantique exploration licenses, situated in the Atlantic Ocean off the coast of Morocco (in this section: the "**Petroleum Asset**" or the "**License**"), 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.

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 of 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

[63] In practice, the License spans the areas of 17 different licenses

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

Sustainable Development and the Ministry of Finance of Morocco (the "**Moroccan Ministry of Energy**").

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 South Morocco, in an area sometimes historically referred to as "Western Sahara", sovereignty over which, 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.

The Boujdour License expired on 31 January 2026, and as of the report approval date the partners in the License are holding discussions with the Moroccan Ministry of Energy regarding the possibility of extending the License by one additional year, for the purpose of completing all of the actions required for the adoption of a decision to drill an exploration well in the area of the License (drill or drop). It is clarified that the description of the Petroleum Asset presented below is based on the assumption that the License will be extended as requested. However, there is no certainty that the License will be extended or for what period.

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. 33,815 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 August 2023.
Original expiration date of the Petroleum Asset:	31 January 2026.

General Details with respect to the Petroleum Asset	
Dates on which an extension of the term of the petroleum asset was decided:	The License expired on 31 January 2026. For details, see Section 7.6.1 above.
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., 31 January 2026); 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:[65]	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):	-

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:

[65] 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 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).

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)
42 months from the License grant date (after extension of the initial term by an additional year)	• Geological and geophysical analysis in the License, including reprocessing of 2D+3D seismic data and ESG work.	Approx. 6,100[66]	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 submitted in connection with the Zone I Licenses, as part of the fourth bid round 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,

[66] As of the report approval date, the partners in the Boujdour License have approved approx. $5.7 million (100%; the Partnership's share – approx. $4.5 million) out of this budget for 2024-2026.

8, and 11, located in the Mediterranean Sea, in the area of Israel's EEZ (in this section: the "**Licenses**").

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%).

On 17 March 2025, the Ministry of Energy granted the said Licenses to the partners.

On 22 December 2025, the partners signed a Joint Operating Agreement (in this section: "**JOA**"). The purpose of the JOA is to determine the parties' mutual rights and obligations in connection with activities in the areas of the Licenses. The JOA includes, inter alia, the following key provisions:

a. SOCAR shall act as operator.

b. The Operator shall be entitled to reimbursement of any and all direct expenses it incurs in connection with the fulfillment of its duties as Operator, as well as reimbursement of indirect expenses deriving from the expenses of the joint operation in accordance with the type of activity in the Licenses, as specified below (where the annual payment for indirect expenses shall in no case be less than $150,000):

    1. During the exploration phase, the rate of indirect expenses shall be 1%-3% of the direct expenses, depending on the annual expense amount;

    2. During the development and production phases, the indirect expenses rate shall be 1% of the direct expenses.

c. Under the JOA, an Operating Committee shall be established, comprising representatives of the partners, whose responsibility and powers shall be to authorize and oversee the joint operations required or necessary for fulfillment of the terms and conditions of the Licenses and the JOA. Unless determined otherwise, any and all decisions, approvals and other actions of the Operating Committee with respect to all proposals presented thereto, shall be decided by the affirmative vote of two or more (unaffiliated) parties, jointly holding at the time of the vote at least 70% of the total working interests.

d. The JOA lists matters which require a unanimous vote of all the partners, including termination of the PSC in the Licenses, waiver of any part of the area of the concession in the Licenses, and amendment of the JOA.

e. The JOA sets forth a process for the submission and approval of work plans, budgets and Authorizations for Expenditure (AFE) for the performance of activities in areas to which the agreement applies.

f. The JOA sets forth additional provisions on other matters, as is customary in agreements of this type, including provisions regarding exclusive operations, sanctions applicable to the parties and conditions for the imposition thereof, certain restrictions on the transfer of interests, withdrawal from the agreement, rights and obligations in connection with production, provisions in cases of change of control, etc. The JOA is governed by English law and any dispute in connection therewith will be settled by arbitration according to the rules of the LCIA in London.

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:	17 March 2025.
Original expiration date of the petroleum asset:	3 years from the grant date (i.e., 17 March 2028).
Dates on which an extension of the term of the petroleum asset was decided:	-
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	▪ 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

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General Details with respect to the Petroleum Asset	
Partnership's knowledge, the names of the control holders of such partners:	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.
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 activities in the petroleum asset, as included in the bid submitted by the Partners in the bid round, and the costs in respect thereof (100%). 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	Conduct, purchase, and processing of seismic surveys and additional work. The partners intend to engage with an international provider for the conduct of a 3D seismic survey in the coming months.	Approx. 27,850	Approx. 9,190

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 bid round. 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 a 50% interest in a license granted by the Bulgarian government in relation to the area of the Block, with rights under an agreement for natural gas and oil exploration within the area of the Block signed with the Bulgarian government and rights under the joint operating agreement (JOA) that will apply between the partners in the Block (in this section: the "**Interest Acquisition Agreement**" or the "**Agreement**"). The Agreement was signed between NewMed Balkan and OMV Bulgaria.

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 GP's Board 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.

d. On 12 March 2025, upon the entry of OMV Bulgaria, NewMed Balkan and the Government of Bulgaria into an agreement authorizing the transfer of the interest in the Bulgaria License to NewMed Balkan, all the conditions precedent under the Agreement were satisfied, and consequently, the transaction contemplated by the Agreement was closed. Upon the closing of the transaction, NewMed Balkan held a 50% interest in the Bulgaria License.

e. As part of its obligations under the Interest Acquisition Agreement, NewMed Balkan has provided the Government of Bulgaria with bank guarantees in the amount of approx. €2.3 million in respect of its share of the Bulgaria License, to secure compliance with the terms and conditions of such Agreement, environmental protection regulations and the receipt of authorization to conduct exploration drilling.

f. On 21 January 2026, the transaction for the sale of an interest in the Bulgaria License to Bulgarian Energy Holding EAD ("**BEH**"), a Bulgarian state-owned company, was closed. Upon the closing of the transaction, NewMed Balkan holds a 45% interest in the Bulgaria License. For further details, see Section 7.8.3 below.

7.8.2. The Interest Acquisition Agreement with OMV Bulgaria

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

a. In consideration for the transfer of the interests in the Block, NewMed Balkan has undertaken to bear the costs of the first exploration well to be drilled in the Vinekh prospect within the area of the Block (out of a number of prospects and leads) (the "**First Well**"), up to a total amount not to exceed €50 million (approx. $59 million), out of the total cost of the First Well, with the balance of the cost of the First Well (if any) being borne by NewMed Balkan and OMV Bulgaria, in accordance with their proportionate share in the license, and to bear the costs of an additional exploration well in the Krum prospect (the "**Second Well**"), after completion of the First Well, in a total (additional) amount not to exceed €50 million out of the total cost of the Second Well, with the balance of the cost of the additional well (if any) being borne by NewMed Balkan and OMV Bulgaria, in accordance with their proportionate share in the license (the First Well and the Second Well collectively: the "**Two Wells**").

Upon the closing of the engagement of NewMed Balkan and OMV Bulgaria in the agreement for sale of the interest to BEH, the amount that NewMed Balkan undertook to pay was reduced from €50 million to €45 million (approx. $53 million), for each one of the Two Wells (for details see Section 7.8.3 below).

It is clarified that, under the terms of the Agreement, NewMed Balkan does not have the right to be reimbursed by OMV Bulgaria for the amounts provided by NewMed Balkan in its favor, as specified in this section above, and that beyond such amounts, OMV Bulgaria and NewMed Balkan shall bear their *pro rata* share (currently 45%-45%) in the expenses of the project.

The aforesaid amounts include €2.6 million (approx. $3 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 further been agreed that NewMed Balkan will bear the fees to be paid to the Bulgarian government in respect of transfer of the Interests.

b. As of the transaction closing date, NewMed Balkan 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, OMV Bulgaria 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 OMV Bulgaria prior to the transaction closing date.

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

d. 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.

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

f. As part of its obligations under the Interest Acquisition Agreement, NewMed Balkan has provided the Government of Bulgaria with bank guarantees in the amount of approx. €2.3 million in respect of its share of the Bulgaria License, to secure compliance with the terms and conditions of such Agreement, environmental protection regulations and the receipt of authorization to conduct exploration drilling.

g. For further details, see the Partnership's immediate report of 21 January 2026 (Ref. 2026-01-008371).

7.8.3. Interest sale agreement with BEH

a. In July 2023, the Bulgarian parliament decided to instruct the Bulgarian Minister of Energy to conduct negotiations on the terms and conditions according to which a Bulgarian state-owned company would acquire up to 20% of the interest in the Block. Further thereto, in October 2024, OMV Bulgaria received a letter from the Bulgarian Ministry of Energy, with a request for information, *inter alia* on the work plans, technical data and technical-economic analyses in connection with the project.

b. Following the negotiations conducted between NewMed Balkan, OMV Bulgaria (jointly: the "**Sellers**"), the Bulgarian Ministry of Energy and BEH, on 20 January 2026 the Sellers and BEH entered into an agreement for the sale a 10% interest in the Bulgaria License to BEH (5% from each one of the Sellers) (in this section: the "**Agreement**"). For further details see the Partnership's immediate report of 21 January 2026 (Ref. 2026-01-008371).

c. In this context, it is noted that the addendum to the concession agreement (PEA) includes the addition of a clause regarding maintenance of fiscal stability, under which the parties and the Bulgarian Minister of Energy undertake to hold negotiations on the protection of the concession holders' rights in case of material fiscal changes. Under the Agreement, the Sellers and BEH have agreed to work jointly vis-à-vis the Bulgarian government and the Bulgarian Ministry of Energy in connection with amendments to the ordinance for determination of the concession payment (royalties) for the production of subsurface resources and extension of the period of appraisal drillings in the project to two years, instead of one year.

d. It was further agreed to amend the original Interest Acquisition Agreement signed between NewMed Balkan and OMV Bulgaria (as described in Section 7.8.2 above) to reduce the sum total NewMed Balkan had undertaken to pay for each one of the Two Wells, pro rata to the reduction of NewMed Balkan's holdings in the Block, i.e. from €50 million to €45 million for each one of the Two Wells (in total, from €100 million to €90 million).

e. Further to the decision of the Council of Ministers of the Bulgarian government on 14 January 2026, which authorized the Bulgarian Minister of Energy to approve the engagement in the transaction, the transaction was closed on 21 January 2026 following the satisfaction of all of the conditions precedent.

7.8.4. General Details

The details presented in relation to the Block are primarily based on information provided to the Partnership by the operator, OMV Bulgaria, and are to the best of the Partnership's knowledge.

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 km^2.
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, such that ownership of all interests in the license was transferred to OMV Bulgaria which, as of the report approval date, 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. For details with respect to BEH's agreement to act in collaboration with NewMed Balkan and OMV Bulgaria vis-à-vis the Government of Bulgaria and the Ministry of Energy to extend the period for appraisal drillings in the project by an additional year, see Section c above. 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.

General Details about the Block	
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 – 45%.[67] ▪ NewMed Balkan – 45%. ▪ BEH – 10%.
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 holds a 42.75% interest in the Block, through its 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. $68.4 million.

[67] 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 whose share capital is held by OMV AG and approx. 21% of whose share capital is held by the Romanian government. OMV AG is a public company, approx. 56% of whose share capital is co-held by ADNOC (the national oil company of Abu Dhabi) and OBAG, a company owned by the Austrian government.

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Item	Percentage Pre-Investment Recovery	Percentage Post-Investment Recovery	Percentage Post-Investment Recovery	Percentage Post-Investment Recovery	Percentage Post-Investment Recovery	Percentage Post-Investment Recovery	Percentage 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 7.8.6(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 7.8.6(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)	42.75%	42.75%	42.75%	42.75%	42.75%	42.75%	42.75%	
Partnership's equity interest holders' total	41.68%	41.68%	40.61%	38.48%	37.41%	33.13%	29.93%	

Item	Percentage Pre-Investment Recovery	Percentage Post-Investment Recovery	Percentage Post-Investment Recovery	Percentage Post-Investment Recovery	Percentage Post-Investment Recovery	Percentage Post-Investment Recovery	Percentage Post-Investment Recovery	Concise Explanation on the Royalty or Payment Calculation Method
rate of the actual 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	1.92%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	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	39.76%	37.62%	36.55%	34.41%	33.35%	29.07%	25.86%	

7.8.5. As specified in Section 7.8.6(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 a 42.75% interest in the Bulgaria License.

7.8.6. 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, under the Interest Acquisition Agreement amended on 20 January 2026, the Partnership has undertaken to bear the funding of OMV Bulgaria's share (45%) in the Two Wells up to a cap (in each one of the Two Wells) of €45 million (approx. $53 million), and beyond the said amounts, NewMed Balkan, OMV Bulgaria and BEH shall bear their *pro rata* shares 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 7.8.9(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.

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.

On 8 December 2025, the Bulgarian Ministry of Energy published a draft of new regulations for determining royalty payments to the Government of Bulgaria (the "**Draft Regulations**"), which royalties are calculated as the product of the economic value of the annual production multiplied by the royalty rate payable to the Government, which is determined based on an R-Factor formula, according to the following brackets (as compared with the royalty rate under the regulation applicable in Bulgaria as of the date of this report):

R-Factor	Royalty Rate	Royalty Rate under the Draft Regulations
< 1.5	2.5%	3.5%
1.5 – 1.75	5%	7%
1.75 – 2	10%	9%-11.49%
2 – 2.5	12.5%	11.5%-13.99%
2.5 – 3	22.5%	14%-19.99%
> 3	30%	20%-35%

It is further proposed to establish in the Draft Regulations a minimum annual royalty payment obligation, calculated based on 10% of the following product: (a) the projected average annual output for the concession period (the output determined at the time the concession was granted or the average output according to the approved work program for production and initial processing), multiplied by (b) the minimum royalty rate according to the R-Factor formula (3.5% at the R<1.5 bracket); and by (c) the weighted average sales price for the period (based on the concessionaire's figures, which shall not be lower than a market price determined by arm's length transactions between unrelated parties).

2. 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	42.75%	42.75%	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	39.76%	25.86%-37.62%	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	29.93%-41.68%		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	43.178%-43.605%	43.178%-43.605%	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 7.8.9(b) below.

Item	Percentage	Concise Explanation on the Royalty or Payment Calculation Method
Total actual expense rate at Block level	101%-102%	
Partnership's equity interest holders' rate of Block expenses (indirectly)	42.75%	After funding the operator's share, as specified in Section 7.8.6(a)1 above.
Partnership's equity interest holders' total actual rate of the expenses, at Block level (and before other payments at Partnership level)	43.178%-43.605%	
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	43.178%-43.605%	

7.8.7. 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

7.8.8. 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 Interest Acquisition Agreement, on 26 March 2025 the partners in the Bulgaria License adopted a decision on exploration drilling in the Vinekh prospect, and on 10 June 2025 the partners in the Bulgaria License adopted a decision on further exploration drilling in the License area, in the Krum prospect. For further details, see the Partnership's immediate reports of 27 March 2025 and 11 June 2025 (Ref. nos. 2025-01-021116 and 2025-01-041723, respectively), which are incorporated herein by reference.

On 4 February 2026, the Partnership reported on the Partnership's estimate that in the exploration well in the Vinekh prospect, non-significant signs of natural gas were discovered, and therefore the Partnership estimates that the well is a "dry hole". The total expenses of the Vinekh well, including the plugging and abandonment costs, according to the Operator's estimate, will total approx. €86 million (approx. $103 million[68] in 100% terms, NewMed Balkan's share – approx. $76 million). The exploration drilling in the Krum prospect, which is scheduled to take about two months, commenced on 18 February 2026. For details, see immediate reports dated 4 February 2026 and 23 February 2026 (Ref. nos. 2026-01-041723 and 2026-01-016810, respectively).

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.

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)[69]
2025	• Identification and characterization of prospects and leads in the area of the license.	Approx. 957	Approx. 431

[68] According to the known dollar rate as of 31 December 2025.

[69] The Partnership's share after the closing of the transfer of the interest to BEH, as specified in Section 7.8.3 above, 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 7.8.6(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)[69]
	• Commencement of drilling of the Vinekh-1 exploration well.	Approx. 46,721	Approx. 46,721
	• Preparations for the Krum-1 exploration well.	Approx. 12,256	Approx. 12,256
	• Planning for future wells.	Approx. 122	approx. 55
	• Preliminary engineering work related to possible development design of the discovery or discoveries, if any.	Approx. 366	Approx. 164
	• Operating expenses, *inter alia*, on environmental, safety, regulatory and project management aspects.	Approx. 1,995	Approx. 898
2026 forth[70]	• Completion of the drilling of the Vinekh-1 exploration well and plugging thereof.	Approx. 54,867	Approx. 24,609
	• Drilling of the Krum-1 exploration well.	Approx. 60,877	Approx. 47,004
	• Depending on the results of the wells, planning of additional (exploration and/or appraisal) wells.	Approx. 3,568	approx. 1,517
	• Continued identification and characterization of prospects and leads in the area of the license.	Approx. 2,335	Approx. 992
	• Continued identification and specification of prospects and leads in the area of the license, conditioned on the success of the Second Well.	Approx. 16,884	Approx. 7,176
	• In the event of discovery of an economically viable reservoir, initial engineering design work prior to the adoption of a development decision.	Approx. 12,933	Approx. 5,496
	• Operating expenses, *inter alia*, on environmental, regulatory and project management aspects.	Approx. 802	Approx. 341
	• 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

[70] These budgets represent the Partnership's estimates and, as of the report approval date, have not yet been approved by the partners in the license, with the exception of the budget for the Vinekh-1 well and the Krum-1 well.

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 OMV Bulgaria 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.

7.8.9. Joint Operating Agreement (JOA)

Operations in the Bulgaria License are carried out under the JOA of 21 January 2026, the current parties to which are NewMed Balkan, OMV Bulgaria and BEH, 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 and amendment of the JOA.

(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 7.8.8 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.

7.8.10. Prospective resources data

For details regarding prospective resources in relation to the Krum prospect as of 31 May 2025, and regarding the exploration well being drilled in the Krum prospect, see the Partnership's immediate report of 11 June 2025 (Ref. 2025-01-041723), the information in which is incorporated herein by reference, while as of 31 December 2025, there has been no change in the said details. NSAI's consent to the inclusion of the said report herein, including by reference, and a letter of no material changes in the Krum prospect from NSAI, are attached hereto as **Annex B**.

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. 45.34% 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 expired Eran License (22%). It was further agreed that the interest in the area of the expired 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 were conducted between the Tamar Partners and the State of Israel and the holders of the interests in the expired 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, and on 18 August 2025, the Partnership learned that the Tamar Partners reached an arrangement with the State whereby, *inter alia*, subject to fulfilment of conditions precedent, the Tamar Partners will pay the state overriding royalties of 5.9% for their income deriving from the gas produced from the Tamar SW reservoir, according to the market value at the wellhead, and the State will approve a change to the boundaries of the Tamar Lease such that it will include all of the natural gas resources in the Tamar SW reservoir (the "**Tamar Arrangement**"). The Tamar Arrangement was agreed without concurrently resolving also the Partnership's rights according to the mediation arrangement and the judgement entered thereon. Further thereto, the Partnership, together with Ratio, approached the Tamar Partners requesting to resolve the economic rights due thereto as holders of interests in the expired Eran License, in accordance with the principles agreed in the Tamar Arrangement. As of the report approval date, the Partnership and Ratio are holding discussions with the Tamar Partners to resolve this issue.

7.9.2 **Tamar project (Tamar Lease (I/12) and Dalit Lease (I/13))**

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 **New Ofek license**

The Partnership previously held 25% of the interests in the onshore license 405/"New Ofek", which expired on 20 June 2022. On 7 November 2024 the partners in this license received a letter from the Petroleum Commissioner whereby, inter alia, the abandonment of the well must be completed by 31 March 2025. On 29 April 2025 the partners received another letter whereby, insofar as the abandonment is not commenced by 15 May 2025, the Petroleum Commissioner will give notice of his intention to forfeit guarantees provided by the partners in favor of the Ministry of Energy. In June 2025 the operator of this license, S.O.A. Energy Israel Ltd ("**SOA**") informed the partners that the well plugging has been completed, and that it had submitted to the Petroleum Commissioner and to the Ministry of Environmental Protection summary reports.

7.10 **Renewable energy**

On 21 September 2022 the unit holders' general meeting authorized the Partnership to make investments in renewable energy projects under the collaboration with Enlight and according to the TASE Rules, for a period of 3 years (the "**First Period**"), with the First Period being extendable for additional periods of 3 years each, subject to the approval of the general meeting of participation unit holders by the required majority under the TASE Rules. The aforesaid notwithstanding, follow-on investments and/or investments in renewable energy projects in which the Partnership had (directly or indirectly) invested and/or committed to invest in the First Period, are not limited to such period, and shall be made out of the Investment Facility (as defined below) and/or from the internal sources of the Co-Owned Corporations and/or the project corporations. The said authorization to carry out renewable energy projects was limited to a cumulative investment amount (the Partnership's share only) of $100 million (in equity and/or shareholder loans, including a capital note or by way of a guarantee for loans to be provided) (the "**Investment Facility**"), as required by the TASE Rules. In this context, approval was given for the outline of the collaboration with Enlight detailed below considering, inter alia, Mr. Abu's personal interest in the transaction. For further details, see the Partnership's immediate reports of 6 September 2022 and 21 September 2022 (Ref. nos. 2022-01-092520 and 2022-01-120358, respectively), the information incorporated in which is incorporated herein by reference.

The First Period ended on 21 September 2025. The collaboration with Enlight (as detailed below) with respect to the projects commenced before such date continues, up to the Investment Facility in accordance with the general meeting's approval, and according to the Collaboration Agreement. The collaboration with Enlight according to the Addendum to the Agreement (as defined below) with respect to additional projects, in which no investment was made, directly or indirectly, or an investment commitment, until the end of the First Period, will be subject to approval by the Partnership's meeting of unit holders.

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

7.10.1 On 13 March 2023, the Partnership engaged with Enlight in a detailed agreement regarding exclusive collaboration for a 3-year period regarding the identification, initiation, development, financing, construction and operation of renewable energy projects, including in the following areas: solar projects, wind projects, energy sequestration 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). On 16 February 2026 the parties entered into an addendum to the agreement, in which they agreed to extend the Term of Exclusivity for the collaboration for an additional 3-year period (i.e., until 31 March 2029) which, in certain circumstances, may be extended up to a period of 5 years from the date of signing of the addendum to the agreement (in this section: the "**Addendum to the Agreement**").

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. As of the report approval date, the chairman of Enlight's board holds office as chairman of the board of the Co-Owned Corporations.

(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. For details regarding the extension of the Term of Exclusivity, see Section 7.10.1 above.

(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. 234 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.

7.10.3 On 12 March 2025, MedLight engaged with a local partner in Egypt (a third party unaffiliated with the Partnership or Enlight, in this section:

the "**Partner**") in a non-binding MOU for the development and construction of a renewable energy project in the Sinai peninsula, with the aim of exporting electricity to the State of Israel, the Palestinian Authority and the Gaza Strip. In this context, land was identified with an estimated production potential of approx. 4-5 GW, and certain geographic areas for construction of the production facilities were considered. The project is expected to be carried out in stages, with consideration being given in the first stage to a potential onshore connection in the Nitzana area, close to the existing gas pipeline route, and later, with the increase of the output, consideration will be given to laying a submarine cable along the route of the EMG pipeline infrastructure, enabling significant electricity transmission, relatively close to the consumption areas in Israel. It is clarified that implementation of the project (if promoted) is subject, *inter alia*, to completion of feasibility studies, engagement in binding agreements, receipt of approvals and permits from third parties and relevant authorities, commercial regulation of the sale of the electricity and the provision of financing, and arrangement/construction of transmission infrastructures and connection.

Caution concerning forward-looking information – The information specified above in connection with the potential renewable energy projects in Morocco and the Sinai Peninsula, including their capacity and the possible timetables for their development and operation, and in connection with the feasibility study, the engagement (if any) in binding agreements for the construction of a renewable energy project in the Sinai Peninsula and the possibility of onshore connection and/or the transmission of power from this project to Israel, 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 not materialize or may materialize in a materially different manner due to factors beyond the Partnership's control, including due to non-completion of feasibility studies and/or non-engagement in binding agreements (including with a local partner in Egypt and/or transmission entities / power purchasers) and/or due to delays in obtaining the permits required for construction of the Projects and/or the ability to connect to existing infrastructures or the construction of new infrastructures for transmission of the power and/or due to the materialization of any of the risk factors specified in this report.

7.10.4 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 2025, 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 2025 to NEPCO and Blue Ocean were approx. 29% and approx. 54%, 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 2025 originated from sales in Israel and Jordan to independent power producers, industrial customers and natural gas marketing companies, and from the sale of condensate to ARF.

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[71].

Customer	Supply commencement year	Agreement period[72]	Total maximum contract quantity for supply (100%) (BCM)	Total quantity supplied until 31 December 2025 (100%) (BCM)	Main linkage basis of the gas price
Independent power producers	2020 or later, as determined in the agreement.	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. 4.4	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".

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

[72] In most of the agreements, the gas supply period is expected to end on the date of supply to the customers of the maximum contract quantity set forth in the agreement.

Customer	Supply commencement year	Agreement period[72]	Total maximum contract quantity for supply (100%) (BCM)	Total quantity supplied until 31 December 2025 (100%) (BCM)	Main linkage basis of the gas price
Industrial customers	2020 or later, as determined in the agreement.	The agreements are for a term of up to 15 years.	Approx. 4.1	Approx. 0.75	The linkage formulas in these agreements are based on the TAOZ Index, the Electricity Production Tariff, the U.S. Consumer Price Index, the Brent price and the oil refining margin. All such price formulas include a "floor price".
NEPCO export agreement (described in Section 7.12.3(b) below)	2020	15 years. The agreement stipulates that in the event that the buyer fails to purchase the total contract quantity, the supply period will be extended by a period of up to two additional years.	Approx. 45	Approx. 15.5	The linkage formula is based on linkage to Brent prices and includes a "floor price".
Blue Ocean export agreement (described in Section 7.12.3(c) below)	2020	Around 15 years. The agreement stipulates that in the event that the buyer fails to purchase the total contract quantity, the supply period will be extended by a period of up to two additional years.	Approx. 60	Approx. 29.7	The linkage formula is based on linkage to 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[73] and after the tenth year of the agreement, upon fulfillment of certain conditions determined in the agreement.
Amendment to the export agreement between the Leviathan Partners and Blue Ocean (described in Section 7.12.3(c)5 below)	First tranche during 2026; second tranche during 2029.	Around 15 years. The agreement stipulates that in the event that the buyer fails to purchase the total contract quantity, the supply period will be extended by a period of up to two additional years.	First tranche – approx. 20; second tranche – approx. 110	No natural gas was supplied under the amendment to the agreement in 2025	The amendment to the agreement includes a mechanism for price updates of up to 10% (increase or decrease) every 5 years beginning at the commencement of the second tranche.
Export agreements with other customers in Jordan	In one agreement in 2025, and in the second agreement supply is expected to commence in 2026.	9-15 years. The agreements stipulate that in the event that the buyer fails to purchase the total contract quantity, the supply period will be extended by a period of up to	Approx. 4.5-5	Approx. 0.03	The linkage formula is based on linkage to Brent prices and includes a "floor price".

[73] The parties have agreed not to update the price after the fifth year of the agreement.

Customer	Supply commencement year	Agreement period[72]	Total maximum contract quantity for supply (100%) (BCM)	Total quantity supplied until 31 December 2025 (100%) (BCM)	Main linkage basis of the gas price
		one additional years.			
Total			Approx. 261	Approx. 50.4[74]	

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.

The following table includes a breakdown of the Partnership's revenues from the Leviathan reservoir in 2024-2025:

	Y2025		Y2024	
Name of Customer	Total Revenues ($ in million)	% of Total Revenues	Total Revenues ($ in million)	% of Total Revenues
Independent Power Producers				
Other	Approx. 121	Approx. 12	Approx. 97	Approx. 8
Industrial Customers and Marketing Companies (including in Jordan)				
Other	Approx. 52	Approx. 5	Approx. 45	Approx. 4
Natural Gas Export				
NEPCO	Approx. 293	Approx. 29	Approx. 291	Approx. 26
Blue Ocean	Approx. 547	Approx. 54	Approx. 703	Approx. 62

(a) 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

1. As of the report approval date, the Partnership is continuing to conduct negotiations, in various stages, with additional potential customers in the domestic market, including independent

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[74] The quantity supplied from the Leviathan project until 31 December 2025 (100%) (under the agreements specified in the table, under spot agreements and under agreements that have expired) totals approx. 62.4 BCM.

electricity producers and industrial consumers, subject, inter alia, to the Leviathan project's supply capacity.

2. In 2025 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. In this context, inter alia, an agreement was signed in May 2025 between the Leviathan Partners and ICL Group Ltd. for the supply of natural gas for a period of approx. 5 years, with a total volume of approx. 0.75 BCM.

3. 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.

4. 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.

5. 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 3 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.

6. The export to Egypt approval of 17 December 2025 sets forth provisions regarding the gas quantities that the Leviathan Partners are required to provide to consumers in the domestic market, as well as the conditions (including the price) to be offered to consumers in the domestic market for the purchase of such gas quantities, as described in Section 7.12.3(c)6 below.

(b) <u>Agreements for the export of gas from the Leviathan reservoir to Jordan</u>

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 15 January 2026, 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 2026-2027, and that the minimum annual quantity that NEPCO had undertaken to take or pay for during 2026-2027 would increase accordingly. The aforesaid does not change the total supply volume under the Export to Jordan Agreement (approx. 45 BCM), and the quantity specified in the export approval, as specified above and below.

5. In October 2024, an agreement was signed between the Marketing Company and FAJR for the supply of a total volume of approx. 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 was also conditioned 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. In July 2025, all the conditions precedent for the entry of this agreement into force were satisfied, and in October 2025 supply of the gas thereunder begun.

6. In July 2025, an agreement was signed between the Leviathan Partners and industrial plants in Jordan for the supply of natural gas for a period of approx. 15 years with a total volume of up to approx. 2 BCM. The gas will be supplied through an INGL system in the Dead Sea area (Jordan-South), and the gas price formula determined in this agreement is based on linkage to the Brent prices and includes a "floor price". The taking effect of the agreement is contingent on several conditions precedent. As of the report approval date, the conditions precedent for the agreement to take effect have been fulfilled, and the supply of gas thereunder is expected to commence in the coming weeks.

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) <u>Agreement for export of gas from the Leviathan reservoir to Blue Ocean in Egypt</u>

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

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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. For details with respect to the amendment of 7 August 2025 to the Export to Egypt Agreement, see Section 7.12.3(c)5 below.

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

(a) The total contract gas quantity the Leviathan Partners undertook to supply the buyer, on a firm basis, is approx. 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 (approx. 2.1 BCM per year); (2) in the period commencing 1 July 2020 and ending 30 June 2022 – 350 MMCF per day (approx. 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 (approx. 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. In addition, in connection with the buyer's 'take or pay' undertaking, the agreement prescribes, *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 price updates of up to 10% (up or down) after the fifth year and after the tenth year of the agreement[75], 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.

[75] For details, see Footnote 73 above.

3. By 31 December 2025, the Leviathan Partners supplied the buyer with approx. 29.7 BCM for total monetary consideration of approx. $6.3 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.

5. On 7 August 2025, the Leviathan Partners engaged with Blue Ocean in an amendment to the Export to Egypt Agreement (the "**Amendment**" or the "**Amendment to the Export to Egypt Agreement**"). Below is a concise description of its highlights:

   (a) Under the Amendment, the total contract quantity under the Export to Egypt Agreement shall be increased by a total volume of approx. 130 BCM (the "**Additional Quantities**"), to be added to the existing quantity set forth in the Export to Egypt Agreement as aforesaid, in two tranches as specified below: (1) An additional gas quantity of approx. 20 BCM from the taking effect of the Amendment (the "**First Tranche**"); and (2) An additional gas quantity of approx. 110 BCM, subject to satisfaction of the conditions specified in Section (c) below (the "**Second Tranche**").

   (b) The First Tranche: The daily gas quantity that the Leviathan Partners are obligated to supply to Blue Ocean in the Export Agreement shall be increased from 450 MMSCF per day (approx. 4.7 BCM per year) to 650 MMSCF (approx. 6.7 BCM per year), from the date on which INGL completes the construction of the Ashdod-Ashkelon offshore section and the Leviathan Partners complete construction of the Third Pipeline Project (for further details about the Ashdod-Ashkelon offshore section and about the Third Pipeline Project, see Sections 7.13.2(c) below and 7.2.5(b) above, respectively).

(c) The Second Tranche: The Leviathan Partners' undertaking to supply the Second Tranche is subject to satisfaction of the following conditions: (1) Adoption of a Final Investment Decision (FID) by the Leviathan Partners for the First Phase of the Expansion Project under the Updated Development Plan for the Leviathan Reservoir. This condition was fulfilled on 15 January 2026. For further details about the Expansion Project, see Section 7.2.5(b)2 above; and (2) Engagement by the Leviathan Partners (or another on their behalf) with INGL in a transmission agreement for the Nitzana Pipeline (collectively: the "**Conditions to the Second Tranche**") for the supply of the gas to the buyer at the delivery point on the Israel-Egypt border. This condition was fulfilled on 16 September 2025. Therefore, as of the report approval date, the Conditions to the Second Tranche have been met.

Upon fulfillment of the conditions for the gas supply in the Second Tranche, the daily gas quantity that the Leviathan Partners are committed to supply to Blue Ocean will be increased to 1,150-1,250 MMSCF (approx. 11.9-12.9 BCM per year), according to the mechanism described below.

The Amendment to the Export Agreement determines a mechanism for the timing of commencement of the supply of the increased daily quantity (the "**Expansion Date**"), which is primarily based on the Leviathan Partners' estimate regarding the progress of the projects required for expansion of the daily supply quantity, and chiefly completion of the First Phase of the Expansion Project and completion of the project for the construction of the Nitzana Pipeline (for further details about the First Phase of the Expansion Project, see Section 7.2.5(b)2 above, and for further details about the Nitzana Pipeline, see Section 7.13.2(b) below). The Leviathan Partners' assessment, as of the report approval date, is that all of the projects described as aforesaid are expected to be completed in 2029.

(d) According to the Amendment to the Export Agreement, on the date of completion of the Ashdod-Ashkelon offshore section and the Third Pipeline Project, the supply period shall be extended until 10 years after such date or until the date on which Blue Ocean shall consume the total contract quantity (i.e., including the First Tranche), whichever is earlier. In addition, on the Expansion Date, the supply period shall be extended until 31 December 2040 or until the date on which Blue Ocean shall consume the total contract quantity (i.e., including the Second Tranche), whichever is earlier. If, at the end of the supply period, Blue Ocean shall not have consumed the total contract quantity, the supply period shall automatically be extended until the date on which Blue Ocean shall consume the total contract quantity, provided that the extension period does not exceed an additional two years.

(e) The Amendment to the Export to Egypt Agreement includes, inter alia, the following additional changes:

1. Blue Ocean undertook to take or pay (TOP) for the Additional Quantities according to the mechanisms determined in the Amendment to the Export Agreement;

2. Blue Ocean's right to reduce the TOP quantity in a year in which the average Brent price (as defined in the Export to Egypt Agreement) falls below $50 per barrel, was cancelled (for further details, see Section 7.27.5 below);

3. Provisions were determined regarding the price of the gas to be supplied to Blue Ocean under the Export Agreement as well as a price mechanism in relation to the gas quantities to be supplied under the Second Tranche, in accordance with a formula based on the Brent oil barrel price which includes a "floor price". The Partnership estimates that the total aggregate revenues from the sale of the Additional Quantities to Blue Ocean under the Amendment to the Export Agreement (100%) is expected to total approx. $35 billion. This estimate is based, inter alia, on the assumption that Blue Ocean will consume the full Additional Quantities, as well as on the Partnership's estimates regarding the natural gas price and the Brent price during the supply period. It is clarified that in practice, the revenues shall be derived from a gamut of other factors which are beyond the Partnership's control;

4. The current price update mechanism, within the meaning thereof in Section (e)3 above, shall apply to the outstanding quantities to be supplied under the original total contract quantity of the Export to Egypt Agreement, as well as to quantities to be supplied under the First Tranche. With respect to quantities to be supplied under

the Second Tranche, a similar mechanism shall apply for updating the price by up to 10% (up or down) after the fifth year (according to the sellers' estimate, in 2035) and after the tenth year from the Expansion Date (according to the sellers' estimate, in 2040). If the parties do not reach agreements on the price update, as detailed above, each one of the parties shall be entitled to reduce the daily gas quantity left to supply under the Amendment to the Agreement, as detailed in Section (c) above, by up to 30% on the first adjustment date and up to 30% on the second adjustment date;

5. Blue Ocean's right to terminate the Export Agreement in the event of termination of the export agreement between Blue Ocean and the holders of the interests in the Tamar project, was canceled (for further details, see Section 7.12.3(c)2(e) above).

(f) Further to the Partnership's immediate reports of 30 October 2025, 30 November 2025 and 31 December 2025 (Ref. nos. 2025-01-082110, 2025-01-094718 and 2025-01-105955, respectively), regarding the extensions for fulfillment of the conditions precedent for the taking effect of the Amendment to the Export to Egypt Agreement, upon receipt of Blue Ocean's approval of the provisions of the export permit on 15 January 2026, all of the conditions precedent for the Amendment to the Export to Egypt Agreement have been fulfilled, and it took effect.

(g) For further details about the Amendment to the Export Agreement, see the Partnership's immediate report of 7 August 2025 (Ref. 2021-01-058576).

6. Further to the engagement in the Amendment to the Export to Egypt Agreement, as detailed in Section 7.2.5(f) above, on 17 December 2025 the leaseholders received the Petroleum Commissioner's approval for export of the Additional Quantities under the Amendment to the Export to Egypt Agreement to Blue Ocean (the "**New Approval**").

   In the Partnership's estimation, the New Approval enables compliance with the provisions of the Amendment to the Export to Egypt Agreement, including the supply of the Additional Quantities to Blue Ocean. The New Approval was granted in addition to the export approval granted to the leaseholders on 16 December 2019 (the "**Previous Approval**") and it stipulates that it supersedes any contradictory provision in any other document, including the Amendment to the Export to Egypt Agreement.

Following is a concise description of the principal conditions of the New Approval:

(a) Natural gas quantities under the New Approval may be exported as of the date on which the daily production capacity of the Leviathan reservoir amounts to a minimum of 1,350 MMSCF. The New Approval shall be effective until the earlier of the following: (1) The date on which Blue Ocean consumes the maximum total quantity specified in the New Approval; (2) The date on which the Amendment to the Export to Egypt Agreement comes to an end; (3) The expiration of the Leviathan lease deeds (the "**Term of Export**").

(b) The New Approval and its provisions do not derogate from the power conferred on the Minister of Energy pursuant to Section 33 of the Petroleum Law nor from the provisions of the Emergency Regulations.

(c) The supply of any quantity to the Buyer shall be subject to supply by the leaseholders of the full gas quantities nominated by the domestic-market consumers (under firm agreements or under binding spot nominations), including at the daily and annual levels.

(d) The New Approval was granted for a maximum total quantity to be added to the export quantities pursuant to the Previous Approval, as follows: (1) Until such time as the reservoir's daily production capacity is 1,850 MMSCF (the "**First Expansion**") – the maximum total quantity shall be approx. 20.7 BCM; (2) Until such time as the reservoir's daily production capacity is 2,100 MMSCF (the "**Second Expansion**") – the maximum total quantity shall be approx. 95.6 BCM; and (3) After the Second Expansion – the maximum total quantity shall be approx. 130.9 BCM (in this section: the "**Total Export Quantity**"). The quantities specified in Subsections (2) and (3) above are subject to the recoverability of a volume of natural gas throughout the life of the reservoir (2C+2P categories) of no less than 535 BCM, as shall be determined by the Petroleum Commissioner based on the opinion of professional experts in the field of reserves evaluation, prepared in accordance with generally accepted industry standards. The Petroleum Commissioner may, from time to time, reduce the aforesaid quantities in the event that the quantity recoverable from the reservoir is lower, or if the he finds that the development plan is not being implemented with due diligence.

(e) The New Approval specifies the maximum daily and annual quantities that may be exported, in accordance with the various expansion phases and the seasonal demand volumes in the domestic market (the "**Maximum Quantities**"). It also provides that in the event of a gap between the total maximum daily quantities in a certain year and the maximum annual quantity determined for that year, the leaseholders may compensate for the shortfall by export on a spot basis, subject to certain conditions as set out in the New Approval.

Beginning on 1 January 2036, the Petroleum Commissioner may, by a reasoned decision, reduce the Maximum Quantities by up to 60%, for all or part of the calendar year, in view of a change between the years in the gap between demand and supply in the domestic market, but without thereby affecting the Total Export Quantity. Notice shall be given to the leaseholders at least one year in advance of the anticipated issuance of such a decision. The aforesaid notwithstanding, in the event that such a notice is given, insofar as the Commissioner finds, in proximity to the reduction date, that there is no need for a reduction, he shall inform the leaseholders as soon as possible. The New Approval states that, based on the Ministry of Energy's assessments as of the approval grant date, such a gap is indeed expected.

Without derogating from the foregoing, where the Petroleum Commissioner finds that the aggregate supply of natural gas delivered to the domestic market from all producing reservoirs has been continuously lower, for a period exceeding 28 days, than the quantities required by the domestic market, he may, after consulting with the Director of the Natural Gas Authority, reduce the Maximum Quantities. The Petroleum Commissioner's decision regarding reduction of the export quantity in these circumstances shall first be examined for the reservoir from which the supply to the domestic market was reduced.

(f) In the event that, after the date of the Second Expansion, the actual production capacity of the leases increases and exceeds 2,100 MMSCF per day (in this section: the "**Increase in Production**"), the leaseholders may export one half of the Increase in Production through spot transactions; and in relation to the second half, the leaseholders may submit an application to the Petroleum Commissioner to increase the maximum daily quantity or to increase the excess quantity permitted for export through spot transactions as noted above.

(g) The New Approval specifies provisions that regulate the possibility of reducing the Maximum Quantities in the event that the production from the reservoir on a certain day is lower than the full production capacity, as determined in the New Approval, the principal purpose of which is to prioritize allocation to domestic-market consumers while ensuring a minimal daily export quantity subject to certain conditions.

(h) In the context of receiving the New Approval, the leaseholders undertook to offer all consumers in the domestic market to enter into binding agreements with them for the purchase of natural gas ("**Firm Contracts**"), for a period of between 1 and 8 years but not beyond expiration of the New Approval (or a longer period insofar as agreed between the parties), for any quantity requested within the difference between the full production capacity at such time, net of the total of (1) the maximum daily quantity specified in the New Approval; and (2) obligations under the leaseholders' existing Firm Contracts, except for the Amendment to the Export to Egypt Agreement. The New Approval includes provisions to ensure the fixed daily quantity that shall be offered in the Firm Contracts, depending on the term of the agreement. In addition, the leaseholders shall offer all consumers in the domestic market to enter into a contract with them for the purchase of natural gas on a spot basis for a period of at least one year (in this section: "**Spot Contracts**"), for any quantity requested within the difference between the Leviathan reservoir's full production capacity on the gas nomination date and the aggregate daily obligations at such time under Firm Contracts they have signed, except for the obligations under the Amendment to the Export to Egypt Agreement. The leaseholders shall offer consumers in the domestic market with which they shall negotiate such Firm Contracts and Spot Contracts, price and linkage formula alternatives, as specified in such obligation. Such alternatives include the price and linkage formula alternatives determined in Government Resolution 476 on the Gas Framework, as well as an additional linkage formula that shall be offered to independent power producers, which is based on the household electricity tariff. Notwithstanding the aforesaid, the obligation to offer the price alternatives in relation to Spot Contracts shall only apply until the date of the Second Expansion or until the end of 2030 (whichever is later). If the date of the Second Expansion falls before the end of 2032, such obligation shall continue to apply solely in relation to the peak months (as defined in the New Approval), until the end of 2032. In addition, on 15 February 2026, the

Partnership received a request for information from the Competition Authority, pursuant to Section 46(b) of the Economic Competition Law, under which the Partnership was required, *inter alia*, to provide the Competition Authority with a complete copy of the obligations of the leaseholders in the Leviathan reservoir that were given in the context of the New Approval, as well as a final document that was delivered to the Petroleum Commissioner that includes the said obligations in connection with the New Approval.

(i) The New Approval sets down provisions whereby, in addition to the foregoing, the leaseholders may export natural gas quantities, in accordance with the New Approval together with the Previous Approval, on a spot basis, subject to all gas quantities that have been nominated by the leaseholders' customers in the domestic market having been supplied and subject to the following limits: Until the date of the Second Expansion or until the end of 2030 (whichever is later) – without any quantitative limit; from the date of the Second Expansion or from the end of 2030 (whichever is later) – up to 2 BCM per year over and above the annual quantity specified in the New Approval, subject to certain daily limits as specified, and also subject to the Commissioner's power to determine additional quantitative limits in certain cases, all up to the Total Export Quantity.

(j) The New Approval sets down additional provisions that address, *inter alia*, the ability to receive approval for the export of gas to the buyer in excess of the Maximum Quantities upon the occurrence of a material change in market conditions; provisions that concern cases in which the export quantity on a certain day is lower than the maximum daily quantity due to nominations received from domestic market consumers; provisions pertaining to reports to the Petroleum Commissioner, disclosure on related agreements, the requirement of the Petroleum Commissioner's approval for any change in the Export Agreement and in related agreements, and provisions on additional matters, including provisions regarding the Commissioner's powers in the case of a breach of the leaseholders' obligations in the context of receipt of the New Approval.

Furthermore, concurrently with receipt of the New Approval and at the request of the Ministry of Energy, the leaseholders have confirmed that they shall work together with the Natural Gas Authority on promotion of a platform for the secondary trading of natural gas for natural gas consumers in the Israeli market, and shall also jointly examine various options in connection with the natural gas quantities that may be directed to the trading platform once established, under spot agreements, which quantities shall be purchased in accordance with the standard contractual terms and conditions in sale agreements and shall be carried out according to standard international practice. In this context it is noted that on 25 February 2026, it was posted on the website of the Ministry of Energy that the Natural Gas Authority is promoting the establishment of a natural gas trading platform. For details, see Section 7.24.9(c)4 7.24.9(b)(4) below.

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, the materialization of which, in whole or in part, is uncertain, and which 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 natural gas consumption by the Buyer, gas price changes in accordance with the terms and conditions of the engagement and the terms of the export permit, and *inter alia*, the formulas and price mechanisms specified therein, and other factors that are not foreseeable on the report approval date and over which the Partnership has no control, or due to the materialization of any of the other risk factors specified in Section 7.30 below.

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.

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**"). As of the report approval date, the Leviathan Partners are exploring the possibility of exporting condensate from the

Leviathan project via existing systems of third parties. In this context, the possibility is being examined of adapting the existing transmission and storage infrastructure for the transmission of condensate from the Leviathan project, its storage and the loading thereof onto vessels for export.

In addition, the Leviathan Partners are exploring the possibility of engagements in agreements for the sale of condensate to potential international customers. The export of condensate from the Leviathan project may be dependent on commercial, technical, operating, regulatory and other factors.

(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.

(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 the Expansion Project.

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

(d) Agreement with ARF

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. On the date of signing of the Agreement, the Sellers estimated that the total revenues generated by the Sellers from the Agreement may total approx. $200-300 million (100%, the Partnership's share – $90-135 million), based on the Brent price level on the date of signing of the Agreement. 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.

(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. Furthermore, as specified below, the capacity of gas supply to Egypt via the said systems is divided between the Tamar Partners and the Leviathan Partners.

(1) The EMG pipeline

The EMG pipeline connects the Israeli transmission system in the Ashkelon area with the Egyptian transmission system in the el-Arīsh area and has served as the main export pipeline to Egypt since the 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 approx. 600 MMCF per day (approx. 6 BCM per year) to approx. 650 MMCF (approx. 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 through the EMG pipeline to approx. 850 MMCF per day (approx. 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, including a further postponement as a result of operation Roaring Lion, and as of the report approval date, transmission is expected to commence in Q3/2026.

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 31 December 2025 and the report approval date, the gas transmission capacity through the Jordan-North Export Pipeline is approx. 7 BCM per year, of which approx. 3.5 BCM are 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, concurrently with transmission in the EMG pipeline. 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, which is expected to increase the transmission capacity to approx. 11 BCM, 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) On 16 September 2025, Chevron entered into an agreement with INGL for provision of transmission services for the purpose of transmitting natural gas from the Leviathan reservoir to 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 (in this section: the "**Transmission Agreement**") and Chevron's participation, on behalf of the Leviathan Partners and the Tamar Partners, in funding the construction of the Nitzana Project. 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 approx. 6-7 BCM per year. For details regarding the Natural Gas Commission's decision of 9 August 2023 on the matter, see Section 7.24.6(f) below.

For promotion of the construction of the Nitzana Pipeline, the Leviathan Partners approved a budget, in accordance with the decision of the Natural Gas Commission on the matter, in the sum total of approx. $608 million (100%), divided between the gas exporters that participated in its funding according to their share in the future capacity; the Partnership's share is approx. $115 million).

Under the Transmission Agreement, the Partnership provided bank guarantees and corporate guarantees in favor of INGL totaling, as of the report approval date, approx. ILS 135.3 million and approx. ILS 95.4 million, respectively. The said amounts will decrease from time to time, based on compliance with the milestones listed in the Transmission Agreement.

In the operator's estimation, the date of completion of the construction of the Nitzana Pipeline and commencement of transmission of the gas are expected to occur during Q4/2028.

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:

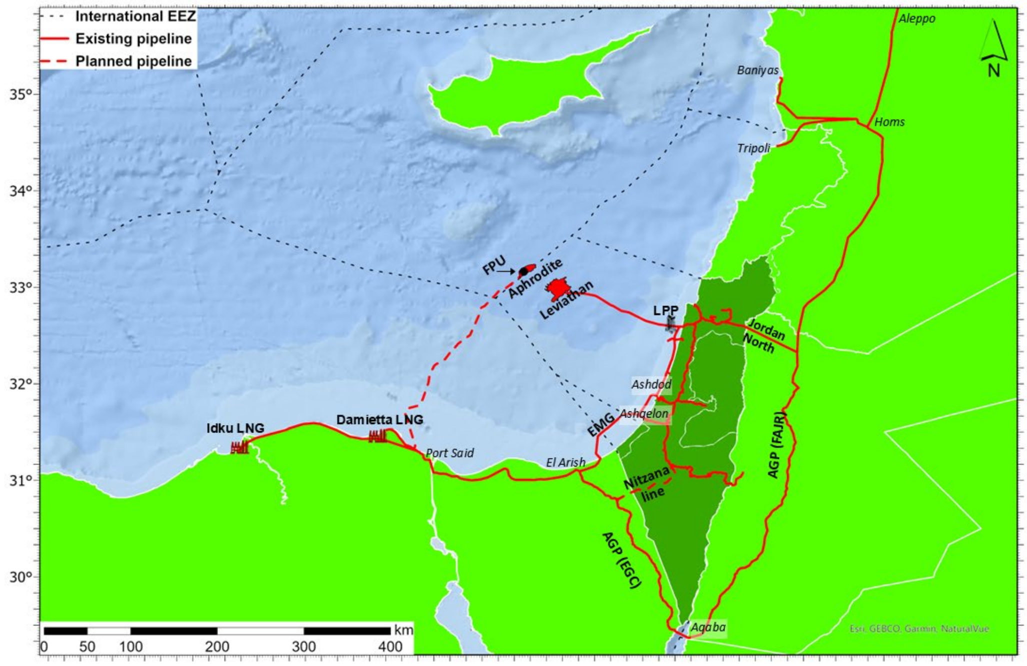
Infrastructure	Current transmission capacity	Possible additional transmission capacity[76]	Total possible transmission capacity	Total current and possible export capacity from the Leviathan reservoir	Additional transmission capacity is contingent on:
EMG	approx. 6.5	approx. 2	approx. 8.5	approx. 6.5	Completion of the Combined Section
Jordan-North Export Pipeline	approx. 7 (approx. 3.5 to Egypt and approx. 3.5 to Jordan)	approx. 4 to Egypt	approx. 11 (approx. 7.5 to Egypt and approx. 3.5 to Jordan)	approx. 7.25 (approx. 3.75 to Egypt and approx. 3.5 to Jordan)[77]	Completion of the project (as defined in Section 7.13.2(b)(3) below)
Nitzana Pipeline	-	approx. 6	approx. 6	approx. 2.5 to 3.5 (estimated)[78]	Completion of the Nitzana Pipeline project
Total	approx. 13.5	approx. 12	Approx. 25.5	approx. 16.25 to 17.25	

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

[76] The data specified in the table with respect to the transmission capacity are according to the Partnership's estimation. 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.

[77] 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).

[78] The available capacity for export from the Leviathan reservoir as noted above is in accordance with the Partnership's assessment of the rate of the Leviathan project's allocation out of the export capacity of the Nitzana Pipeline project, according to which the capacity shall be allocated as follows: The Leviathan Partners and the Tamar Partners – approx. 2.5 BCM each, and Energean – approx. 1 BCM. The Leviathan project's proportionate share in the gas transmission in the pipeline may be greater, insofar as use is made of capacity not used by the other allocation holders in the Nitzana Pipeline project. In addition, the total quantity that is transmitted in the pipeline may increase, subject to the pipeline's actual transmission capacity. For details, see Sections 7.13.2(b)(4) and 7.24.6(f) below.



(c) Engagement with INGL in transmission agreements in relation to the export to Egypt

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.

2. On 25 December 2024, an addendum to the 2019 Agreement was signed between Chevron and INGL, according to which the agreement was extended on that date until the earlier of: (a) the date of expiration of the agreement according to the terms and conditions thereof; or (b) the transmission commencement date, as defined in the transmission agreement on a firm basis described below, which, under the settlement agreement signed between Chevron and INGL in relation to the 2019 Agreement and the 2021 agreement, was scheduled for 5 August 2025. 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 (in this section: the "**Transmission Agreement**" or 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 7.24.6(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.[79] 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 "**Transmission Commencement Date**"), but from time to time INGL has

[79] 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 rates are linked to the CPI from the date of the said decision until the date of any relevant payment.

given notice of delays and postponements in the performance of the construction work due to various constraints which have resulted in postponement of the Transmission Commencement Date, *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. On 11 May 2025 and 18 September 2025, the GP's Board approved an additional budget of approx. $29 million (100%, the Partnership's share – approx. $13 million) and approx. $7.6 million (100%, the Partnership's share – approx. $3.5 million), respectively, for completion of the said work, as a result of the war and the delay in the timetable for completion of the work consequently thereto, such that, as of the report approval date, the approved budget totals approx. $139 million (100%, the Partnership's share – approx. $63 million).

In the operator's estimation, the dates of completion of construction of the Combined Section and the commencement of gas transmission are expected to occur in Q3/2026.

(e) The Transmission Agreement stipulates 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 Transmission Commencement Date; 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. Furthermore, it was agreed that allocation of the construction costs among the partners in the Leviathan and Tamar projects will be carried out based on the actual transmission rates. In July 2024, the distribution ratio between the Leviathan Partners and the

Tamar Partners was updated to 72.04% and 27.96%, respectively.

(g) 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, 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.

(h) 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.

(i) In view of the delays in completion of the construction work and postponement of the Transmission Commencement Date 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.

(j) On 25 December 2025, and further to Chevron's engagement with INGL in a settlement agreement (the "**Settlement Agreement**"), the parties entered into an amendment to the 2019 Agreement, whereby the agreement was extended until the earlier of: (a) The agreement expiration date in accordance with its terms; or (b) 1 January 2027 (in lieu of 1 January 2026); or (c) the Transmission Commencement Date, as defined in the transmission agreement on a firm basis, which is described in Section 7.13.2(c)2 above (scheduled for 5 August 2025), at which time the Transmission Agreement would enter into force on the terms specified in the Settlement Agreement, which include, *inter alia*, Chevron's obligation to pay for the transmission of gas in a quantity no lower than 4 BCM per year.

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 natural gas transmission capacity (through Chevron) under the Transmission Agreement, and will be responsible for fulfillment of the undertakings and payment of the costs of Chevron 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 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 applicable) used the unutilized capacity of the other party, in which case the distribution will be based on actual use. In July 2024, the distribution ratio between the Leviathan Partners and the Tamar Partners was updated to 72.04% and 27.96%, respectively.

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 Transmission Commencement Date, 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 or geopolitical changes.

(d) <u>Export of natural gas to Egypt via the Jordan-North Export Pipeline</u>

In view of the delay in completion of the project for construction of the Combined Section, in February 2022, the Leviathan Partners signed a set of agreements intended to allow the transmission of additional 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.

As of the report approval date, and as the Partnership was informed by the Operator of 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 the provision 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, which stipulates, *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. An agreement between Chevron and INGL for the provision 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 2027, as part of the amendment signed on 25 December 2025 between Chevron and INGL, under which Chevron has undertaken to pay for the transmission of a gas quantity no lower than 0.25 BCM per year.

   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 28 December 2025, the Natural Gas Authority stated, *inter alia*, that the annual available transmission capacity for 2026 in the Jordan-North pipeline is 4.2 BCM. Further thereto, 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. 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 and which are not transmitted via the EMG pipeline.

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 65%-70% of consumption being used for power production, and the remainder serving energy-intensive industry, households and transport. In 2025, local consumption totaled approx. 64 BCM, an increase of approx. 9% compared with 2024. For further details, see Section 7.15.5(a) below.

(b) The natural gas market in Jordan[80]

In 2025, domestic demand in Jordan totaled approx. 3.6 BCM per year, an increase of approx. 3% compared with consumption in 2024. For further details, see Section 7.15.5(d) below.

(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 approx. 0.45 BCM per year, and the demand for natural gas for operation of the existing power plant in the Gaza Strip will total approx. 0.25 BCM per year.

(d) The natural gas market in Cyprus

For details, see Section 7.15.5(b) below.

(e) The natural gas market in Morocco

According to media reports, natural gas production in Morocco in 2025 totaled less than approx. 0.05 BCM. Early 2026 saw the commencement of production from the natural gas field in eastern Morocco, Tendrara, which is expected to contribute approx. 0.1 BCM to annual production. In general, Morocco has gas resources of

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

approx. 1.5-2 TCF in 2 different ventures (Anchois (offshore, pre-development) and Tendrara (onshore, in commissioning stages)), which are operated by international companies. Electricity in Morocco is currently generated primarily on a thermal basis (approx. 59%, mainly coal and some gas) renewable energy (approx. 41%). Natural gas currently provides a secondary solution of approx. 10% relative to electricity demand in Morocco. However, Morocco has declared that it will phase out coal use entirely by 2040, transitioning to natural gas and green energy. As of the report approval date, domestic demand for natural gas in Morocco totals approx. 1 BCM per year, most of which is imported from the global market through Spain. The gas arrives in Spain as LNG, is regasified there and is transmitted via the GME pipeline to Morocco. Almost all of the imported gas is used for power generation. According to media reports, Morocco is expected to increase consumption and planned import volumes to approx. 12 BCM by 2030. As of the report approval date, there are no active LNG regasification or production facilities in Morocco. Morocco is promoting the construction of an FSRU in the Nador Port, which is expected to start operating in 2026, and it is exploring the construction of additional terminals. In addition, according to reports in the media, Morocco is promoting an initiative involving several African countries for the export of gas in a pipeline from Nigeria, via the Atlantic Ocean to Europe. This plan is in its initial stages, and therefore it is difficult to assess whether it will go ahead. To the best of the Partnership's knowledge, there are about 4 power plants in Morocco with the ability to produce electricity based on natural gas, which may create demand of up to approx. 150 MMCF per day, and there is a plan to build an additional power plant, which is expected to facilitate an increase of the natural gas-based electricity generation capacity.

(f) The Bulgarian natural gas market

According to reports from various media sources and independent consultancy agencies, natural gas production in Bulgaria in 2025 totaled less than approx. 0.01 BCM per year. To the best of the Partnership's knowledge, there is no expectation of a significant increase in the coming years due to Bulgaria's limited gas resources. Electricity generation in Bulgaria in 2025 totaled approx. 40 TWh, with the distribution by energy source estimated as follows[81]: Coal 26%, nuclear energy 40%, renewable energy 29%, and natural gas 5%. Nevertheless, Bulgaria aims to reduce greenhouse gas emissions, *inter alia*, by replacing coal with natural gas for a transition period until 2035-2040. In 2024, according to Eurostat[82], Bulgaria imported approx. 2.2 BCM from various sources, primarily from Azerbaijan. To the best of the Partnership's knowledge,

[81] Breakdown by energy source based on data in the link.
[82] Information on import-export as specified in the link.

domestic natural gas consumption in Bulgaria in 2025 totaled approx. 2.7 BCM per year, almost all of which is imported. The majority of the gas was supplied via imports from Azerbaijan via the IGB (Greece-Bulgaria) pipeline, the Alexandroupolis terminal in Greece, and through Turkey. As of the report approval date, Azeri gas constitutes a central and stable pillar in the country's natural gas supply mix. According to ICGB, the operator of the natural gas pipeline between Greece and Bulgaria, the intention is to increase the annual transmission capacity to 3 BCM per year, with the possibility of a further capacity increase up to 5 BCM per year, through the construction of a compressor station.

Furthermore, Bulgaria is networked with regional natural gas pipelines connecting Russia, Azerbaijan, and Turkey to European market countries, such as Hungary, the Czech Republic, Serbia, Austria, Germany, Albania, and Italy. Gas in transit through Bulgaria is estimated at approx. 18 BCM. As stated above, a portion of the gas passing through the country's pipelines remains for domestic use, while the remainder continues to other customers in Europe. Historically, Russia supplied approx. 90% of the domestic natural gas consumption in Bulgaria. Since 2022, no gas has been imported from Russia. As of the report approval date, there are no LNG production or regasification facilities in Bulgaria.

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.

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 report on the resources in the Leviathan project; 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 December 2025[83]
Q1/2026*	Approx. 202
Q2/2026*	Approx. 198
Q3/2026*	Approx. 198
Q4/2026*	Approx. 198
2027	Approx. 855
2028	Approx. 851
2029	Approx. 846
2030	Approx. 1,403
2031	Approx. 1,419
2032	Approx. 1,423
2033	Approx. 1,563
2034	Approx. 1,592
2035	Approx. 1,397

* 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 Leviathan project backlog for 2025, as included in Chapter A of the 2024 Periodic Report, was approx. $720 million. The Partnership's actual revenues from the Leviathan project in 2025 totaled approx. $1.01 billion. The difference between the backlog figures for 2025 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 under spot-based supply agreements.

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

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, Katlan 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 relevant to the Partnership.

   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 several reservoirs referred to jointly as the Katlan field, which is located between the Karish and Tanin leases, and contains approx. 31.9 BCM[84] 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 a natural gas discovery in the Drakon reservoir in the area of license 31, situated south-east of the Tamar reservoir, which contains approx. 7.5-12 BCM[85]. Additionally, in December 2024, the Commissioner notified Energean of confirmation of a discovery in the Hercules natural gas reservoir estimated at approx. 3 BCM in the area of license 23. According to the provisions of the Gas Framework and 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 below, 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 other petroleum interests. Notwithstanding the aforesaid, to the best of the Partnership's knowledge, Energean was working on obtaining a permit for the export of natural gas from the Karish North reservoir.

c. According to Tamar Partners' reports, 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

[84] Ministry of Energy, new Katlan natural gas discovery in Israel's waters, 31 May 2023 (link).
[85] Announcement by the Spokespersons Office of the Ministry of Energy of 22 July 2024 (link).

of approx. 16 BCM as of 2026. Completion of the said expansion work may affect competition, in both the domestic and the export markets. On 10 February 2026, the Tamar Partners announced completion of the first stage of a project for expansion of the Tamar reservoir, and that the second stage of upgrading the compressors at the terminal in Ashdod is expected to be completed within several weeks.

d. According to reports of the Tamar Partners, as released up to the report approval date, the Tamar Partners and Blue Ocean have signed agreements for the export of natural gas on a firm basis in the total volume of approx. 25 BCM (approx. 200 MMCF per day, or approx. 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 approx. 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 approx. 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 reports of the Tamar Partners, as released up to the report approval date, 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 by the Leviathan Partners jointly, up to 1 January 2030. As of the report approval date, no arrangements have yet been determined for separate marketing of the gas produced from the Leviathan reservoir. 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. To the best of the Partnership's knowledge, according to reports by some of the Tamar partners, in July 2025 a non-binding MOU was signed between some of the partners in the Tamar project and the IEC, for amendment of the gas supply agreement between the

Tamar partners and the IEC. In view of the gamut of circumstances at that time, some of the Tamar partners decided not to join the MOU.

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 bid rounds in 2016, 2018, 2020 and 2022.

In the bid round 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. On 17 March 2025 the Minister of Energy and Infrastructure and the Petroleum Commissioner issued 6 licenses in the fourth bid round to the group awarded Zone "I". According to the Ministry's announcement, each one of the companies BP, SOCAR and the Partnership shall hold approx. one third of the interest in each one of the licenses, and SOCAR shall act as operator86. 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, although as of the report approval date, no exploration license has been granted in connection with Zone G. The Ministry of Energy's announcement of 17 March 2025 states that at the end of October 2023, the winning companies awarded two of the four zones put on offer were announced, and that the rest of the process results are expected to be announced at a later date.

On 25 February 2026, the Minister of Energy announced the launch of the fifth Call for Bids (CFB) for natural gas exploration in Israel's EEZ[87]. The fifth CFB is being promoted, *inter alia*, against the backdrop of growing demand for natural gas, and following the approval of the Export to Egypt Agreement, in which context six offshore zones covering a total area of approx. 8,600 km^2 are expected to be marketed. The press release further noted that, according to Ministry of Energy estimates, hundreds of additional BCM of undiscovered natural gas may be located in Israel's EEZ, and that the selected zones were finalized following a professional whitepaper including geological analyses and seismic surveys gathered over the years. It was also noted that the proposed zones were examined also from environmental perspectives, including the maintenance of a minimum distance of 30 km from Israel's coastline, and that the ranking of bids will be based, *inter alia*, on the quality of the work programs and a signature bonus, as well as on competition considerations in consultation with the Competition Authority. In this context it is noted that an opinion of the Competition

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[86] Link (in Hebrew).

[87] Link (in Hebrew).

Authority was released classifying the companies participating in the CFB into 3 competitive categories. According to this classification, the Partnership is included in the third ranking group, representing the lowest bracket. The Partnership is studying the said opinion and is considering its options.

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 Coal and other alternative energy products

Coal and other alternative energy products also constitute competition for 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. In 2024, the share of natural gas in the mix of electricity production in Israel amounted to approx. 74%.[88] For details about the Israeli government Resolutions regarding the reduction of coal use, see Section 7.24.11(a) below.

Following the war and prior measures taken by the IEC to procure and store fuels for use by all domestic power producers to ensure functional continuity, the Electricity Authority (the government body responsible for managing the Israeli electricity market during emergencies and wartime under the Ministry of Energy), as well as the Director General of the Ministry of Energy, requested that the IEC procure additional quantities of coal and diesel and lease additional diesel storage facilities[89]. Concurrently, the Ministry of Finance decided, via a temporary order, to reduce the excise tax rate on diesel purchased for power generation, effectively eliminating it almost entirely, in order to prevent an increase in the electricity tariff resulting from the need to expand the IEC's emergency diesel reserves[90].

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

[88] Review of the Natural Gas Sector – Summary of 2024 (May 2025) (link) (in Hebrew).
[89] See the IEC's immediate reports to TASE of 29 October 2023 and 5 November 2023.
[90] Customs Tariff and Exemptions and Purchase Tax on Goods Order (Temporary Provision No. 4), 5784-2023, *Regulations* 2095.

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, hydrogen is expected to gradually enter the mix of energy sources. Hydrogen can be used in electricity production, transportation and heavy industry (such as concrete, steel, chemicals, etc.). Hydrogen can be produced using various methods, some of which are polluting, such as natural gas reforming without capturing the carbon dioxide emitted during the process (grey hydrogen), and others are "clean", such as blue hydrogen produced from natural gas reforming with the capture of carbon dioxide and the prevention of its release into the atmosphere through underground storage or sequestration in other materials, and green hydrogen produced from the electrolysis of water using electricity produced through the electrolysis of water using electricity generated from renewable sources. In addition, in the context of the growing global energy-market trend to reduce, to the greatest extent possible, greenhouse gas emissions in general, and carbon-dioxide emissions in particular, hydrogen itself does not leave a carbon footprint and its use energy the production does not produce greenhouse-gas emissions, demonstrating its advantage. At present, hydrogen production and consumption in Israel are primarily concentrated in two main areas: Haifa Bay and the eastern Negev, with production totaling approx. 70 thousand tons per year. Most hydrogen in Israel is currently produced from natural gas or ammonia by ORL and Dor Chemicals[91]. However, several companies in Israel, including energy and technology companies, are exploring hydrogen production and production process improvement by various methods.

According to Ministry of Energy publications[92], and in accordance with the directives of the Natural Gas Authority and the policy of the Ministry of Energy and Infrastructures, INGL is examining the use of hydrogen as part of the transition to clean energy. In addition, the impact of the developing hydrogen sector in Israel on natural gas infrastructure is being assessed by the Natural Gas Authority and INGL, with the Multisectoral Hydrogen Forum recommending the completion of an assessment of the compatibility of natural gas infrastructure with hydrogen transmission and the mapping of gaps.[93]

On 3 December 2023, the Ministry of Energy issued an international RFP for information regarding hydrogen valleys, aiming to formulate an outline for establishing a "hydrogen valley" in Israel. According to the annual report of the Multisectoral Hydrogen Forum, hydrogen valleys constitute an ecosystem for demonstrating and examining the

[91] Annual Report of the Multisectoral Hydrogen Forum (October 2025) (link) (in Hebrew).
[92] Review of the Natural Gas Sector – Summary of 2024 (May 2025) (link) (in Hebrew).
[93] Annual Report of the Multisectoral Hydrogen Forum (October 2025) (link) (in Hebrew).

hydrogen value chain (production, sequestration, storage, transportation, and end uses). The Forum recommends promoting a bid round for a hydrogen valley in Israel and examining regulatory relief for pilot projects ("sandbox"/"green track"). 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.

7.15.4 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 electricity generation purposes.

(b) According to the Natural Gas Sector Review[94], in 2024 natural gas accounted for approx. 71% of Israel's electricity generation mix, with the remainder composed of renewable energy (14%) and coal (15%). According to a July 2023 review report published by the Ministry of Energy[95], electricity generation from renewable energy facilities in 2022 totaled approx. 7,061 MWh, representing about 10.1% of total electricity consumption that year. Such production was distributed between photovoltaic facilities – approx. 83%; thermo-solar facilities – 11%; wind facilities – approx. 4%; and biogas, hydro, biomass, and landfill facilities – approx. 2%. According to the draft report of the Inter-ministerial Committee for the Examination of the Natural Gas Sector Policy[96], the use of natural gas as an energy source for electricity generation in Israel is expected to increase in the coming years with the anticipated closure of coal-fired power plants, prior to a projected decline following the integration of renewable energy in accordance with government targets. In the said draft report, various scenarios for the penetration rate of renewable energy in electricity generation were examined, including a low-case scenario of 18% renewables in 2030 and 40% in 2050, and a high-case scenario of 30% renewables in 2030 and 54% in 2050.

(c) 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 sequestration. 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 sequestration, improvement of

[94] Review of the Natural Gas Sector – Summary of 2024 (May 2025) (link) (in Hebrew).
[95] Link (in Hebrew).
[96] The Inter-Ministerial Committee for the Periodic Examination of the Natural Gas Sector Policy and Strengthening Energy Security – Draft Report for Public Comment (9 April 2025) (Link (in Hebrew)).

regulation processes and promotion of an innovation-encouraging regulatory policy[97]. In this context, it is noted that according to the Multisectoral Hydrogen Forum report, the production of green hydrogen (if developed) may increase electricity demand, and therefore the integration of hydrogen production facilities and the use thereof (including in power plants) may be required in the development plans of the electricity sector.

(d) On 29 January 2025, the Ministry of Energy released an update to the "Roadmap for Renewable Energies in 2030"[98], whereby meeting the target of 30% renewable energies in 2030 requires production of approx. 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 approx. 5,700 MW. On 21 October 2025, the Minister of Energy presented the governmental preparation for meeting the 2030 targets, and further presented a plan to set more ambitious goals for 2035, of 35%-45% electricity production from renewable energy facilities. According to the Minister, the installed capacity in Israel, as of the end of 2024, is approx. 7,500 MW out of the 16,000 MW required in 2030.[99]

7.15.5 <u>Natural gas discoveries and exploration activity in neighboring countries</u>

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.[100]

(a) <u>Egypt</u>

Egypt is a regional natural gas hub, being the country with the highest demand, with the largest production capacity and with the most comprehensive infrastructure, including facilities that allow import and export of LNG. However, Egypt has been dealing with a shortage of domestic production, which has turned it from an exporter into a significant importer of gas from Israel and LNG from the global market.

[97] Link (in Hebrew).
[98] Link.
[99] Link (in Hebrew).
[100] The Partnership is unable to independently corroborate the information in this section, which originates from various public reports.

1. Resources (proven reserves): According to estimates of various consulting firms, approx. 41 TCF (1,170 BCM).

2. Current gas production capacity: While domestic gas production in Egypt was approx. 42 BCM in 2025, 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 up to approx. 75 BCM per year.

3. Domestic gas production in Egypt in 2025 totaled approx. 42 BCM, representing a decrease of approx. 15% compared to 2024. Furthermore, approx. 82% of said gas was produced from Mediterranean reservoirs, with the most prominent reservoir in Egypt being the Zohr reservoir, which supplied approx. 25% of the total domestic gas production in 2025. The decline in domestic gas production in 2025 was primarily caused by a decrease in production from the Zohr field, as well as a lack of investment in gas assets throughout Egypt as a result of the pursuit of improved commercial terms by the various gas developers. Production from producing fields and those in development stages during 2026–2028 is expected to range between approx. 37–46 BCM per year, such that domestic demand forecasts are expected to continue to exceed domestic production.

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

5. Key facilities: Egypt has an extensive offshore and onshore network of natural gas transmission and processing facilities , including two LNG production facilities: (a) the ELNG facility in Idku, primarily owned by Shell, with a production capacity of approx. 7.2 million tons of LNG per year; and (b) the SEGAS facility in Damietta, primarily owned by Eni, with a production capacity of approx. 5 million tons of LNG per year. It is clarified that the joint capacity of these two facilities is equivalent to approx. 17.5 BCM per year. As of the report approval date, the liquefaction facilities are not operating at full capacity nor on a regular basis, due to the shortage of natural gas to meet domestic demand. Thus, the LNG exports from such facilities, according to forecasts by independent consulting firms for the coming years, will be made possible through gas imports via pipeline. At present, Egypt imports gas via pipeline only from Israel; however, according to media reports, Egypt is expected to begin importing gas from Cyprus as well in 2027. For further details, see Section 7.15.5(a)7 below. It is further noted that in 2025, Egypt significantly increased its LNG import capacity in order to address the gas shortage, and during that year, 4 floating LNG regasification units (FSRUs) with a weighted

capacity of approx. 27 BCM per year were stationed off the coast of Egypt.

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 recent years, exploration wells in Egypt yielded no significant commercial discoveries, resulting *inter alia* from the ratio between the size of the discovery, technical parameters (such as distance from infrastructure, distance from the shore, depth) and the commercial terms and conditions. Notwithstanding the very limited success in exploration and development, there is still considerable ongoing exploration activity in Egypt, and significant discoveries may be made in its territory in the coming years.

7. Import/export balance: With the commencement of production from the Zohr reservoir in 2017, the domestic production capacity has slightly exceeded domestic demand on an annual basis (for details regarding demand seasonality, see Section 7.16 below). However, since May 2023, Egypt has reverted to being a gas importer. Domestic demand is exceeding the domestic production capacity on an annual basis, and the gap is particularly large in the summer months at the peak of electricity demand, *inter alia* as a result of population growth, increased electricity consumption 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 approx. 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 2025, the gap between domestic production and domestic consumption totaled approx. 22 BCM. Egypt covered the said deficit through the import of natural gas from Israel in a volume of approx. 9.3 BCM, and import of LNG in deliveries from around the world (mainly from the U.S.) in a volume of approx. 12 BCM (approx. 8.9 million tons of LNG). In addition, since the domestic demand for natural gas exceeded domestic production, Egypt used alternative sources, such as refined oil products and renewable energies, and implemented proactive power cuts for several hours on a daily basis (a policy which was gradually stopped during H2/2025 with the increase in import of LNG). Total export of LNG from Egypt in 2025 was relatively negligible, totaling approx. 1 BCM.

   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

Aphrodite and Cronos 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 Cronos field to the Egyptian market, using infrastructures of the Zohr field. Furthermore, according to reports in the media, some of the gas in the Cronos field is expected to be liquefied, for export through the LNG facility in Damietta. Furthermore, against the background of the domestic shortage of natural gas, 2025-2026 mark a trend of increasing energy imports to Egypt, including through the import of large volumes of LNG and the increase of gas imports via pipeline from Israel, as stated in Section 7.12.3(c)5 above.

(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 approx. 3.5-6.5 TCF of resources, held by Eni and TotalEnergies; and (c) Glaucus in Block 10, which contains approx. 6-9 TCF of resources, held by ExxonMobil and QatarEnergy. The resources discovered in Cyprus (including the Aphrodite reservoir) total approx. 13-19 TCF. 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 consultancy firms. In addition, the zone of discoveries in Block 6 is expected to be developed through Zohr infrastructures in Egypt, and the gas is expected to undergo liquefaction in the Damietta LNG facility, subject to approval of a development plan and the adoption of a final investment decision (FID) for the Cronos discovery in 2026, with the transmission of gas expected to commence at the end of 2027-start of 2028.

2. Current gas production capacity: None. First gas from the Cronos discovery is expected at the end of 2027-start of 2028.

3. Domestic demand: As of the report approval date, Cyprus consumes no natural gas at all, and approx. 80% of electricity production in Cyprus is based on imported oil-based products, although there is consistent increase in the share of renewable energies out of the total electricity production in Cyprus. The Cypriot Government is promoting the "Great Sea

Interconnector" project, to connect the island to the European electricity grid via Greece and Israel, with the aim of overcoming its energy isolation.

4. Key facilities: In January 2023, work began on the construction of a floating regasification facility (FSRU) for LNG import in the Port of Vasilikos in the south of Cyprus, by a consortium led by China Petroleum Pipeline Engineering Co. Ltd. In 2024, it was reported that the engagement with this company had been terminated, that a significant portion of the onshore infrastructure needed to be completed, and that there was also agreement in principle regarding the delivery of the FSRU. Accordingly, there is uncertainty regarding the facility's date of full commercial operation. It is further noted that the onshore infrastructure work has not yet been completed, and in a third-party contractor's assessment, significant gaps emerged in the design, documentation, and engineering, and the initiative now faces cancellation.

5. Exploration activity: Cyprus has granted licenses for most of its offshore territory to the majors, including Eni, Total Energies, and ExxonMobil. ExxonMobil has drilled a well in the Pegasus prospect in Block 5, where gas quantities were found which, according to media reports, are estimated at approx. 3-5 TCF. This is the second discovery of ExxonMobil in Block 10, after the Glaucus discovery in 2019. To the best of the Partnership's knowledge, the Block 10 partners are considering a combined development of the two aforesaid discoveries. In addition, three blocks were returned by Eni and Total Energies to Cyprus upon expiration of the licenses. The dispute between Cyprus and Turkey in relation to the rights in the EEZ of Cyprus was and still is a source of 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 7.30.7 below.

6. 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 approx. 3 GW (less than one tenth of that of Israel), of which approx. 15% MW

may be produced using natural gas in the power plant in Dir Ammar in the north of the country. In cases of shutdown or low-power operation of other power plants in Lebanon, the capacity of the plant increases to 45% of the total power supplied to the national grid.

4. Key facilities: None.

5. Exploration activity: As of the report approval date, a new exploration license was received for Block 8, 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, and where a seismic survey is planned to be conducted. The consortium also previously held Blocks 4 and 9, where drilling conducted in 2020 and 2023, respectively, did not result in the discovery of gas in commercial quantities. The other areas in Lebanon's EEZ are currently being offered under the third tender, the closing date of which has not yet been updated by the Lebanese government. According to various media reports, exploration activity in Lebanon over the years has been very limited due to internal and security instability. Insofar as the Lebanese regime stabilizes in a manner that enables investment in exploration within the country, the Lebanese exploration arena may become attractive.

6. Import/export balance: As of the report approval date, Lebanon relies exclusively on the import of fuels. In 2025, Egypt signed an MOU for the supply of gas to the power plant in Dir Ammar.

(d) Jordan

1. Resources: Most of Jordan's gas resources are located in the Risha field in Eastern Jordan, which was discovered in the 1980s. For years, the rate of production therefrom was approx. 30 MMCF per day, and in 2025 the field's resource evaluation was updated, such that according to media reports, it is currently approx. 5 TCF. In addition, according to media reports, Jordan is acting to promote a technical plan for development of the field to a daily production capacity of approx. 418 MMCF by the end of the current decade. As part of the plan to develop the field and increase production in the coming years, an agreement was signed in October 2025 with the Kuwait Drilling Company (KDC) for the drilling of 80 new wells in the field within four years. Furthermore, to the best of the Partnership's knowledge, the Jordanian government has issued a tender for the planning and construction of a pipeline which is expected to connect the Risha field to the AGP pipeline, in order to supply gas to the Jordanian market, and possibly also for export. If gas from Jordan is indeed connected to the AGP pipeline, competition may arise

for the demand among the regional customers of the Partnership. Moreover, if gas produced in Jordan enters the AGP system, the daily capacity of gas export from the Leviathan reservoir to customers in the region may be reduced. In addition, oil shale extracted as part of the Attarat power plant project is used as fuel at this plant.

2. Current gas production capacity: The Risha field produces approx. 0.41 BCM per year, which is supplied to consumers near the field.

3. Domestic demand: Demand for natural gas is impacted by electricity demand and by electricity production using gas alternatives, which include renewable energies and refined oil products. Natural gas accounts for approx. 75% of all electricity production sources available to Jordan's electric company, NEPCO. In the last three years, and in the coming three years, demand for gas in Jordan totaled and is expected to continue to total approx. 3.7-3.9 BCM per year. In the more distant future, demand for natural gas in Jordan is expected to decline due to the accelerated penetration of renewable energy and the government's policy aimed at achieving 50% electricity generation from renewable sources by 2030. As of the report approval date, the Leviathan reservoir is the main source of natural gas imported to Jordan for power production.

4. Key facilities: Jordan has LNG import capability thanks to the Energos Force FSRU unit moored in Aqaba. The unit is used for the import of LNG as a redundancy to the gas imported from Israel, as well as to enable commercial flexibility and to purchase gas from LNG suppliers and even perform therein swap transactions, such as the transaction for the export of gas from Jordan to Syria, under which quantities of up to approx. 140 MMCF per day are delivered.

5. Exploration activity: In recent years, Jordan appears to be attempting to promote exploration activity in the area thereof, 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.

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

(e) Morocco

1. Resources: Gas resources in Morocco are limited and are based on small onshore discoveries, such as Tendrara, and offshore discoveries, such as Anchois (see Section 7.13.3(e) above).

2. Current gas production capacity: Approx. 0.1 BCM per year, from several small onshore projects. The Tendrara project is expected to yield an additional approx. 0.1 BCM per year over the coming years, and approx. 0.35 BCM per year toward the end of this decade.

3. Domestic demand: 1 BCM, as specified in Section 7.13.3(e) above.

4. Key facilities: Morocco currently lacks LNG import capabilities, but aims to establish such capacity through tenders for the deployment of an FSRU and the construction of related infrastructures.

5. Exploration activity: Historically, Morocco has been a site of unsuccessful exploration despite significant activity by various companies, including Eni, Shell, BP, Chevron, Total Energies, Kosmos and Repsol, which held offshore and onshore licenses. Following several years of decline in exploration activity in Morocco, during the past year, two significant players, ExxonMobil and Murphy (each independently), received extensive offshore areas off the Atlantic coast.

   On 24 September 2021, Ratio Petroleum Energy – Limited Partnership signed an agreement for a reconnaissance license called Dakhla Atlantique. For further details, see Section 7.13.3(e) above.

6. Import/export balance: Historically, Morocco imported gas from Algeria via the GME pipeline, which transmitted gas from Algeria to Spain. Due to disputes between Morocco and Algeria, transmission via the GME pipeline ceased in November 2021.

(f) Syria

1. Resources: Syria has maintained extensive onshore oil and gas exploration and production activity. Since the civil war, which began in 2011, numerous fields, facilities and infrastructures have been abandoned and even damaged. Current estimates for proven resources, according to consultancy agencies, are approx. 2-3 TCF, although these are expected to be updated as the trend of recovery in Syria continues. In early 2026, Syria seized control of areas in the northeast of the country previously controlled by the SDF, which include significant oil and gas fields. Although there is no current estimate of the resource volumes there, they may add up to approx. 5 TCF to the country's gas resources. While their operational condition is poor, Syria may succeed in gaining access to additional significant gas resources in the future as a result of this move.

2. Current gas production capacity: Prior to the civil war, the rate of production totaled approx. 7-8 BCM per year, alongside extensive oil activity. Currently, due to heavy infrastructure damage sustained throughout the years of war, production has decreased significantly to only 2.5 BCM per year. Since the end of 2024, following the change in regime and the waning of Iranian influence, Syria has gradually begun to attract the attention of foreign companies, such as Chevron, ConocoPhillips, and CNPC, as well as smaller companies with historical experience in the region, such as INA and Gulfsands. In addition, many countries, and chiefly the U.S., Qatar, and Turkey, have aspirations to play a role in shaping the 'New Syria', and view it as a strategic opportunity, *inter alia* in terms of investment in gas fields and infrastructure.

3. Domestic demand: According to various reports in the foreign press, domestic gas demand in Syria totals approx. 5-7 BCM per year.

4. Key facilities: Although Syria has no LNG seaports, it has an extensive gas pipeline network, as described below. Furthermore, there are several central processing facilities integrated into a national management system. During the war, heavy damage was sustained by large sections of the system, but the past year has seen the commencement of a rehabilitation process led by the new administration, aimed at restoring the system to a functional level that will enable connection to the regional energy market. Additionally, Syria aspires to restore its status as a regional transit hub, including reexamination of the Kirkuk-Banias pipeline project in Iraq.

5. Exploration activity: Over the past year, a significant resurgence has also been evident in the field of exploration. Syria is attempting to reposition itself under the new administration as an attractive arena for international energy companies, with significant potential for discoveries still available in the Mediterranean Sea, an area largely unexplored. The national petroleum company, SPC, has repartitioned Syria's EEZ into five blocks, and reports substantial interest from major companies such as Chevron, Total, Eni, QatarEnergy, and ConocoPhillips. Chevron has already begun processing preliminary data and is leading the renewed exploration activity in the Syrian Mediterranean Sea. There is also growing interest from companies with historical experience in the region. Dana Gas has already signed an MOU with SPC for the performance of technical testing in fields in northeast Syria, including an evaluation of the potential for increased production and infrastructure rehabilitation.

6. Import/export balance: Syria has an extensive pipeline network used for the distribution of gas to customers throughout the country, for connectivity with Arab countries in the region (Jordan, Lebanon) via the AGP pipeline, and connection in the north to Turkey. The gas supply for the Syrian market is currently based primarily on gas imports, mainly from Azerbaijan (via Turkey) and from Jordan. Imports currently total an estimated rate of approx. 250 MMCF per day. Additionally, regional negotiations are ongoing regarding future pipelines (primarily in Iraq) that may contribute to energy stability in the future. As of the report approval date, Syria still needs to find additional import sources to fully meet domestic demand, and it is far from being an exporter and remains dependent on import.

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: [101]

PERIOD	Q1 (IN BCM)	Q2 (IN BCM)	Q3 (IN BCM)	Q4 (IN BCM)
2024	Approx. 2.6	Approx. 2.8	Approx. 3.1	Approx. 2.7
2025	Approx. 2.9	Approx. 2.0	Approx. 3.1	Approx. 2.8

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.

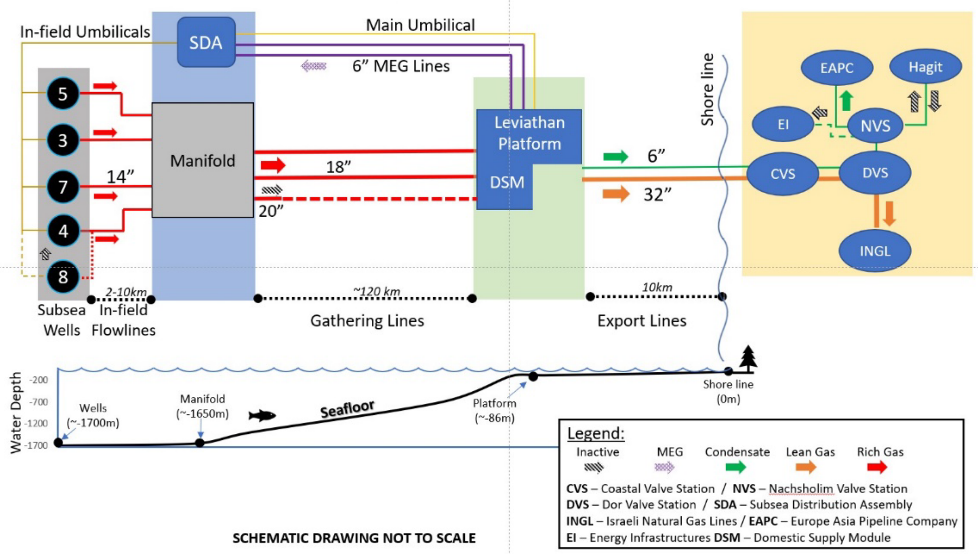
(b) Subsea production system: Connects the production wells to the production platform and lies on the seabed. The subsea system comprises 14-inch infield pipes through which the natural gas, condensate and related fluids are transported from each well to the subsea manifold. Two 18-inch gathering lines 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 was 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 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.

[101] 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.

(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 production capacity of the platform after operation of the third pipeline is approx. 1,380 MMCF of gas per day (approx. 14 BCM per year) 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[102] 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.

Leviathan Project Phase 1A– Schematic Diagram



(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

[102] For details regarding a license for construction and operation of a transmission system, see Section 7.24.17(a) below.

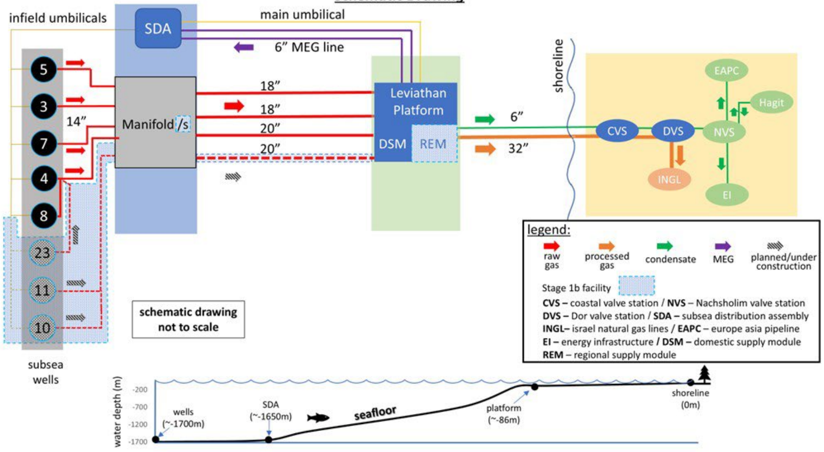
site is designated to allow for continued regular supply of natural gas also in situations where it is not possible to pipe condensate through a direct pipe from the Nahsholim Valve Station to the refinery. As of the report approval date, condensate cannot be stored at the Hagit site due to damage caused 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

On 15 January 2026, the Leviathan Partners adopted a final investment decision (FID) for the development of the First Stage of the Expansion Project, the objective of which is to increase the total gas production capacity of the Leviathan project up to approx. 21 BCM per year (and to allow the production of first gas in H2/2029), as specified in Section 7.2.5.(g) above. The Expansion Project is intended to increase the Leviathan project's daily production capacity up to approx. 2.1 BCF (approx. 21 BCM per year), and under certain operating conditions even above that. In accordance with the Development Plan, the First Stage of the Expansion Project includes, *inter alia*: 3 additional production wells with a production capacity of up to approx. 400 MMCF per day, each, to be connected to the platform through a pipeline and subsea systems which mostly serve the existing production system, including the Third Pipeline Project. According to the plan, the platform will be supplemented with an REM – Regional Export Module, which includes additional facilities for natural gas and condensate production and processing, with the aim of increasing the installed capacity of the platform up to approx. 23 BCM per year. However, the First Stage of the Expansion Project is expected to increase the total gas production capacity of the Leviathan project up to approx. 21 BCM per year, *inter alia* given restrictions of the subsea pipeline. The Second Stage of the Expansion Project, aimed at increasing the total gas production capacity of the Leviathan project up to approx. 23 BCM per year, is subject to regulatory approvals and additional investments, including investments in the laying of a fourth pipeline between the field and the platform and in the installation of additional subsea systems, an FID in respect of which is expected to be adopted in the coming years.

7.17.3 See Section 7.2.5 above for details regarding the updated development plan for the Leviathan reservoir, which was approved by the Petroleum Commissioner, and mainly includes updates in connection with the Expansion Project, 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. See Section 7.12.3(c)5 above for details regarding expansion of the total contract quantity according to the amendment to the export agreement with Blue Ocean.

Leviathan Project – Stage 1a and Stage 1b
Schematic Drawing



7.18 **Raw materials and suppliers**

In general, engagements with suppliers or professional contractors, are made by the operator of the various projects. 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, 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 during the War in Israel, the availability of foreign contractors and suppliers required for the execution and advancement of the various projects and joint operation was 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 GP's Board. 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 GP, 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 in which is incorporated herein by reference.

7.19.3 As of 31 December 2024, 23 employees were employed by the Partnership, 10 of whom are officers, and as of 31 December 2025 and as of the report approval date, the Partnership employs 24 employees, 11 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 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 par value, which were repaid by 30 June 2023, and bore fixed annual interest at the rate of 5.75%.

(b) Bonds totaling $600 million par value, which were repaid by 30 June 2025 (in one installment), which bore fixed annual interest at the rate of 6.125%.

(c) Bonds totaling $600 million 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 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, while the interest on the Bonds of each series is 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 to the Partnership as a loan by the subsidiary, as aforesaid, 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 2025 (net of capital raising and buyback costs, as specified below) was approx. $1.18 billion.

On 21 January 2023, the GP's Board approved the adoption of a plan for buyback of the Bonds, in the aggregate sum of up to $100 million, for a period of two years, and accordingly, the Partnership performed buybacks of the Bonds, in the full sum of such plan.

On 15 October 2024 the GP's Board approved the adoption of another Bond buyback plan, in the aggregate sum of up to $100 million, for a period of two years, and accordingly, the Partnership performed buybacks of the Bonds, in the amount of approx. $98.5 million under this plan.

On 11 May 2025, Leviathan Bond gave notice of partial prepayment of the second bond series, whose original maturity date was 30 June 2025, in accordance with the provisions of the Deed of Trust of the Bonds. According to the prepayment notice, Leviathan Bond partially repaid the second series on 29 May 2025 in the amount (principal) of $400 million in lieu of the original maturity date, plus accrued interest in the sum of approx. $10.1 million. Since the prepayment was completed in the quarter prior to the original maturity date, it was not subject to a prepayment fee. The balance of the Bonds was repaid on the original maturity date as aforesaid.

On 6 January 2026, the GP's Board approved the adoption of another bond buyback plan, in the aggregate sum of up to $100 million, for a period of two years (the "**Additional Buyback Plan**"). By the report approval date, the Partnership did not perform any buybacks of Bonds under the Additional Buyback Plan.

It is clarified that the aforesaid decisions do not obligate the Partnership and/or Leviathan Bond to buy back the Bonds, in whole or in part, and that the Partnership's management may decide not to buy back bonds at all, and/or to buy back bonds in an amount lower than the amount approved.

For further details about the Additional Buyback Plan, see the Partnership's immediate report of 6 January 2026 (Ref. 2026-01-002487), the information in which is incorporated herein by reference, as well as Section 3E of 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 facilities

(a) 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 (in this section: the "**Credit Facilities**"). 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 10D1 to the Financial Statements (Chapter C of this report). The Credit Facilities are intended to be used by the Partnership for its operating activities, including in connection with the Leviathan reservoir Expansion Project. 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 (in this section: the "**Loans**"). The Loans that shall be drawn down as aforesaid shall be partially repaid by 15 April 2027, and the balance by 15 October 2027. As of the report approval date, the sum of $100 million out of the credit facility, which was drawn down in June 2025, has been repaid in full. On 5 October 2025 and 9 November 2025, amendments to the documents in connection with one of the Credit Facilities were signed between the parties, which, *inter alia*, extended the availability period, as defined in the Partnership's immediate report of 9 October 2024 (Ref. 2024-01-608995), until 10 November 2026, and amended some of the financial covenants that the Partnership is required to meet.

For further details, see the Partnership's immediate reports of 9 October 2024, 5 October 2025 and 9 November 2025 (Ref. 2024-01-608995, 2025-01-073918 and 2025-01-085177, respectively), the information in which is incorporated herein by reference, and Note 10D2 to the Financial Statements (Chapter C of this report).

(b) On 16 June 2025, the Partnership signed an agreement with an Israeli bank for the provision of two credit facilities totaling $350 million, which are intended to be used by the Partnership for its operating activities, including in connection with the Leviathan reservoir Expansion Project (in this section: the "**Credit Facilities**"). These include a credit facility of $275 million (in this section: "**Credit Facility A**"), which was fully drawn down in accordance with the terms of the agreement, and a credit facility of $75 million (in this section: "**Credit Facility B**"), which the Partnership drew down in full on 10 February 2026. It was agreed that the loan from Credit Facility B would bear fixed annual interest ranging between 5.45% and 5.85% (in lieu of variable annual interest), and in the case of prepayment by the Partnership, the loan would bear a prepayment fee at the rate applicable to Credit Facility A. It is clarified that the Credit Facilities replace a credit facility of $200 million, which was provided to the Partnership by the same bank on 8 October 2024, as detailed in Note 10D3 to the 2024 financial statements, attached to the periodic report. It is further clarified that the Credit Facilities are in addition to the credit facility, as detailed in Section 7.21.3(a) above. For further details, see the Partnership's immediate report of 17 June 2025 (Ref. 2025-01-042961), the information in which is incorporated herein by reference.

(c) On 16 February 2026, the Partnership signed an agreement with Bank Leumi Le-Israel Ltd. for the provision of two credit facilities totaling $500 million, which are intended to be used by the Partnership for its operating activities, including in connection with the Leviathan reservoir Expansion Project (in this section: the "**Credit Facilities**"). According to the terms of the agreement, on 26 February 2026, the Partnership drew down $100 million (in this section: "**Credit Facility A**"), and it may draw down, from time to time, up to one year from the signing date, up to $400 million more (in this section: "**Credit Facility B**"). It is clarified that the Credit Facilities are in addition to the credit facilities as detailed in Sections 7.21.3(a) and 7.21.3(b) above. For further details, see the Partnership's immediate reports of 17 February 2026 and 26 February 2026 (Ref. 2026-01-015403 and 2026-01-018276, respectively), the information in which is incorporated herein by reference.

7.21.4 Financial covenants

(a) The Credit Facilities, as defined in Section 7.21.3(a) above, prescribe financial covenants which the Partnership is required to meet, and a breach of which establishes for the lender grounds for acceleration. On 9 November 2025, some of the financial covenants were amended. Below are details regarding these financial covenants, according to the Partnership's financial statements as of 31 December 2025 (Chapter C of this report):

Covenant	Calculated value as of 31 December 2025
The ratio between the value of the Partnership's assets[103] and the net financial debt[104] shall be no less than the ratios stated below: up to Net Financial Debt of $2.5 billion – no less than 1.5; for any additional Net Financial Debt exceeding $2.5 billion and not exceeding $2.75 billion – no less than 2.5; and for any Net Financial Debt exceeding $2.75 billion – no less than 4.1, on two consecutive testing dates	The Partnership's Net Financial Debt is lower than $2.5 billion and the said ratio is approx. 5.02
The Partnership's liquidity (on a standalone basis) shall not fall below $20 million	Approx. $382.7 million
The sum of the Financial Debt, other than limited recourse loans which are not Leviathan Bond Ltd. bonds, shall not exceed $3 billion	Approx. $1.4 billion
The Surplus Sources[105] shall not be negative	Not negative

[103] "**Value of the Partnership's Assets**" – The sum of the discounted cash flow (at a rate of 10%), net of taxes of the probable and/or contingent reserves (2P and/or 2C) of the Partnership's share in all of the Projects, based on the latest discounted cash flow (DCF) publicly released by the Partnership, plus the value of additional assets of the Partnership (which are not included in the definition of Projects) based on an independent third-party valuation by a valuator whose identity is acceptable to the bank. The value of assets that secure financial debt which is included in the definition of Financial Debt below shall be taken into account in the calculation of the Value of the Partnership's Assets and the value of assets that secure financial debt which is not included in the definition of Financial Debt below will not be taken into account in the calculation of the Value of the Partnership's Assets.
"**Projects**" – Gas and oil projects held by the Partnership and for which a DCF report was publicly released.

[104] "**Financial Debt**" - Debts and liabilities of the Partnership to banks and other financial institutions and/or which derive from all types of bonds, including straight bonds and convertible bonds and/or which derive from loans received by the Partnership from affiliates or any third parties (except loans in respect of which letters of subordination were signed vis-à-vis the bank by the Partnership and by the entity that provided such loan, and except limited recourse debts or liabilities (other than Leviathan bonds)). For the avoidance of doubt, the term "financial debt" does not include facilities for guarantees and bank guarantees issued thereunder per the Partnership's request, and does not include financial debt of corporations held by the Partnership (except Leviathan bonds or financial debt of companies guaranteed by the Partnership (and with respect to such a guarantee, in any event no more than the guarantee amount and except a guarantee that is limited to assets and liabilities that are specified in the definition of limited recourse). It is agreed that any calculation determined to be made according to the Partnership's consolidated statements, will be made adjusted to the definition of Financial Debt as aforesaid, and this amendment has a corresponding effect on the definition of Net Financial Debt.
"**Net Financial Debt**" - Financial Debt, net of: (1) cash and cash equivalents; and (2) deposits with banks and financial institutions; (3) funds and safety cushions provided to secure a Financial Debt (insofar as not included in Subsections (1) or (2), provided that none of the assets specified above are subject to a fixed charge and/or to an undertaking not to withdraw such assets in favor of any entity that is not the lender, other than in respect of the debt or liability included in the definition of Financial Debt.

[105] "**Surplus Sources**" - The aggregate amount of the sources until the earlier of: (a) the end of one year from the date to which the calculation relates; or (b) the end date of the loans that were drawn down (as specified in the sources and uses report), net of the uses amount (as defined in the sources and uses report) for such period. For the avoidance of doubt, the Surplus Sources shall also include sources and uses for the said period that relate to all of the Partnership's credit, other than the credit facility under the credit facility documents of 8 October 2024.

(b) The Credit Facilities, as defined in Section 7.21.3(b) above, determine financial covenants which the Partnership is required to meet every testing date, and a breach of which establishes for the lender grounds for acceleration, as detailed in the immediate report as aforesaid.

Below are details regarding the said financial covenants, according to the Partnership's financial statements as of 31 December 2025 (Chapter C of this report) (the definitions are identical to those determined in the credit facilities as stated in Section 7.21.4(a) above):

Covenant	Calculated value as of 31 December 2025
The ratio between the Value of the Partnership's Assets and the Net Financial Debt shall be no less than the ratios stated below: up to Net Financial Debt of $2.5 billion – no less than 1.5; for any additional Net Financial Debt exceeding $2.5 billion and not exceeding $2.75 billion – no less than 2.5; and for any Net Financial Debt exceeding $2.75 billion – no less than 4.1, on two consecutive testing dates	The Partnership's Net Financial Debt is lower than $2.5 billion and the said ratio is approx. 5.02
The Partnership's liquidity (on a standalone basis) shall not fall below $20 million	Approx. $382.7 million
The sum of the Financial Debt, other than limited recourse loans which are not Leviathan Bond Ltd. bonds, shall not exceed $3 billion	Approx. $1.4 billion
The Surplus Sources shall not be negative	Not negative

(c) The Credit Facilities, as defined in Section 7.21.3(c) above, determine financial covenants which the Partnership is required to meet every testing date, and a breach of which establishes for the lender grounds for acceleration, as detailed in the immediate report as aforesaid.

Below are details regarding the said financial covenants, according to the Partnership's financial statements as of 31 December 2025 (Chapter C of this report) (the definitions are identical to those determined in the credit facilities as stated in Section 7.21.4(a) above):

Covenant	Calculated value as of 31 December 2025
The ratio between the Value of the Partnership's Assets and the Net Financial Debt shall be no less than the ratios stated below: up to Net Financial Debt of $2.5 billion – no less than 1.5; for any additional Net Financial Debt exceeding $2.5 billion	The Partnership's Net Financial Debt is lower than $2.5 billion and the said ratio is approx. 5.02

Covenant	Calculated value as of 31 December 2025
and not exceeding $2.75 billion – no less than 2.5; and for any Net Financial Debt exceeding $2.75 billion – no less than 4.1, on two consecutive testing dates	
The Partnership's liquidity (on a standalone basis) shall not fall below $20 million	Approx. $382.7 million
The sum of the Financial Debt, other than limited recourse loans which are not Leviathan Bond Ltd. bonds, shall not exceed $3 billion	Approx. $1.4 billion
The Surplus Sources shall not be negative	Not negative

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).[106] For additional details in this regard, see Note 20A to the Financial Statements (Chapter C of this report).

7.22.2 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**")[107] 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

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[106] Link (in Hebrew) to the Tax Regulations as published in the Official Gazette on 14 September 2021.
[107] Link (in Hebrew).

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 current income of the venture according to its proportionate share in the petroleum interest (in the case of joint marketing), or the current income of the Petroleum Interest Holder (in the case of separate petroleum sale). It is further determined that in the first 3 tax years, from the tax year following the tax year in which the Levy coefficient is 1 or more, or 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%.

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, of the income of the venture or of the oil profits of the venture, and the recipient of the derivative payment will be liable for payment of the Levy in the sum of the "participation amount" defined in the section. The section determines that the participation amount shall be subtracted from the Levy owed by the Petroleum Interest Holder (in accordance with the other provisions of Section 9(b) of the Law), 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) 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 Assessing Officer, payment of 75% of the balance of the amount of a Levy that has been appealed may be compelled (before the dispute is resolved in court), and other amendments designed to confer powers on the assessing office to streamline the collection of the Levy. For further details, see Note 19C4 to the Financial Statements (Chapter C of this report).

7.22.3 The 2015-2016 tax years

(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. $143.0 million and approx. $129.7 million, respectively (rather than approx. $121.8 million and approx. $108.5 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. $56.1 million and approx. $76.3 million, respectively (rather than approx. $8.6 million and approx. $20.6 million, respectively, as included in the Partnerships' tax reports as filed with the Tax Authority). The said amounts were converted from ILS to $ according to the dollar exchange rate known as of 31 December 2025.

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. $66.4 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. Pretrial hearings on the appeal were held on 25 November 2021 and 17 March 2025, and in accordance with the court's decision, the parties are required to inform the court of the method of continuation of the proceedings by 30 March 2026.

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, 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.

7.22.4 The 2017 tax year

(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. $391.3 million (rather than approx. $233.6 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. $830.3 million (rather than approx. $674.8 million, as included in the Partnership's tax report as filed with the Tax Authority). The said amounts were converted from ILS to $ according to the dollar exchange rate known as of 31 December 2025.

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 assessment in the appeal were filed by the Assessing Officer on 30 May 2023, and a notice explaining the grounds for the appeal on behalf of the Partnership was filed on 31 January 2024. A pretrial hearing on the appeal was held on 17 March 2025, and according to the court's decision, the parties are required to inform the court of the method of continuation of the proceedings by 30 March 2026.

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. $147.1 million.

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%.

(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.

7.22.5 The 2018 tax year

(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 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. $205.3 million (rather than approx. $156.7 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. $18.1 million, as stated in the report so filed thereby. The said amounts were converted from ILS to $ according to the dollar exchange rate known as of 31 December 2025.

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 7.22.3(c) and 7.22.4(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 sum of approx. $18.3 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 explaining the grounds for the assessment of the Assessing Officer was filed, and the Partnership filed the notice explaining the grounds for the appeal on its behalf on 17 February 2025. A pretrial hearing on the appeal was held on 17 March 2025, and according to the court's decision, the parties are required to inform the court of the method of continuation of the proceedings by 30 March 2026.

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%.

(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.

7.22.6 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) In view of the disputes which arose between the Partnership and the Tax Authority and disagreements regarding the amount of the Partnership's taxable income for 2019, on 31 December 2025 a non-agreed assessment was received from the Tax Authority according to Section 145(a)(2)(b) of the Income Tax Ordinance (in this section: the "**Tax Assessment**"), whereby the Partnership's taxable business income for 2019 is approx. $405.3 million (in lieu of approx. $169.8 million, as stated in the Partnership's tax report filed with the Tax Authority), and the Partnership's capital gains for 2019 are approx. $10.6 million, as declared in the report filed thereby as aforesaid. The said amounts were translated from ILS to USD according to the dollar rate known as of 31 December 2025.

The main disputes pertain to the interpretation of the method of recognition of financial income and other expenses borne by the Partnership, similarly to the disputes for which assessments to the best of judgment were issued for the years 2016 and 2018, as detailed in Sections 7.22.3(c) and 7.22.4(b) above, respectively.

As of the report approval date, according to the Tax Assessment, and insofar as all of the Tax Authority's claims are granted, the Partnership will be required to pay additional tax (including linkage differences and interest), at the expense of the Partnership's participation unit holders, in the sum of approx. $90.1 million.

The Partnership will be filing a reasoned administrative objection to all of the Assessing Officer's findings in the Tax Assessment, by 31 March 2026.

In view of the aforesaid, a delay is possible in the issuance of a final tax certificate for entitled holders for the holding of a participation unit of the Partnership for the tax year 2019, pending completion of the proceedings required to determine the final assessment.

In the Partnership's estimation, based on the opinion of its professional advisors, the chances of the Partnership's key arguments being granted are higher than 50%.

(c) 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.

7.22.7 <u>The 2020 tax year</u>

(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 in which is incorporated herein by reference.

(b) In view of the disputes which arose between the Partnership and the Tax Authority and disagreements regarding the amount of the Partnership's taxable income for 2020, on 31 December 2025 a non-agreed assessment was received from the Tax Authority according to Section 145(a)(2)(b) of the Income Tax Ordinance (in this section: the "**Tax Assessment**"), whereby the Partnership's taxable business income for 2020 is approx. $369.1 million (in lieu of approx. $87 million, as stated in the Partnership's tax report filed with the Tax Authority). The said amounts were translated from ILS to USD according to the dollar rate known as of 31 December 2025.

The main disputes pertain to the interpretation of the method of recognition of financial income and other expenses borne by the Partnership, including expenses similar to those for which assessments to the best of judgment were issued for the years 2016-2018, as detailed above, and the recording of financial income for negative exchange rate differences, the method of depreciation of assets according to the provisions of the law, and recognition of other expenses in accordance with the provisions of the Income Tax Ordinance.

As of the report approval date, according to the Tax Assessment, and insofar as all of the Tax Authority's claims are granted, the Partnership will be required to pay additional tax (including linkage differences and interest), at the expense of the Partnership's participation unit holders, in the sum of approx. $107.7 million.

The Partnership will be filing a reasoned administrative objection to all of the Assessing Officer's findings in the Tax Assessment, by 31 March 2026.

In view of the aforesaid, a delay is possible in the issuance of a final tax certificate for entitled holders for the holding of a participation unit of the Partnership for the tax year 2020, pending completion of the proceedings required to determine the final assessment.

In the Partnership's estimation, based on the opinion of its professional advisors, the chances of the Partnership's key arguments being granted are higher than 50%.

(c) 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.

7.22.8 <u>The 2021 tax year</u>

(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 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.

7.22.9 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.

7.22.10 It is clarified that the Partnership has used a similar interpretation on the issues in dispute since the tax year of 2016 to date. The said issues are currently the subject of legal proceedings between the Tax Authority and the Partnership in reference to the tax years 2016-2018.

7.22.11 It is further clarified that the vast majority of the issues in dispute pertain to the timing, rather than the amount, of recognition of income and expenses in the years in dispute, and therefore, even if the Assessing Officer's position on such issues is accepted, no material effect is expected on the Partnership's total tax liability over the years, but rather only on the timing of tax payments during the course thereof.

7.22.12 For each of the tax years from 2016 to 2021, for which court proceedings or administrative objection proceedings against the Assessing Officer 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 Assessing Officer 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. 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.

7.22.13 It is further noted 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.

7.22.14 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 Environmental risks and management thereof

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. Environmental and climate risk management, including methodological mapping and a risk survey, 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 (the financial climate risk reporting standard).

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 The Partnership is subject to the provisions of the law and/or instructions of competent authorities on environmental issues.

(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, by way of an update to the excise 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 significantly, 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). On 4 June 2023, Chevron submitted its position regarding such document, as part of the public comments. On 18 February 2026 Chevron received a detailed response to its comments, which it is currently studying.

(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. As of 1 September 2024, some legislative amendments took effect in the Hazardous Materials Law, 5753-1993 and the Clean Air Law, 5768-2008, and transition provisions were determined for gradual implementation of the reform, which are due to 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 7.24.8(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) <u>Environmental directives for offshore exploration and production of oil and natural gas</u>

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.

(j) 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 2025 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 of 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 of 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. 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 Material legal or administrative proceedings in connection with the environment

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 GP and/or of the Partnership in connection with environmental protection, which is expected to have a material effect on the Partnership.

(a) Administrative monetary penalties

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) Hearings

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.

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 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-Arīsh, 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[108] 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 Economic Competition Law, 5748-1988[109] 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 trade practices which ostensibly may have been attributed to the Parties, as specified in the Government Resolution (the "**Restrictive Trade Practices**"). 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 restraints of trade 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 Partnership, Avner and Chevron; and the Restrictive Trade Practice that was

[108] 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 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".

[109] 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".

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.[110]

3. The Restrictive Trade Practice that shall ostensibly be created in a case where the Parties or some of them jointly market the gas that shall be extracted from the Leviathan reservoir 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 2030.

5. With respect to their then 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 7.24.3(a) below.

(b) The Exemption from the aforesaid Restrictive Trade Practices 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 valid, other than the following restrictions:

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.

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[110] 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 by 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 one of which having, at such time, a domestic supply obligation (DSO) of at least 30 BCM, and that no entity holds more than 25% of any interest 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 satisfied.

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 The Export to Egypt Permit of 17 December 2025

The Export to Egypt Permit of 17 December 2025 prescribes provisions regarding the gas quantities that the Leviathan Partners are required to make available to consumers in the domestic market, and the terms and conditions (including the price) to be offered to consumers in the domestic market for the purchase of such gas quantities, as described in Section 7.12.3(c)6 below.

7.24.3 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 then-partners in the Tamar project, and individually – 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 7.30.21 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[111], 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 gas swap request 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 of a 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, to comply with such request.

2. The duty of the parties as stated in Section 7.24.3(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 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 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.

[111] Link (in Hebrew).

6. EMED shall not exercise the option granted thereto to extend the capacity and operation agreement by 10 additional years (as described in Section 7.26.6 below). EMED intends to extend the term of the capacity and operation agreement and to this end to apply to the Competition Authority for the required approval.

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 for the merger transaction. However, the Competition Court ordered the Competition Commissioner to issue a supplementary 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: "**Supplementary Decision**"). The judgment became peremptory on 5 February 2023. Following the aforesaid, discussions were held between representatives of the Partnership, Chevron, EMG and EMED and between representatives of the Competition Authority regarding the Supplementary Decision, and on 20 August 2025, the Competition Commissioner announced amended conditions for approval of the merger transaction, which include, *inter alia*:

1. An obligation not to refuse a gas swap request, i.e., to supply natural gas to customers in Israel who signed an agreement with a supplier in Egypt;

2. An obligation to enable third parties to use any available capacity in the pipeline which is not used by the Leviathan and Tamar partners, where the service will be given according to the conditions of the EMG transmission license;

3. An obligation to obtain the Commissioner's approval prior to exercising the extension option for the operation agreement. In this context, insofar as the extension is not exercised, EMED will not be able to operate the pipeline without the Commissioner's approval, and if the Commissioner does not approve the extension, a decision on the making of any other operation agreement for the pipeline will not be subject to the veto rights of the EMED shareholders. As aforesaid, EMED intends to exercise the option granted thereto and to this end to apply to the Competition Authority for the required approval.

For this purpose, see also the "Applicable competition-related regulation" clause in Section 7.30.21 below.

(d) On 4 June 2025, the Competition Commissioner announced a call for public comment regarding natural gas sale contracts, and the impact of various provisions set forth in contracts between Israeli gas suppliers and natural gas consumers on competition in the Israeli natural gas market[112].

[112] Link (in Hebrew).

On 6 August 2025 the Leviathan partners submitted their position on the call for public comment to the Competition Authority.

(e) Information request from the Competition Authority in the natural gas sector

On 10 December 2024, Chevron notified the Partnership that it had 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.

7.24.4 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.

7.24.5 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 km^2), 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 3 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 requires that the lease holder 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.

7.24.6 <u>The Natural Gas Sector Law and the regulations promulgated thereunder</u>

(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.

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. To the best of the Partnership's knowledge, the Minister of Energy has extended INGL's transmission license by an additional 15 years until 31 July 2049. 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. Following the Swords of Iron war and Operation Rising Lion, In 2024 and 2025, the government renewed, from time to time, the authorization it granted to the Minister of Energy to declare a state of emergency in the natural gas sector, also without the approval of the government plenum, insofar as it is necessary to exercise the powers set forth in the Emergency Regulations. To the best of the Partnership's knowledge, the government renewed the authorization granted to the Minister of Energy to declare a state of emergency in the natural gas market, insofar as it is necessary to exercise the powers set forth in the Emergency Regulations, from 14 September 2025 to 28 November 2025[113]. In view of Operation Rising Lion, on 28 February 2026, the government released Government Resolution No. 3938, in which it authorized the Minister of Energy to declare a state of emergency until 11 March 2026. Accordingly, on 1 March 2026, the Minister of Energy ordered the activation of Emergency Regulations, according to the authority vested in him as aforesaid, from 1 March 2026 until 11 March 2026. Further thereto, on 10 March 2026, according to Government Resolution no. 3959, the Minister of Energy was authorized to declare a state of emergency in the natural gas sector until 25 March 2026, and on the same day the Minister of Energy declared a state of emergency in the natural gas sector for the period from 12 March 2026 until 25 March 2026. By virtue of his authority, with the Government's approval, and after the Minister of Energy consulted with the Director of the Natural Gas Authority and with the Director of the Electricity Authority, the Minister of Energy set forth instructions regarding the method and order of allocation of natural gas to consumers in the Israeli market, which are valid until the earlier of: (a) 16 March 2026; and (b) the date on which aggregate supply

[113] Link (in Hebrew).

from the natural gas reservoirs returns to the quantity of at least 100,000 MMBTU per hour.[114]

In accordance with Section 8 of the Emergency Regulations, in the event that a state of emergency is declared in the natural gas sector, the Minister is authorized, *inter alia*, to order a different allocation of the natural gas quantities for supply, when the shortage of natural gas has a prolonged negative impact on the proper functioning of the market or the regular supply of electricity. 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 (the "**Commission**") adopts resolutions that update the rates of the various transmission services.

2. According to Commission resolution no. 5/2020 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. In this context, it is noted that on 26 November 2025, the Commission released a draft resolution for public comment on the criteria and tariffs regarding balancing the pressure in the transmission system. The draft resolution proposes amending the flow control balancing regime set forth in Commission resolution no. 8/2019, whereby transmission system users were required to maintain a balance between the gas

[114] Link (in Hebrew).

quantities they nominated at the points of entry to the transmission system, and the quantities actually consumed at the points of exit. In the draft resolution, the Commission proposes transitioning to a daily balancing regime only, which is based on the purchase and sale of gas at market-based prices. Such balancing transactions would be carried out via a gas trading platform.

3. On 4 June 2024, Commission resolution no. 1/2024 was adopted, regarding an annual update to the uninterrupted transmission tariffs[115], which reduced the natural gas transmission capacity tariff by 12.9% to ILS 0.5871 per MMBTU, and the natural gas flow tariff by approx. 7.6% to ILS 0.1071 per MMBTU.

4. On 20 December 2022, the Commission released resolution no. 4/2022, which determines a system-wide tariff that is due from consumers of the natural gas transmission system, to fund projects of infrastructures, development, backup, redundancy of system-wide needs of the natural gas sector, or actions a license holder is required to take under the Natural Gas Sector Law. According to Commission resolution no. 4/2025 of 24 July 2025, the system-wide tariff for 2026 is ILS 0.0038 per MMBTU.

5. On 24 December 2025, the Commission issued resolution no. 5/2025 regarding tariffs for interruptible transmission services in projects for natural gas export to neighboring countries. According to this resolution, the interruptible transmission tariff for export shall be calculated according to a formula combining the capacity component and the transmission component in the general transmission tariff, using a designated export load factor. The resolution distinguishes between two situations and sets a load factor of 0.95 when the exporter cannot sign a firm transmission agreement due to a regulatory decision or operational constraints (which are not the exporter's), and a load factor of 0.45 when the exporter chooses, for its own reasons, to sign an interruptible transmission agreement. It was also determined that interruptible transmission agreements for export shall be signed for a period of one year or more. It was further determined that this resolution would replace the interim order set forth in resolution 2/2019 and in the resolutions that amended it[116].

(e) <u>Resolutions of the Natural Gas Commission regarding the financing of export projects via the national transmission system</u>

The Commission 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

[115] Link (in Hebrew).
[116] Link (in Hebrew).

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. During the years 2022-2025, INGL updated the project's budget several times, which, as of the report approval date, is approx. $139 million (100% the Leviathan Partners, the Partnership's share approx. $63 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.

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.

On 16 September 2025, Chevron, on behalf of the Leviathan Partners, entered into an agreement with INGL for the provision of transmission services, for the transmission of natural gas from the Leviathan reservoir to Egypt via the Nitzana Project (in this section: the "**Transmission Agreement**"). For further details, see the Partnership's immediate report of 16 September 2025 (Ref. 2025-01-069899), the information in which is incorporated herein by reference.

On 23 October 2025, the Leviathan Partners received a notice on behalf of the Gas Authority according to which the allocation rate for the Leviathan project in the Nitzana Project has been updated and will be 41.8% (the "**Updated Allocation Rate**"), and further to this notice, on 23 October 2025, Chevron signed, on behalf of the Leviathan Partners, an amendment to the Transmission Agreement intended to reflect the Updated Allocation Rate. For further details, see the Partnership's immediate report of 26 October 2025 (Ref. 2025-01-079841), the information in which is incorporated herein by reference.

On 23 October 2025, Energean entered into a transmission agreement with INGL in connection with the Nitzana Pipeline for the transmission of 1 BCM per year for a period of 15 years, with its share in the pipeline's construction costs being 16.4%[117].

To the best of the Partnership's knowledge, due to the signing of the Transmission Agreement by all of the exporters, the Transmission Agreement took effect on 23 October 2025. Moreover, to the best of the Partnership's knowledge, on 5 November 2025, an agreement was signed between Chevron and INGL for the performance of work on planning, purchase and construction of a compressor system and valve station for the Nitzana Project (the "**Compressor Station**"), which regulates the terms and conditions of construction of the Compressor Station.

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.

(g) The Gas (Safety and Licensing) (Amendment No. _) (Various Amendments) Legislative Memorandum, 5785-2025

On 31 July 2025, the Ministry of Energy published the Gas (Safety and Licensing) Legislative Memorandum, 5785-2025, the purpose of which is to make adjustments and updated regulation for the safety and licensing aspects of the natural gas sector, *inter alia* due to the regulatory split between natural gas and LPG and the developments in the gas sector in recent years. The memorandum proposes, *inter alia*, simplifying regulatory processes and expanding the use of self-regulation mechanisms, such that specifications and transmission approvals for certain gas facilities will be approved by license holders, subject to random test sampling by the regulator; prescribing that permits for the construction of certain facilities will be granted through inspection entities; establishing detailed regulation for the domestic segment and its connection to the distribution network (including provisions regarding planning, construction, testing, and approvals); and updating supervision and enforcement mechanisms, including by updating penal provisions and adding an administrative fine mechanism[118].

7.24.7 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)

[117] Link.
[118] Link (in Hebrew).

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 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. This confirmation is valid until February 2026. To the best of the Partnership's knowledge, and as it was informed by the operator, as of the report approval date, the actions required for extension of the said confirmation by an additional two years have been completed, such that it is expected to be received in the coming months.

(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.

7.24.8 <u>Directives of the Petroleum Commissioner</u>

(a) <u>Provision of collateral in connection with petroleum interests</u>

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.[119] The Partnership's total share in the said guarantees totals approx. $54.3 million.

(b) <u>Directives regarding the report of safety events in offshore facilities</u>

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

[119] 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 guarantees the Partnership has provided in respect of the Boujdour license and the Bulgaria License, see Sections 7.6.1 and 7.8.1E above, respectively. For details regarding guaranties the Partnership has provided in favor of Customs in connection with the Leviathan project and Yam Tethys project, see Notes 12E5 and 12O6 to the Financial Statements (Chapter C of this report).

oil at sea. As of the report approval date, the Directives have not yet been published.[120]

(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 15B3 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

[120] Link (in Hebrew).

Ministry of Energy in connection with the Tamar reservoir, see Note 15B7 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) <u>The transfer and pledge of a petroleum asset interest and benefit in a petroleum asset interest</u>

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.

7.24.9 Regulatory restrictions and government decisions in respect of the export of natural gas

(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 signed by the Partnership as specified in Section 7.12.3 above.

(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%
For every additional 1 BCM from 50 BCM to 200 BCM	50%
Lower than 50 BCM	No domestic supply obligation (DSO) shall apply

For reservoirs shared by Israel and other countries, the Petroleum Commissioner shall determine specific arrangements and conditions.[121] 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.

[121] The permitted export quota from the Tanin and Karish leases in the amount of 47 BCM was replaced, against the domestic supply obligation (DSO) 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.

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. On 25 February 2026, the Ministry of Energy and Infrastructure posted on its website that the Natural Gas Authority is promoting the establishment of a natural gas trading platform to enable companies to trade in surplus natural gas. In this context, the Natural Gas Authority, together with representatives from key government agencies (including the Ministry of Energy, the Budgets Department, the Competition Authority and other entities) held a comprehensive professional discussion with FGSZ (the national transmission company of Hungary and the operator of the country's gas trading platform), which focused on learning, exchange of ideas and knowledge sharing, and raised the challenges and opportunities involved in the establishment of a natural gas trading platform in Israel[122].

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 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 had instructed the Director General of his Ministry to begin setting up the interministerial committee for periodic examination of the natural gas sector policy. Further thereto, on 14 February 2024, the committee began its discussions for the purpose of reviewing 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 – energy, economic, environmental and security-related. On 9 April 2025, the committee released a draft report for public comment that includes a mapping of challenges facing the natural gas sector and recommendations on how to address these challenges (in this section: the "**Draft Report**"). Below is a concise description of the committee's main recommendations, as specified in the Draft Report:

[122] Link (in Hebrew).

1. Ensuring the natural gas needs of the domestic market alongside encouraging investments in exploration and production, maintaining energy security, and balancing reliance on natural gas with the reduction of pollutant emissions;

2. Continuing to examine considerations of encouragement of investment and competition in the domestic market, including maintaining a competitive supply of natural gas, in decisions regarding the granting of export approvals;

3. The committee considered increasing the reservoirs' total domestic supply obligation (DSO), which is approx. 440 BCM[123]. Nevertheless, the committee recommended that in the event of the discovery of new reservoirs for which a specific DSO shall be determined, an equivalent quantity shall be added to the total DSO, up to a total DSO of 515 BCM;

4. Maintaining the tiered domestic market connection obligation established in Government Resolution 4442;

5. Preparing a white paper to define a benchmark for energy security in the natural gas sector and promoting infrastructure projects to improve energy security levels (including reference to nuclear energy, renewable energies, and energy efficiency);

6. Operative recommendations for promoting competition in the natural gas sector, such as promoting import and storage, establishing a trading platform and promoting secondary trading, etc., regulating separate marketing, and examining the possibility of setting benchmarks for new contracts and a Gas Release Program (GRP);

7. Preparing a white paper to examine alternatives for the continued use of natural gas while minimizing greenhouse gas emissions, including Carbon Capture and Storage (CCS).

The committee further recommended that 5 years after approval of its recommendations by the government, an inter-ministerial committee be convened to recommend to the government required updates to the export policy, considering, *inter alia*, the existence or absence of new discoveries, the rate of penetration of alternatives to natural gas, and the development of the demand for natural gas in the domestic market, which shall submit its conclusions by 31 December 2030. The committee also recommended the establishment of an inter-ministerial thinktank headed by the Director General of the Ministry of Energy, to examine the implementation of government policy regarding the natural gas sector. The said thinktank will discuss, *inter alia*, options for encouraging natural gas exploration, aspects of energy security, economics, political and geopolitical aspects, environmental aspects, and competition aspects, and shall be convened once a year or prior to the making of a significant decision within the committee's purview.

[123] 500 BCM, as determined in Government Resolution 4442, net of the natural gas consumed in the domestic market until 1 January 2024.

As of the report approval date, the committee has not yet released the final report.

(d) On 28 April 2025, the Budgets Department of the Ministry of Finance (the "**Budgets Department**") released a separate position paper presenting, *inter alia*, recommendations that do not appear in the Draft Report (in this section: the "**Position Paper**"), as follows:

1. To promote regulation that will allow for the financing of connection of small reservoirs to the domestic market through Gas Authority tariffs, in exchange for a specific DSO;

2. In the granting of export permits, to establish a consultation obligation for the Ministry of Finance, the Ministry of Foreign Affairs, and the National Security Council (NSC), and to increase transparency in the granting of export permits;

3. To establish an open-access policy for export infrastructures that will ensure the possibility of new reservoirs to export gas.

In addition, the Budgets Department recommended, in the Position Paper, updating the total natural gas DSO to 515 BCM for the next 25 years.

In the Position Paper, the Budgets Department further recommended considering, subject to a feasibility and viability study, prohibiting from 2030 aggregate cross-holdings amounting to over 80% of the gas reserves in the market. Another recommendation by the Budgets Department in the Position Paper was to establish, in a government resolution, default regulation leading to the implementation of separate marketing in the Leviathan reservoir, commencing from the date of expiration of the restrictive trade practice permit granted thereto in the Gas Framework (1 January 2030).

Moreover, in the Position Paper, the Budgets Department recommended to the Minister of Energy that the government resolution adopting the committee's conclusions shall prescribe separate marketing regulation, under which an obligation shall be imposed on the partners in the Leviathan reservoir to propose, by 1 January 2028, a framework for separate marketing regulation in accordance with the international standard in the gas industry. The Gas Authority and the Competition Authority may adopt the framework as proposed by the reservoir, or make changes thereto to enhance the framework's attractiveness in fostering competition.

As of the Report approval date, it is not known whether the principles specified in the Position Paper will be incorporated into the committee's final conclusions.

7.24.10 <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.

7.24.11 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) Phase-out of coal use for power production

On 3 June 2018, the government, in Resolution no. 3859, approved electricity sector reform and a restructuring of the IEC[124]. According to the resolution, the IEC will reduce its power production operations by selling 5 production sites with a total maximum capacity of approx. 4,000 MW, accounting for around one half of its power production capacity, and the IEC will build two modern natural gas-fired production units at Orot Rabin (Unit) 70 and Unit 80), as part of the trend of reducing the use of coal in the power production process. According to the IEC's reports, in January 2025, commercial operation of Unit 70 began, and in January 2026, commercial operation of Unit 80 began. In November 2019 the Ministry of Energy released a document of policy principles, whereby until 2026, the two coal-fired production units at Orot Rabin (Units 5 and 6) and the four coal-fired production units at the Rutenberg power plant in Ashkelon (Units 1-4) will be converted to natural-gas fired power production units[125]. In this context it is noted that according to the IEC's reports[126], in 2025, the IEC worked on updating the emission permits and coordinating the timetables for conversion of the production units to gas, *inter alia* against the backdrop of delays in the project. It was further noted that Noga approved the work according to the schedule delivered to the Ministry of Energy, although insofar as malfunctions and delays are discovered during the conversion/ testing, Noga may put off the continued conversion to gas. As of the report approval date, the conversion of Units 1 and 2 at Rutenberg has been completed, and the conversion of Unit 3 has not yet begun. Commercial operation of Unit 1 was launched in February 2025, and commercial operation of Unit 2 was launched in January 2026. On 5 September 2025, the IEC reported completion of the conversion of Unit 4, and that it is awaiting approvals from Noga for commercial operation of the unit.

[124] Link (in Hebrew).
[125] Link (in Hebrew).
[126] Link (in Hebrew).

The updated forecast for the commercial operation date of Units 5 and 6 at Orot Rabin is in 2026 and 2027, respectively[127].

7.24.12 On 24 August 2024, the government approved Resolution no. 2147[128] regarding the gradual decommissioning of power production units 1-4 at Orot Rabin[129], according to which two units at Orot Rabin will be shut down on the date of operation of the first CCGT (Unit 70), and two additional units will be shut down on the date of operation of the second CCGT (Unit 80).

In January 2025, upon the commercial operation of Unit 70, Units 3-4 at Orot Rabin were decommissioned. Notwithstanding the commercial operation of Unit 80, as of the report approval date, Units 1-2 at Orot Rabin have not yet been shut down.

In policy principles of 8 February 2021, the Minister of Energy determined that, given the need to maintain the reliability, availability, and continuity of the electricity supply in emergencies in the coming years, the IEC would preserve Units 1-4 at Orot Rabin until 31 December 2025, according to the framework specified in the Electricity Authority's recommendation, and that shortly before the end of the preservation period, the need for new policy principles on this matter would be examined. On 28 November 2024, the Minister of Energy approached the Electricity Authority requesting its position regarding the preservation of Units 1-4 at Orot Rabin and the transition to coal-fired power generation when necessary. In July 2025, a hearing of the Electricity Authority was published regarding the method and scope of preservation of Units 1–4 at Orot Rabin[130], in which the authority recommended the continued preservation of Units 1-4 for three years on 'hot standby' until the end of 2028. As of the report approval date, to the best of the Company's knowledge, Units 1-4 are still under emergency operation.

A report of the Knesset Research and Information Center of February 2024[131] points to gaps between the planning and the reality in the transition from coal-fired to natural gas-fired power generation. In 2023, coal accounted for approx. 17% of electricity generation, compared to previous Ministry of Energy forecasts that predicted a rate of 14%-15%. According to the report, a delay in the conversion of coal-fired plants to natural gas leads to higher levels of pollutant emissions, an increase in electricity prices, a loss of State revenues, and an adverse effect on the Gross Domestic Product (GDP).

7.24.13 According to the Electricity Sector Status Report released by the Electricity Authority in September 2025[132], the downward trend in coal use for power generation continues (with a significant reduction upon the operation of CCGT Unit 70 in January 2025), and shall continue until routine coal-fired production is phased out by 2030, which is dependent on the IEC's meeting the schedules

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[127] Link to the economic review of the Knesset Research and Information Center on "Phase-out of coal use for electricity generation – November 2025" of 9 November 2025 (in Hebrew).

[128] Link to Government Resolution no. 2147.

[129] This resolution amended the government's previous resolutions of June and July 2018, according to which commencing from June 2022, production in coal-fired Units 1-4 at Orot Rabin would be discontinued.

[130] Link to hearing of the Electricity Authority of 6 July 2025 (in Hebrew).

[131] Review on "Coal to Natural Gas and Renewables Power Generation Transition" of 5 February 2024 (Link in Hebrew).

[132] Link to Electricity Sector Status Report, September 2025 (in Hebrew).

for conversion of the coal-fired units, the construction of CCGT Unit 80 at Orot Rabin (commercial operation of which has already been launched), and the shutdown and preservation of Units 1-4 at Orot Rabin.

According to the Natural Gas Sector Review – 2024 Summary, in 2023 the rate of "coal, diesel oil, and others" in Israel's electricity production mix was 18%, and in 2024, the share of natural gas in Israel's electricity production mix was 74%.

(a) 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 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[133] . 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.

(b) 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**").[134] 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[135], 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 power plants 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

[133] Link (in Hebrew).
[134] Link (in Hebrew).
[135] A review from the Knesset website on the coal to natural gas and renewables power generation transition of 5 February 2024. Link (in Hebrew).

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.[136] On 17 February 2025, the outline was released, in its final language.[137]

On 6 November 2024, the Ministry of Energy and Infrastructure released a document on "The Roadmap for Renewable Energy in 2030".[138] 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.[139]

(c) Formulation of a critical minerals policy in Israel for a net-zero future

As part of the energy sector's preparations for net-zero emissions and expansion of the use of renewable energies, in November 2025, the Ministry of Energy and Infrastructures released a report for public comment regarding the formulation of a critical minerals policy in Israel for a net-zero future[140]. According to the report, in 2024, electricity generation in Israel totaled approx. 80 TWh, of which generation from renewable sources totaled only approx. 11 TWh (approx. 14%). By 2050, these values are expected to increase significantly, and the renewable energies percentage is projected to reach approx. 55%. In accordance with government targets for 2030, coal use in Israel is expected to total approx. 3%, natural gas use approx. 76%, and renewables use approx. 20%.

(d) The Paris Agreement and the Powering Past Coal Alliance (PPCA)

136 Link (in Hebrew).
137 Link (in Hebrew).
138 Link to the Ministry of Energy's publication on the matter of 7 November 2024 (in Hebrew).
139 Link to the outline for (net) zero greenhouse gas emissions in the energy sector in Israel by 2050 (in Hebrew).
140 Link (in Hebrew).

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 phase-out of coal use. 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 ("**CO2**").[141] 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.

7.24.14 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 sequestration, 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

[141] Link (in Hebrew).

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.

7.24.15 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. 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.

7.24.16 On 28 May 2025, the Ministry of Energy and Infrastructures released the 'Natural Gas Sector Review – 2024 Summary' report[142]. According to the report, the growth rate in recent years has become slower than the growth rate in the years following commencement of production from the Tamar reservoir, although the upward trend in the demand for natural gas in the domestic market is expected to continue also in the coming decade due to the projected increase in the demand for electricity, including the transition to electric transportation, the conversion of coal-fired plants to natural gas, and the continued trend of the transition of industry to natural gas from other fossil fuels. Moreover, the upward trend in the demand for natural gas is expected to continue also given significant growth in the use of renewable energies. The report further noted that in 2024, approx. 78% of the natural gas consumed in the domestic market (approx. 10.9 BCM) was used for electricity generation (excluding electricity produced in cogeneration facilities), approx. 11% was used by transmission and distribution consumers in the industrial sector (approx. 1.5 BCM), and the remainder (11%) was used by cogeneration consumers. In this context, export in 2024 totaled approx. 13.2 BCM, accounting for approx. 49% of the total natural gas supply, compared to approx. 11.6 BCM exported in 2023, which accounted for approx. 47% of the total natural gas supply in that year. While natural gas prices fell sharply internationally in 2024 in view of the significant price hikes of 2023, the Israeli market was almost entirely unaffected by global price fluctuations, and gas price levels remained stable.

[142] Link (in Hebrew).

7.24.17 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.

7.24.18 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.

7.24.19 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. Cyprus and Bulgaria are full members of the European Union and are 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, respectively.

7.25 **Pledges**

For details regarding pledges the Partnership has given on its assets, see Note 10 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 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 2025, 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. $83.5 million was repaid (100%, the Partnership's share approx. $32.3 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.

On 15 January 2026, an amendment was signed to the Capacity Allocation Agreement for expansion of the capacity reserved for Blue Ocean by an additional 200 MMSCF, to enable the transmission of additional quantities in accordance with the amendment to the export agreement with Blue Ocean (see Section 7.12.3(c)6 above). Expansion of the reserved capacity shall take effect on the date on which BOE gives notice to EMED (the Expansion Date, as defined in Section 7.26.6(d)2 above), and shall remain in effect until the end of 2040. The parties undertook to work on extending the term of the Capacity Lease and Operatorship Agreement (see Subsection c. above) or finding an alternative to enable the transmission of gas in the EMG pipeline under similar conditions.

(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 The Joint Operating Agreement in respect of the Leviathan Leases[143]

(a) General

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.

(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

[143] Until 1 January 2012, the activity in the Leviathan Leases was carried out in the framework of a single joint operating agreement.

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,[144] and all the credits to the joint account,[145] 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. 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*, 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[146] 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.

[144] 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.

[145] 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.

[146] 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.

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 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.

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) Sole Risk operations

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. 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) Change of control

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 of Block 12. However, 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 15B7 to the Financial Statements (Chapter C of this report).

In February 2025, the draft royalty audit reports for 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, January 2025 and January 2026, 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 2023-2026 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 royalty reports submitted by Chevron to the Ministry of Energy for the years 2020, 2021, 2022 and 2023, the rate of the State Royalties in the Leviathan project will be approx. 9.58%, approx. 10.17%, approx. 10.08% and approx. 9.34%, respectively. Accordingly, the rate of the royalties on which the Partnership relied was approx. 10.57% in its financial statements for 2024, and approx. 10.61% in its financial statements for 2025.[147] 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 2025 is approx. $25.9 million. For further details see Note 15B to the Financial Statements (Chapter C of this report).

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 [148]

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.[149] ("**Delek Israel**" and jointly in this section: the "**Transferors**") and the GP, the Transferors transferred

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[147] In the discounted cash flow figures for the Leviathan project, the Partnership assumed that the Effective Rate of the State Royalties was 11.06%.

[148] 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.

[149] Following the reorganization that was carried out in the past, the royalty right as aforesaid of Delek Israel was transferred to Delek Group.

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 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.

Additionally, in accordance with the Partnership's immediate report of 16 January 2026 regarding a report on updated reserves, contingent resources and discounted cash flow figures in the Leviathan Leases (Ref. 2026-01-006999), the discounted cash flow was calculated on the assumption that for the purpose of payment of the royalties to related parties, the Investment Recovery Date will fall in H1/2026. The said assumption was calculated after the sale of a total quantity (from commencement of production in the reservoir, for 100% of the interests in the petroleum asset) of approx. 2,265 BCF of natural gas and approx. 5.1 million barrels of condensate. It is clarified that the Investment Recovery Date is affected by various factors (including gas and/or condensate prices, the pace of production, the production and development costs, etc.), and is subject to approval of the Investment Recovery Date calculation in an audit by the Partnership's accountants (which has not yet been completed), and therefore the total natural gas and/or condensate quantity that shall be sold by the Investment Recovery Date may be different to the quantity stated above.

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. 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**").[150] 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. Avner Partnership Royalties

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

[150] 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.

Agreement[151] (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.

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.

[151] 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**").

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 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 Agreement for the sale of the Partnership's interests in the Tanin and Karish Leases

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 of 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 The agreement for the sale of 9.25% of the interests in the Tamar and Dalit Leases to Tamar Petroleum

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 2021 periodic report.

7.26.12 Agreement for the sale of the Partnership's remaining interests (22%) in the Tamar and Dalit leases

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.[152]

For further details regarding the agreement, see Section 7.24.12 of Chapter A of the 2021 periodic report.

[152] 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.

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 17 May 2026.

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.

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. $8 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 GP 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 3 August 2026.

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 stage ended and according to the instructions of the court, the closing arguments of the Petitioners were filed with the court in March 2025, the closing arguments of the Respondents were filed in August 2025, and responding arguments on behalf of the Petitioners was filed in 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 trade practice, 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 a motion for class certification against the Partnership, the GP, Delek Group, Yitzhak Sharon (Tshuva), the GP's directors (including the former chairman of the board) and the GP's CEO (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 in the period relevant to the Certification Motion, the Reduction Clause was not material and was not required to be disclosed to the public, and that there is no causal link 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, announced that at that stage, he did not deem fit to take a position on the proceeding. Trial hearings were held in November 2022. On 10 December 2023, the Petitioner filed closing arguments on his behalf, on 13 March 2025, the Respondents filed closing arguments on their behalf, and on 3 August 2025, the Petitioner filed responding arguments on his behalf. On 12 August 2025, the Petitioner filed a motion to submit a new document as evidence in the proceeding, and on 30 October 2025, the Respondents filed their response to the said motion. On 9 November 2025, the court accepted the Petitioner's proposal whereby each party address the evidence to be filed, and according to the court's decision, on 11 November 2025, the Petitioner filed the additional evidence on his behalf, on 8 December 2025, the Partnership filed its response to the new evidence, and on 16 December 2025 the Petitioner filed his reply. The court also ruled in its decision of 18 December 2025 that the Certification Motion is to be decided.

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 sum 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 at 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 Coral and Gold-Line 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 sum 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 agreements on completion of the preliminary proceedings, 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, aside from Haifa Port's motion to summon the customs representative for testimony, and on 28 July 2024, the court denied the motions filed by 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 the court's decision to deny the motions filed thereby, and a motion to postpone the date for the filing of the responding affidavits. The court granted the said motion for postponement and ruled that the responding affidavits 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. On 10 March 2025, the final pretrial hearing and the hearing of Haifa Port's motion to summon the customs representative for testimony were held, and dates were scheduled for the trial hearings in the months of September through November 2025. In the court's decision of 20 March 2025, Haifa Port's motion to summon the customs representative for testimony was denied. Further thereto, the parties agreed to refer the case to mediation, and in September, several mediation sessions in the proceeding were held before the Hon. Justice (Ret.) Zvi Zylbertal. Accordingly, some of the trial hearings that were scheduled in the proceeding were canceled. On 14 December 2025, the court entered a judgment on the mediation agreement on which the parties had agreed, according to which the claims were mutually dismissed, with no order for costs.

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. The court denied the said motion on 21 June 2023, and issued an order for costs against Haifa Port.

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 GP, Mr. Abu, the GP's CEO, and the members of the GP's Board (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 the GP's CEO, 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.

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 Partnership filed its closing arguments in October 2025, and the Petitioner filed a responding arguments on his behalf in December 2025. The court further ruled that the Attorney General is required to file her position on the status of the institutional bodies in overrulings, such as those contemplated in the Discovery Motion, and accordingly, on 15 February 2026 the Attorney General filed a notice with the Court whereby she does not deem to add anything to the positions filed by her in the proceeding to date.

On 25 June 2025, the Petitioner filed a motion for the adjudication of a fee in the sum of ILS 950,000 (plus VAT) for his counsel, and according to the court's decision, on 7 August 2025, the Partnership filed its response to the motion. On 10 August 2025, the court ordered dismissal of the said motion, with no order for costs.

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). Concurrently with the said arbitration proceeding, the parties have referred the case to mediation with the aim of attempting to reach agreements without an arbitration award. On 2 April 2025, a preliminary hearing in the proceeding was held, during which dates were scheduled for mutual discovery between the parties and for the filing of affidavits in lieu of direct testimony on their behalf. In this context, two trial dates in the proceeding were scheduled, in the months of November-December 2025. It is further noted that on 6 May 2025, a third mediation session in the proceeding was held, at the end of which the parties reached an in-principle agreement, which was subject to final approval by INGL and the partners in the Leviathan and Tamar projects, in connection with a settlement arrangement whereby, *inter alia*, INGL shall credit Chevron (and consequently the partners in the Leviathan and Tamar projects) with part of the transmission fees paid to INGL for the transmission to EMG's terminal in Ashkelon, and in connection with several changes to the transmission agreement, including the transmission fees that Chevron shall pay in 2025-2026, and extension of the transmission agreement by two years. The reimbursement expected to be received by the Partnership is in a non-material amount. On 5 August 2025, the parties signed a settlement agreement that is based on the principles on which they agreed as aforesaid, and on 19 August 2025, an arbitration award was entered on the said settlement agreement, with each party bearing its own costs.

7.28 Goals and business strategy

7.28.1 General

Based on meetings of the GP's Board on the matter, 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 outside of Israel, development and commercialization thereof, 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, as well as review of opportunities in the renewable energy sectors as detailed in Section 7.10 above. The said strategy is realized mainly through exhaustion of the production and sales potential of the Leviathan Project, as specified in Section 7.2.5 above, promotion of the development of the Aphrodite reservoir to exhaust its economic potential, 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 consideration of the ESG policy adopted by the Partnership, in order to generate optimal value for the Partnership's stakeholders.

For this purpose, the Partnership takes action, *inter alia*, to increase of the demand for natural gas, both through expansion and assimilation of the use of natural gas in the domestic market and through natural gas export via 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. In the context of the said export activities, the Partnership may, from time to time, also explore and enter into commercial volume swap transactions, in which gas produced from the Partnership's assets may be swapped for gas volumes from another source, at different delivery points, for supply to nearby markets with existing transmission infrastructure. The performance of such transactions is subject, *inter alia*, to the existence of appropriate commercial agreements, regulatory approvals (insofar as required), and geopolitical conditions that allow the actual realization thereof.

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. This activity includes promotion through MedLight of, *inter alia*, renewable energy projects in Morocco, and review of the feasibility for the development of a renewable energy project in the Sinai peninsula for the possibility of exporting electricity to regional markets. The Partnership is also exploring possibilities for the 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. The Partnership is also exploring options for the research and development of energy technologies, including the production of low-carbon energy, and specifically civil nuclear energy and hydrogen, subject to obtaining various regulatory approvals and to the approval of the Partnership's competent organs, as specified in Section 7.28.3(c) below.

In addition, the Partnership is exploring the possibility of listing the participation units for trade in a key international stock exchange outside of Israel, which may, in its estimation, fit its activity characteristics and relevant investor base, *inter alia*, by way of dual listing such that the participation units will continue to be traded on the Tel Aviv Stock Exchange and concurrently also on another stock exchange outside of Israel. The review of such a move, insofar as it is promoted, is subject, *inter alia*, to a review of its feasibility, including operational feasibility, the rules and directives applicable in the relevant stock exchanges, receipt of the approvals required by law, if any, and approvals by the Partnership's competent organs. As of the report approval date, there is no certainty that the move will be promoted or completed, and on what track.

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. Performing the First Stage of the Expansion Project, as specified in Sections 7.2.5(b)(2) and 7.13.2 above.

3. Performing a 3D seismic survey in H2/2026, *inter alia*, for the purpose of formulating deep target exploration prospects in the Leviathan Leases.

(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

The Partnership is continuing its exploration efforts with the aim of expanding its oil and gas asset portfolio. In this context, *inter alia*: (1) The Partnership is promoting a 3D seismic survey in the Leviathan Leases in H2/2026, *inter alia* to define deep prospects; (2) and is promoting a 3D seismic survey in the Zone I Licenses. The partners intend to engage an international supplier to carry out a 3D seismic survey in the coming months; (3) It is a partner in the drilling of exploration wells in the Bulgaria License; and (4) It is promoting the work plan as operator of the Boujdour Atlantique exploration license, which is located in the Atlantic Ocean offshore Morocco, to identify drilling prospects. For further details, see Sections 0, 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, the transportation conversion volume is expected to increase the demand for natural gas by approx. 3.7 BCM over the coming decade.

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.

4. Server farms, data centers, and cloud computing (including AI applications): To the best of the Partnership's knowledge, the growth rate of server farms, data centers, and cloud computing, including for data processing and AI applications, is driving an increase in electricity demand, while imposing stringent standard requirements regarding availability, reliability, and stability. Such growth may lead to a further increase in the demand for natural gas, *inter alia*, for purposes of continuous power supply, backup, and system stabilization. As part of the Partnership's preparations for shifts in the energy industry and the needs arising from these infrastructures, the Partnership also periodically examines opportunities for the research and development of energy technologies, as detailed in Section 7.28.1 above.

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 exploring promotion of a blue hydrogen venture, in which natural gas is split into hydrogen and carbon dioxide (CO2), with the carbon dioxide being captured and sequestered in downstream products. 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 7.15.3 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.

(c) Nuclear energy

The Partnership is exploring possibilities for research and development of technologies in the area of civilian nuclear energy, subject, *inter alia*, to the restrictions applicable to the activity of public petroleum partnerships according to the TASE Rules, as being from time to time, the receipt of various regulatory approvals, and the approval of the Partnership's competent organs.

7.28.4 **ESG**

The Partnership strives to realize the potential of its assets and also expand its activity to additional assets, responsibly and efficiently, in order to maximize value for its stakeholders while managing and mitigating the ESG risks in its operations.

An ESG risk survey recently conducted by the Partnership, based on the ESRS methodology and the double materiality approach, identified impacts, risks and opportunities (IROs) in various ESG areas.

The said survey identified four key areas which had been rated by stakeholders as highly material, both in terms of impacts on the environment and society (inside-out) and in terms of potential financial impacts on the Partnership (outside-in). These areas, which include climate and energy, adaptation to climate change, health and safety, and geopolitics, consistently emerged as both a risk and an opportunity for the Partnership. Alongside these areas, the Partnership analyzed several additional ESG matters that had been rated with varying materiality levels, such as pollution, water and sea resources, biodiversity, employment conditions along the value chain, ethics and business conduct.

Such analysis took into account the management practices and risk mitigation measures taken by the Partnership in connection with the various ESG areas. Activity in the natural gas sector, with its environmental impacts on the one hand, and its contribution to the reduction of emissions and energy and geopolitical stability in the region on the other hand, as well as the impact of the Partnership's activity on many stakeholders, lead the Partnership to exercise strict care in terms of transparency, management and corporate governance to the highest standards.

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 **Insurance coverage**

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).

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. 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 Leviathan partners in Operation Rising Lion and Operation Roaring Lion.

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 7.30.13 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 and the security situation

As specified in Section 6.8 above, as of the report approval date, there is uncertainty as to the possible developments of the security situation on the various fronts. Accordingly, it is impossible to assess the impact of these developments on the Partnership's operations, and primarily on the continued regular production from the Leviathan and/or Tamar and/or Karish reservoir and on the marketing of gas to export customers and to the domestic market. For details regarding suspension of the production of natural gas and condensate from the Leviathan reservoir as a result of operations 'Rising Lion' and 'Roaring Lion', see Section 6.8 above.

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 event of escalation, the risk of imposition by the government of restrictions on the regular production operations of one of the reservoirs may also increase. Restriction or suspension of production from the Tamar and/or Karish reservoirs is expected to compel the Leviathan Partners to increase the supply quantities to the domestic market, predominantly at the expense of export to Egypt.

Additionally, escalation may also increase the geopolitical risk related to the export of natural gas from the Leviathan reservoir under the export agreements, which accounts for most of the Partnership's revenues.

According to common practice, the various agreements signed by the Partnership include *force majeure* clauses. *Force majeure* events may exempt a party to the agreement from performing 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 deriving therefrom. In addition, in certain cases, a *force majeure* event which lasts for a long time may establish grounds for termination of the agreements.

In addition, in all of the natural gas sale agreements of the Partnership (in this section: the "**Gas Agreements**"), customers undertake to pay for a minimal annual quantity of natural gas (Take or Pay) in accordance with the mechanisms set forth in the Gas Agreements. However, customers may be exempt from this obligation, upon the occurrence of a *force majeure* event which prevents them from fulfilling their undertakings, as defined in the Gas Agreements. A *force majeure* event is defined as an event that is beyond the customer's control, which bars it from fulfilling its undertakings under the Gas Agreement, and which could not have been reasonably prevented in the circumstances. The Gas Agreements list cases which are not deemed as a *force majeure* event, even where they are beyond the customer's control. It is noted that the Partnership too may be exempt from its obligations under the Gas Agreements upon the occurrence of a *force majeure* event, which prevents it from fulfilling its obligations under the agreements. In this context, it is noted that with the cessation of gas production following Operations Rising Lion and Roaring Lion, the Leviathan partners issued a notice to customers of exercise of the *force majeure* clause.

Insofar as a *force majeure* event lasts over an extended period of time set forth in Gas Agreement and has a material effect on the ability of a party to the agreement to fulfill its undertakings of as aforesaid, grounds for termination of the agreement may be established thereby. Therefore, the occurrence of a *force major* event for a long period of time, which suspends the obligations of a customer to purchase a significant quantity of natural gas, may have a material adverse effect on the Partnership's income.

In the event that escalation in the security situation will result in the early termination of export agreements, or if physical damage is caused to the Leviathan project which cannot be repaired fully and immediately, or insofar as other events occur that are reasonably expected to result in a material adverse effect, and subject to remediation periods, exceptions, and conditions, there is a risk of a breach of the terms and conditions of the Leviathan Bond bonds, which are secured by the Partnership's interests in the Leviathan project and are traded on the TACT-Institutional system of TASE, which may confer on the bondholders grounds for acceleration and enforcement of the collateral. In addition, an increase in the bond yields may have an adverse effect on the Partnership's ability to raise additional debt and increase the financial costs in respect of another debt raising as aforesaid.

For details on delays in the performance of the Combined Section project and the Third Pipeline project due to the security situation, see Section 7.13.2(c)2 above.

7.30.2 Pandemic outbreaks

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 Fluctuations in the linkage components in the natural gas price formulas in the supply contracts

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 has engaged, other than agreements that include a non-linked fixed price, also specify, along with the price formulas, floor prices 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 floor prices in new agreements that are signed thereby in the future. In this context it is noted that in the terms and conditions of the new export approval for Egypt, the lease holders undertook to offer consumers in the domestic market, in the context of negotiations for engagement in firm and spot contracts, various linkage formulas and price alternatives.

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.

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.

Given the limited demand for natural gas in the domestic market, the entry of additional competitors and suppliers, regulatory restrictions on the volume of gas export and government incentives to develop renewable energies, there is a risk of decrease in the demand for natural gas marketed by the Partnership, which may have an adverse effect on its ability to sell the gas reserves attributed to its assets.

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, and global trends of transition to a low-carbon economy and expansion of the use of renewable energies, including the taking effect of regulation to reduce greenhouse gas emissions, which may accelerate such trends, 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 2025, the Partnership's operations and results were influenced by various factors, including energy price volatility resulting from global events and shifts in the supply-demand balance and global inventory levels, as well as macroeconomic developments, which included the moderation of inflationary trends and the commencement of interest rate decreases by some of the world's central banks. 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, including an escalation in regional tensions which may affect stability in the region, including continuation of the fighting between the U.S. and Israel and Iran, may have a material adverse effect on 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 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 became a buffer zone supervised by the UN and referred to as the "Green Line".

Since 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 a number of resolutions on the dispute over the Occupied Territories throughout the years, and two draft agreements were delivered in 1977 and 1979.

In 1983 the "Turkish Republic of Northern Cyprus" unilaterally declared independence; however Turkey is the only country that recognized 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.

Following the declaration of independence of the Turkish Republic of Northern Cyprus, Turkey is performing natural gas and oil 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 Eastern Mediterranean, which may have a (direct or indirect) effect on 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, in accordance with its official reports, the Government of Turkey is not claiming ownership of the areas in which Block 12 is located.

Furthermore, the dispute in respect of the sovereignty of Morocco over the area referred to as the "Western Sahara" 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 activities in this region.

In addition, the Partnership's activity in the Bulgaria License is conducted in the Black Sea, in proximity to the Crimean Peninsula and under airspace that falls within Russia's sphere of influence, which is exposed to spillover effects arising from the conflict between Russia and Ukraine.

7.30.8 Difficulties in obtaining financing

For the continued development of the Leviathan reservoir Expansion Project, development of additional reservoirs in the future, such as the Aphrodite reservoir, and exploration activities in Israel or overseas (including in the Bulgaria license), insofar as it is decided to perform 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 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 crisis, which is expressed in a reduction of the available credit sources, the tightening of requirements of the finance providers for provision of the financing, and shifts and fluctuations in the interest rates by central banks around the world (including interest rate increases, even if interest rate decreases/reductions are recorded during certain periods), which may affect the Partnership's financial expenses and in exceptional cases, may prevent the ability to raise the financing required.

Likewise, an increase in the requirements of investors and banks, the toughening of financial regulation, geopolitical and security volatility, dependence on regulatory permits and third-party infrastructures, export-customer profile with low credit rating, a debt structure with concentrated repayments, the Partnership's affiliation with the Delek Group and the "Single Borrower" limit, may limit the credit sources and prejudice the Partnership's ability to fund activity, repay existing liabilities and invest in new projects.

7.30.9 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 reservoir 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, until 1 January 2030. 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. As of the Report approval date, arrangements have not yet been determined for separate marketing of the gas produced from the Leviathan reservoir. Separate gas marketing, 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.

7.30.10 Restrictions on export

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 7.24.9 above, limit the quantity of gas that may be exported. Therefore, in the event that a resolution is adopted regarding further restrictions on the quantities of natural gas permitted for export, this may result in significant damage to the Partnership's business.

In the event of a decrease in the natural gas supply capacity of 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 of the Leviathan, Tamar and Karish reservoirs, the Leviathan Partners will be required to supply the demand in the domestic market at the expense of quantities designated for export. In addition, the terms and conditions of the new export approval prescribe provisions whereby the export of natural gas will only be possible subject to the supply of all of the gas quantities nominated by customers in the domestic market and subject to quantitative restrictions after the second expansion date or from the end of 2030, and subject to the Commissioner's authority to order additional restrictions. Accordingly, an increase in the demand in the domestic market and/or supply restrictions of other reservoirs may lead to a reduction of the export volume. For details regarding the export agreements and the new approval, 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.

7.30.11 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 penalties 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 7.30.12 and 7.30.14 below.

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.

7.30.12 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 errors of the operator or a contractor on its behalf, 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.

7.30.13 Lack of sufficient insurance coverage

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 and/or damage to property of the Partnership and/or of a third party during the development and construction period, including due to terrorism, war, cybersecurity, property on which work is conducted, business interruption due to development work 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 suspension of production following receipt of a mandatory regulatory directive, as received by the Leviathan partners in Operations Rising Lion and Roaring Lion. 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 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 infrastructure 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.

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.

7.30.14 <u>Construction risks, dependence on contractors and on professional service and equipment suppliers</u>

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, as a result of 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 also significantly increase the costs. The Partnership's activity, 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 Israel's political and security situation. The price of the services and costs of exploration, development, production and decommissioning operations is determined according to supply and demand in 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 construction and operation of part of the transmission systems in Israel and neighboring countries. For details, see Section 7.30.11 above.

7.30.15 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, geophysical and technical means do not provide a precise picture of the location, form, characteristics or size of geological structures and layers in the subsurface, and therefore may ultimately yield no results, despite substantial investments having been made.

Similarly, reserve estimates are based on production data, drilling results, and partial information, and may change materially over time, potentially affecting forecasts for production, revenues, and the economic viability of the projects.

In addition, estimates relating to exploration, development, and operating activities are based on past experience and general assumptions, and may therefore deviate significantly due to malfunctions or unforeseen events, potentially resulting in substantial budget overruns and delays. In this context, it is also possible that the development of a finding defined as a commercial discovery may ultimately prove not to be economically viable.

7.30.16 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.

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, the Brent price and the exchange rate, which there is no certainty will materialize. For details regarding the main assumptions underlying the Leviathan project cash flows, see the Resources Report for the Leviathan project.

7.30.17 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(c)2 above.

7.30.18 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, on the ability to consummate joint projects, to fund operating activities and to realize undertakings to third parties. Such a situation may lead to delays in development and production, increased costs, legal and contractual risk and impairment of the value and goodwill of the Partnership.

7.30.19 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. Use of the best available technologies (BAT) for the reduction of emissions and current monitoring may enable the Partnership address the need to comply with regulatory requirements and the terms and conditions of the approvals. In this context, activities carried out to reduce leak risks enable the Partnership to address the risk of shutdown of the platform activity due to a severe pollution event or reputational damage.

7.30.20 Regulatory changes

In general, the scope of the regulation that applies to the Partnership's field of business is constantly growing. The tightening of the regulation applicable, *inter alia*, to the 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 the allocation of new petroleum interests, insurance and guaranties, transfer and pledge of petroleum interests, antitrust, the Anti-Concentration Law, control of gas prices, planning regulation, including in the field of environmental protection and environmental and climate regulation, including regulation pertaining to emissions reduction and shift to a low-carbon economy, 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. In addition, changes of regulation and/or policy in countries in which the Partnership operates outside of Israel, including in connection with gas and petroleum assets in Bulgaria, may have an adverse effect on the Partnership's activity, costs, activity timetables and/or their economic feasibility.

Furthermore, a change in the rate of royalties may affect the feasibility of investments, raise the need to open up existing contracts and significantly increase the total fiscal burden alongside corporate tax and windfall profits tax. Likewise, an increase of the concession payments may impair the economic viability of gas and petroleum production in Bulgaria.

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.

7.30.21 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 7.24.3(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. 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 7.24.3(c) above, on 20 August 2025, the supplementary decision of the Competition Commissioner regarding the purchase of EMG shares was received, which includes conditions that will, to a certain extent, 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 7.24.3(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.

In addition, and as specified in Section 7.24.4 above, insofar as the Partnership is classified in the future as a "concentration entity" or a "significant non-financial corporation" under the Anti-Concentration Law, additional regulatory considerations or restrictions may apply in the context of allocation of a "right" (as defined in the Anti-Concentration Law), including in connection with the allocation of rights in the industries listed in the law (including utilities), in a manner that may restrict, delay, or condition the allocation of rights required for the Partnership's operations, and having an adverse effect on its business and its results.

7.30.22 Applicable environmental regulation

The Partnership's activity, performed mainly by the operator of 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 of 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.

The interpretation and enforcement of the environmental laws and regulation change from time to time and may be stricter in the future. In recent years, environmental regulatory requirements have expanded and complying with these and other requirements that may be imposed in the future may mandate additional investments. Furthermore, such requirements in connection with the disassembly and decommissioning of facilities may increase the costs involved therein

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 GP's Board regarding the management of environmental risks, see Section 7.23 above.

7.30.23 Climate change

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 (mitigation, such as decreasing the temperature increase rate) and in terms of contending with the implications of such phenomena (adaptation, such as addressing 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 7.24.11 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 the 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 sequestration 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.

7.30.24 <u>Dependence on weather and sea conditions</u>

The activity in the Partnership's assets 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. In addition, the Partnership may also be exposed to extreme and irregular natural events at sea, which may, in extreme scenarios, cause severe and irreversible structural damage to offshore drilling/production infrastructure and/or full loss of operational capacity for an extended period of time.

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.

7.30.25 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 business, 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 and suppliers also depend on equipment and IT systems, including computers, information systems, and infrastructures. 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, including data leakage, data disruption, and harm to processes in connection with ICS.

In extreme cases, such access may also lead to disruption or cessation of the natural gas supply, or even casualties. Damage to information or data, and to operational continuity, may also cause, either directly or indirectly, business damage and reputational harm to corporations.

The aforesaid is intensified by: (a) the increase in cyber threats in Israel, including threats from various entities, such as state-sponsored entities and criminal elements, which may seek to harm critical national infrastructure, such as the reservoir; (b) changes in labor markets, including the expansion of remote work and remote connections to enterprise networks; and (c) the growing use of AI tools, which may, *inter alia*, facilitate the creation of more sophisticated attacks and malware. All of these factors may increase the potential attack surface as well as the probability of a successful cyberattack on various organizations.

To minimize cyber risks insofar as possible, the Partnership implements cyber risk management and information security principles, and operates in accordance with relevant regulatory directives (insofar as applicable), including directives of the Privacy Protection Authority for the effective management of information security and cyber defense at the Partnership. It is the Partnership's understanding that with respect to the operational aspect of the Leviathan platform and the facilities for the production and transmission of natural gas and condensate from the Leviathan reservoir, it is the operator that is responsible for the operation of the facilities and the actual implementation of directives of the relevant authorities regarding operational IT systems, including the Israel National Cyber Directorate at the Ministry of Energy, in its capacity as critical national infrastructure.

The Partnership has established an information security and cyber defense policy (the "**Defense Policy**"), which is approved once a year by the Partnership's relevant organs, defines the key objectives of the Partnership and its position with respect to aspects of information security and cyber defense. 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 who 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 for cyber and information security events, 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 the natural gas supply or casualties, as specified above.

7.30.26 Changes in investment trends due to ESG (Environment, Social, Governance) 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; thereafter, in June 2023, Banking Directive 345 was released, which will take effect in June 2026, and which requires banks to incorporate climate risks in risk management and credit provision; 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 September 2024 it released the lateral audit findings report on this subject, including the ISA Staff Papers on climate and environmental disclosures in annual reports; 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 consider addressing ESG aspects when making investments. 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 the years 2024-2025.

7.30.27 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.

7.30.28 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 early termination of export agreements, or physical damage to the Leviathan Project that is not fully and immediately repairable, or the occurrence of 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.

7.30.29 Dependence on customers

The Partnership is exposed to risks that are beyond its control regarding the financial strength of its customers and their ability to fulfill their undertakings under the gas supply agreements.

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.

7.30.30 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[153].

Insofar as the Partnership's 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

[153] For details, see Footnote 73 above.

supply agreement to other customers, this will have a material adverse effect on the Partnership's revenues and on its financial results. Furthermore, in extreme scenarios, unilateral decisions and/or other events that are beyond the Partnership's control may lead to a significant reduction and/or termination of engagements with more than one material customer within a short period of time and/or at the same time, which may intensify the potential harm to the Partnership's revenues and cash flow.

7.30.31 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).

In addition, the operator's activity in areas such as environmental protection, safety and security may have a material effect on the Partnership, even though it is not directly responsible for the operation of the reservoir.

7.30.32 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.

7.30.33 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.

7.30.34 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 potential overflow of the Aphrodite reservoir into the area of the Ishai lease and the negotiations taking place for a financial arrangement, see Section 7.3 above.

7.30.35 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 said security risks. The activity of NewMed Balkan in the Bulgaria license is carried out in an area adjacent to the Crimean Peninsula's airspace, which may be exposed to the effects of the Russia-Ukraine war. For further details with respect to security risk factors regarding the Swords of Iron War and the security situation, 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.

7.30.36 Fluctuations in the dollar exchange rate

In 2025, volatility was recorded in the ILS/dollar exchange rate, including depreciation of the dollar against the ILS. 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, changes in the ILS/dollar exchange rate may affect the Partnership's revenues in an amount which is dependent, *inter alia*, on the linkage mechanisms in the gas sale agreements and on the extent of the effect of the exchange rate on the Electricity Production Tariff; 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.

7.30.37 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, the Partnership's belonging to Delek Group may affect the examination of the applicability of the provisions of the Anti-Concentration Law and market-wide anti-concentration considerations in the context of the allocation of rights, as specified in Section 7.24.4 above and the risk factor 7.30.21 above.

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 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.

7.30.38 Launch of activity as operator

The Partnership commenced operations as an operator in the Morocco license, whether itself or through third party contractors. This activity constitutes the launch of a new operating segment which involves significant operating risks related to safety, environmental protection and security, as well as risks associated with exploration, development, production and decommissioning of deep water oil and gas assets. Such risks include leaks, loss of well control, uncontrolled outbursts of liquids and gas, combustion or explosions, malfunctions in the production and transmission systems, and other events which may impair the proper functioning of the production facilities. The occurrence of such events may lead to a reduction or total discontinuation of gas production and supply, timetable delays, budget overruns, harm to the quality of hydrocarbons produced and exposure to penalties, breach of agreements and even termination of existing gas sale contracts.

* * *

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 GP, 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 and the security situation	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		X	
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	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
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	

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	Degree of Risk Factor's Effect on Partnership's Business		
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	
Launch of operations as operator			X

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, 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, condensate 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).

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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.
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 of the production wells and the connecting pipelines array. In the Yam Tethys 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 Leviathan project, the term refers to the processed natural gas stream, *before* removal of liquids (e.g., water and MEG)
Seismic survey	A sensing method 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 using 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 Leviathan project, 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 Leviathan project, 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:

MMCF	BCF	BCM
35,314.7	35.3147	1

BCM	MMCF	BCF
0.0283	1000	1

BCM	BCF	MMCF
0.00003	0.001	1

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)

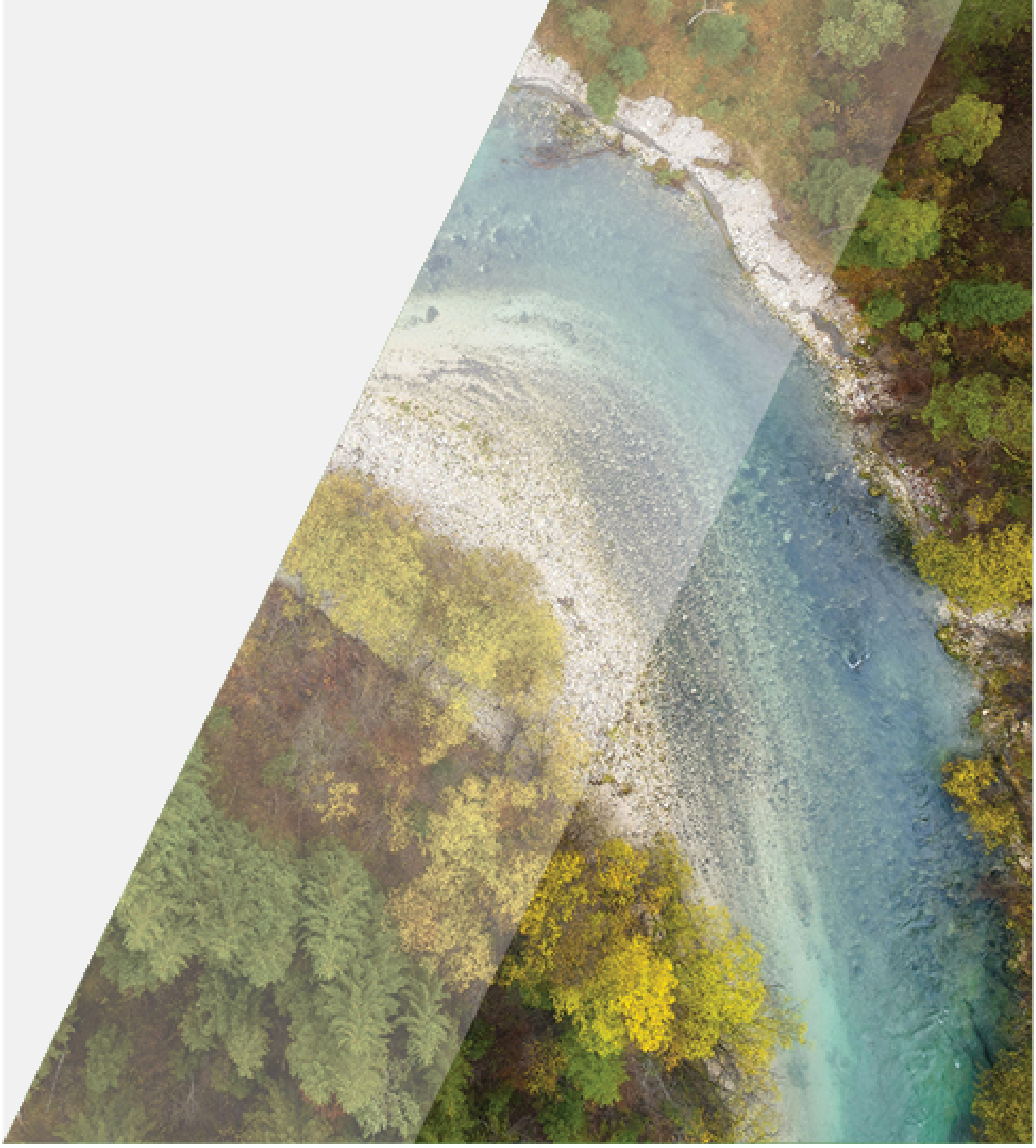
Geological ages and periods, appearing in the report

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

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.

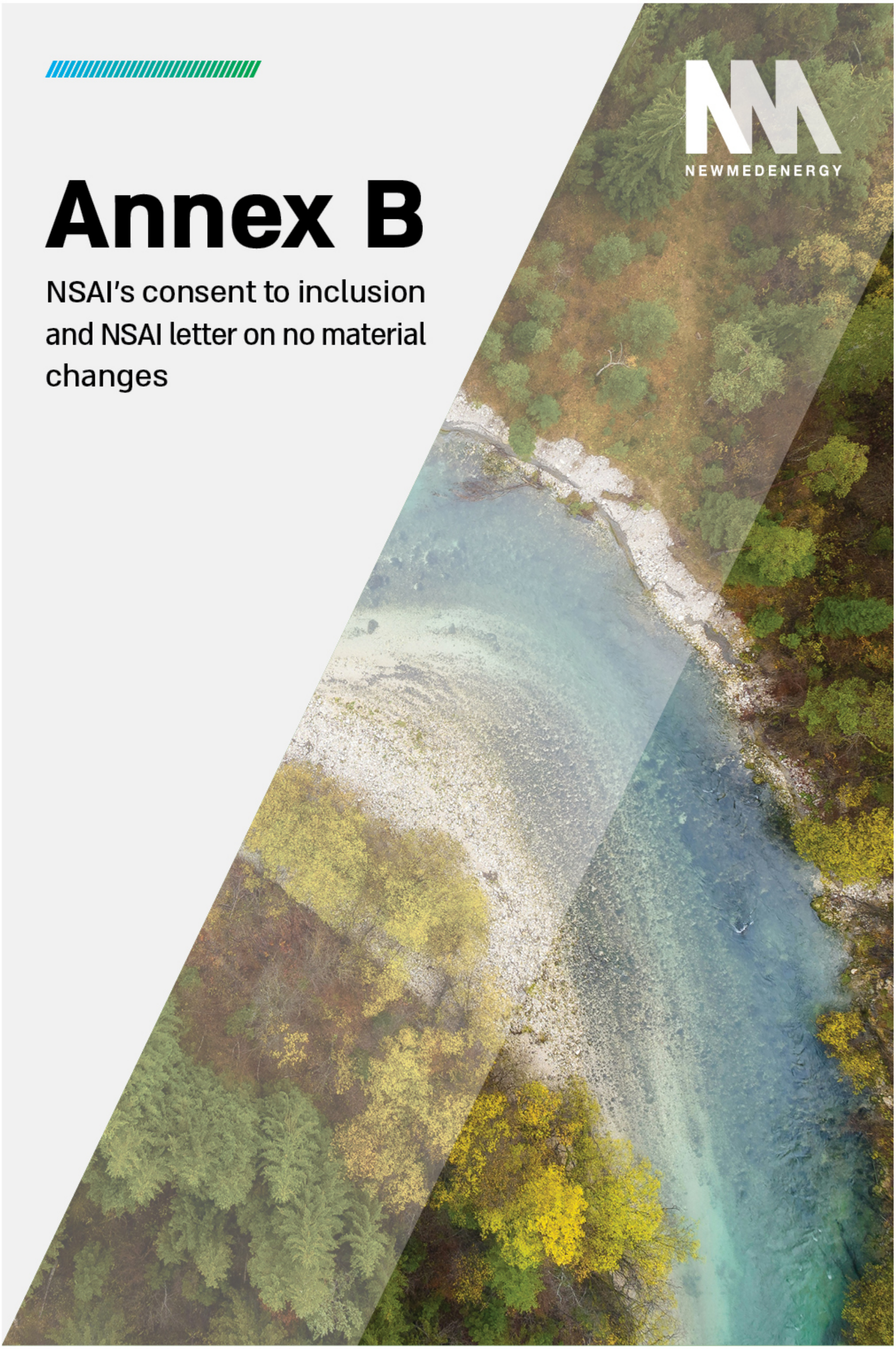
Risk and Reward	3.3	Risk and reward associated with oil and gas production activities are attributed primarily from the variation in revenues cause by technical and economic risks. The exposure to risk in conjunction with entitlement rights is required to support an entity's resources recognition. Technical 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.

Annex B

NSAI's consent to inclusion and NSAI letter on no material changes



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

March 15, 2026

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 2025 Annual Report of NewMed to be published in March 2026 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, 2026, which sets forth our estimates of the unrisked contingent and prospective resources, as of February 28, 2026, to the NewMed working interest in discoveries and prospects located in the Aphrodite Field Area, Block 12, offshore Cyprus.
- The report dated January 16, 2026, which sets forth our estimates of the proved, probable, and possible reserves and future revenue, as of December 31, 2025, to the NewMed interest in certain gas properties located in Leviathan Field, Leases I/14 and I/15, offshore Israel. The January 16 report also sets forth our estimates of the contingent resources, as of December 31, 2025, to the NewMed working interest in these properties.
- The report dated June 10, 2025, which sets forth our estimates of the unrisked prospective gas resources, as of May 31, 2025, to the NewMed working interest in certain Krum prospects located in Block 1-21 Han Asparuh, offshore Bulgaria.
- 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.

Since our January 16 report, we have received daily well production data for Leviathan Field through March 10, 2026; it is our understanding that production from the field has been suspended since February 28, 2026. The daily well production data has been reviewed by NSAI. It is our opinion that, with the exception of the near-term impact of the suspension, there are no material changes to the production profile for each reserves category or the reserves and contingent resources referenced in our January 16 report.

As of the date hereof, nothing has come to our attention regarding the Aphrodite Field Area, the Krum prospects, and the Leviathan Deep prospects that could cause us to make any revisions in our March 9, 2026; June 10, 2025; and March 9, 2025, 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 contingent and prospective resources referenced in our March 9, 2026, report; the unrisked prospective gas resources referenced in our June 10, 2025, report; and the unrisked prospective resources in our March 9, 2025, report.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.

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

JRC:MDK

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.

15 March 2026

NewMed Energy – Limited Partnership (the "Partnership") Report of the Board of Directors of the General Partner for the Year Ended 31 December 2025

The board of directors of NewMed Energy Management Ltd. (the "**Board**" and the "**GP**", respectively) hereby respectfully submits the Board's report for the year ended 31 December 2025 (the "**Report Year**").

Part One – Explanations of the Board on the State of the Partnership's Business

1. Key information from the Description of the General Development of the Corporation's Business

For a description of the Partnership's business and the developments that occurred in the Report Year – see the Description of the General Development of the Corporation's Business (Chapter A). It is clarified that the Description of the General Development of the Corporation's Business, its fields of activity, its main assets, the operating environment and the material events which affected its activity in the Report Year, as detailed in this Board's report, are consistent with the statements in Chapter A of the periodic report. The statements in the Board's report are not intended to add to or derogate from the statements in Chapter A, but rather to supplement them from a management perspective and in accordance with the requirements of the law.

2. Results of operations

A. General

NewMed Energy – Limited Partnership is a publicly traded limited partnership, which primarily engages in exploration, development, production and marketing of natural gas, condensate and oil in Israel. Over the years the Partnership's activities have expanded to Cyprus, Morocco, and Bulgaria. In addition, the Partnership is promoting various natural gas-based projects with the aim of increasing the volume of sales of the natural gas produced by the Partnership. In parallel, the Partnership is examining business opportunities for exploration, development, production and marketing of natural gas, condensate and oil in other countries, and is also considering and promoting possible investments in renewable energy projects in the context of the collaboration with Enlight Renewable Energy Ltd.[1] Furthermore, the Partnership is 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.[2]

In 2025, the Partnership operated in accordance with its business strategy, focusing on the exploration, development, production, and marketing of natural gas, condensate and oil, primarily through the Leviathan reservoir which continued to serve as the Partnership's core asset, supplying natural gas and condensate to both domestic and export markets. The Partnership's activities throughout the year were characterized by operational and financial stability, despite the impact of the security situation, as provided below, which led to isolated delays in specific

[1] For details regarding the collaboration with Enlight, see Section 7.10 of the Description of the General Development of the Corporation's Business (Chapter A).

[2] For details regarding potential projects for hydrogen production, see Section 7.28 of the Description of the General Development of the Corporation's Business (Chapter A).

infrastructure projects and suspensions of production, without a material effect on its ongoing operations. Concurrently, the Partnership continued to advance strategic initiatives, including the advancement of the first stage of the project for expansion of the Leviathan reservoir, a Final Investment Decision for which was adopted on 15 January 2026, the continued promotion of the planning and consideration of the Aphrodite reservoir in Cyprus, in accordance with the agreements governing Block 12 and the project's stage as of the report date, and progress in exploration activities in Bulgaria and Morocco, as well as evaluating investments in renewable energy and natural gas-based energy solutions. For details on the Partnership's goals and long-term operational strategy, see Section 7.28 of the Description of the General Development of the Corporation's Business (Chapter A).

In 2025, the average price of a Brent oil barrel declined versus 2024, a trend which affected the average sale price of natural gas and condensate, as some of the contracts are linked to the price of oil. This effect was expressed in a decline in the average price per MMBTU, as detailed below.

In Q2/2025, with the commencement of the military operation Rising Lion on 13 June 2025, the operator in the Leviathan project, Chevron Mediterranean Limited ("**Chevron**"), received an instruction from the Minister of Energy and Infrastructure (the "**Minister**"), whereby following the security situation it is required to suspend activity on the Leviathan platform, and accordingly natural gas and condensate production from the Leviathan reservoir was suspended. To the best of the Partnership's knowledge, similar instructions were given regarding cessation of activity on the Karish platform (in which the Partnership holds a right to receive royalties from production). Upon the end of the operation on 24 June 2026, a notice was received from the Petroleum Commissioner at the Ministry of Energy and Infrastructure, whereby all preparations may be carried out for the recommissioning of the Leviathan platform, which resumed regular production on 25 June 2025.

The suspension of production during this period led to a loss of revenue (gross, pre-royalties) from the sale of natural gas and condensate and to a loss of revenue from overriding royalties from the Karish lease in a total amount of approx. $33 million, and to a decrease in net profit of approx. $20 million, alongside a certain decrease in transmission, operating and depreciation expenses during the period thereof. With the exception of the aforesaid, the operation did not have a material impact on the Partnership's business in 2025.

Furthermore, for about 11 days in Q2/2025, scheduled work was performed as part of the third pipeline project for the transport of gas from the wells to the Leviathan reservoir (the "**Third Pipeline Project**"). For details regarding the Third Pipeline Project, see Section 7.2.5(b)(1) of the Description of the General Development of the Corporation's Business (Chapter A), which was completed on 1 March 2026, combined with ongoing maintenance work, during which natural gas production from the Leviathan reservoir was suspended.

On 4 February 2026, the Partnership announced that, in its estimation, the exploration well performed in the Vinekh prospect, located in the exploration license in Block 1-21 Han Asparuh in the EEZ of the Republic of Bulgaria in the Black Sea (the "**Bulgaria License**"), revealed insignificant signs of natural gas and therefore, the Partnership estimates it is a dry hole. Total drilling expenses, including past expenses in which the Partnership participated, plugging and abandonment costs, are estimated at approx. €86 million (approx. $103 million on a 100% basis), while the Partnership's share through NewMed Energy Balkan Limited (a subsidiary of the Partnership) totals approx. $76.4 million. Accordingly, the Partnership recognized a loss in its consolidated financial statements for 2025 in respect of the full amount of the said costs, which was recorded under the 'depreciation depletion and amortization' item. For further details regarding the Bulgaria License and the activity therein, see Section 7.8 of the Description of the General Development of the Corporation's Business (Chapter A).

On 28 February 2026, following the commencement of Operation Roaring Lion, the operator in the Leviathan project received an instruction from the Minister of Energy, whereby, pursuant to a security recommendation provided to him, it is required to suspend operations at the Leviathan platform until notified otherwise. The Minister's notice specified that, in accordance with security requirements, the Petroleum Commissioner may issue additional instructions regarding the platform's operations. Accordingly, natural gas and condensate production from the Leviathan reservoir was suspended. On 28 February 2026, the Petroleum Commissioner notified the Leviathan partners that, in view of the developments and the special situation on the home front, Chevron must prepare for a variable operational policy for the platform. This policy may include, *inter alia*, directives for temporary production shutdowns, based on periodic situational assessments and ongoing updates from the security forces. According to the gas sale agreements, the Leviathan partners issued notices to customers regarding the invocation of the *'Force Majeure'* clause in relation to such production suspension. For further details, see the Partnership's immediate report as of 1 March 2026 (Ref. 26-01-018843), the information in which is incorporated herein by reference. To the best of the Partnership's knowledge, similar instructions were given with regard to the cessation of the Karish platform's operation.

As of the report approval date, the Operator of the Leviathan Project has not yet received an update from the Minister of Energy on the date of resumption of production from the reservoir. According to the Partnership's initial assessment, the suspension of production until the date of approval of the Report (16 days of non-production) and the apparent delay in completion of the Combined Section project are not expected to have a material aggregate impact on the total value of the Partnership's discounted cash flow from the Leviathan project. However, a positive aggregate impact is expected on the projected cash flow for 2026, *inter alia*, given an updated Brent forecast[3], relative to the Partnership's discounted cash flow figures as of 31 December 2025, as released by the Partnership on 16 January 2026.

The Partnership's comprehensive income in 2025 totaled approx. $344.2 million, compared with approx. $524.6 million last year, representing a decrease of approx. 34.39%. The decrease in the comprehensive income mainly derived from an increase in depreciation, depletion and amortization expenses resulting from the depreciation of the costs for the Vinekh well as aforesaid, from a decrease in net revenues from the sale of natural gas and condensate, resulting from the decrease in gas quantities due to the gas production suspensions as aforesaid, from the decrease in the average price per thermal unit (MMBTU), which mainly resulted from the decrease in the Brent barrel price (as stated below), as well as from a decrease in the financial income which was partially offset by a decrease in the costs of natural gas and condensate production, in financial expenses and in income tax expenses.

The Partnership's comprehensive income in Q4/2025 totaled approx. $18.3 million, compared with approx. $119.5 million in the same quarter last year, representing a decrease of approx. 84.69%. The decrease in income mainly derived from the increase in depreciation, depletion and amortization expenses resulting from the depreciation of the costs for the Vinekh well as aforesaid, a decrease in revenues from natural gas and condensate sales, which resulted from the decrease in the average price per thermal unit (MMBTU) as aforesaid, and an expense in respect of discontinued operations as detailed below, which was offset mainly by a decrease in financial expenses, net.

[3] Several entities are working to update the Brent forecast for the remainder of 2026, including the EIA (U.S. Energy Information Administration), which updated the Brent price forecast for 2026 to approx. $79, versus $58 before the outbreak of the War (link).

B. Analysis of statements of comprehensive income

Below are key figures with regard to the Partnership's statements of comprehensive income ($ in millions):

	1-3/25	4-6/25	7-9/25	10-12/25	2025	10-12/24	2024
Revenues							
From natural gas and condensate sales	287.6	191.7	279.0	254.4	1,012.7	264.2	1,136.3
Net of royalties	42.0	27.7	40.1	36.3	146.1	37.5	163.2
Revenues, net	**245.6**	**164.0**	**238.9**	**218.1**	**866.6**	**226.7**	**973.1**
Expenses and costs:							
Cost of natural gas and condensate production	37.8	29.0	43.2	39.7	149.7	40.5	168.4
Depreciation, depletion and amortization expenses	22.6	16.6	28.8	103.5	171.5	16.8	80.7
Other direct expenses	3.1	2.8	2.9	3.0	11.8	2.4	5.9
G&A expenses	3.2	5.5	5.2	3.7	17.6	3.7	16.9
Total expenses and costs	**66.7**	**53.9**	**80.1**	**149.9**	**350.6**	**63.4**	**271.9**
The Partnership's share in the profits (losses) of entities accounted for at equity	(0.7)	(0.8)	(0.6)	(1.5)	(3.6)	0.5	2.9
Operating income	**178.2**	**109.3**	**158.2**	**66.7**	**512.4**	**163.8**	**704.1**
Financial expenses	(31.9)	(22.6)	(17.5)	(18.8)	(90.8)	(27.4)	(113.8)
Financial income	6.2	11.8	23.8	16.1	57.9	15.5	90.9
Financial income (expenses), net	(25.7)	(10.8)	6.3	(2.7)	(32.9)	(11.9)	(22.9)
Profit before taxes on the income	**152.5**	**98.5**	**164.5**	**64.0**	**479.5**	**151.9**	**681.2**
Taxes on the income	(36.1)	(17.3)	(36.0)	(32.1)	(121.5)	(32.1)	(156.6)
Income from continuing operations	**116.4**	**81.2**	**128.5**	**31.9**	**358.0**	**119.8**	**524.6**
Income (loss) from discontinued operations	-	-	-	(15.0)	(15.0)	(0.3)	*)
Net income	**116.4**	**81.2**	**128.5**	**16.9**	**343.0**	**119.5**	**524.6**
Other comprehensive income (loss) (after tax effect):							
Amounts that shall be or are reclassified to profit or loss upon fulfillment of specific conditions:							
Adjustments from translation of foreign business financial statements	-	(0.2)	*)	1.4	1.2	-	-
Other comprehensive income (loss)	-	**(0.2)**	*)	**1.4**	**1.2**	-	-
Total comprehensive income	**116.4**	**81.0**	**128.5**	**18.3**	**344.2**	**119.5**	**524.6**

*) Profit (loss) lower than $0.1 million

Net revenues totaled approx. $866.6 million in the Report Year, compared with approx. $973.1 million last year, representing a decrease of approx. 10.94%. The decrease in net revenues mainly derived from a decrease in natural gas quantities produced and sold from the Leviathan reservoir from approx. 11.20 BCM (100%) last year to approx. 10.89 BCM (100%) in the Report Year, and from a decrease in the average price per thermal unit (MMBTU) from approx. $6.12 per MMBTU in 2024 to approx. $5.58 per MMBTU in 2025.

The decrease in gas quantities sold from the Leviathan reservoir occurred in Q2/2025 and resulted from the production suspension both due to Operation Rising Lion, as aforesaid, and for the performance of scheduled work and work in the context of the Third Pipeline Project as aforesaid. The decrease in the average price per thermal unit resulted from the decrease in the price per Brent oil barrel, to which some of the natural gas sales contracts are linked.

The aforesaid decrease in net revenues was partially offset by an increase in condensate sales, approx. 857 thousand barrels of condensate in the sum of approx. $45.2 million (100%) (the Partnership's share in gross revenues – approx. $20.5 million) in the Report Year, compared with approx. 561 thousand barrels of condensate in the sum of approx. $37.0 million (100%) (the Partnership's share in gross revenues – approx. $16.8 million) last year. It is noted that the aforesaid increase in the sale of condensate was partially offset by a decrease in the price per condensate barrel, which is linked to the price per Brent oil barrel.

Net revenues in Q4/2025 totaled approx. $218.1 million, compared with approx. $226.7 million in the same period last year, representing a decrease of approx. 3.79%. The decrease mainly derived from a decrease in the average price per thermal unit (MMBTU) from approx. $5.82 in Q4/2024 to approx. $5.41 in Q4/2025, which mainly resulted from the decrease in the price per Brent oil barrel, to which some of the natural gas sales contracts are linked. The decrease was partially offset by an increase in natural gas quantities produced and sold from the Leviathan reservoir from approx. 2.73 BCM in Q4/2024 (100%) to approx. 2.82 BCM in Q4/2025 (100%) and also by an increase in condensate sales, approx. 212 thousand barrels of condensate in the sum of approx. $10.4 million (100%) (the Partnership's share in gross revenues – approx. $4.7 million) in Q4/2025, compared with approx. 136 thousand barrels of condensate in the sum of approx. $8.4 million (100%) (the Partnership's share in gross revenues – approx. $3.8 million) in the same quarter last year. It is noted that such increase in the sale of condensate was partially offset by a decrease in the condensate barrel price, which is linked to the price per Brent oil barrel.

The table below specifies the gas quantities (100%) sold from the Leviathan reservoir in the Report Year and in 2024, referring to the customers' geographic location and the average sale price per thermal unit (MMBTU):

2025***					
	(BCM)*				$**
	Israel	Jordan	Egypt	Total	Average Price**
Q1	0.4	0.8	1.7	2.9	**5.85**
Q2	0.2	0.5	1.3	2.0	**5.63**
Q3	0.5	0.8	1.8	3.1	**5.43**
Q4	0.6	0.8	1.4	2.8	**5.41**
Total/Average annual price	**1.8**	**2.9**	**6.2**	**10.9**	**5.58**

* 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.

*** The amounts in the table may not add up due to rounding-off differentials

	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**

* 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.

*** The amounts in the table may not add up due to rounding-off differentials

Cost of natural gas and condensate production in the Report Year totaled Cost of natural gas and condensate production totaled approx. $149.7 million in the Report Year, compared with approx. $168.4 million last year, representing a decrease of approx. 11.10%, and mainly includes management and operation expenses of the Leviathan project, which include, *inter alia*, haulage and transport expenses, salaries, professional consulting, maintenance, environment, guarding and security, insurance and the cost of natural gas transmission to Egypt. The decrease year over year mainly derived from a decrease in the costs of natural gas transmission to Egypt, resulting, *inter alia*, from a decrease in the transmission tariff paid to INGL for transmitting gas to Egypt and as a result of the arbitration agreement in connection with the transmission agreement as stated in Note 12J8 to the Financial Statements (Chapter C) below.

Cost of natural gas and condensate production in Q4/2025 totaled approx. $39.7 million, compared with approx. $40.5 million in the same quarter last year.

Depreciation, depletion and amortization expenses totaled approx. $171.5 million in the Report Year, compared with approx. $80.7 million last year, representing an increase of approx. 112.51%. The increase mainly derives from the depreciation of costs, in the Report Year, in the sum of approx. $76.4 million in respect of the Vinekh well in Bulgaria which was found to be dry, as provided in Section A above, from an update to the abandonment obligation in the Yam Tethys project relative to the same period last year, as well as an increase in depreciation, depletion and amortization expenses for the Leviathan project, driven by an increase in the depreciation and depletion asset base, which was offset by a decrease in the depletion rate due to lower natural gas production volumes in the Report Year relative to the same period last year, as well as from an update to the gas reserves report following the adoption of an investment decision in the first phase of the expansion project of the Leviathan reservoir (for details see Note 7C1F to the Financial Statements (Chapter C) below).

Depreciation, depletion and amortization expenses in Q4/2025 totaled approx. $103.5 million, compared with approx. $16.8 million in the same quarter last year. The increase mainly derived from the reasons stated above.

Other direct expenses totaled approx. $11.8 million in the Report Year, compared with approx. $5.9 million last year, representing an increase of approx. 100%. The expenses include, *inter alia*, geologists, engineers and consulting expenses as well as G&A expenses of various projects which are not at the production stage, including in the field of renewable energy. The increase in the said expenses mainly derived from an increase in expenses in respect of the projects in Morocco and Bulgaria.

Other direct expenses in Q4/2025 totaled approx. $3.0 million, compared with approx. $2.4 million in the same quarter last year. The increase in the said expenses mainly derived from the aforesaid.

G&A expenses totaled approx. $17.6 million in the Report Year, compared with approx. $16.9 million last year, representing an increase of approx. 4.14%. G&A expenses include, *inter alia*, salary expenses, professional services and D&O insurance. The increase in expenses mainly derived from an increase in salaries and professional services costs, which was offset by a decrease in other expenses and D&O insurance expenses.

G&A expenses in Q4/2025 totaled approx. $3.7 million, similar to the same quarter last year.

The Partnership's share in the profits (losses) of entities accounted for at equity totaled a loss of approx. $3.6 million in the Report Year, compared with a profit of approx. $2.9 million last year, mainly derived from 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 loss in the Report Year mainly derived from amortization of the excess cost of the investment in EMED BV which was partially offset by the profits from natural gas transmission in the EMG pipeline.

The Partnership's share in the profits (losses) of entities accounted for at equity in Q4/2025 totaled a loss of approx. $1.5 million, compared with a profit of approx. $0.5 million in the same quarter last year. The loss derived from the reasons stated above.

Financial expenses totaled approx. $90.8 million in the Report Year, compared with approx. $113.8 million last year, representing a decrease of approx. 20.21%. Financial expenses in the Report Year mainly derived from interest on the Leviathan Bond bonds, which were issued by Leviathan Bond Ltd., a wholly owned subsidiary of the Partnership, in the sum of approx. $91.7 million (last year: approx. $113.0 million). Furthermore, the Partnership recorded interest expenses in respect of loans and credit facilities from banking corporations in the sum of approx. $12.6 million (last year: approx. $1.7 million). Conversely, the Partnership capitalized financial expenses for eligible assets in the sum of approx. $20.8 million (last year: approx. $6.3 million). The decrease in financial expenses mainly derived from the repayment of the second series (6/2025) of the Leviathan Bond bonds during Q2 of the year, and from the implementation of the Buyback Plan as specified in Section 3E below, as well as from an increase in expenses which were capitalized to qualifying assets mainly for natural gas transmission projects to Egypt and for the Third Pipeline Project.

Financial expenses in Q4/2025 totaled approx. $18.8 million, compared with approx. $27.4 million in the same quarter last year, representing a decrease of approx. 31.39%. The decrease in financial expenses mainly derived from the reasons stated above.

Financial income totaled approx. $57.9 million in the Report Year, compared with approx. $90.9 million last year, representing a decrease of approx. 36.30%. The decrease in financial income mainly derives from a decrease in revenues from revaluation of royalties based on future production from the Karish and Tanin leases from the sum of approx. $60.9 million last year to a sum of approx. 25.8 million in the Report Year (for further details, see Note 8B to the Financial Statements (Chapter C) below). In addition, the Report Year included the recording of interest income from deposits and from exchange rate differences in the sum of approx. $25.5 million, compared with approx. $22.3 million last year.

Financial income in Q4/2025 totaled approx. $16.1 million, compared with approx. $15.5 million in the same quarter last year.

Taxes on income totaled approx. $121.5 million in the Report Year, compared with approx. $156.6 million last year, representing a decrease of approx. 22.41%. The decrease mainly derived from the decrease in profit before tax in the Report Year compared with last year, and as a result of a decrease in the $/ILS exchange rate which brought about a decrease in temporary differences mainly with respect to oil and gas assets whose tax basis is in ILS. The decrease was partially offset, primarily by the non-recognition of deferred taxes in respect of tax losses in subsidiaries in Bulgaria and Morocco.

Taxes on income in Q4/2025 totaled an expense in the sum of approx. $32.1 million, similar to the same quarter last year. The expense remained unchanged compared to the previous year, despite the decrease in pre-tax profit, primarily due to the aforesaid reasons regarding the tax losses in Bulgaria and Morocco.

Income (loss) from discontinued operations totaled a loss in the Report Year in the sum of approx. $15 million, compared with a profit in an amount lower than approx. $0.1 million last year. The source of the discontinued operations is the Partnership's holdings in the Tamar project, which were sold in December 2021. The loss in the Report Year mainly derived from a provision for the payment of an oil and gas profit levy in the Tamar project in respect of an arrangement for the years 2013-2021, and from an update to the provision for payment of royalties to the State of Israel and overriding royalties in the Tamar project in respect of an arrangement for the years 2019-2020. For further details, see Notes 7C9 and 15B to the Financial Statements (Chapter C) below.

Loss from discontinued operations in Q4/2025 totaled a loss in the sum of approx. $15 million, compared with a loss in the sum of approx. $0.3 million in the same quarter last year. The increase in the loss derives from the reasons stated above.

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 2025, compared with the statement of financial position as of 31 December 2024, are specified below:

Total assets as of 31 December 2025 totaled approx. $3,965.8 million, compared with approx. $3,992.3 million as of 31 December 2024.

Current assets as of 31 December 2025 totaled approx. $468.2 million, compared with approx. $734.1 million as of 31 December 2024, as specified below:

(1) **Cash and cash equivalents** as of 31 December 2025 totaled approx. $107.7 million, compared with approx. $51.2 million as of 31 December 2024. The revenues mainly derived from receipt of loans from banking corporations (as stated in Section 3C below), from repayment of the Leviathan Bond bonds (which were purchased as part of a buyback plan (see Section 3E below), net income from the sale of natural gas and condensate from the Leviathan project, a refund of income tax advances for previous years, and from income from Energean in respect of production-based royalties from the Karish lease. Conversely, the Partnership made payments in the Report Year, mainly in connection with profit distributions to the participation unitholders, buyback and redemption of Leviathan Bond bonds, payments for investments in projects, and income tax advances.

(2) **Short-term deposits** as of 31 December 2025 totaled approx. $49.8 million, compared with approx. $333.3 million as of 31 December 2024, and primarily include deposits in connection with the Leviathan Bond Bonds in the sum of approx. $49.6 million, compared with approx. $333.1 million as of 31 December 2024. The decrease in the short-term deposits balance mainly derived from use of deposits for redemption of the Series 2025 Leviathan Bond bonds in May and June 2025.

(3) **Trade receivables** as of 31 December 2025 totaled approx. $181.5 million, compared with approx. $209.6 million as of 31 December 2024. The decrease mainly derived from a change in the sales mix to customers during Q4/2025 compared with the same quarter last year and from a decrease in the average natural gas price sold to Egypt and Jordan compared with the average price last year, following the decrease in the Brent barrel price as aforesaid.

(4) **Other receivables** as of 31 December 2025 totaled approx. $125.3 million, compared with approx. $140.0 million as of 31 December 2024. The decrease mainly derives from a decrease in the balance of short-term future production-based royalties from the Karish and Tanin leases, which was mainly offset by an increase in other receivables balances in the context of joint ventures.

(5) **Income taxes receivable** as of 31 December 2025 totaled approx. $3.9 million (last year: 0) and primarily include the advances paid by the Partnership to Income Tax, net of the estimated tax payment for the Partnership's taxable income.

Non-current assets as of 31 December 2025 totaled approx. $3,497.6 million, compared with approx. $3,258.2 million on 31 December 2024, as specified below:

(1) **Investments in oil and gas assets** as of 31 December 2025 totaled approx. $2,848.3 million, compared with approx. $2,682.3 million as of 31 December 2024. The movement in the Report Year derived mainly from investments in the Leviathan project in a total sum of approx. $205.8 million, in the project in Bulgaria of approx. $98.8 million, and in the Block 12 project in Cyprus of approx. $13.8 million; conversely, the Partnership recorded depreciation, depletion and amortization expenses in the Leviathan project in the sum of approx. $75.5

million and also wrote-off the expenses invested in respect of the Vinekh well in Bulgaria in the sum of approx. $76.4 million as provided in Section A above.

(2) **Investment in entities accounted for at equity** as of 31 December 2025 totaled approx. $59.0 million, compared with approx. $61.7 million as of 31 December 2024, and is in respect of investment in shares of EMED BV and in Enlight NewMed Development Limited Partnership. The decrease mainly derived from the recording of a loss in respect of the Partnership's share in these entities, which was offset by an investment of approx. $0.9 million in Enlight NewMed Development Limited Partnership.

(3) **Long-term deposits** as of 31 December 2025 totaled approx. $0.8 million, compared with approx. $0.5 million as of 31 December 2024, and mainly derive from deposit-backed guarantees.

(4) **Other long-term assets** as of 31 December 2025 totaled approx. $589.5 million, compared with approx. $513.7 million as of 31 December 2024. The increase mainly derived from the Partnership's investments in infrastructures and pipelines for export to Jordan and Egypt, as well as from an update to future-production based royalties from the Karish and Tanin leases. The increase was mainly offset by a decrease in amounts receivable from a company accounted for at equity and a decrease in advances in respect of the oil and gas profit levy in the Tamar project.

Current liabilities as of 31 December 2025 totaled approx. $201.8 million, compared with approx. $603.0 million as of 31 December 2024, as specified below:

(1) **@Current maturities of bonds** as of 31 December 2024 totaled approx. $485.6 million and included the Series 2025 Leviathan Bond Bonds, net of issue expenses and net of bonds which were purchased in the context of a buyback plan (for details, see Sections C6 and E below); the aforesaid Series 2025 Leviathan Bond bonds were fully redeemed during May and June 2025.

(2) **Income taxes payable** as of 31 December 2024 totaled approx. $10.8 million as of 31 December 2024. These primarily include an estimate of income tax payable in respect of the Partnership's taxable income in 2024, net of the advances paid by the Partnership to the tax authorities in respect of this year.

(3) **Trade and other payables** as of 31 December 2025 totaled approx. $201.8 million, compared with approx. $106.6 million as of 31 December 2024. The increase mainly derived from an increase in the payables balances in the context of the joint ventures, including a provision for a burdensome contract for the completion of the Vinekh well in Bulgaria in the sum of approx. $30.8 million which was declared a dry hole as provided in Section A above.

Non-current liabilities as of 31 December 2025 totaled approx. $1,872.4 million, compared with approx. $1,602.0 million as of 31 December 2024, as specified below:

(1) **Bonds** as of 31 December 2025 totaled approx. $1,117.3 million and include the Leviathan Bond bonds (net of issue expenses) (for details see Part Five below), compared with approx. $1,140.0 million as of 31 December 2024. The decrease mainly derives from the performance of a buyback plan as stated in Section 3E below.

(2) **Long-term loan from a banking corporation** as of 31 December 2025 totaled approx. $275 million. For details see Section C2 below and Notes 10A and 10D to the Financial Statements (Chapter C) attached below.

(3) **Deferred taxes** as of 31 December 2025 totaled approx. $396.7 million, compared with approx. $391.5 million as of 31 December 2024. 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, which was partially offset as a result of the effect of the decrease in the exchange rate.

(4) **Other long-term liabilities** as of 31 December 2025 totaled approx. $83.4 million, compared with approx. $70.5 million as of 31 December 2024. The increase mainly derived from an update to the oil and gas asset retirement obligation in the Leviathan and Yam Tethys projects, as a result of a decrease in the cap rate used to estimate the liabilities.

The capital of the Partnership as of 31 December 2025 totaled approx. $1,891.6 million, compared with approx. $1,787.3 million as of 31 December 2024. The change in capital mainly derived from comprehensive income recorded in the Report Year in the sum of approx. $344.2 million, which was partially offset by profit distributions in the Report Year in the sum of approx. $240.3 million. In the Report Year, the Partnership recorded for the first time an expense in the statement of comprehensive income against non-controlling interests in the sum of approx. $0.2 million, in accordance with the mechanism of the equity grant given to Mr. Yossi Abu, the Partnership's CEO. For further details see Note 20C6 to the Financial Statements (Chapter C) below.

B. Cash flow

(1) Cash flows generated by the Partnership from operating activities in the Report Year totaled approx. $505.4 million, compared with approx. $577.5 million last year. The decrease mainly derived from a decrease in the Partnership's net profit, in view of the decrease in revenues from sales of natural gas and condensate. Such decrease was partially offset by an increase in non-cash flow adjustments, mainly an increase in depreciation, depletion and amortization expenses, and from certain positive changes in working capital, including a decrease in the trade receivables balance.

(2) Cash flows generated from investing activities totaled in the Report Year approx. $27.9 million, compared with cash flows used for investing activities in the sum of approx. $114.2 million last year. Net cash flows from investing activities in the Report Year mainly derived from the withdrawal of funds from short-term deposits during the Report Year and were offset mainly by an increase in the flow used for investment in oil and gas assets and other long-term assets.

(3) Cash flows used for financing activities totaled in the Report Year approx. $476.8 million, compared with approx. $441.2 million last year. Cash flows in the Report Year were mainly used for profit distribution to the holders of the participation units in the sum of approx. $240.3 million, for buyback and for redemption of Leviathan Bond bonds in the sum of approx. $511.5 million; conversely, net cash flows in the sum of approx. $275 million were generated for the Partnership in respect of the receipt of loans from banking corporations. Last year, cash flows were mainly used for profit distribution in the sum of approx. $250 million to the holders of the participation units, for buyback of Leviathan Bond bonds for the sum of approx. $113.8 million and for redemption of loan of approx. $80 million which the Partnership took in 2023 from the credit facility provided to it by a banking corporation.

C. Financing

(1) On 8 October 2024, the Partnership signed agreements for the provision of credit facilities from two Israeli banks ("**Bank A**" and "**Bank B**") in the amount of $200 million from each of them (hereinafter in this section: the "**Lenders**" and the "**Credit Facilities**", respectively). One of the said Credit Facilities replaced a credit facility from the same bank, in the amount of $100 million which was provided to the Partnership on 14 March 2024. The Credit Facilities are intended to be used by the Partnership in its operating activities, including in connection with the first phase of the expansion project of the Leviathan reservoir. In accordance with the terms of the Credit Facilities, the Partnership was able, during a period which commenced on 8 October 2024 and ended on 8 October 2025 (in this section: the "**Availability Period**"), to draw down from time to time loans in US Dollars, up to a total amount of $200 million from each of the Lenders (in this section: the "**Loans**"). The Loans that will be drawn as aforesaid will be partially repaid by 15 April 2027 and the balance thereof by 15 October 2027. On 16 June 2025, the Partnership drew down a total of approx. $100 million from one of the said Credit Facilities,

which was fully repaid on 21 July 2025.
On 5 October 2025, an amendment to the credit facility agreement was signed between the Partnership and one of the Lenders, which extended the Availability Period until 10 November 2025. On 9 November 2025, the Partnership and Bank A signed another amendment to the credit facility documents, which extended the Availability Period until 10 November 2026. In addition, an extension was made to the dates of repayment of the Loans to be drawn down during the Availability Period, the annual interest rate was amended, the facility non-utilization fee was amended, the negative pledge clause was amended, and two of the financial covenants the Partnership is required to meet were amended. For further details, see Note 10D to the Financial Statements (Chapter C) below.

(2) On 16 June 2025, the Partnership signed an agreement with Bank B for the provision of two new credit facilities in a total amount of $350 million (hereinafter in this section: the "**Agreement**", the "**Lender**" or the "**Bank**" and the "**Credit Facilities**", respectively). The Credit Facilities replace a credit facility which the Partnership received from the Bank in the amount of $200 million, as stated in Section 1 above. The Credit Facilities are intended to be used by the Partnership in its operating activities, including in connection with the first phase of the expansion project of the Leviathan reservoir.
In accordance with the terms of the Agreement, the Partnership undertook to draw down by 30 June 2025 the full amount of Credit Facility A, in the sum of $275 million (in this section: "**Credit Facility A**"), and it will be entitled to draw down from Credit Facility B, from time to time and until 15 July 2027 (the "**Availability Period**"), up to an additional $75 million (in this section: the "**Credit Facility B**").
The loans that will be utilized from the two Credit Facilities (the "**Loans**") will be repaid in unequal installments: 5% - on 31 December 2027; 10% - on 31 December of each of the years 2028 to 2030 (inclusive); and 65% - on the final maturity date on 30 June 2031 (in this section: the "**Final Maturity Date**").
The Loans will bear interest which shall be paid semi-annually, with the first interest payment occurring on 31 December 2025 and the final payment on the Final Maturity Date. The Loan from Credit Facility A will bear fixed annual interest at a rate of 5.99%. The Loan from Credit Facility B will bear variable annual interest based on Three-Month Term SOFR, plus a margin of 2.35% per annum.
The Partnership paid the Lender, on the date of provision of the Loan from Credit Facility A, a one-time commitment fee in a total sum of $1.3 million. In addition, the Partnership will pay the Lender on each interest payment date a non-utilization fee, on the undrawn portion of Credit Facility B and until the end of the Availability Period, at an annual rate of 0.75%. Under the terms of the Agreement, the Partnership is entitled to reduce Credit Facility B at any time without charge.
On 18 June 2025 the Partnership drew down Credit Facility A in full, and on 10 February 2026, the Partnership drew down Credit Facility B in full. It was agreed that the Loan from Credit Facility B would bear fixed annual interest of 5.55%, in lieu of variable annual interest as detailed above. In the event of prepayment by the Partnership, the Loan will bear a prepayment fee at the rate applicable to Credit Facility A.
For further details see Note 10D to the Financial Statements (Chapter C) below.

(3) On 16 February 2026, the Partnership signed an agreement with Bank Leumi Le-Israel Ltd. for the provision of two new credit facilities in a total amount of $500 million (hereinafter in this section: the "**Date of Signing**", the "**Agreement**", the "**Lender**" or the "**Bank**" and the "**Credit Facilities**", respectively). The Credit Facilities are intended to be used by the Partnership in its operating activities, including in connection with the first phase of the expansion project of the Leviathan reservoir.
In accordance with the terms of the Agreement, the Partnership undertook to draw down by 2 March 2026 the full amount of Credit Facility A, in the sum of $100 million (hereinafter in this section: the "**Credit Facility A**"), and it will be entitled to draw down from Credit Facility B, from time to time and until one year from the Date of Signing (hereinafter in this section: the "**Availability Period**"), up to a total of an additional $400 million (hereinafter in this section: the

"**Credit Facility B**"). On 26 February 2026, the Partnership drew down a sum of $100 million from Credit Facility A.

A loan utilized out of Credit Facility B and repaid during the Availability Period, will be available for repeat withdrawal until the end of the Availability Period.

The loans that will be utilized from the two Credit Facilities (hereinafter in this section: the "**Loans**") will be repaid in non-equal installments: 5% - on 31 December 2028; 10% - on 31 December of each of the years 2029 to 2031 (inclusive); and 65% on 30 June 2032 (hereinafter in this section: the "**Final Maturity Date**").

The Loans will bear interest which shall be paid semi-annually, with the first interest payment occurring on 30 June 2026 and the final payment on the Final Maturity Date. The Loan from Credit Facility A will bear fixed annual interest of 5.65%. The Loan from Credit Facility B will bear variable annual interest based on Six-Month Term SOFR, plus a margin in a range of between 2.3% and 2.4%.

The Partnership paid the Lender, on 2 March 2026, a one-time commitment fee at a rate of 0.37% of the total Credit Facilities. In addition, the Partnership paid the Lender a non-utilization fee on the undrawn portion of Credit Facility B at a rate of 0.35%.

For further details see Note 10D to the Financial Statements (Chapter C) attached below.

(4) Following the Swords of Iron War (the "**War**"), the Leviathan Bond bonds were placed on negative monitoring by the rating agencies Moody's and Fitch. In addition, the rating agency S&P lowered the rating outlook of the bonds to negative. In February 2024, with the lowering of the credit rating of the State of Israel and the banks in Israel by the rating agency Moody's, Moody's updated that after a review process that was carried out with a possibility for a rating downgrade, it decided to affirm the rating of the Leviathan Bond bonds and not to lower it. However, in the shadow of the War, Moody's updated the rating horizon of the Leviathan Bond bonds to negative and also published a reaffirmation of the rating and the horizon in October 2024. In March 2024, the rating agency P&S published a rating reaffirmation report in which it left the rating of the Leviathan Bond bonds unchanged and the rating outlook negative following the risk of expansion of the War. In October 2024, P&S affirmed this rating and outlook. In June 2024, the rating agency Fitch published a rating report in which it left the rating of the Leviathan Bond bonds unchanged and removed the bonds from negative monitoring.

On 10 April 2025, the rating agency Fitch released a rating for the Leviathan Bond Bonds, whereby the rating of the bonds is BB, stable outlook. On 24 June 2025, the company S&P GLOBAL RATING ("S&P") also Standard & Poor's Maalot ("**Maalot**") announced that they had placed the ratings – BB- and ilA+, respectively, of the secured senior debt of Leviathan Bond Ltd. on the watchlist (CreditWatch) with negative implications. On 20 October 2025, S&P and Maalot announced the reaffirmation of the bond rating with a stable outlook and their removal from the watchlists with negative implications.

In addition, it is noted that 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 in respect of raising additional debt as aforesaid.

(5) On 30 June 2025, the rating agency Midroog released an initial issuer rating for the Partnership of A1.il with a stable outlook. For further details see an immediate report of 30 June 2025 (Ref. 2025-01-047055).

(6) On 11 May 2025, the subsidiary, Leviathan Bond Ltd., notified the holders of the bonds it had issued to foreign and Israeli accredited investors, which are listed for trading on the TACT-Institutional system of the Stock Exchange, of the partial early redemption of the second series of the bonds, whose original redemption date occurred on 30 June 2025, in accordance with the provisions of the trust deed for the bonds (the "**Early Redemption Notice**"). In accordance with the Early Redemption Notice, it partially redeemed the second series on 29 May 2025, in the amount of $400 million (the "**Principal Amount**") out of a total series amount of $600 million, in lieu of the original redemption date as aforesaid. The partial early redemption amount included the Principal Amount, plus accrued interest in the sum of approx. $10.1 million. It is noted that in accordance with the terms of the bonds, early redemption during the quarter preceding the original redemption date is not subject to the payment of early redemption fees to the bondholders. It is noted that the remaining bonds were redeemed on the original redemption date as aforesaid.

D. Profit Distributions:

(1) On 9 March 2025, after receiving the recommendation of the GP's financial statements review committee, the GP's Board approved a profit distribution in the sum total of $60 million ($0.05112 per participation unit), with the record date for the distribution being 20 March 2025. The said profit distribution was performed on 3 April 2025.

(2) On 11 May 2025, after receiving the recommendation of the GP's financial statements review committee, the GP's Board approved a profit distribution in the sum total of $60 million ($0.05112 per participation unit), with the record date for the distribution being 21 May 2025, which profit distribution was performed on 5 June 2025.

(3) On 7 August 2025, the GP's Board, after adopting the recommendation of the GP'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 which is 19 August 2025. Such distribution of profit was carried out on 28 August 2025.

(4) On 9 November 2025, the GP's Board, after adopting the recommendation of the GP'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 which is 19 November 2025. Such distribution of profit was performed on 4 December 2025.

(5) On 15 March 2026, the GP's Board, after receiving the recommendation of the GP's Financial Statements Review Committee, approved a profit distribution in the sum total of $70 million ($0.05963 per participation unit). The record date for the distribution is 24 March 2026. The profit distribution will take place on 31 March 2026.

E. Plan for buyback of Leviathan Bond Bonds:

On 15 November 2023, the GP's Board approved the continued performance of buybacks in an aggregate sum of up to $100 million in accordance with the buyback plan of 22 January 2023, and specifically from the bond series maturing on 30 June 2025 and/or the bond series maturing on 30 June 2027. Accordingly, the Partnership performed buybacks of the bonds in the full amount of this plan.

On 15 October 2024, the Board of the Partnership's GP 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 off-exchange acquisition, an acquisition on the TACT-Institutional system on TASE, or by other methods, which entered into effect on 15 October 2024, and will expire at the lapse of two years, namely on 15 October 2026.

On 6 January 2026, the Board of the Partnership's GP approved the adoption of an additional plan for the purchase of the bonds, according to which the Partnership and/or Leviathan Bond may, from time to time, at the discretion of the Partnership's management and in accordance with the details of the additional buyback plan, perform buybacks of the bonds in an aggregate sum of up to $100 million, by way of an off-exchange acquisition, an acquisition on the TACT-Institutional system on TASE, or by other methods, which entered into effect on 6 January 2026 and will expire at the lapse of two years, namely on 6 January 2028.

The financing sources for the performance of the purchases according to the additional buyback plan shall be the internal sources of the Partnership and of Leviathan Bond. It is further noted that, profit or loss as a result of the purchase of the bonds will be taken into account in the calculation of the Partnership's taxable income.

As of the date of the Financial Statements, the Partnership performed buybacks in the sum of approx. $153.8 million par value of the Series 2025 Leviathan Bond bonds, in consideration for approx. $153.6 million. These bonds were redeemed in full during May and June 2025.
Furthermore, by the date of approval of the Financial Statements, the Partnership performed buybacks in the sum of approx. $25.4 million par value of the Series 2027 Leviathan Bond bonds in consideration for approx. $26.1 million and buybacks in the sum of approx. $10.7 million par value in consideration for approx. $11.1 million of the Series 2030 Leviathan Bond bonds. It is noted that, the consideration paid for the bonds includes the interest accrued as of the date of purchase.
For further details regarding the bonds, see Part Four below and Notes 10A and 10B to the Financial Statements (Chapter C) below.

F. **Principal risks and uncertainty in connection with the Partnership's activity**

The Partnership's activity is exposed to various material risks, the materialization of which, in whole or in part, may have a material adverse effect on its results of operations, its financial position and its cash flows. These risks include, *inter alia*, risks resulting from the security and geopolitical situation in the Partnership's areas of operation, including the possibility of damage to infrastructures for the production, transmission and marketing of natural gas and condensate, temporary or prolonged shutdown of facilities, delays in development and infrastructure projects, as well as the imposition of regulatory, operational or other restrictions, including during an emergency. Furthermore, the Partnership's activity involves operational and geological risks, including in connection with exploration and production activity, where there is no certainty that drillings and exploration operations will yield commercial results.
Similarly, the Partnership is exposed to risks resulting from energy price volatility, and specifically from changes in the Brent oil barrel price and in other linkage components included in the gas price formulas, which may affect its revenues and profitability. The Partnership's activity is also affected by demand volumes for natural gas in the domestic market and the export markets, by regulatory, environmental and policy developments, including the promotion of renewable energies and the reduction of emissions, as well as by financing and capital markets risks, including changes in credit ratings, availability of financing sources and financing costs. A full description regarding the risk factors applicable to the Partnership's activity, including additional risks, is provided in Section 7.30 of the Description of the General Development of the Corporation's Business (Chapter A).

G. **The War and the security situation and their potential impact on the Partnership's business**

Further to Section 2A above, since 7 October 2023, Israel has been at war on several fronts against the Hamas terrorist organization, and the Islamic Jihad terrorist organization in the Gaza Strip; the Hezbollah terrorist organization in Lebanon, the Houthi terrorist organization in Yemen, Shia militias in Iraq; the Iranian regime; and against terrorist activity originating from Judea and Samaria. At the same time, in most of 2025, the Israeli economy operated under a routine overshadowed by the war.

On 13 June 2025, the State of Israel declared operation Rising Lion, involving a direct conflict between Israel and Iran. The operation lasted 12 days. In November 2024, the Israeli government approved an agreement for the cessation of hostilities with the Hezbollah terrorist organization in Lebanon, and in October 2025, the Israeli government approved an agreement for the cessation of hostilities in the Gaza Strip and the return of the hostages. On 28 February 2026, a combined offensive was launched by Israel and the U.S., named Roaring Lion, against government targets in Iran, following which a conflict began between Israel and the Hezbollah terrorist organization in Lebanon.

As a result of the War and the security escalation, Moody's downgraded Israel's credit rating in two stages: in February 2024, from A1 to A2, and in September 2024, from A2 to Baa1. As of January 2026, Moody's has left the rating (Baa1) unchanged while updating the rating outlook to stable. S&P Global Ratings downgraded Israel's credit rating in two stages: from AA- to A+ with a negative outlook, and later from A+ to A. In November 2025, the agency affirmed the rating and updated the rating outlook to stable. The rating agency Fitch downgraded the rating in August 2024 from A+ to A (with a negative outlook), and as of the report approval date, the rating remains unchanged.

The War did not have a material impact on the Partnership's business in 2025. However, there was a delay in the timetables for completion of the Third Pipeline Project (as defined in Section 7.2.5(B)1 of the Description of the General Development of the Corporation's Business (Chapter A)), as well as a delay in the timetables and an increase in costs for the INGL project for the laying of a subsea pipeline in the offshore transmission section between Ashdod and Ashkelon (see Section 7.13.2(c) of the Description of the General Development of the Corporation's Business (Chapter A)). As of the report approval date, there is uncertainty as to the development of the current conflict with Iran, including its potential expansion to additional arenas in the Middle East (including the Persian Gulf states) and the possible implications for regional infrastructures and supply chains, including oil and gas production and export infrastructures and shipping routes. Furthermore, there is uncertainty regarding the possible developments of the security situation on the various fronts, and accordingly, it is not possible to estimate what the impact of these developments will be on the Partnerships' operations, and in particular on the continued regular production from the Leviathan and/or Tamar and/or Karish reservoir and on the marketing of gas to the export customers and to the domestic market.

As a result of operation Roaring Lion and military strikes by Israel and the U.S. against targets in Iran, and conversely, military responses by Iran against targets in the Middle East and the Persian Gulf, a sharp increase has been recorded in geopolitical uncertainty and heightened volatility in global energy markets. In particular, a material impact has been recorded on the liquefied natural gas (LNG) market, due, *inter alia*, to extensive disruptions in the regional supply chain, damage to energy infrastructures, and de facto restrictions on navigation through the Strait of Hormuz, a primary transit route for a significant portion of global trade in LNG and crude oil, as well as the shutdown of manufacturing facilities.

At the start of Operation Roaring Lion, INGL gave notice that the foreign contractors carrying out the Combined Section project have left the country. As a result, another delay was caused in completion the project, such that as of the date of approval of the Report, and in the Partnership's estimation, completion of the Combined Section project is expected in Q3/2026.

At this stage, there is uncertainty as to the development of Operation Roaring Lion, its duration and impacts, as well as the date of resumption of production from the Leviathan project. As of the report approval date, and in view of the said developments, it is impossible to predict how the fighting and/or the regional escalation will develop, and in this context whether further disruptions will occur in energy infrastructures and/or shipping routes in the Middle East (including in the Gulf region and the Strait of Hormuz). Accordingly, it is impossible to assess the scope of their potential impact, if any, on global energy prices, including the Brent oil barrel price and/or on the prices of natural gas and/or LNG. Furthermore, it is impossible to predict the impact of the Operation and/or the regional escalation on the Partnership, its assets, and its business, including the possibility of the materialization of risk factors arising therefrom and their potential impact, including the risk factors specified in Section 7.30 of the Description of the General Development of the Corporation's Business (Chapter A), the materialization of which may have a material negative effect on the Partnership, its assets and its business.

The natural gas platforms, the production and transmission facilities at sea and on land, treatment and transmission facilities of natural gas and condensate and other essential infrastructure systems in Israel as well as in the export countries may constitute targets for missile fire and acts of sabotage, and damage to them, if any, may cause extremely significant damage and disrupt or shut down the production and/or transmission activity for a period of time and to an extent which may be significant. In these cases, it is possible that the insurance policies purchased by Chevron and the Partnership will not suffice to cover the damages and losses that will be caused to the Partnership. In the case of escalation, the risk may also increase that the Government will impose restrictions on regular production activity from one of the reservoirs. Restriction or cessation of production from the Tamar and/or Karish reservoirs is expected to require the Leviathan partners to increase the supply quantities to the domestic market mainly at the expense of export to Egypt.

The resumption of fighting may even affect the schedules and costs of various projects promoted by the Partnership, including the Combined Section, the Nitzana pipeline, scheduled surveys in Block I, and the first phase of the expansion project of the Leviathan reservoir.

In addition, in the case of escalation, the geopolitical risk may also increase in connection with natural gas export from the Leviathan reservoir under the export agreements, which constitutes most of the Partnership's revenues.

In addition to the aforesaid, in the event of a significant deterioration in the security situation, which would lead to the premature termination of the export agreements or as a result of which unrepaired physical damage is caused to the Leviathan project or insofar as other events occur which are reasonably expected to cause a material adverse effect, and subject to cure periods, qualifications and conditions, there is a risk of a breach of the terms and conditions of the Leviathan Bond bonds, which are secured by the Partnership's rights in the Leviathan project and traded on the TACT-Institutional system of the Stock Exchange, which may confer on the bondholders a cause for acceleration and enforcement of the pledges. In addition, an increase in the bond returns may adversely affect the Partnership's ability to raise additional debt and increase the financing costs in respect of raising additional debt as aforesaid.

H. **Inflation and interest rate rise and their potential impact on the Partnership's business and the financial disclosure and reporting**

As a result of global macro-economic developments, 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 began to raise interest rates.

It is noted that energy product prices, the interest rate environment, trade wars, 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, and 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 and part of the Partnership's credit facilities 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 10D to the Financial Statements (Chapter C) below, this may also affect the Partnership's financial expenses.

In 2025, there was a moderation in the rate of inflation in Israel and globally, following the sharp increases that characterized previous years. Such trend resulted, *inter alia*, from the stabilization of commodity and energy prices, improvements in supply chains, and a relative slowdown in global economic activity. As a result of the moderation in inflation, central banks including the Bank of Israel and the U.S. Federal Reserve, began a gradual process of lowering interest rates. These measures were intended to support economic growth, ease financing costs, and assist in economic recovery. Nevertheless, volatility in inflation and interest rate levels remains a source of uncertainty, and its impact on the Partnership's operations depends on macroeconomic developments in Israel and worldwide.

The Partnership's assessments regarding the impacts of the suspension of production from the Leviathan project, the War and the security situation, and the inflation and rise of the interest rate constitute forward-looking information, as this term is defined in the Securities Law, and is based on the information available to the Partnership as of this date, the Partnership's agreements with its customers, the prices and quantities of gas sale and additional factors. There is no certainty that the above assessments will materialize, in whole or in part, and they may materialize in a materially different manner due to factors beyond the Partnership's control, including the risk factors specified in Section 7.30 below.

Part Two – Exposure to and Management of Market Risks

Report on exposure to and management of market risks

The statements in this part are intended to expand on and detail the Partnership's exposures to market risks, and are not intended to derogate from the statements in the first part above.

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, the change of the ILS/Dollar exchange rate may have a 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

In natural gas supply agreements, the gas price is determined according to price formulas that include various linkage components, and primarily 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 this regard, it is noted that in the context of the export permit to Egypt of 17 December 2025, the Leviathan partners committed to offer the domestic market several price formulas, including a formula linked to the general TAOZ index.

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. It is noted that 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 the context of the aforesaid export permit, the Leviathan partners committed to offer the domestic market a price formula linked to the electricity production tariff.

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 energy sources, including coal, sources of renewable energy and other substitute products for 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 the markets relevant to the Partnership and impair the Partnership's revenues from the Leviathan reservoir. It is noted that all of the Partnership's long-term agreements include a TOP (Take or Pay) component in which the customer is obligated to consume a minimum annual or quarterly quantity.

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, and including with Bank Leumi le-Israel, for the provision of the credit facilities, it is noted that according to the terms of part 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 first phase of the expansion project of the Leviathan reservoir 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 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 GP, which manages the Partnership, invested the Partnership's available funds in Dollar-denominated financial assets, which mainly include bank deposits (as of the date of the statement of financial position).

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 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 for the long term, 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 handling of exposure to currency and interest risk, formulation of hedging strategies and supervision of the performance thereof is entrusted to the Board of the GP.
The Partnership's investment policy is set forth in the Partnership Agreement. On 20 November 2018, the Board of the GP 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 the Partnership's GP. The committee was established in view of the need for professional and thorough discussions by a special forum (designated by the Board of the GP). 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 the GP. The committee is required to report its recommendations to the Board 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 financial statements, are: Messrs. Eliyahu Zamir (Chairman of the Investment Committee, independent director), Yoram Cohen (external director) and Eran Yaacov (external director).

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".

<u>Description of the parameters, assumptions and models</u>

Parameter	Source/Manner of Treatment
ILS/Dollar exchange rate	Representative rate as of 31 December 2025
Dollar interest	Discount rate/SOFR interest

A. For details regarding an analysis of the sensitivity of the value of royalties 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) below.

B. For details regarding an analysis of the sensitivity of the value of royalties 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) below.

C. For details regarding an analysis of the sensitivity of financial instruments with variable interest see Note 21F2 to the Financial Statements (Chapter C) below.

D. Tests of sensitivity to changes in the Dollar/ILS exchange rate ($ in millions):

Sensitive Instrument	Profit/(Loss) from Changes 10%	5%	Fair value	Profit/(Loss) from Changes -5%	-10%
	3.509	3.35	3.19	3.031	2.871
Cash and cash equivalents	(0.1)	(*)	0.8	*	0.1
Short-term deposits	(*)	(*)	0.2	*	*
Trade and other payables	0.6	0.3	(6.2)	(0.3)	(0.6)
Total	**0.5**	**0.3**	**(5.2)**	**(0.3)**	**(0.5)**

*) Lower than $0.1 million.

7. Report on linkage bases ($ in thousands), as of 31 December 2025:

	Financial Balances			
	In foreign currency	In non-linked ILS	Non-financial balances	Total
Assets				
Cash and cash equivalents	106.9	0.8	-	107.7
Short-term deposits	49.6	0.2	-	49.8
Trade receivables	181.5	-	-	181.5
Other receivables	107.4	-	17.9	125.3
Taxes receivable	-	-	3.9	3.9
Investment in entities accounted for at equity	-	-	59.0	59.0
Investments in oil and gas	-	-	2,848.3	2,848.3
Long-term deposits	0.8	-	-	0.8
Other long-term assets	223.4	-	366.1	589.5
Total assets	**669.6**	**1.0**	**3,295.2**	**3,965.8**
Liabilities				
Trade and other payables	1.8	6.2	193.8	201.8
Bonds	1,117.3	-	-	1,117.3
Long-term loan from a banking corporation	275.0	-	-	275.0
Deferred taxes	-	-	396.7	396.7
Other long-term liabilities	-	-	83.4	83.4
Total liabilities	**1,394.1**	**6.2**	**673.9**	**2,074.2**
Total net balance	**(724.5)**	**(5.2)**	**2,621.3**	**1,891.6**

8. <u>Report on linkage bases ($ in thousands), as of 31 December 2024:</u>

	Financial Balances			
	In non-linked ILS	Non-financial balances	In non-linked ILS	Non-financial balances
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	-	-	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**

Part Three – Corporate Governance Aspects

1. **The Partnership's donation policy**

   In November 2023, the GP's Board 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. In 2025, the Partnership donated approx. ILS 6.2 million, mainly to support the many communities adversely impacted by the War.

2. **Directors having accounting and financial expertise**

   The Board of the GP 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 two. The Board of the GP believes that considering the type of business of the company which, as aforesaid, is the GP 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 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 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 GP, 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 GP's Board (Messrs. Eran Yaacov, Yoram Cohen, Eli Zamir, Tamir Polikar and Yair Neuman). For details regarding the education, experience and qualifications of these directors, see Regulation 26 of Chapter D of this report (Additional Details regarding the Corporation).

3. **Independent directors**

   The Partnership did not adopt a clause in the Trust and Partnership Agreements with regard to the percentage of independent directors, as defined by the Companies Law. As of the report approval date, two external directors and an independent director serve on the GP's Board. For details on the independence of the directors, see Regulation 26 of Chapter D of this Report (Additional Details regarding the Corporation).

4. **Disclosure on the internal auditor at the Partnership**

   A. **Details of the internal auditor**

      (1) Internal auditor's name: Gali Gana, CPA.
      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 GP 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 the GP 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 the GP.

D. The work plan

The internal audit performs audits on different 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 GP'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 the GP 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 the GP on its findings and results.

E. Scope of employment

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 employment at the Partnership and at the GP in the reporting year totaled approx. 600 hours.

The scope of the internal auditor's employment was determined, inter alia, based on the size and complexity of the Partnership's business activity. The GP's management, the audit committee and the Board of the GP 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 the GP 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 the GP.

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 GP'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 GP's Board and discussed at length by the audit committee. Below are dates on which the audit committee discussed the internal auditor's reports: 9 July 2025, 10 February 2026 and 11 March 2026. Additional audit reports under the 2025 work plan will be submitted by the end of Q1/2026.

I. **Board' assessment of the internal auditor's activity**

The Board of the GP 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 GP 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 2025, the Partnership recorded a total annual expense of ILS 159 thousand in respect of the internal audit services. The GP's Board 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:

	Y2025		Y2024	
	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	1,160	915	1,090	555

* Mainly tax advice and market and environmental forecasts

According to the Companies Law, the auditor's fee for the audit work is determined by the general meeting, which has empowered the GP's Board for this purpose. The GP's Board is the organ that authorizes the auditors' fees for the audit work as well as for other services, 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 the GP as aforesaid.

6. <u>The Partnership's policy on negligible transactions</u>

On 11 March 2009, the Board of the GP 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 GP on 14 March 2019 and 17 March 2019, respectively.

The audit committee and Board of the GP (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 the GP 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 ongoing follow-up and supervision of the performance thereof. The first enforcement program was adopted in 2018 and updated in 2022 (based on a compliance survey), and some of its procedures have been updated from time to time (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 in Q1/2026, some of the Enforcement Program's procedures have been updated according to changes in the law since the latest update of the Enforcement Program. 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. ESG

In view of the importance that the Partnership attributes to the Environmental, Social, and Governance ("**ESG**") area, in February 2022 the GP's Board decided 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 this matter within the Partnership. The audit committee appointed an officer within the Partnership, who is in charge, *inter alia*, of managing the risks in this area. The audit committee receives periodic reports from the officer in charge and from the internal auditor of the Partnership, who conducts independent audits on ESG, with a focus on environmental and climate change issues. The most recent audit on this issue was conducted in 2024.

In June 2025, the Partnership launched a sustainability risk assessment in the ESG area in accordance with the ESRS (European Sustainability Reporting Standards) based on the double materiality analysis approach, assisted by BDO Israel and with the support of BDO's offices in the Netherlands and Germany. The assessment included comprehensive interviews with internal (all of the Partnership's departments) and external stakeholders (primarily investors and the Partnership's insurance and legal advisors). The assessment identified 144 impacts, risks, and opportunities (IROs), 31 of which were defined as material. The results of the assessment were presented to the audit committee in February 2026.

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 in the coming months an ESG report for 2024-2025.

Part Four – Disclosure in connection with the Partnership's Financial Reporting

Subsequent events

See Note 22 to the Financial Statements (Chapter C) below.

Part Five – Details of bonds issued by Leviathan Bond Ltd .

Leviathan Bond bond series	2027	2030
Par value on the issue date	600	550
Issue date	18.8.2020	18.8.2020
Par value as of 31.12.2025	600	550
Linked par value as of 31.12.2025	600	550
Value on the partnership's books as of 31.12.2025[4]	572.6	544.7
Tase value as of 30.9.2025[5]	579.2	560.1
Fixed annual interest rate	6.500%	6.750%
Principal payment date	30.6.2027	30.6.2030
Interest payment dates	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 [6]	None	
Conversion right	None	
Right to early redemption or mandatory conversion [7]	Right to early redemption	
Guarantee for payment of the liability	See Note 10B to the Financial Statements (Chapter C) below	
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 [8]	Fitch Rating: BB stable Moody's: Ba3 Stable S&P: BB- Stable Maalot: ilA+ stable	
Rating as of the date of approval of the financial statements[9]	Fitch Rating: BB stable Moody's: Ba3 stable S&P: BB- stable Maalot: ilA+ stable	

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[4] Net of principal and interest in respect of a buyback, see Section 3E of Part One above regarding the bond buyback plan that was adopted by the board.

[5] The market value, net of the value of the bonds that were purchased under a buyback plan. The bonds are traded in Israel on the "TACT-institutional" system on TASE.

[6] The bonds' principal and interest are stated in dollars .

[7] The financing documents prescribe provisions regarding early redemption of the bonds, including (1) early redemption initiated by the issuer, subject to payment of an early redemption 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 a tender offer to all of the bondholders, including upon a sale of all or some of the interests in the Leviathan project.

[8] 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.

[9] See immediate reports of 21 December 2025, 17 December 2025, 20 October 2025, 20 October 2025, 24 June 2025, 24 June 2025, and 10 April 2025 (Ref. no.: 2025-01-101391, 2025-01-100865, 2025-01-078063, 2025-01-078061, 2025-01-044980, 2025-01-044973, and 2025-01-027121, respectively), the information in which is incorporated herein by reference.

Leviathan Bond bond series	2027	2030
Has the company fulfilled, by 31.12.2025 and during the report year, all of the conditions and undertakings under the trust deed	Yes	
Is the bond series material [10]	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) below.	

[10] A series of bond certificates will be deemed material if the total liabilities of the corporation thereunder as of the end of the report period, as presented in the Consolidated Financial Statements, constitute five percent or more of the total liabilities of the corporation.

Additional information

The GP's Board 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.

On 15 March 2026 Mr. Gabi Last gave notice that he was stepping down as Chairman of the GP's Board on 31 March 2026. The GP's Board thanks Mr. Last for his significant contribution to promotion of the Partnership's business and wishes him success in the future, alongside his continued office as a director of the GP's Board.

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) below and to Part Five of the Board's 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)

	31.12.2025 Audited	31.12.2024 Audited
Assets:		
Current Assets:		
Short-term Bank deposits	1	258,039
Loans to shareholders	-	599,611
Related parties	99,555	*
	99,556	857,650
Noncurrent Assets:		
Loans to shareholders	1,148,369	1,148,799
Long-term bank deposits	55	-
	1,148,424	1,148,799
	1,247,980	2,006,449
Liabilities and Equity:		
Current Liabilities:		
Bonds	-	600,000
Related parties	-	158,039
	-	758,039
Noncurrent Liabilities:		
Bonds	1,150,000	1,150,000
Loans from shareholders	100,000	100,000
	1,250,000	1,250,000
Equity (Deficit)	(2,020)	(1,590)
	1,247,980	2,006,449

*** Less than $1,000**

Statements of Comprehensive Income (Expressed in US$ Thousands)

	For the year Ended 31.12.2025 Audited	For the year Ended 31.12.2024 Audited
Financial expenses	100,359	125,079
Financial income	(99,929)	(124,455)
Total comprehensive expenses (income)	430	624

SPONSOR FINANCIAL DATA REPORT[11]

	ITEM	YEAR ENDED 31.12.2025 QUANTITY/ACTUAL AMOUNT (IN USD$,000)
A.	Total Offtake (BCM)	[12]10.9
B.	Leviathan Revenues (100%)	2,233,627[13]
C.	Loss Proceeds, if any, paid to Revenue Account	-
D.	Sponsor Deposits, if any, into Revenue Account	174,500
E.	Gross Revenues (before Royalties)	1,051,390
F.	Overriding Royalties	
	(a) Statutory Royalties	(112,528)
	(b) Third Party Royalties	(45,013)
G.	Net Revenues	893,849
H.	Costs and Expenses:	
	(a) Interest Income (Fees Under the Financing Documents)	3,220
	(b) Taxes	(127,226)
	(c) Operation and Maintenance Expenses	(141,589)
	(d) Capital Expenditures	(236,179)
	(e) Insurance	(20,546)
I.	Total Costs and Expenses (sum of Items H(a), (b), (c), (d) and (e))	(522,320)
J.	Total Cash Flows Available for Debt Service (Item G *minus* Item H)	371,529
K.	Total Cash Flow from operation (Item G minus Items H(c) and H(e)	731,714
L.	Total Debt Service	[14]665,150
M.	Total Distribution to the Sponsor	75,000

[11] 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.

[12] Quantity of Gas sold from January 1st 2025 until December 31st 2025 for 100% of the Leviathan partners on an accrual basis.

[13] Gas & Condensate sales from January 1st 2025 until December 31st 2025 for 100% of the Leviathan partners on an accrual basis.

[14] Including buyback of bonds by the sponsor of approximately 26 Million dollars.

Annex B to the Board of Directors' Report
Summary of Data of a Valuation of Royalties from the Karish and Tanin Leases

Following are details of a 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) 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 2025.
Value of the object of the valuation shortly before the date of the valuation, if GAAP, including depreciation, depletion 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. $251.1 million, which is included under other long-term assets and trade and other receivables of the Partnership.
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:[15]	The valuation was performed by a team headed by Mr. Shalom Sofer, CPA, a partner at Price Waterhouse Coopers Israel and an expert in finance and valuations. Mr. Sofer holds a B.A. in Accounting and Economics with honors, and an M.A. in Economics with honors, both from Tel Aviv University. The valuator has no personal interest in the securities of the Partnership, other than the fee paid to him for this work. The valuator, as concerns the provision of the services, is independent of the Company, including in accordance with Israel Securities Authority Legal Position 105-30 of 22 July 2015. We further note that the Valuator's fee is not contingent on the results of this work. PwC Israel was granted indemnification, except if and insofar as it is conclusively determined that the damages resulted from gross negligence or intentional misconduct on its part, in connection with the said services and/or product. The said indemnification obligation shall apply only with respect to sums in excess of three times the total fee.
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: valuation date until 2045; 2. Average annual natural gas production rate from the Karish and Karish North leases: approx. 2.86 BCM; average annual condensate

[15] As of the Report date, the valuation is carried out by a team led by Mr. Shalom Sofer, CPA, partner in PriceWaterhouseCoopers Israel, in lieu of Mr. Gadi Beeri, Head of the Economic Department and Corporate Finance and senior partner at Giza Singer Even Ltd.

Identification of the object of the valuation:	Royalties in respect of the sale of all of the interests in the Karish and Tanin leases.
	production rate from the Karish lease: approx. 3.86 million barrels; 3. Period of gas production from the Tanin reservoir: 2032 to 2042; 4. Average annual rate of natural gas production from the Tanin lease: approx. 2.36 BCM; average annual rate of condensate production from the Tanin lease: approx. 0.40 million barrels; 5. Cap rate: 9.5%; 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 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. In March 2025, Energean published an updated resources report by 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. 28.3 BCM and the quantity of hydrocarbon liquids is approx. 40.9 MMBBL; in the Karish North reservoir, the gas quantity is approx. 34.5 BCM and the quantity of hydrocarbon liquids is approx. 41.2 MMBBL; and in the Tanin lease, the gas quantity is approx. 26.0 BCM and the quantity of 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, April 2025.
[17] U.S Energy Information Administration: Short-Term Energy Outlook, September 2025.

Part C

Consolidated Financial statements

15 March 2026

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 15 March 2026 on the Partnership’s consolidated financial statements as of 31 December 2025 and for the year then ended.
2. The Auditors’ report of 15 March 2026 on the audit of components of internal control over financial reporting of the Partnership as of 31 December 2025.

Kost Forer Gabbay & Kasierer
Certified Public Accountants

Ziv Haft
Certified Public Accountants

NewMed Energy – Limited Partnership

Consolidated Financial Statements as of 31 December 2025

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 2025

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 2025. 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 2025.
We have also audited, based on Generally Accepted Auditing Standards in Israel, the consolidated financial statements of the Partnership as of 31 December 2025, and for the year then ended, and our report of 15 March 2026 included an unqualified opinion on the aforesaid consolidated financial statements.

Tel Aviv, 15 March 2026

Kost Forer Gabbay & Kasierer	**Ziv Haft**
Certified Public Accountants	**Certified Public Accountants**

Independent Auditors' Report to the Partners of NewMed Energy – Limited Partnership

The Opinion

We have audited the consolidated financial statements of NewMed Energy – Limited Partnership (the "**Partnership**") which include the consolidated statement of financial position as of 31 December 2025 and the consolidated statements of comprehensive income, changes in equity and cash flows for the year then ended, and the notes to the consolidated financial statements, including the Significant Accounting Policies.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of the Partnership as of 31 December 2025 and its consolidated financial results and consolidated cash flows for the year then ended in accordance with International Financial Reporting Standards (IFRS Accounting Standards) and the provisions of the Securities Regulations (Annual Financial Statements), 5770-2010.

Basis for our opinion

We conducted our audit in accordance with generally accepted auditing standards in Israel, including standards prescribed by the Accountants Regulations (Mode of Operation of Accountants), 5733-1973. Our responsibilities under such standards are further described in the Auditor's Responsibilities for the Audit of the Consolidated Financial Statements section of our report. We are independent of the Partnership and its consolidated companies in accordance with the legal provisions applicable in Israel regarding independence and the prevention of conflict of interest of an auditor in Israel. Furthermore, we have fulfilled our other ethical responsibilities in accordance with the Auditors Law, 5715-1955, and the regulations promulgated thereunder. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key audit matters

Key audit matters detailed below are matters that were communicated, or should have been communicated, to the board of directors of the Partnership's general partner, and the Partnership's management 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 consolidated 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 consolidated 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 2025 is $2,848.3 million and the depletion costs for the investments in oil and gas assets for the year ended 31 December 2025 amounts to a total of $71.9 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 2-I 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 2025 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.

Responsibilities of the Board of Directors of the General Partner of the Partnership for the Consolidated Financial Statements

The Board of Directors of the General Partner and the Partnership's management are responsible for the preparation and fair presentation of the consolidated financial statements in accordance with International Financial Reporting Standards (IFRS Accounting Standards) and the provisions of the Securities Regulations (Annual Financial Statements), 5770-2010; and for such internal control as the board of directors of the General Partner of the Partnership determine is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, the Board of Directors of the General Partner of the Partnership are responsible for assessing the Partnership's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the Board of Directors of the General Partner of the Partnership intends to either liquidate or cease the Partnership's operations, or have no realistic alternative but to do so.

The Auditor's responsibilities for the audit of the consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit prepared in accordance with generally accepted auditing standards in Israel will always detect a material misstatement if such exists. Misstatements may arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to impact the economic decisions of users taken on the basis of such consolidated financial statements.

In an audit conducted in accordance with generally accepted auditing standards in Israel, we exercise professional judgment and maintain professional skepticism throughout the audit. In addition, we:

- Identify and assess the risks of material misstatement in the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, deliberate misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances.
- Evaluate the appropriateness of the accounting policies applied and the reasonableness of the accounting estimates and related disclosures made by the Board of Directors of the General Partner of the Partnership.
- Conclude on the appropriateness of the determination by the Board of Directors of the General Partner of the Partnership regarding the use of the going concern assumption and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Partnership's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify the uniform language of our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Partnership to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with the Board of Directors of the General Partner and the management of the Partnership, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that the auditor identifies during the audit.

We also provide the Board of Directors of the General Partner of the Partnership with a statement that we have complied with the relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be considered to bear on our independence, and, where relevant, the safeguards applied to eliminate identified threats to our independence.

From the matters that were communicated, or were required to be communicated, to the Board of Directors of the General Partner of the Partnership, we determined those matters that were of most significance in the audit of the financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditors' report unless law or regulation precludes public disclosure about the matter.

Nexus Paragraph

We have also audited, pursuant to Audit Standard (Israel) 911 of the Institute of Certified Public Accountants in Israel regarding "Audit of Components of Internal Control over Financial Reporting", components of the Partnership's internal control over financial reporting as of 31 December 2025 and our report as of 15 March 2026 included an unqualified opinion on the effective maintenance of such components.

The engagement partners on the audit resulting in this independent auditors' report are Ran Shir-Az and Amir Eitan.

Tel Aviv, 15 March 2026

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	31.12.2025	31.12.2024
Assets:			
Current assets:			
Cash and cash equivalents	3	107.7	51.2
Short-term deposits	4	49.8	333.3
Trade receivables	21G	181.5	209.6
Trade and other receivables	5	125.3	140.0
Income taxes receivable	19	3.9	-
		468.2	**734.1**
Non-current assets:			
Investments in entities accounted for at equity	6	59.0	61.7
Investments in oil and gas assets	7	2,848.3	2,682.3
Long-term deposits	4	0.8	0.5
Other long-term assets	8	589.5	513.7
		3,497.6	**3,258.2**
		3,965.8	**3,992.3**
Liabilities and equity:			
Current liabilities:			
Current maturities of bonds	10B-C	-	485.6
Income taxes payable	19	-	10.8
Trade and other payables	9	201.8	106.6
		201.8	**603.0**
Non-current liabilities:			
Bonds	10B-C	1,117.3	1,140.0
Long-term loan from a banking corporation	10D3	275.0	-
Deferred taxes	19E	396.7	391.5
Other long-term liabilities	11	83.4	70.5
		1,872.4	**1,602.0**
Partnership's equity:	13		
Equity attributable to the holders of the Partnership's participation units			
Partnership's equity		154.8	154.8
Capital reserves		(26.7)	(28.1)
Retained earnings		1,763.3	1,660.6
		1,891.4	**1,787.3**
Non-controlling interests		0.2	-
		1,891.6	**1,787.3**
		3,965.8	**3,992.3**

The attached notes constitute an integral part of the consolidated financial statements.

15 March 2026			
Date of approval of the Financial Statements	Gabi Last Chairman of the Board	Yossi Abu CEO	Tzachi Habusha VP Finance

NewMed Energy – Limited Partnership

Consolidated Statements of Comprehensive Income (Dollars in millions)

	Note	For the year ended		
		31.12.2025	31.12.2024	31.12.2023
Revenues:				
From natural gas and condensate sales	14	1,012.7	1,136.3	1,094.4
Net of royalties	15	146.1	163.2	159.8
Net revenues		**866.6**	**973.1**	**934.6**
Expenses and costs:				
Cost of production of natural gas and condensate	16	149.7	168.4	148.6
Depreciation, depletion and amortization expenses	7,8	171.5	80.7	79.2
Other direct expenses		11.8	5.9	5.3
G&A	17	17.6	16.9	20.8
Total expenses and costs		**350.6**	**271.9**	**253.9**
The Partnership's net share of earnings (losses) of entities accounted for at equity	6	(3.6)	2.9	(1.3)
Operating income		**512.4**	**704.1**	**679.4**
Financial expenses	18	(90.8)	(113.8)	(133.8)
Financial income	18	57.9	90.9	28.7
Net financial expenses		(32.9)	(22.9)	(105.1)
Income before income taxes		**479.5**	**681.2**	**574.3**
Taxes on income	19	(121.5)	(156.6)	(142.8)
Income from continuing operations		**358.0**	**524.6**	**431.5**
Income (loss) from discontinued operations	7C9	(15.0)	*)	2.1
Total net income		**343.0**	**524.6**	**433.6**
Other comprehensive income (after tax effect):				
Amount that will be reclassified or are reclassified to profit or loss upon fulfillment of specific conditions				
Adjustments arising from the translation of financial statements of foreign operations		1.2	-	-
Other comprehensive income		1.2	-	-
Total comprehensive income		**344.2**	**524.6**	**433.6**
Basic and diluted income (loss) per participation unit attributable to the holders of participation units of the Partnership (in Dollars):				
from continuing operations		0.305	0.447	0.368
from discontinued operations		(0.013)	**)	0.001
Income per participation unit		0.292	0.447	0.369
Number of participation units weighted for the basic profit calculation (in thousands)		1,173,815	1,173,815	1,173,815
Number of participation units weighted for the diluted profit calculation (in thousands)		1,175,625	1,174,366	1,173,963

***) Profit lower than $0.1 million**

****) Profit per participation unit lower 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)

	Note	Attributable to holders of participation units of the Partnership						
	Note	Equity of the Partnership	Capital Reserve for Equity-Based Financial Instruments at Fair Value against Other Comprehensive Income	Other Capital Reserves	Retained Earnings	Total	Non-controlling Interests	Total Equity of the Partnership
Balance as of 31 December 2022		154.8	(57.0)	27.1	1,162.5	1,287.4	-	1,287.4
Changes in the year ended 31 Dec. 2023:								
Comprehensive income		-	-	-	433.6	433.6	-	433.6
Profit distributed	13C	-	-	-	(210.6)	(210.6)	-	(210.6)
Advance tax payments receivable for previous years	19A	-	-	-	0.8	0.8	-	0.8
Participation unit-based payment	20C4	-	-	1.3	-	1.3	-	1.3
Balance as of 31 December 2023		154.8	(57.0)	28.4	1,386.3	1,512.5	-	1,512.5
Changes in the year ended 31 Dec. 2024:								
Comprehensive income		-	-	-	524.6	524.6	-	524.6
Profit distributed	13C	-	-	-	(250.3)	(250.3)	-	(250.3)
Participation unit-based payment	20C4	-	-	0.5	-	0.5	-	0.5
Balance as of 31 December 2024		154.8	(57.0)	28.9	1,660.6	1,787.3	-	1,787.3
Changes in the year ended 31 Dec. 2025:								
Net income		-	-	-	343.0	343.0	-	343.0
Other comprehensive income		-	-	1.2	-	1.2	-	1.2
Total comprehensive income		-	-	1.2	343.0	344.2	-	344.2
Profit distributed	13C	-	-	-	(240.3)	(240.3)	-	(240.3)
Participation unit-based payment	20C4	-	-	0.2	-	0.2	0.2	0.4
Balance as of 31 December 2025		154.8	(57.0)	30.3	1,763.3	1,891.4	0.2	1,891.6

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 31.12.2025	31.12.2024	31.12.2023
Cash Flows - Current Operations:			
Net profit	**343.0**	**524.6**	**433.6**
Adjustments for:			
Depreciation, depletion and amortization	174.9	85.2	84.3
Taxes on income	(9.6)	57.8	75.4
Update of asset retirement obligations	4.9	*)	(1.3)
Revaluation of short-term and long-term investments and deposits	(0.4)	(2.6)	(0.1)
Participation unit-based payment (Note 20C4)	0.4	0.5	1.0
Revaluation of other long-term assets	(30.2)	(67.6)	(8.1)
The Partnership's net share of losses (earnings) of entities accounted for at equity	3.6	(2.9)	1.3
Changes in asset and liability items:			
Decrease (increase) in trade receivables	28.1	(15.1)	4.5
Increase in trade and other receivables (including operator of joint ventures)	(16.7)	(1.7)	(3.1)
Decrease (increase) in other long-term assets	(4.6)	(7.5)	19.0
Increase (decrease) in trade and other payables (including operator of joint ventures)	(2.9)	6.8	(29.7)
Increase (decrease) in oil and gas profit levy	14.9	*)	(17.3)
	162.4	**52.9**	**125.9**
Net cash deriving from current operations	**505.4**	**577.5**	**559.5**
Cash Flows - Investment Activity:			
Investment in oil and gas assets	(223.9)	(114.2)	(136.4)
Investment in partnership accounted for at equity	(0.9)	(0.4)	-
Investment in other long-term assets	(89.1)	(31.8)	(13.2)
Royalties based on production from the Karish lease (Note 8B)	52.6	55.0	36.7
Repayment of loan provided to Energean in the context of sale of the Karish and Tanin leases (Note 8B4)	-	47.4	13.3
Net withdrawal of (deposit into) short-term deposits	283.8	(71.7)	238.4
Deposit into long-term deposits	(0.3)	-	(101.4)
Decrease (increase) in other receivables – for operator of the joint ventures	5.7	1.5	(1.3)
Net cash deriving from (used for) investment activity	**27.9**	**(114.2)**	**36.1**
Cash Flows - Financing Activity:			
Receipt of a short-term loan from a banking corporation	100.0	-	80.0
Repayment of a short-term loan from a banking corporation	(100.0)	(80.0)	-
Receipt of a long-term loan from a banking corporation	275.0	-	-
Profit distributed	(240.3)	(250.3)	(260.6)
Taxes on income for the period up to and including 2021 (See Note 20A)	-	2.9	17.1
Repayment of bonds and buybacks of bonds	(511.5)	(113.8)	(425.4)
Net cash used in financing activity	**(476.8)**	**(441.2)**	**(588.9)**
Increase in cash and cash equivalents	56.5	22.1	6.7
Cash and cash equivalents balance at the beginning of the year	51.2	29.1	22.4
Cash and cash equivalents balance at the end of the year	107.7	51.2	29.1
Annex A – Non-cash flow finance and investment activity:			
Net investments in oil and gas assets against liabilities	110.8	59.1	63.0
Investments in other long-term assets against liabilities	11.6	12.7	5.1
Annex B - Additional information on cash flows:			
Interest paid (including capitalized interest)	100.9	108.1	124.9
Interest received	14.4	24.8	17.6
Taxes and levy paid	149.2	94.3	53.1

*) Less than $0.1 million

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 Renewable Energy Ltd. ("**Enlight**") (see Note 12F2 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 12F(1) 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**"), in Block 1-21 Han Asparuh exploration license situated in the exclusive economic zone of the Republic of Bulgaria in the Black Sea (the "**Bulgaria License**") and in other petroleum assets, as specified in Note 7 below.

Note 1 - General (Cont.):

D. The "Swords of Iron" War and the security situation and their impact on the Partnership's business activities:

Since October 7, 2023, Israel has been engaged in a war on several fronts against the Hamas terrorist organization and the Islamic Jihad terrorist organization in the Gaza Strip; the Hezbollah terrorist organization in Lebanon; the Houthi terrorist organization in Yemen; the Shiite militias in Iraq; the regime in Iran; as well as against terrorist activity originating in the Judea and Samaria territories. At the same time, during most of 2025 the Israeli economy operated under a routine in the shadow of the war. In November 2024, the Government of Israel approved an agreement for the cessation of hostilities with the Hezbollah terrorist organization in Lebanon, and in October 2025, the Government of Israel approved an agreement to end the war hostilities in the Gaza Strip and for the return of the hostages.

On 13 June 2025, the State of Israel announced Operation Rising Lion involving a direct confrontation between Israel and Iran. The operation lasted 12 days. With the commencement of Operation Rising Lion on 13 June 2025, the Operator of the Leviathan Project received an instruction from the Minister of Energy that, due to the security situation, it was required to cease the operation of the Leviathan platform until further notice. Accordingly, the production of natural gas and condensate from the Leviathan reservoir was halted. Upon completion of the operation, on 24 June 2025, operation of the Leviathan platform and regular production from the reservoir were resumed on 25 June 2025. To the best of the Partnership's knowledge, similar instructions were issued with respect to the cessation of operations of the Karish platform.

The war did not have a material effect on the Partnership's business in 2025. However, delays occurred in the timetable for the completion of the Third Pipeline Project (as defined in Note 7C1B(2) below), as well as delays in the timetable and an increase in costs in the INGL project for the installation of a subsea pipeline in the offshore transmission segment between Ashdod and Ashkelon (see Note 12D2(a) below).

On 28 February 2026, a combined offensive was launched by Israel and the U.S., named Roaring Lion and Epic Fury, respectively, against government targets in Iran, following which a conflict began on the northern front between Israel and the Hezbollah terrorist organization in Lebanon. With the commencement of operation Roaring Lion on 28 February 2026, the Operator of the Leviathan project received an instruction from the Minister of Energy, whereby in accordance with a security recommendation delivered to him, the Operator is required to suspend the Leviathan platform's operations until further notice. The Minister's notice stated that, in accordance with security requirements, the Petroleum Commissioner may issue additional instructions regarding the platform's activity. Accordingly, the production of natural gas and condensate from the Leviathan reservoir was suspended. On 28 February 2026, the Petroleum Commissioner notified the Leviathan Partners that, in view of developments and the special situation on the home front, Chevron must prepare for a variable operation policy for the platform's activity, which policy may include, *inter alia*, directives for temporary suspensions of production, based on periodic situation assessments and ongoing updates from the security forces. In accordance with the gas sale agreements, the Leviathan Partners issued notices to customers regarding the occurrence of a force majeure event in connection with the said suspension of production. To the best of the Partnership's knowledge, similar instructions were issued in connection with suspension of the Karish platform's operations.

Note 1 - General (Cont.):

D. (Cont.):

At the start of Operation Roaring Lion, INGL gave notice that the foreign contractors carrying out the Combined Section project have left the country. As a result, another delay was caused in completion the project, such that as of the date of approval of the consolidated financial statements, and in the Partnership's estimation, completion of the Combined Section project is expected in Q3/2026.

At this stage, there is uncertainty as to the development of Operation Roaring Lion, its duration and impacts, as well as the date of resumption of production from the Leviathan project. As of the date of approval of the consolidated financial statements, and in view of the said developments, it is impossible to predict how the fighting and/or the regional escalation will develop, and in this context whether further (or prolonged) disruptions will occur in energy infrastructures and/or shipping routes in the Middle East (including in the Gulf region and the Strait of Hormuz). Accordingly, it is impossible to assess the scope of their potential impact, if any, on global energy prices, including the Brent oil barrel price and/or on the prices of natural gas and/or LNG. Furthermore, it is impossible to assess the impact of the Operation and/or the regional escalation on the Partnership, its assets, and its business.

As of the date of approval of the consolidated financial statements, the Operator of the Leviathan Project has not yet received an update from the Minister of Energy on the date of resumption of production from the reservoir. According to the Partnership's initial assessment, suspension of production until the date of approval of the consolidated financial statements (16 days of non-production) and the apparent delay in completion of the Combined Section project are not expected to have a material impact on the Partnership's results of operations, *inter alia*, due to the rise in the Brent oil barrel (see Note 21F3 below).

E. 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 Leviathan and Block 12 reservoirs, which are Chevron Mediterranean Limited ("**Chevron**" or the "**Operator of the Leviathan Project**") and Chevron Cyprus Limited ("**Chevron Cyprus**"), respectively, which are subsidiaries of a wholly-owned subsidiary of Chevron Corporation ("**Chevron Corp**"). The operator of the Bulgaria License is OMV Offshore Bulgaria GmbH ("**OMV Bulgaria**"), a subsidiary of OMV Petrom, which, to the best of the Partnership's knowledge, is a public company traded on the Bucharest Stock Exchange in Romania and is considered the largest energy corporation in Southeast Europe.

Note 1 - General (Cont.):

F. 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. For the purpose of the aforesaid examination, the Partnership discounted the impact of one-time events.

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.

G. As of 31 December 2025, 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**").

Note 1 - General (Cont.):

G. (Cont.):

3) 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.
4) 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.
5) 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**"), see Section 9 below, and 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%.
6) 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.
7) NewMed Energy UK Limited is an SPC ("**NewMed Morocco**") incorporated in England and wholly owned by the Partnership, and 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.
8) NewMed Energy Balkan Limited is an SPC ("**NewMed Balkan**") incorporated in England and which holds 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 and whose shares are held as follows: the Partnership – 95%, Mr. Yossi Abu, CEO of the Partnership ("**Mr. Abu**") – 5%. For further details, see Notes 7C6 and 20C6 below.
9) Enlight-NewMed Development (UK) Ltd. is an SPC ("**MedLight**") incorporated in England as part of the collaboration with Enlight, as specified in Note 12F2 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%).

Note 1 - General (Cont.):

G. (Cont.):

10) 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%.
11) EMED BV and Enlight corporation are treated in the consolidated financial statements as associates, i.e., in accordance with the equity method.

[1] An Egyptian government-owned company.

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.

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 and investments in associates 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.
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.

Note 2 - Significant Accounting Policies (Cont.):

C. Joint ventures (Cont.):

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.

<u>The Partnership measures debt instruments at amortized cost where:</u>

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.

Note 2 - Significant Accounting Policies (Cont.):

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 consolidated financial statements:

1) **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 J below).

2) **Asset retirement obligation:**
An asset retirement obligation was recorded on the Partnership's books. See Section H below regarding costs in respect of asset retirement obligations.

3) **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.

4) **Onerous contract**:
A provision for an onerous contract is recognized when the benefits expected to be received by the Partnership from the contract are lower than the unavoidable costs of meeting the contractual obligations. The provision is measured at the lower of the present value of the expected cost of terminating the contract and the present value of the expected net cost of continuing to fulfill the contract. During the period of the consolidated financial statements, the Partnership recognized a provision for an onerous contract in respect of the unavoidable costs of the Vinekh well in the Bulgaria License, which was found to be a Dry Hole. For further details, see Note 7C6C.

Note 2 - Significant Accounting Policies (Cont.):

G. 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 consolidated 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 H 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 I below).
7) A Farm-In is the acquisition of a portion of the interests in an oil and/or gas license in consideration for the agreement of the purchaser (the "**Farmee**") to bear specific costs that would otherwise have been borne by the seller (the "**Farmor**") (see Note 7C6 below). In transactions of this type, where the acquired asset does not constitute a business, the accounting treatment is as follows:
   Upon incurrence of the costs, the Farmee recognizes an expense and/or asset, as applicable, for its share in the oil and gas assets and for the interests that remain with the Farmor, consistently with its accounting policy for treatment of exploration and evaluation assets. The Farmee reports the arrangement as follows:
   a. The Farmee recognizes its share of the costs in accordance with the farm-in agreement, including costs arising from the portion that the Farmor has imposed on the Farmee under the farm-in agreement.

Note 2 - Significant Accounting Policies (Cont.):

G. Expenses of oil and gas exploration, development of proved reservoirs and investment in oil and gas assets: (Cont.):
7) (Cont.)

b. The Farmee recognizes costs under the farm-in agreement in the same manner in which it accounts for exploration and evaluation costs that it incurs directly.

H. 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 G5 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 "**other long-term liabilities**" item), see Note 11B below, and the asset balance after amortization (under the "**investments in oil and gas assets**" item), see Note 7A below.

I. 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, the recoverable amount is determined in relation to transactions made recently in assets with a similar character and location to the subject of the assessment.

J. Oil and gas profit levy:
The Partnership includes, in its consolidated 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.

Note 2 - Significant Accounting Policies (Cont.):

K. 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. 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 G5 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 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 due to resource valuation and the estimate of cap rates, considering the assessment of risks which include, *inter alia*, the liquidity risk, credit risk and volatility, may affect the fair value of this asset.

Note 2 - Significant Accounting Policies (Cont.):

K. Critical accounting estimates and judgements (Cont.):

Taxes on income – Deferred tax assets and liabilities are calculated in respect of temporary differences between the amounts of the assets and liabilities included in the financial statements and the amounts taken into account for tax purposes. The calculation of the deferred and current taxes 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.

L. 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.

M. Equity instrument-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.):

M. Equity instrument-based payment (Cont.):

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**").

N. Taxes on income:

Starting from tax year 2022, a change took place in the tax regime that applies to the Partnership, such that it is taxed as a company (see Note 19A below). Accordingly, the consolidated financial statements include current income tax expenses starting from 2022. 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 equity attributable to the holders of the Partnership's participation units.

O. 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.

P. Disclosure on new standards in the period preceding their application:

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.

Notes to the Consolidated Financial Statements as of 31 December 2025 (Dollars in millions)

Note 2 – Significant Accounting Policies (Cont.):

P. Disclosure on new standards in the period preceding their application (Cont.):

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 and financing category, 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 31.12.2025	31.12.2025	31.12.2024
In dollars:	%		
Cash in banks		7.3	8.6
Deposits in banks	4.6	99.3	40.2
		106.6	**48.8**
In foreign currency:			
Cash in banks		0.4	2.1
Deposits in banks	1.3-3.8	0.7	0.3
		1.1	**2.4**
Total		**107.7**	**51.2**

Notes to the Consolidated Financial Statements as of 31 December 2025 (Dollars in millions)

Note 4 – Short-Term and Long-Term Deposits[2]:

Composition:

	Interest rate as of	31.12.2025	31.12.2024
Under current assets:	%		
in dollars	3.4	49.6	333.1
in foreign currency	3.5	0.2	0.2
		49.8	**333.3**
Under non-current assets:			
in dollars		0.5	0.5
in foreign currency	3.2	0.3	-
		0.8	**0.5**

Note 5 – Trade and Other Receivables:

Composition:

	31.12.2025	31.12.2024
Trade and other receivables in the context of joint ventures	53.6	39.8
Receivables from a company accounted for at equity (see Note 21G3 below)	16.3	17.6
Royalties based on future production from the Karish and Tanin leases (see Note 8B below)	37.1	69.9
The Ministry of Energy in respect of royalties (see Note 15 below)	0.7	5.7
Institutions	9.6	-
Prepaid expenses and other receivables	8.0	7.0
Total	**125.3**	**140.0**

Note 6 – Investment in Entities Accounted for at Equity:

Composition:

	31.12.2025	31.12.2024
Investment in EMED BV (see Note 1G4 above)	58.2	61.5
Investment in the Enlight Corporation (see Note 1G8 above)	0.8	0.2
	59.0	**61.7**

[2] For pledges and guarantees, see Notes 10B and 12E.

Notes to the Consolidated Financial Statements as of 31 December 2025 (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 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**
Changes in the course of 2025:			
Investments	81.7	209.0	290.7
Write-offs	(46.0)[4]	(7.9)	(53.9)
Balance as of 31 December 2025	**196.9**	**3,367.4**	**3,564.3**
Accumulated depreciation[5]			
Balance as of 31 December 2023	**-**	**575.6**	**575.6**
Changes in the course of 2024:			
Depreciation and amortization[6]	-	69.7	69.7
Write-offs	-	(0.1)	(0.1)
Balance as of 31 December 2024	**-**	**645.2**	**645.2**
Changes in the course of 2025:			
Depreciation and amortization[8]	-	71.9	71.9
Write-offs	-	(1.1)	(1.1)
Balance as of 31 December 2025	**-**	**716.0**	**716.0**
Amortized cost as of 31 December 2024	**161.2**	**2,521.1**	**2,682.3**
Amortized cost as of 31 December 2025	**196.9**	**2,651.4**	**2,848.3**

[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. $33.4 million (31 December 2024: approx. $29.1 million).

[4] For details regarding the write-off of the investments in the Vinekh-1 well in the Bulgaria License, see Note 7C6(c) below. Such write-off does not include the costs of the onerous contract for the Vinekh well, see Note 2F4 above.

[5] In 2025, the Leviathan project depletion rate was approx. 2.4% (2024: 2.6%).

[6] In 2025, 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. $3.1 million recorded directly in the statement of comprehensive income under the 'depletion, depreciation and amortization' item (2024: approx. $6 million).

Notes to the Consolidated Financial Statements as of 31 December 2025 (Dollars in millions)

Note 7 – Investments in Oil and Gas Assets (Cont.):

A. Composition (Cont.):

2. Composition by joint venture:

	31.12.2025	31.12.2024
Oil and gas assets:		
Ratio-Yam joint venture (Section C1)	2,651.4	2,521.1
Exploration and appraisal assets:		
Block 12 Cyprus (Section C2)	174.5	161.2
Block 1-21 Han Asparuh in Bulgaria (Section C6)	22.4	-
Total exploration and appraisal assets:	**196.9**	**161.2**
Total	**2,848.3**	**2,682.3**

B. Details with respect to the Partnership's rights in oil and gas assets and in exploration and appraisal assets (as of 31 December 2025):

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. In the matter of pledges registered on some of the oil and gas assets, see Note 10B.

	Type of Right	Name of Right	Right Valid Through	Partnership's Share
Ratio-Yam	Lease[7]	I/15 Leviathan North	13.2.2044	45.34%
Ratio-Yam	Lease[8]	I/14 Leviathan South	13.2.2044	45.34%
Yam Tethys	Lease[8]	I/10 Ashkelon	10.6.2032	48.5%
Yam Tethys	Lease[8]	I/7 Noa	31.1.2030	48.5%
Block 12 in Cyprus	Production and utilization license	Block 12	7.11.2044	30%
Block 1-21 Han Asparuh	Exploration license	Han Asparuh	18.10.2026[8]	50%[9]
Morocco	Exploration license	Boujdour Atlantique	31.1.2026[10]	37.5%

[7] The lease deeds in Israel were granted subject to the Petroleum Law and grant the partners in the leases an exclusive right to produce oil and natural gas in the lease areas for a period of 30 years, with the right to extend the same for an additional 20 years, in accordance with and subject to the provisions of the Petroleum Law.

[8] To the best of the Partnership's knowledge, from a legal standpoint, there is no possibility for further extension of the license over and above its current expiration date in October 2026, as stated. It is clarified that the license expiration date is the final date by which exploration drilling may be conducted in the block area. However, in the event of a discovery in the license area, it may be extended for an additional year, i.e., until October 2027, for purposes of evaluation of the discovery.

[9] For details regarding the sale of rights in the Bulgaria License, see Note 7C6(b) below.

[10] The agreements grant 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 (i.e., 31 January 2026); 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:

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**").

b) Leviathan reservoir development plan:

1) 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 approx. 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 was 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 were installed. Gas is 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 is 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. Furthermore, the Development Plan includes the construction of a temporary 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 12D1 below.

2) **The Development Plan is implementable in full or in two main phases, according to the maturity of the relevant markets, as specified below:**

Phase 1A – The current stage, in which 5 subsea production wells were drilled (4 wells at beginning of production and another well in 2023), 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 approx. 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 2025 (including investments in the Third Pipeline project), is approx. $4.4 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 approx. 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.):**

b) (Cont.)

2) (Cont.)

During 2025 and throughout Q1/2026, ongoing maintenance work was carried out at the Leviathan reservoir, including planned works for the completion of the Third Pipeline project, during which natural gas production from the Leviathan reservoir was reduced and even suspended. On 1 March 2026, Chevron notified the Leviathan Partners that the Third Pipeline project had been completed. As of the date of approval of the consolidated financial statements, the total cost of the Third Pipeline project is approx. $480 million (100%, the Partnership's share – approx. $217 million).

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 updates in connection with the implementation of 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 (the "**Expansion Project**").

According to the Updated Leviathan Reservoir Development Plan, the Expansion Project may be implemented in full or in stages, as follows:

a) First stage – consists of drilling and completion of 3 additional production wells, adding supplementary subsea systems and expanding the processing systems on the platform, in order to increase the system's total gas production capacity up to approx. 21 BCM per annum (the "**First Stage of the Expansion Project**").

b) Second stage – consists of receipt of regulatory approvals and the making of additional investments, including investments in laying down a fourth pipeline between the field and the platform (the "**Fourth Pipeline**"), and installation of additional subsea systems in order to increase the maximum daily production capacity up to a total quantity of approx. 23 BCM per annum (the "**Second Stage of the Expansion Project**").

On 21 August 2025 the Commissioner approved the Updated Development Plan for performance of the Expansion Project. The Commissioner's said approval was granted in consideration of several conditions, primarily the delivery and presentation of further technical information to the Ministry of Energy, whose fulfillment shall be made in coordination with and under the guidance of the professional staff at the Ministry of Energy's Natural Resources Administration. In his approval, the Commissioner noted that in order to increase the pace of production beyond 2,100 MMSCFD, upon performance of the Second Stage of the Expansion Project, filing of supporting documents will be required, in accordance with the guidance of the professional staff at the Ministry of Energy's Natural Resources Administration, which shall constitute an update to the Updated Development Plan, and approval thereof by the Commissioner.

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) 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. 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. After the signing of an amendment to the export agreement between the Leviathan Partners and Blue Ocean on 7 August 2025, as detailed in Note 12C3B below, the Leviathan Partners applied to the Commissioner for an export approval. On 17 December 2025 the Leviathan Partners received the Commissioner's approval to export the additional quantities under the Amendment to the Export to Egypt Agreement (as defined in Note 12C3(c) below, in this section: the "**New Approval**"). In the Partnership's estimation, the New Approval enables compliance with the provisions of the Amendment to the Export to Egypt Agreement, including the supply of the additional quantities to Blue Ocean. The New Approval was granted in addition to the export approval granted to the leaseholders on 16 December 2019, and provides that it supersedes any conflicting provision in any other document, including the Amendment to the Export to Egypt Agreement.

d) In the context of promotion of the Expansion Project, the Leviathan Partners approved, in 2024, in accordance with the joint operating agreement (JOA), budgets in the sum total of approx. $504 million (100%, the Partnership's share – approx. $228.5 million), for performance of the FEED, which include, *inter alia*, advance procurement of long lead items.

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) On 15 January 2026, the Leviathan Partners made a final investment decision (FID) for the development of the first stage of the Expansion Project, intended to increase the total gas production capacity of the Leviathan project up to approx. 21 BCM per year (and to enable first gas production in H2/2029). The Expansion Project is designed to increase the daily production capacity of the Leviathan project up to approx. 2.1 BCF (approx. 21 BCM per year), and in certain operating conditions, even more.

At the same time, all of the conditions precedent for the taking effect thereof were fulfilled in the engagement of the Leviathan Partners in the amendment to the agreement for the export of natural gas produced from the Leviathan reservoir to Egypt, in which it was agreed to increase the total contract quantity by approx. 130 BCM (the "**Additional Quantities**"). For further details, see Note 12C3B below. The estimate timetables for first gas production from the first stage of the Expansion Project is in H2/2029, with a total budget of approx. $2.36 billion (100%, the Partnership's share being a total of approx. $1.07 billion). Such budget includes the FEED budget as specified above. In this context, it is noted that in view of the adoption of a final investment decision (FID) for the development of the first stage of the Expansion Project, the Leviathan Partners no longer examine the possibility of construction of an FLNG facility as a development alternative.

During the years of operation of the project, additional production wells will be required for maintaining a production ability 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. Furthermore, the preparatory work for the connection and operation of the Expansion Project will include work underwater and on the platform, which will from time to time cause a temporary reduction of the production capacity and even temporary suspension of production.

f) Evaluation of reserves and contingent resources in the Leviathan Leases:

In January 2026, 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 2025. According to the report, the overall quantity (2P+2C) of natural gas and condensate in the Leviathan Project is estimated at approx. 572.2 BCM and approx. 44.5 million barrels, respectively, and includes reserves in the category of proved+probable reserves and contingent resources under the best estimate. The quantity of proved reserves is approx. 437.8 BCM and the quantity of proved + probable reserves is approx. 552.9 BCM. In addition, proved condensate reserves total approx. 34 million barrels, and the quantity of proved + probable reserves totals approx. 43 million barrels.

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.):

f) Evaluation of reserves and contingent resources in the Leviathan Leases (Cont.):

The contingent resources stated in the report are classified "Development Unclarified", and range between approx. 98.3 BCM (high estimate) and approx. 19.2 BCM (best estimate). The quantity of contingent condensate resources ranges between approx. 7.6 Million Barrels (high estimate) and approx. 1.5 Million Barrels (best estimate). See Note 7C10 below on evaluations of natural gas and condensate reserves, contingent resources and prospective resources.

g) 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 such 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 2025. According to the Resources Report, the best estimate in the carbonate buildup for gas and oil is estimated at approx. 4.6 BCM and approx. 155.3 million barrels, respectively, and the best estimate in the clastic channel for gas and oil is estimated at approx. 6.2 BCM and approx. 212.7 million barrels, respectively. See Note 7C10 below with regards to uncertainty in the evaluation of reserves. In 2025 the Leviathan Partners held several meetings to evaluate the prospectivity of the deep layers in the Leases, and a decision was made to advance the performance in H2/2026 of a 3D seismic survey for imaging and specification of the producing gas field's layers and of the deep targets.

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 (d) 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.

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).

On 22 December 2025, a decision was made regarding the execution of the FEED (for details see paragraph (d) below).

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.

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) 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. 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 (in this section: 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, from which natural gas would be transmitted through a subsea pipeline to the Egyptian transmission system (the "**Updated Development Plant**").

On 26 March 2025, the General Partner's Board approved a budget to consider the construction of transmission infrastructure from the Aphrodite reservoir, as part of the Updated Development Plan for the reservoir, totaling approx. $20 million (100%; the Partnership's share – approx. $6 million), mainly for infrastructure and seabed route surveys.

In addition, on 18 September 2025 the General Partner's Board approved the 2026 budget for the Aphrodite reservoir, totaling approx. $111.5 million (100%; the Partnership's share – approx. $33.5 million). The FEED part of the budget (totaling approx. $105.7 million (100%; the Partnership's share – approx. $31.7 million)) was subject to a decision by the partners in the Aphrodite reservoir to carry out FEED.

Further thereto, on 22 December 2025 the partners in the reservoir adopted a decision to commence FEED for the production systems and transmission infrastructure with a budget of approx. $105.7 million (100%; the Partnership's share – approx. $31.7 million).

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.):

According to an up-to-date assessment by the reservoir operator's, prior to completion of the FEED, the projected cost of the Updated Development Plan is estimated at approx. $4.1 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 results of the 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 interest holders in the Aphrodite reservoir, 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 for the setting up of a direct pipeline to Egypt, and sale arrangements (in this section: the "**MOU**"). As of the date of approval of the consolidated financial statements, the said parties are continuing to negotiate the signing of a detailed MOU for the sale to Egypt (to EGAS) of the full quantities of natural gas to be produced from the reservoir, whereby EGAS shall serve as the sole purchaser of the natural gas produced from the reservoir. Additionally, the interest holders in the Aphrodite reservoir are conducting negotiations with the Egyptian government toward the signing of an agreement aimed at regulating the key principles of the Midstream activity, which includes the laying of an underwater pipeline and the connection of the Aphrodite reservoir from the Cyprus-Egypt border to the Egyptian transmission system.

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 the approval of the development plan and the decision regarding the execution of the FEED, a resources evaluation report for the Aphrodite reservoir was prepared by NSAI according to the rules of the Petroleum Resource Management System (SPE-PRMS), such that as of 28 February 2026, the quantity of contingent resources of natural gas classified under the "Development Pending" stage ranges between approx. 99 BCM (the high estimate) and approx. 59 BCM (the low estimate), whereas the quantity of contingent resources of natural gas classified under the "Development Unclarified" stage ranges between approx. 31 BCM (the high estimate) and approx. 18 BCM (the low estimate).

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.):

f) (Cont.):

According to the aforesaid report, the quantity of contingent resources of condensate in the Aphrodite reservoir, classified under the "Development Pending" stage, ranges between approx. 8.4 million barrels (the high estimate) and approx. 4.2 million barrels (the low estimate), whereas the quantity of contingent resources of condensate classified under the "Development Unclarified" stage, ranges between approx. 2.6 million barrels (the high estimate) and approx. 1.3 million barrels (the low estimate). See Note 7C10 below regarding the evaluation of reserves of natural gas, condensate, contingent and prospective resources.

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 lease (the "**Ishai Lease**"), 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 Lease, 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. On 20 January 2026, a professional delegation on behalf of the Ministry of Energy, and in collaboration with representatives from the Ministry of Justice, departed for Cyprus to continue negotiations for the implementation of the in-principle agreements regarding the Aphrodite-Ishai natural gas reservoir and to establish it in an intergovernmental agreement. Under these agreements, the reservoir will be developed by the interest holders on the Cypriot side, while the holders of the Ishai Lease and the State of Israel will receive one-time compensation for their share in the reservoir, the rate of which shall be determined by an international expert. On 17 February 2026, a similar delegation departed for Cyprus to continue these discussions. 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. $132 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.

In his letter of 21 September 2025, the Commission invited the partners in the Yam Tethys project and in the Tamar Project to present, by 30 November 2025, their position on the decommissioning of the platform. Further thereto, the Operator informed the Partnership that in coordination with the Commissioner, the date for presentation of the partners' position as aforesaid has been postponed to a date not yet determined.

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 12G8 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 12I 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[11] ("**Adarco**"), signed agreements concerning oil and natural gas exploration and production activities in the Boujdour Atlantique exploration licenses, which are situated in the Atlantic Ocean off the coast of Morocco (in this section, the "**Petroleum Asset**" or the "**License**")[12], 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[13] 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 Southern Morocco in the area 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.

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[11] Adarco has informed the Partnership that Adarco is a company controlled by Mr. Yariv Elbaz (a Moroccan investor) and members of his family.

[12] *De facto*, the License includes 17 areas of different licenses.

[13] 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.):

4. The Boujdour License in Morocco: (Cont.):

The Boujdour license expired on 31 January 2026, and as of the date of approval of the consolidated financial statements, the partners in the license are conducting discussions with the Moroccan Ministry of Energy regarding the possibility of extending the license's validity by an additional year, for the purpose of completing all necessary actions required to reach a drill or drop decision in the license area. As of the date of approval of the consolidated financial statements, the partners in the Boujdour license have approved a budget for the years 2025-2026 in the sum of approx. $6.1 million (100%).

5. **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. 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. Accordingly, in December 2023, the partners provided 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). On 17 March 2025, the Ministry of Energy issued the Licenses to the Partners. On 22 December 2025 the Partners signed a JOA with the aim of determining the parties' mutual rights and obligations in connection with activities within the area of the Licenses.

6. **Block 1-21 Han Asparuh within the EEZ of the Republic of Bulgaria in the Black Sea (the "Block")**
   a. 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 and OMV Bulgaria (in this section: the "**Buyer**" and the "**Seller**", respectively). 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.):

6. 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. (Cont.)

On 12 March 2025, with the engagement of OMV Bulgaria, NewMed Balkan and the Government of Bulgaria in an agreement approving the transfer of the interests in the Bulgaria License to NewMed Balkan, all of the conditions precedent under the Agreement were fulfilled, and the transaction contemplated in the Agreement was consequently closed. With the closing of the transaction, NewMed Balkan held 50% of the interests in the Bulgaria License. The transaction for the sale of interests in the Bulgaria License to the Bulgarian government-owned corporation Bulgarian Energy Holding EAD ("**BEH**") was closed on 21 January 2026. With the closing of the transaction, NewMed Balkan holds 45% of the interests in the Bulgaria License.

A concise description of the principles of the Agreement follows:

1) In consideration for transfer of the interests in the Block, NewMed Balkan has undertaken to fund the costs of the first exploration well 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. $59 million), out of the overall cost of the First Well, where the balance of the cost of the First Well (if any) shall be borne by NewMed Balkan and OMV Bulgaria according to their *pro rata* share in the license, and has undertaken to bear the costs of another exploration well in the Krum prospect (the "**Second Well**"), after completion of the First Well, in a total (additional) amount that shall not exceed €50 million out of the overall cost of the Second Well, where the balance of the cost of the additional well (if any) shall be borne by NewMed Balkan and OMV Bulgaria according to their *pro rata* share in the license (the First Well together with the Second Well: the "**Two Wells**"). With the closing of the engagement between NewMed Balkan and OMV Bulgaria in the agreement for the sale of the interests to BEH, the amount that NewMed Balkan is committed to pay was reduced from €50 million to €45 million (approx. $53 million) for each one of the Two Wells. It is clarified that, under the terms of the Agreement, NewMed Balkan does not have the right to be reimbursed by OMV Bulgaria 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 current *pro rata* share (45%-45%) in the expenses of the project. Of note, the aforesaid amounts include €2.6 million (approx. $3 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 (approx. $5.9 million) in expenses incurred by the Seller in relation to preparations for the wells. It has been further agreed that NewMed Balkan will bear the fees to be paid to the Bulgarian Government in respect of transfer of the interests.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

6. 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. (Cont.)

2) As of the transaction closing date, NewMed Balkan 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, OMV Bulgaria 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 OMV Bulgaria prior to the transaction closing date.
3) On the transaction closing date, the parties entered into a joint operating agreement (JOA) in such form as agreed, which stipulated, among other things, that OMV Bulgaria will continue to serve as the operator of the license.
4) 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.
5) 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.
6) 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) As part of its undertakings in the Interest Acquisition Agreement, NewMed Balkan provided the Government of Bulgaria with bank guarantees for its share in the Bulgaria License, to guarantee compliance with the terms and conditions of the Agreement as aforesaid, environmental regulations, and receipt of approval to drill exploration wells, in the sum total of approx. €2.3 million (approx. $2.7 million).

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

6. **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.):**

b. Agreement for the sale of interests to BEH

1) In July 2023, the Bulgarian parliament decided to instruct the Bulgarian Minister of Energy to conduct negotiations for the terms and conditions according to which a Bulgarian government-owned corporation shall 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 with a request for information about, *inter alia*, the work plans, technical data and technical-economic analyses in connection with the project. On 14 January 2026, the Council of Ministers at the Bulgarian government decided to authorize the Bulgarian Minister of Energy to approve an engagement between the holders of the interests in the Bulgaria License and BEH, in an agreement for the sale of 10% of the interests in the Bulgaria License to BEH.
2) Following the negotiations conducted between NewMed Balkan, OMV Bulgaria (in this section, the "**Sellers**"), the Bulgarian Ministry of Energy and BEH, on 20 January 2026 the Sellers and BEH engaged in an agreement for the sale of 10% of the interests in the Bulgaria License to BEH (5% from each one of the Sellers) (in this section: the "**Agreement**"). In consideration for the transfer of the interests, BEH undertook to pay to the Sellers its pro rata share (10%) in the costs incurred in connection with the preparations for the Two Wells from 1 January 2021 until the date of closing of the transaction.
3) In this context, it is noted that the addendum to the concession agreement (PEA) includes the addition of a clause regarding maintenance of fiscal stability, under which the parties and the Bulgarian Minister of Energy undertake to hold negotiations on the protection of the concession holders' rights in case of material fiscal changes. Under the Agreement, the sellers and BEH have undertaken to work jointly vis-à-vis the Bulgarian government and the Bulgarian Ministry of Energy in connection with amendments to the ordinance for determination of the concession payment (royalties) for the production of subsurface resources and extension of the period of appraisal drillings in the project to two years, instead of one year.
4) It was further agreed to amend the original Interest Acquisition Agreement signed between NewMed Balkan and OMV Bulgaria (as described in Section (a) above) to reduce the sum total NewMed Balkan had undertaken to pay for each one of the Two Wells, pro rata to the reduction of NewMed Balkan's holdings in the Block, i.e. from €50 million to €45 million for each one of the Two Wells (in total, from €100 million to €90 million).
5) Further to the decision of the Council of Ministers of the Bulgarian government on 14 January 2026, which authorized the Bulgarian Minister of Energy to approve the engagement in the transaction, the transaction was closed on 21 January 2026 following the satisfaction of all of the conditions precedent.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

6. **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.):**

   c. In February 2026 the Partnership reported that, in its estimation and as it was informed by OMV Bulgaria, that non-significant signs of natural gas were discovered in the target layers of the exploration well drilled in the Vinekh prospect in the Bulgaria License, and therefore the well has been found to be a "dry hole". The total expenses of the well, including plugging and abandonment costs, are estimated at approx. €86 million (approx. $103 million in 100% terms), the share of the Partnership through NewMed Energy Balkan Limited being approx. $76 million. Accordingly, the Partnership recognized a loss in its consolidated financial statements for the full said costs, which was recorded under the depreciation, depletion and amortization expenses item. The other exploration well in the Krum prospect, to different target layers than those of the Vinekh prospect, began in February 2026 and is expected to take around two months.

   d. According to the Resource Report[14] prepared by NSAI as of 31 May 2025, the best estimate of prospective resources (2U) (100%) in the Krum prospect is approx. 7,505.6 BCF of natural gas. See Note 7C10 below on the uncertainty of reserves evaluation.

7. **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 "**Licenses**"). The partners in the Ofek license entered into an existing well in order to conduct production tests, Ofek 2-Bypass (in this section: the "**Well**"). 20 June 2022 saw the expiration of the 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 and on 29 April 2025 the partners received another letter whereby, insofar as the abandonment is not commenced by 15 May 2025, the Commissioner will give notice of his intention to forfeit guarantees provided by the partners in favor of the Ministry of Energy. In June 2025 the operator of this license, S.O.A. Energy Israel Ltd ("**SOA**") informed the partners that the well plugging has been completed, and that it had submitted final reports to the Commissioner and to the MoEP.

8. **The Eran License:**

   The Partnership had previously held approx. 45.34% 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.

[14] Following the findings of the exploration well in the Vinekh prospect as stated in Note 7C7(c) above, the prospective resources (2U) in this prospect have not been specified.

Note 7 – Investments in Oil and Gas Assets (Cont.):

C. The Partnership's oil and gas exploration business (Cont.):

8. The Eran License (Cont.):

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 that had expired (22%). It was further agreed that the interest in the expired 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 expired 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 and on 18 August 2025, the Partnership learned that the Tamar partners had reached an arrangement with the State whereby, *inter alia*, subject to the fulfilment of conditions precedent, the Tamar partners would pay the state overriding royalties of 5.9% for their income deriving from the gas produced from the Tamar SW reservoir, according to the market value at the wellhead, and the State shall approve a change in the boundaries of the Tamar Lease, so as to include all natural gas resources in the Tamar SW reservoir (the "**Tamar Arrangement**"). The Tamar Arrangement was agreed without concurrently resolving also the Partnership's rights according to the mediation arrangement and the judgement entered thereon. Further thereto, the Partnership applied, together with Ratio, to the Tamar partners, in a request to regulate the economic rights due to them as holders of rights in the expired Eran license, in accordance with the principles agreed upon in the Tamar Arrangement. As of the date of approval of the consolidated financial statements, the Partnership and Ratio are conducting discussions with the Tamar partners to arrange such matter.

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[15] (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 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).
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.

[15] 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.

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) (Cont.)

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).

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.

Notes to the Consolidated Financial Statements as of 31 December 2025 (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 -

The following table presents activity results' figures relating to the discontinued operations in the periods of the consolidated financial statements:

	For the year ended		
	31.12.2025	31.12.2024	31.12.2023
Revenues:			
From natural gas and condensate sales	-	-	-
Plus (net of) royalties	(2.1)	[11](1.0)	2.6[16]
Net revenues (expenses)	**(2.1)**	**(1.0)**	**2.6**
Other revenues			
Reimbursement of insurance expenses	-	0.6	-
Operating income (loss) before oil and gas profit levy	(2.1)	(0.4)	2.6
Oil and gas profit levy (see Note 19C7)	(17.4)	0.4	-
Operating income (loss)	**(19.5)**	***)**	**2.6**
Tax benefit (taxes on income)	4.5	*)	(0.5)
Total profit (loss) from discontinued operations	**(15.0)**	***)**	**2.1**

***) Less than $0.1 million**

The following table presents net cash flow figures relating to the discontinued operations and deriving from (used for) the operations:

	For the year ended		
	31.12.2025	31.12.2024	31.12.2023
Current	4.3	20.2	(17.3)
Investment	-	-	-
Financing	-	-	-

[16] 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.

Note 7 – Investments in Oil and Gas Assets (Cont.):
C. The Partnership's oil and gas exploration business (Cont.):

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.

Notes to the Consolidated Financial Statements as of 31 December 2025 (Dollars in millions)

Note 8 – Other Long-Term Assets:

A. Composition:

	31.12.2025	31.12.2024
Future production-based royalties from the Karish and Tanin leases (see Paragraph B below)	223.4	217.4
Ministry of Energy for royalties (see Note 15 below)	25.7	21.3
Interested parties in respect of overriding royalties (see Notes 12B and 15 below)	3.0	2.6
Third party in respect of overriding royalties (see Notes 12B and 15 below)	6.1	5.7
Access fees in respect of the Blue Ocean agreement (see Note 12C3 below)[17]	77.1	85.7
Receivables from a company accounted for at equity (see Note 21G3 below)	-	9.7
Property, plant and equipment	0.3	0.3
Lease right-of-use asset	1.9	2.2
Oil and gas profit levy (see Note 19C5 below)	-	12.6
Investment in a joint project with Airovation Technologies (see Note 12F1 below)	2.0	1.0
Investment in condensate transmission infrastructure and pipeline (see Note 12D1 below)[17]	4.6	6.4
Investment in natural gas transmission infrastructures and pipelines for export to Jordan and Egypt (see Note 12D2)[17]	241.7	148.8
Long-term prepaid expenses	3.7	-
Total	**589.5**	**513.7**

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[18], 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[19] 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 ("**Royalties Based on Future Production from the Karish and Tanin 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 (the "**Energean Loan**") (see Section 4 below).

[17] Such investments are depreciated on a straight-line basis over the term of the agreements.
[18] Pursuant to the Gas Framework, the Partnership and Chevron were required to sell their entire interests in the leases; see Note 12G1.
[19] 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 Royalties Based on Future Production from 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 Based on Future Production from the Karish and Tanin Leases as of 31 December 2025. On 20 March 2025 Energean released an updated Reserves and Resources Report for the Leases as of 31 December 2024 (the "Reserves and Resources Report") for the Karish, Karish North and Tanin reservoirs. According to this report, the natural gas reserves in the 2P category total approx. 88.8 BCM and the hydrocarbon liquids total approx. 86.5 MMBBL. Based on Energean's financial statements as of 30 September 2025, the operational update for 2025 released by Energean on 27 January 2026, the royalties actually received from Energean, and the conversion ratio between the quantity of natural gas and the quantity of hydrocarbon liquids as released in the Reserves and Resources Report, it is assumed that that quantity of natural gas and hydrocarbon liquids sold by Energean in 2025 is estimated at approx. 5.6 BCM and approx. 4.83 MMBBL, respectively, and that the quantity of natural gas and hydrocarbon liquids Energean will sell in 2026 is estimated at approx. 5.3 BCM and approx. 6.04 MMBBL, respectively. The main parameters used to measure the fair value under the valuations were as follows: The pre-tax cap rate (WACC) for the royalty component was estimated at 9.5% (2024: 11.4%); the rate of the value of State royalties at the wellhead was 11.06%; gas production from the Karish lease: from 2022 until 2045; forecasted average annual rate of production from the Karish lease: approx. 2.86 BCM of natural gas; average annual rate of production from the Karish lease of approx. 3.86 million barrels of condensate; time of gas production from the Tanin lease: from 2032 until 2042; forecasted average annual rate of production from the Tanin lease: approx. 2.36 BCM of natural gas; average annual rate of production from the Tanin lease of approx. 0.40 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 and Reserves Report.

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.):

3) (Cont.)

The gas price formula: The base price in the contracts according to which the valuation was made was estimated through the formula specified in the price mechanism between Energean and ICL and ORL and between Energean and OPC, and weighting of the gas price in the Ramat Hovav contract. The price of condensate: The condensate price forecast was assessed based on the average long-term oil price forecast of the World Bank and the EIA and the Brent forward prices according to Bloomberg data, and assuming the price of condensate will be derived from the Brent price, with adjustments for oil quality differences. The update to the valuation compared with the valuation as of 31 December 2024, primarily derives from the cap rates, adjustment to the actual quantity produced in 2025 and the production forecast in 2026 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).

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 Energean 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 Energean Loan 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 2025 (Dollars in millions)

Note 9 – Trade and Other Payables:

Composition:

	31.12.2025	31.12.2024
Related parties (see also Note 20 below)	0.4	0.3
Related parties for overriding royalties (see Notes 12B and 15 below)	3.9	3.6
Third parties for overriding royalties (see Notes 12B and 15 below)	8.3	7.7
Ministry of Energy in respect of royalties (see Notes 12B and 15 below)	11.2	12.4
Payables in the context of joint ventures[20]	139.6	78.2
Current maturities for a lease liability (see Note 20E2)	0.4	0.3
Oil and gas asset levy (see Note 19C5 below)	2.4	-
Expenses due	0.6	0.8
Provision for burdensome contract (see Notes 2F3 and 7C6C above)	30.8	-
Trade and other payables	4.2	3.3
Total	**201.8**	**106.6**

Note 10 – Bonds, loans and credit facilities from banking corporations:

A. Composition and maturities by years as of the date of the consolidated statement of financial position:

1) Composition:

	31.12.2025	31.12.2024
Leviathan Bond (see Section B below)	1,117.3	1,625.6
Long-term loan from banking corporation	275.0	-
Net of current maturities[21]	-	(485.6)
Total (net of current maturities)	**1,392.3**	**1,140.0**

2) Maturities by years after the date of the consolidated statement of financial position:

A) Leviathan Bond –

	Amount	Amortized Cost	Interest	Stated Maturity
Leviathan Bond-2027	600.0	572.6	6.500%	30 June 2027
Leviathan Bond-2030	550.0	544.7	6.750%	30 June 2030
Total	**1,150.0**	**1,117.3**		

B) Loans from Banking Corporations

	Amount	Interest	Repayment Dates				
			31/12/2027	31/12/2028	31/12/2029	31/12/2030	30/06/2031
			5%	10%	10%	10%	65%
Facility A	275.0	5.99%	13.75	27.50	27.50	27.50	178.75

[20] Mostly consisting of expenses incurred by the operator of the joint ventures and not yet paid.
[21] Net of approx. $25.4 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:

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 and $0.6 billion were repaid in 2023 and in 2025, respectively).

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**").

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 natural 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 Leviathan 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:

Note 10 – Bonds, loans and credit facilities from banking corporations (Cont.):

B. Bonds of Leviathan Bond (Cont.):

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. 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.

Note 10 – Bonds, loans and credit facilities from banking corporations (Cont.):

B. Bonds of Leviathan Bond (Cont.):

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.

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[22].

[22] 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.):

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. 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 2023 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), and on 30 June 2023, the outstanding balance of the Series 2023 Bonds was repaid in full and on schedule, according to the terms and conditions of the bonds. On 29 May 2025, a partial prepayment of the Series 2025 Bonds was made as described below, whose original maturity date was 30 June 2025, according to the terms and conditions of the bonds, for a total of $400 million (out of a total series of $600 million), and on 30 June 2025 the outstanding balance of the Series 2025 Bonds was repaid in full and on schedule, according to the terms and conditions of the bonds.

Notes to the Consolidated Financial Statements as of 31 December 2025 (Dollars in millions)

Note 10 – Bonds, loans and credit facilities from banking corporations (Cont.):

C. 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 Bond would be able, from time to time, according to the discretion of the Partnership's management and in accordance with the details of the purchase plan, make purchases of bonds of Leviathan Bond, by way of an off-exchange purchase, purchase via the TACT-Institutional system on TASE or otherwise, as follows:

Date of approval of purchase plan	Period	Plan Amount	Leviathan Bond Series	Amount Used[23]	Balance as of Reports Approval Date
21.1.2023	23.1.2023-23.1.2025	100	2023-2025	100	-
15.10.2024	15.10.2024-15.10.2026	100	2025-2027-2030	98.5	1.5
6.1.2026	6.1.2026-6.1.2028	100	2027-2030	-	100

D. Credit facilities from banking corporations:

1) **A credit facility by two Israeli banks in the amount of $200 million each ("Bank A" and "Bank B")**

A) 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). One of such credit facility substituted a $100-million credit facility provided to the Partnership by that bank on 14 March 2024. 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 was 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**").

B) Below is a concise description of the additional key conditions stipulated in the documents of the Credit Facilities:

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 weighted 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.

[23] As of the date of approval of the consolidated financial statements, the Partnership purchased a total of approx. $25.4 million and approx. $10.0 million from the 2027 and 2030 Series, respectively

Note 10 – Bonds and credit facilities from banking corporations (Cont.):
D. Credit facilities from banking corporations (Cont.):
1) (Cont.)

B) (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, payment of economic damage in 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 of an amount exceeding $200 million of which 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 7D 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.
7. Below are details regarding the financial covenants with which the Partnership is required to comply –
   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.
   b. The Partnership (standalone) shall maintain a minimum liquidity of $20 million.
   c. Total financial debt, at any given time and excluding limited-recourse loans other than the bonds of Leviathan Bond Ltd., shall not exceed $3 billion.
   d. The ratio between surplus sources and the amount of the Credit Facilities in each bank separately shall be no less than 1.
8. 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 10 – Bonds and credit facilities from banking corporations (Cont.):

D. Credit facilities from banking corporations (Cont.):

2) **Credit facility from Bank A in the sum of $200 million**

Further to the provisions of Section D1(a) and (b) above in connection the provision of a credit facility in the sum of approx. $200 million from an Israeli bank above, on 16 June 2025 the Partnership drew down a sum of approx. $100 million from the said credit facility, and on 21 July 2025 such amount was repaid in full. On 5 October 2025, the Partnership and Bank A signed an amendment to the credit facility agreement, in which the availability period was extended to 10 November 2025. On 9 November 2025, the Partnership and Bank A signed an additional amendment to the credit facility documents, the key points of which are as follows:

a. The period during which the Partnership will be able to draw down loans from time to time from the credit facility was extended until 10 November 2026 (in this section: the "**Loans**", "**Availability Period**" and "**Effective Date**", respectively), and the due dates for repayment of the Loans drawn during the Availability Period were also extended, such that they be repaid within 21 months of the Effective Date, with the exception of Loans totaling up to $150 million, which, per the Partnership's choice, will be repaid within 27 months of the Effective Date.

b. The annual interest rate on the Loans was revised to SOFR + a margin ranging between 2.3% and 2.35%.

c. The fee in respect of the unused credit facility was revised such that, during the Availability Period, its annual rate will be 0.33% of the balance of the unused credit facility until the end of the Availability Period.

d. The negative pledge clause was revised, deleting the Partnership's undertaking not to sell and/or transfer its royalty interests in the Karish and Tanin Leases without the bank's prior written consent, and leaving the Partnership's undertaking not to encumber and/or pledge its royalty interests in the Karish and Tanin Leases without the bank's prior written consent.

e. Two of the financial covenants with which the Partnership is required to comply and breach of which gives rise to the lender's acceleration right were revised as follows:

Note 10 – Bonds and credit facilities from banking corporations (Cont.):

D. Credit facilities from banking corporations (Cont.):

2) Credit facility from Bank A in the amount of $200 million (Cont.):

1. The ratio between the Value of the Partnership's Assets[24] and Net Financial Debt[25] was revised such that it be no less than the following ratios: Up to a Net Financial Debt of $2.5 billion – no less than 1.5; for any additional Net Financial Debt exceeding $2.5 billion and not exceeding $2.75 billion – no less than 2.5; and for any Net Financial Debt exceeding $2.75 billion – no less than 4.1, on two consecutive quarterly review dates in the case of quarterly financial statements, or on one half-year review date in the case of semiannual financial statements, with the review of the covenant conducted on a quarterly basis pursuant to the Partnership's annual consolidated financial statements or pursuant to the Partnership's quarterly consolidated financial statements, or on a semiannual basis in the event that the Partnership only prepares semiannual statements.

2. The covenant related to Surplus Sources[26] was revised such that Surplus Sources are not negative. For the purpose of calculating sources, in respect of capital or debt raising, the Partnership may include the following amounts (in the aggregate) in the sources, in accordance with the CEO's or CFO's planned raising for that period: (1) An amount equal to the balance of binding credit facilities from any financial entity not yet drawn at that time (or renewal of which during the period is assumed); (2) An amount the Partnership may raise pursuant to the terms and conditions of the Leviathan Bonds, provided that Leviathan Bonds' international rating is no lower than a (B) rating by at least one rating agency; (3) An additional amount of debt or capital up to $300 million (in the aggregate); and (4) An additional amount of debt or capital which is not included in Sections (1)-(3) above and satisfies one of the following: (a) The Partnership presents the bank with an agreed term sheet or MOU or any similar document in relation thereto that attests to the earnestness of the process; or (b) the additional amount of debt or capital is found satisfactory by the bank, which may only object on reasonable grounds during the period specified.

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[24] The definition of "**Value of the Partnership's Assets**" was revised such that the value of assets that secure a financial debt which is included in the following definition of Financial Debt will be taken into account when calculating the value of the Partnership's assets and the value of assets that secure a financial debt which is not included in the following definition of Financial Debt will not be taken into account when calculating the value of the Partnership's assets.

[25] "**Net Financial Debt**" – Financial Debt net of (1) cash and cash equivalents; and (2) deposits in banks and financial institutions; (3) funds and safety cushions given to secure Financial Debt (insofar as not included in sub-section (1) or (2)), provided however that any of the aforesaid assets is not subject to a fixed charge and/or an undertaking of non-withdrawal in favor of any entity other than the lender, other than due to the debt or a liability that are included in the definition of the Financial Debt. The definition of "**Financial Debt**" was revised as follows: The Partnership's debts and liabilities to banks and other financial institutions and/or deriving from bonds of any type, including straight bonds and convertible bonds and/or deriving from loans received by the Partnership from affiliated companies or from any third parties (excluding loans for which the Partnership and the lender of the loan signed letters of subordination vis-à-vis the bank and excluding Limited Recourse debts or liabilities (other than Leviathan Bonds)). For the avoidance of doubt, the term "Financial Debt" does not include guarantee facilities and bank guarantees issued thereunder per the Partnership's request, nor includes the financial debt of corporations that are held by the Partnership (with the exception of Leviathan Bonds or companies' financial debt which is guaranteed by the Partnership (and as concerns such a guarantee, in any case no more than the amount of the guarantee, and excluding any guarantee which is limited to assets and liabilities that are listed in the definition of Limited Recourse)). It is agreed that any calculation required to be made according to the Partnership's consolidated statements will be made after adjustment thereof to the aforesaid definition of Financial Debt, and this revision affects the definition of Net Financial Debt accordingly.

[26] The definition of "**Surplus Sources**" was revised as follows: The aggregate amount of sources until the earlier of: (a) the expiration of one year from the date to which the calculation refers; or (b) the date of termination of the loans drawn down (as specified in the sources and uses report) after deduction of the amount of uses (as defined in the sources and uses report) for that period. For the avoidance of doubt, surplus sources shall also include sources and uses for the said period which are related to all the Partnership's credit other than the credit facility under the credit facility documents of 8 October 2024.

Note 10 – Bonds and credit facilities from banking corporations (Cont.):

D. Credit facilities from banking corporations (Cont.):

2) Credit facility from Bank A in the amount of $200 million (Cont.):

The Surplus Sources review will be conducted on a semiannual basis according to the sources and uses report, the details of which are defined in the credit facility documents.

Below are details regarding the financial covenants with which the Partnership is required to comply and which establish for the lender a right to acceleration, and the calculated value thereof as of the date of the consolidated financial statements:

1) The ratio between the Value of the Partnership's Assets and Net Financial Debt shall be no less than the following ratios on two consecutive review dates: Up to a Net Financial Debt of $2.5 billion – no less than 1.5; for any additional Net Financial Debt exceeding $2.5 billion and not exceeding $2.75 billion – no less than 2.5; and for any Net Financial Debt exceeding $2.75 billion – no less than 4.1. As of 31 December 2025, the Partnership's Net Financial Debt is less than $2.5 billion and the said ratio is approx. 5.02.
2) The Partnership (on a standalone basis) shall maintain Liquidity (as defined in the Agreement) of $20 million at a minimum. As of 31 December 2025, this amount totals approx. $382.7 million.
3) Total Financial Debt shall at no time exceed $3 billion. As of 31 December 2025, total Financial Debt amounts to approx. $1.4 billion.
4) Surplus Sources shall not be negative. As of 31 December 2025, Surplus Sources are not negative.

3) **Credit Facilities from Bank B in the sum total of $350 million**

a) On 16 June 2025, the Partnership signed an agreement with an Israeli bank for the provision of two new credit facilities in the total amount of $350 million (in this section: the "**Agreement**, the "**Lender**" or the "**Bank**", and the "**Credit Facilities**", respectively). The Credit Facilities are in lieu of a credit facility received by the Partnership from the Bank in the sum of $200 million that was made available to the Partnership on 8 October 2024, as detailed in Section D1 above. The Credit Facilities are intended to be used by the Partnership in its operating activities, including in relation to Phase 1B of the Leviathan reservoir's development plan.

b) Below is a concise description of the additional key terms determined in the Credit Facilities documents of 16 June 2025:

1) The Partnership undertook to withdraw, by 30 June 2025, the entire Credit Facility A, in the amount of $275 million ("**Credit Facility A**") and shall be entitled to withdraw from Credit Facility B, from time to time and until 15 July 2027 (in this section: the "**Availability Period**"), up to $75 million more ("**Credit Facility B**"). Any loan taken from Credit Facility B and repaid will be available for repeat withdrawal and repayment until the end of the Availability Period. On 18 June 2025, the Partnership withdrew all of Credit Facility A, and on 10 February 2026 the Partnership withdrew all of Credit Facility B. See Section (c) below.

Note 10 – Bonds and credit facilities from banking corporations (Cont.):

D. Credit facilities from banking corporations (Cont.):

3) Credit Facilities from Bank B in the sum total of $350 million (Cont.):

2) Loans that are taken from both of the Credit Facilities (the "**Loans**") shall be repaid in non-equal instalments: 5% on 31 December 2027; 10% on 31 December of each of the years 2028 through 2030 (inclusive); and 65% on 30 June 2031 (the "**Final Maturity Date**").
3) The Loans will bear interest payable semi-annually, with the first interest payment due on 31 December 2025, and the last payment on the Final Maturity Date. The loan from Credit Facility A will bear a fixed annual interest rate of 5.99%. The loan from Credit Facility B will bear a variable annual interest rate based on Three-Month Term SOFR, plus a margin of 2.35% per annum (see also Section (c) below).
4) The Partnership paid the Lender a one-time commitment fee totaling $1.3 million on the date of provision of the loan from Credit Facility A. The Partnership will also pay the Lender a non-utilization fee on each interest payment date, on the undrawn portion of Credit Facility B, until the end of the Availability Period, at an annual rate of 0.75%. Under the terms and conditions of the Agreement, the Partnership may reduce Credit Facility B at any time, free of charge.
5) The Partnership has the right to prepay each of the Loans (in whole or in part) at all times. Due to prepayment of loans utilized from Credit Facility A (only), the Partnership shall be charged a prepayment fee, the terms and conditions of which were provided in the Agreement (see also Section (c) below). Other than the aforesaid, the Partnership shall not be charged a prepayment fee or another payment due to a prepayment.
6) The Partnership undertook not to pledge and not to mortgage or undertake to pledge or mortgage, in any manner whatsoever and for any purpose whatsoever, for the benefit of any third party, all of its rights in relation to its rights to receive royalties from the Karish and Tanin Leases, without obtaining the Bank's consent in advance and in writing.
7) The Credit Facilities documents provide directives in relation to circumstances of sale of all or part of the Partnership's interests in the Leviathan project, which directives include an undertaking to reduce the Credit Facilities total in the event of such sale and/or prepayment of the Loans under certain conditions.
8) The Partnership has undertaken that after signing the Agreement, it shall not assume an additional financial debt, that is not from the Lender, the principal payment date in respect of which falls in the period of the 12 months before the Final Maturity Date of the Loans. The aforesaid shall not apply to current credit facilities or on-call loans (payable upon demand) or to series 6/2030 Leviathan Bonds. The aforesaid notwithstanding, such limitation shall not apply, if: (a) the balance of the principal due on the Final Maturity Date does not exceed $150 million; or (b) the cumulative principal amount of the additional financial debt does not exceed $100 million (or higher amounts with the Lender's consent in advance and in writing).

Note 10 – Bonds and credit facilities from banking corporations (Cont.):

D. Credit facilities from banking corporations (Cont.):

3) Credit Facilities from Bank B in the sum total of $350 million (Cont.):

9) The Partnership's prior principal sums shall not exceed, at all times, the cumulative amount of $1,550 million. According to the Agreement, the "prior principal sums" of the Partnership shall mean, at all times, the cumulative principal payment amounts of any financial debt[27] which is not to the Bank (that are yet to be paid), whose payment date according to the payment schedule relevant to such financial debt, falls before the Final Maturity Date, net of amounts deposited at such time in funds pledged to guarantee such financial debts, and other than the principal amount payable on 30 June 2025 due to Leviathan Bonds and payment amounts of principal due to bonds constituting a financial debt (including Leviathan Bonds) bought back by the Partnership or a subsidiary thereof.

10) The aforesaid notwithstanding, the Partnership shall be entitled to assume a financial debt, even if the same does not meet the conditions listed in Section 9 above (the "**Non-Conforming Financial Debt**"), subject to the following conditions: the Partnership shall notify the Bank in writing within 5 business days from the date of provision of the Non-Conforming Financial Debt, and the Bank shall be entitled, in its discretion, in a written notice no later than 30 days from the date of receipt of the notice from the Partnership (the "**Aforesaid Date**") to terminate the credit facility and demand that the Partnership prepay all of the Loans provided thereto by virtue of the Credit Facilities (the "**Bank's Notice to Repay**"). If the Bank's Notice to Repay is given by the Aforesaid Date, the Partnership shall prepay the outstanding balance of all of the Loans provided thereto by virtue of the Credit Facilities by and no later than 60 days from the date of receipt of the Bank's Notice to Repay, plus one half of the amount of the prepayment fee which the Partnership is obligated (if it is so obligated) to pay for prepayment of Loans by virtue of the Credit Facilities. If the Bank does not give the Bank's Notice to Repay by the Aforesaid Date to the Partnership, the Bank shall be deemed to agree to the assumption of the Non-Conforming Financial Debt.

11) Below are details on the financial covenants with which the Partnership is required to comply and breach of which gives rise to the Lender's acceleration right, and the calculated value thereof as of the date of the Consolidated Statements of Financial Position.

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[27] For this purpose, "**Value of the Partnership's Assets**" – the total discounted cash flow (at the rate of 10%), after deduction of taxes, of the probable and/or contingent (2P and/or 2C) reserves of the Partnership's share in all of the projects, based on the latest discounted cash flow (DCF) publicly released by the Partnership, plus the value of other assets of the Partnership (which are not included in the definition of projects), based on an external independent evaluation by an evaluator whose identity is acceptable to the Lender. For the avoidance of doubt, the value of assets that secure a financial debt included in the definition of Financial Debt below shall be taken into account in the calculation of the Value of the Partnership's Assets, and the value of assets that secure a financial debt that is not included in the definition of Financial Debt below shall not be taken into account in the calculation of the Value of the Partnership's Assets.

"**Financial Debt**" – debts and liabilities of the Partnership to banks and other financial institutions and/or which derive from all types of bonds, including straight bonds and convertible bonds and/or which derive from loans received by the Partnership from affiliates or any third parties (except loans in respect of which letters of subordination were signed vis-à-vis the Lender by the Partnership and by the entity that provided such loan, and except limited recourse debts or liabilities (other than Leviathan Bonds)). For the avoidance of doubt, the term "financial debt" does not include facilities for guarantees and bank guarantees issued thereunder per the Partnership's request, and does not include financial debt of corporations held by the Partnership (except Leviathan Bonds or financial debt of companies guaranteed by the Partnership (and with respect to such a guarantee, in any event no more than the guarantee amount and except a guarantee that is limited to assets and liabilities that are specified in the definition of limited recourse).

"**Net Financial Debt**" – Financial Debt, net of: (1) cash and cash equivalents; and (2) deposits at banks and financial institutions; (3) funds and safety cushions provided to secure Financial Debt (if not included in Subsection (1) or (2)), and provided that none of the assets specified above are subject to a fixed charge and/or an undertaking of non-withdrawal in favor of any entity other than the Lender has been given, not for the debt or liability included in the definition of the Financial Debt.

Note 10 – Bonds and credit facilities from banking corporations (Cont.):

D. Credit facilities from banking corporations (Cont.):

3) Credit Facilities from Bank B in the sum total of $350 million (Cont.):

a) The ratio between the Value of the Partnership's Assets and the Net Financial Debt shall, on two consecutive review dates, be no less than the ratios stated below: up to Net Financial Debt of $2.5 billion – no less than 1.5; due to any additional Net Financial Debt exceeding $2.5 billion and not exceeding $2.75 billion – no less than 2.5; and due to any additional Net Financial Debt exceeding $2.75 billion – no less than 4.1[27]. As of 31 December 2025, the Partnership's Net Financial Debt is below $2.5 billion and the said ratio is approx. 5.02.

b) The Partnership (standalone) shall maintain minimal Liquidity (as defined in the Agreement) of $20 million. As of 31 December 2025, this amount is approx. $382.7 million.

c) At all times, the total Financial Debt shall not exceed $3 billion. As of 31 December 2025, the total Financial Debt is approx. $1.4 billion.

d) Surplus Sources shall not be negative. As of 31 December 2025, the Surplus Sources are not negative.

12) Review of the covenants as specified in Section 11 above other than Section 11(d) above will be conducted every quarter according to the Partnership's annual consolidated financial statements or according to the Partnership's quarterly consolidated financial statements, or every half-year if the Partnership only prepares semiannual statements.

Note 10 – Bonds and credit facilities from banking corporations (Cont.):

D. Credit facilities from banking corporations (Cont.):

3) Credit Facilities from Bank B in the sum total of $350 million (Cont.):

13) In the Agreement, the Partnership undertook that the Surplus Sources (as defined in the Agreement)[28] shall not be negative. For the Partnership's raising of capital or debt, for the purpose of calculation of the sources, the Partnership shall be entitled to include, in the sources, the following amounts (in the aggregate) according to the fund-raising plan of the CEO or CFO of the Partnership at such time: (a) the outstanding amounts of binding credit facilities from any and all financial bodies yet to be withdrawn (or assumed to be renewed in the period); (b) amounts the Partnership is entitled to raise according to the conditions of the Leviathan Bonds, provided that the international bond rating does not fall below B by at least one rating agency; (c) an additional debt or capital amount up to $300 million (in the aggregate); and (d) additional debt or capital amounts in respect of which the Lender was presented with an agreed term sheet or MOU or a similar document or that are to the satisfaction of the Lender, which is entitled to object on reasonable grounds only in the determined period. The examination of the Surplus Sources shall be performed every half-year according to the sources and uses report, whose details were defined in the Agreement.

14) The Credit Facilities documents describe certain representations of the Partnership and warranties and additional terms and conditions as is customary in financing agreements of this kind, and in such context, the Credit Facilities documents define specific default events upon the occurrence of which the Lender has a the right to accelerate the Loans or any part thereof. These include *inter alia* the following events: termination or ongoing suspension of production from the Leviathan project due to war or terrorism including by way of a regulatory directive for a period of 180 days or longer, insofar as this amounts to, or will reasonably have a material adverse effect; Change of Control[29]; cancellation of the lease deeds in the Leviathan reservoir; adoption of a resolution on Restructuring[30]; non-payment, acceleration or notice of acceleration of any debt or demand to prepay any debt (in whole or in part) in the amount exceeding $15 million[31], a material change to the incorporation documents that may harm the Lender; if the Partnership breaches or does not fulfill the provisions of the Agreement with the Lender and such breach is not remedied within 21 days (and regarding the financial covenants, within one quarter) and;

[28] For this purpose, "**Surplus Sources**" – the aggregate amount of the sources until the earlier of: (a) the end of the year from the date to which the calculation relates, or (b) 30 June 2031, as specified in the sources and uses report net of the uses amount as defined in the said report for such period.

[29] For this purpose, "**Change of Control**" means if Delek Group ceases to hold, directly or indirectly, at least 25% of the means of control of the Partnership and to be the largest holder of the means of control in the Partnership and/or there is another control holder in the Partnership (separately or together with Delek Group). "**Control**" and "**Means of Control**" are as defined in the Securities Law, 5728-1968. The aforesaid notwithstanding, if Delek Group shall hold, directly or indirectly, 50% of the Partnership's participation units, with the remaining participation units being held by BP and/or ADNOC, this shall not be deemed as a Change of Control. The Lender shall not unreasonably withhold consent to such a Change of Control.

[30] For this purpose, "**Restructuring**" means a merger or split, including consolidation and reorganization, whether as a surviving company or a target company, as well as any action other than in the ordinary course of business that results in the acquisition of assets and/or liabilities of another entity, including a settlement or arrangement pursuant to Sections 350 and 351 of the Companies Law, 5759-1999, and any transaction or transactions for the transfer of assets in consideration for shares or other securities. The aforesaid notwithstanding, the transfer or sale of the Partnership's interests in the Leviathan reservoir, a transaction with BP and/or ADNOC, another transaction that does not have a material adverse effect on the Partnership's business, and a change in the Partnership's holding structure from direct to indirect ownership, shall not be deemed as a Restructuring.

[31] Except in relation to limited-recourse loans other than Leviathan Bonds.

Note 10 – Bonds and credit facilities from banking corporations (Cont.):

D. Credit facilities from banking corporations (Cont.):

3) Credit Facilities from Bank B in the sum total of $350 million (Cont.):

other standard clauses such as breach of a representation or undertaking, discontinuation of business, material adverse effect, lawsuits and attachments on the Partnership's assets or property, a going concern note in the financial statements, insolvency, resolution on dissolution, appointment of a (temporary or permanent) receiver/liquidator, etc. and all, subject to specific exceptions and terms and conditions and the qualifications and/or remediation periods determined in the Credit Facilities documents.

c) On 10 February 2026 the Partnership drew down Credit Facility B in full. It was agreed that the loan from Credit Facility B shall bear fixed annual interest of 5.55% (in lieu of variable annual interest as detailed in Section B3 above). In the case of prepayment by the Partnership, the loan shall bear a prepayment fee at the rate applicable to Credit Facility A as aforesaid.

4) Credit Facilities from Bank Leumi in the sum total of $500 million

a) On 16 February 2026, the Partnership signed an agreement with Bank Leumi Le-Israel Ltd. for the provision of two new credit facilities in the sum total of $500 million (the "**Signing Date**", the "**Agreement**", the "**Lender**" or the "**Bank**" and the "**Credit Facilities**", respectively). The Credit Facilities are intended to be used by the Partnership for its operating activities, including in connection with the Leviathan reservoir expansion project. In accordance with the terms and conditions of the Agreement, the Partnership undertook to draw down, by 2 March 2026, all of credit facility A, in the sum of $100 million ("**Credit Facility A**"), and it will be entitled to draw down from credit facility B, from time to time, and until one year from the Signing Date (the "**Availability Period**"), up to an additional $400 million ("**Credit Facility B**"). On 26 February 2026, the Partnership drew down the full amount of Credit Facility A as aforesaid. A loan drawn from Credit Facility B and repaid in the Availability Period, may be drawn down again until the end of the Availability Period. The loans drawn from the two Credit Facilities (the "**Loans**") shall be repaid in non-equal installments, as specified in Section A below, until final repayment thereof on 30 June 2032 (the "**Final Maturity Date**").

b) Below is a concise description of other main terms set forth in the Credit Facility documents:

1) Principal, interest and fees

The principal of the Loans shall be repaid in 5 installments, as follows:

- 5% - on 31 December 2028;
- 10% - on 31 December of each one of the years 2029 to 2031 (inclusive); and
- 65% - on the Final Maturity Date.

Note 10 – Bonds and credit facilities from banking corporations (Cont.):

D. Credit facilities from banking corporations (Cont.):

4) Credit Facilities from Bank Leumi in the sum total of $500 million (Cont.):

The Loans shall bear interest to be paid every six months, with the first interest payment due on 30 June 2026 and the last payment on the Final Maturity Date. The loan drawn from Credit Facility A shall bear fixed annual interest of 5.65%. The loan drawn from Credit Facility B shall bear variable annual interest based on 6-month Term SOFR, plus a margin of between 2.3% and 2.4%.

On the date of drawdown of Facility A, the Partnership paid the Lender a one-time commitment fee at the rate of 0.37% of the sum of the Credit Facilities. The Partnership shall also pay the Lender a non-usage fee on the unutilized portion of Credit Facility B at a rate of 0.35%.

2) **Prepayment right**

The Partnership is entitled to prepay any one of the Loans (in whole or in part) at any time. In respect of prepayment of loans drawn from Credit Facility A (only), the Partnership shall be charged a prepayment fee, whose terms and conditions are specified in the Agreement. Except as stated above, the Partnership shall not be charged any fee for the prepayment of Loans drawn from Credit Facility B or any other payment.

3) **Negative pledge**

The Partnership undertook not to pledge or charge and not to undertake to pledge or charge, in any manner and for any purpose: (a) in favor of any third party, all of its rights in connection with its rights to receive royalties from the Karish-Tanin reservoirs; and (b) in favor of the lenders under the current credit facilities, retained earnings (free cash flow received by the Partnership for its free use after senior debt) from accounts of the bonds issued by Leviathan Bond Ltd., a wholly owned subsidiary of the Partnership ("**Leviathan Bonds**"), all except in the following cases: (a) the Partnership concurrently pledges the assets listed in Subsections (a) or (b) above in favor of the Bank under a pari passu pledge on a pro-rata basis with the other beneficiaries of the pledge; or (b) the Bank's prior written consent has been obtained.

4) **Sale of interests in the Leviathan project**

The Credit Facility documents determine provisions in connection with a case of the sale of all or part of the Partnership's interests in the Leviathan project, including an undertaking to reduce the sum of the Credit Facilities in the event of such a sale and/or prepay the Loans or part thereof under certain conditions.

5) **Undertakings in connection with Financial Debts**

a. The Partnership undertook that after the Signing Date it will not incur any additional Financial Debt, other than from the Lender, and that the principal repayment date of which falls in the 9-month period preceding the Final Maturity Date of the Loans. The aforesaid shall not apply to current credit facilities or on-call loans (repayable on demand). The aforesaid notwithstanding, the said restriction shall not apply if: (a) the outstanding principal balance due on the Final Maturity Date does not exceed $215 million; or (b) the aggregate principal amount of the additional Financial Debt does not exceed $140 million (or higher amounts with the Lender's prior written consent).

Note 10 – Bonds and credit facilities from banking corporations (Cont.):

D. Credit facilities from banking corporations (Cont.):

4) Credit Facilities from Bank Leumi in the sum total of $500 million (Cont.):

b. The Partnership's Preceding Principal Amounts shall not exceed, at any time, the aggregate sum of $1,900 million. According to the Agreement, the Partnership's "Preceding Principal Amounts" mean, at any time, the aggregate principal repayment amounts of any Financial Debt[27] other than to the Bank (which have not yet been repaid), the repayment date of which, according to the payment schedule relevant to such Financial Debt, falls prior to the Final Maturity Date, net of any amounts deposited at such time in funds that are pledged to secure such Financial Debts. The Preceding Principal Amounts shall not include the principal amount due on 30 June 2027 in respect of Leviathan Bonds and amounts to repay the principal of bonds which constitute a Financial Debt (including Leviathan Bonds) which were bought back by the Partnership or a subsidiary thereof. The aforesaid notwithstanding, the Partnership shall be entitled to incur Financial Debt even if it does not satisfy the conditions listed in Section A above (the "**Non-Conforming Financial Debt**"), subject to the following conditions: The Partnership shall notify the Bank in writing within 5 business days from the date of provision of the Non-Conforming Financial Debt, and the Bank shall be entitled, at its discretion, by written notice no later than 30 days from the date of receipt of the Partnership's notice (the "**Said Date**"), to cancel the Credit Facilities and demand that the Partnership prepay all of the Loans provided thereto under the Credit Facilities (the "**Bank's Notice to Repay**"). Where the Bank's Notice to Repay is given by the Said Date, the Partnership shall prepay the outstanding balance of all of the Loans provided thereto under the Credit Facilities by no later than 60 days from the date of receipt of the Bank's Notice to Repay, plus the amount of the prepayment fee which the Partnership is liable (insofar as it is liable) to pay in respect of prepayment of Loans under the Credit Facilities. Where the Bank does not give the Partnership the Bank's Notice to Repay by the Said Date, the Bank shall be deemed as consenting to the incurrence of the Non-Conforming Financial Debt.

6) Financial covenants

The Credit Facility documents determine financial covenants with which the Partnership is required to comply, and the breach of which establishes for the Lender a right of acceleration, as specified below:

a) The ratio between the Value of the Partnership's Assets and the Net Financial Debt will be no lower, on two consecutive testing dates, than the ratios stated below: up to Net Financial Debt of $2.5 billion – no less than 1.5; for any additional Net Financial Debt exceeding $2.5 billion and not exceeding $2.75 billion – no less than 2.5; and for any additional Net Financial Debt exceeding $2.75 billion – no less than 4.1[32].

[32] For this purpose, "**Value of the Partnership's Assets**" – the total discounted cash flow (at the rate of 10%), after deduction of taxes, of the probable and/or contingent (2P and/or 2C) reserves of the Partnership's share in all of the projects, based on the latest discounted cash flow (DCF) publicly released by the Partnership, plus the value of other assets of the Partnership (which are not included in the definition of projects), based on an external independent evaluation by an evaluator whose identity is acceptable to the Lender. For the avoidance of doubt, the value of assets that secure a financial debt included in the definition of Financial Debt below shall be taken into account in the calculation of the Value of the Partnership's Assets, and the value of assets that secure a financial debt that is not included in the definition of Financial Debt below shall not be taken into account in the calculation of the Value of the Partnership's Assets.

Note 10 – Bonds and credit facilities from banking corporations (Cont.):

D. Credit facilities from banking corporations (Cont.):

4) **Credit Facilities from Bank Leumi in the sum total of $500 million (Cont.):**

According to the Partnership's financial statements as of 31 December 2025, the Partnership's Net Financial Debt is lower than $2.5 billion, and the ratio between the Value of the Partnership's Assets and the Net Financial Debt is approx. 5.02.

b) The Partnership (on a standalone basis) shall maintain minimum Liquidity (as defined in the Agreement) of $20 million. According to the Partnership's financial statements as of 31 December 2025, this amount totals approx. $382.7 million.

c) At all times, the sum of the Financial Debt shall not exceed $3 billion. According to the Partnership's financial statements as of 31 December 2025, the sum of the Financial Debt totals approx. $1.4 billion.

d) The covenants as specified in Sections A-C above shall be tested on a quarterly basis according to the Partnership's annual consolidated financial statements or the Partnership's quarterly consolidated financial statements, or every six months insofar as the Partnership only prepares semiannual statements.

7) Surplus Sources commitment

The Surplus Sources (as defined in the Agreement)[33] shall not be negative. With respect to equity or debt raisings by the Partnership, for the purpose of calculating the sources, the Partnership shall be entitled to include the following amounts (in the aggregate) in the sources, in accordance with the fund-raising plan of the Partnership's CEO or CFO for such period: (a) the balance of binding credit facilities from any financial body that have not yet been drawn down (or assumed to be renewed during the period); (b) amounts that the Partnership is entitled to raise under the terms of the Leviathan Bonds, provided that the bonds' international bond rating is no less than B by at least one rating agency; (c) additional debt or equity amounts up to $300 million (in the aggregate); and (d) any additional debt or equity amounts for which an MOU or agreed term sheet or similar document is presented to the Lender, or which are to the satisfaction of the Lender, which may object only on reasonable grounds in the stipulated period. The Surplus Sources test shall be carried out every six months according to the sources and uses report, the details of which are defined in the Agreement. As of 31 December 2025, the Surplus Sources are not negative.

"**Financial Debt**" – debts and liabilities of the Partnership to banks and other financial institutions and/or which derive from all types of bonds, including straight bonds and convertible bonds and/or which derive from loans received by the Partnership from affiliates or any third parties (except loans in respect of which letters of subordination were signed vis-à-vis the Lender by the Partnership and by the entity that provided such loan, and except limited recourse debts or liabilities (other than Leviathan Bonds)). For the avoidance of doubt, the term "financial debt" does not include facilities for guarantees and bank guarantees issued thereunder per the Partnership's request, and does not include financial debt of corporations held by the Partnership (except Leviathan Bonds or financial debt of companies guaranteed by the Partnership (and with respect to such a guarantee, in any event no more than the guarantee amount and except a guarantee that is limited to assets and liabilities that are specified in the definition of limited recourse).

"**Net Financial Debt**" – Financial Debt, net of: (1) cash and cash equivalents; and (2) deposits at banks and financial institutions; (3) funds and safety cushions provided to secure Financial Debt (if not included in Subsection (1) or (2)), and provided that none of the assets specified above are subject to a fixed charge and/or an undertaking of non-withdrawal in favor of any entity other than the Lender has been given, not for the debt or liability included in the definition of the Financial Debt.

[33] For this purpose, "**Surplus Sources**" – the aggregate amount of the sources until the earlier of: (a) the end of the year from the date to which the calculation relates, or (b) 30 June 2032, as specified in the sources and uses report net of the uses amount as defined in the said report for such period.

Note 10 – Bonds and credit facilities from banking corporations (Cont.):

D. Credit facilities from banking corporations (Cont.):

4) **Credit Facilities from Bank Leumi in the sum total of $500 million (Cont.):**

8) **Representations, undertakings and events of default which grant the Lender grounds to accelerate the Loans**

The Credit Facility documents specify certain representations of the Partnership and additional terms and undertakings as standard in financing agreements of this type, and in this context the Credit Facility documents define certain events of default which, upon their occurrence, entitle the Lender to accelerate all or any part of the Loans. These include, *inter alia*, the following events: A prolonged suspension or cessation of production from the Leviathan project due to war or terrorism, including by way of regulatory directive, for a period of 180 days or more, insofar as such event has, or is likely to have, a material adverse effect; a Change of Control[34]; cancellation of the lease deeds for the Leviathan reservoir; adoption of a decision regarding a Restructuring[35]; non-payment; acceleration or notice of intention to accelerate any debt, or a demand to prepay any debt (in whole or in part) in an amount exceeding $15 million[36]; a material change to the incorporation documents that may prejudice the Lender; if the Partnership breaches or fails to comply with the provisions of the Agreement with the Lender, which breach is not remedied within 21 days (and with respect to the financial covenants, within one quarter) and; other standard clauses such as breach of a representation or undertaking, cessation of business, material adverse effect, claims and attachments against the Partnership's assets or property, a 'going concern' note in the financial statements, insolvency or adoption of a dissolution resolution, the appointment of a (temporary or permanent) receiver / liquidator, etc., all subject to certain conditions and exceptions and to the qualifications and/or remediation periods set forth in the Credit Facility documents.

E. As of the date of approval of the consolidated financial statements, the Partnership is considering various other financing alternatives, including financing by way of loans from banking and financial corporations, bonds, various equity instruments and other alternatives, if any, for the purpose of, *inter alia*, funding the development of the first stage of Stage 1B of the Leviathan Project Development Plan, and for the purpose of the Partnership's continued investments and operations.

[34] For this purpose, "**Change of Control**" means if Delek Group ceases to hold, directly or indirectly, at least 25% of the means of control of the Partnership and to be the largest holder of the means of control in the Partnership and/or there is another control holder in the Partnership (separately or together with Delek Group). "**Control**" and "**Means of Control**" are as defined in the Securities Law, 5728-1968. The Lender shall not unreasonably withhold consent to such a Change of Control.

[35] For this purpose, "**Restructuring**" means a merger or split, including consolidation and reorganization, whether as a surviving company or a target company, as well as any action other than in the ordinary course of business that results in the acquisition of assets and/or liabilities of another entity, including a settlement or arrangement pursuant to Sections 350 and 351 of the Companies Law, 5759-1999, and any transaction or transactions for the transfer of assets in consideration for shares or other securities. The aforesaid notwithstanding, the transfer or sale of the Partnership's interests in the Leviathan reservoir, another transaction that does not have a material adverse effect on the Partnership's business, and a change in the Partnership's holding structure from direct to indirect ownership, shall not be deemed as a Restructuring.

[36] Other than limited recourse loans which are not Leviathan Bonds.

Notes to the Consolidated Financial Statements as of 31 December 2025 (Dollars in millions)

Note 11 - Other Long-Term Liabilities:

A. Composition:

	31.12.2025	31.12.2024
Oil and gas asset retirement obligation (see Note 2H and Section B)	81.3	68.5
Liability due to lease	2.1	2.0
Total	**83.4**	**70.5**

B. Movement in oil and gas asset retirement obligation:

	2025	2024
Balance as of 1 January	**68.5**	**73.5**
Change of cost estimate	1.7	(3.8)
Effect of the lapse of time[37]	4.9	3.5
Effect of update of the cap rate and indexation[21]	6.2	(5.1)
Amounts incurred for abandonment of oil and gas assets (see Note 7C3(b) above)	-	0.4
Balance as of 31 December	**81.3**	**68.5**

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).

[37] The cap rate for measuring the oil and gas asset retirement obligation as of 31 December 2025 is 6.9% (31 December 2024: 7.2%).

Note 12 – Contingent Liabilities, Engagements and Pledges

B. Royalty payment engagements (Cont.):

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. In this context, in the Partnership's estimation, the investment recovery date for the Leviathan Project is expected to be in H1/2026.

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[38]:

[38] 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 2025 (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[39]	Total Maximum Contractual Supply Quantity (100%) (BCM)[40]	Total Quantity Supplied by 31 December 2025 (100%) (BCM)	Primary Gas Price Linkage Base
Independent power producers	2020, or a later date as set forth in the agreement	Medium- and 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.	approx. 17.1	approx. 4.4	In most of the agreements the natural gas price linkage formula is based on the electricity prices (the Electricity Production Tariff and the TAOZ Tariff) and includes a "price floor".
Industrial customers	2020, or a later date as set forth in the agreement	The agreements are for up to a period of 15 years.	approx. 4.1	approx. 0.75	The linkage formulas in these agreements are based partly on linkage to the TAOZ Tariff, the Electricity Production Tariff, the US Consumer Price Index (CPI), the Brent price, and the oil refining margin. All such price formulas include a "price floor".
NEPCO export agreement (described in Section 2A 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 a period of up to another two years.	approx. 45	approx. 15.5	The linkage formula is based on linkage to the Brent prices and includes a "price floor".
Blue Ocean export agreement (described in Section 3A below)	2020	Approx. 15 years. The agreement stipulates that if the buyer does not buy the total contract quantity, the supply period will be extended by a period of up to another two years.	approx. 60	approx. 29.7	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[41] and 10th years of the agreement, in certain conditions specified in the agreement.
Amendment to the Blue Ocean export agreement (described in Section 3B below)	First tranche during 2026; second tranche during 2029	Approx. 15 years. The agreement stipulates that in the event the buyer does not buy the total contract quantity, the supply period will be extended for a period of up to two additional years.	approx. 20 for the first tranche; approx. 110 for the second tranche	-	The amendment to the agreement includes a mechanism for price updates by up to 10% (up or down) every 5 years, starting from the commencement of the second tranche.
Export agreements – additional customers in Jordan	One agreement during 2025 and in the second agreement it is expected to commence during 2026	9-15 years. The agreements stipulate that in the event the buyer does not buy the total contract quantity, the supply period will be extended for a period of up to one additional year.	approx. 4.5-5	approx. 0.03	The linkage formula is based on linkage to the Brent prices and includes a "price floor".
Total			**approx. 261**	**approx. 50.4**[42]	

[39] Under most of the agreements, the gas supply term is expected to end when the maximum contract quantity specified in the agreement shall have been supplied to the customers.

[40] This quantity represents the total quantity that the Leviathan Partners undertook to supply to customers throughout the term of the agreements. In several agreements, a total contractual supply quantity is not specified.

[41] The parties agreed not to update the price after the fifth year of the agreement.

[42] The total quantity supplied from the Leviathan project by 31 December 2025 (100%) (under the agreements listed in the table, under SPOT agreements and agreements that have come to an end) is approx. 62.4 BCM.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

C. Engagements for the supply of natural gas and condensate (Cont.)

1. **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) As of the date of approval of the consolidated financial statements, the Partnership is continuing to conduct negotiations, at various stages, with other potential customers in the domestic market, including independent power producers (IPPs) and industrial consumers, subject, *inter alia* to the Leviathan project supply capacity.

   b) In 2025 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. In this context, *inter alia*, in May 2025, an agreement for the supply of natural gas was signed between the Leviathan Partners and ICL Group Ltd. for a period of approx. 5 years, with a total volume of approx. 0.75 BCM.

   c) 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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

C. Engagements for the supply of natural gas and condensate (Cont.):

1. 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: (Cont.):

d) 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.

e) In accordance with the terms of 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 by the buyer in the 3 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. During 2024 and 2025, two customers announced the exercise of their option, and in accordance with the option terms, the reduction took effect during 2025 and 2026, respectively.

f) The export to Egypt approval of 17 December 2025 sets forth instructions regarding the gas quantities the Leviathan partners are required to make available to domestic consumers, as well as the terms and conditions (including the price) to be offered to domestic consumers for the purchase of such gas quantities, as described in Section C3C below.

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 approx. 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.

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 (Cont.):

a) (Cont.)

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 15 January 2026, 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 2026-2027, and that the minimum annual quantity that NEPCO had undertaken to take or pay for during 2026-2027 would increase accordingly. The aforesaid does not change the total supply volume under the Export to Jordan Agreement (approx. 45 BCM), and the quantity specified in the export approval as specified above and below.

In October 2024, an agreement was signed between the Marketing Company and FAJR for the supply of a total volume of approx. 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". Furthermore, the agreement was conditioned upon the obtainment of the required regulatory approvals in Israel, including an export approval from the Petroleum Commissioner, and in Jordan, the signing of a transmission agreement with INGL, which will enable the flow of the quantities under the agreement, and the receipt of a tax ruling. In July 2025, all of the conditions precedent have been fulfilled for the taking effect of this agreement, and the supply of gas thereunder commenced in October 2025.

b) In July 2025 the Leviathan partners and industrial plants in Jordan signed an agreement for the supply of natural gas for a period of approx. 15 years, with a total volume of up to approx. 2 BCM. The gas will be supplied via the INGL system in the Dead Sea area (Jordan South). The gas price formula set forth in this agreement is based on linkage to the Brent prices and includes a "floor price". The agreement taking effect is contingent upon several conditions precedent. As of the date of approval of the consolidated financial statements, the conditions precedent for its taking effect have been fulfilled, and gas supply thereunder is expected to commence in the coming weeks.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

D. 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:

a. 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. For details about the amendment of the export to Egypt agreement of 7 August 2025, see Section 12C3(b) below.

Below is a summary of the details and terms and conditions of the Leviathan project export agreement:

1. The total contract gas quantity which the Leviathan Partners have undertaken to supply to the Buyer on a firm basis is approx. 60 BCM (the "**TCQ**").
2. 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.
3. 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, approx. 2.1 BCM per year; (ii) in the period that commenced on 1 July 2020 and ended 30 June 2022, approx. 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, approx. 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 12D2 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.
4. 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 12J4 below regarding a claim and a motion for class certification thereof which was filed against the Partnership in connection with such clause).

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.):

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).

5. 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[43] 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. The parties consensually waived the price update for the fifth year (2025).
6. To facilitate an increase in the export quantities to Egypt, 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 12D2(c) below.

b. On 7 August 2025, On 7 August 2025, the Leviathan Partners engaged with Blue Ocean in an amendment to the Export to Egypt Agreement (the "**Amendment**" or the "**Amendment to the Export to Egypt Agreement**"). Below is a concise description of its highlights:

1) Under the Amendment, the total contract quantity under the Export to Egypt Agreement shall be increased by a total volume of approx. 130 BCM (the "**Additional Quantities**"), to be added to the existing quantity set forth in the Export to Egypt Agreement as aforesaid, in two tranches as specified below: (1) An additional gas quantity of approx. 20 BCM from the taking effect of the Amendment (the "**First Tranche**"); and (2) An additional gas quantity of approx. 110 BCM, subject to satisfaction of the conditions specified in Section (c) below (the "**Second Tranche**").

[43] See footnote 41 above.

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.):

2) The First Tranche: The daily gas quantity that the Leviathan Partners are obligated to supply to Blue Ocean in the Export Agreement shall be increased from 450 MMSCF per day (approx. 4.7 BCM per year) to 650 MMSCF (approx. 6.7 BCM per year), from the date on which INGL completes the construction of the Ashdod-Ashkelon offshore section and the Leviathan Partners complete construction of the Third Pipeline Project (for further details about the Ashdod-Ashkelon offshore section and about the Third Pipeline Project, see Sections 7C1B(2) above and 12D2(a) below, respectively).

3) The Second Tranche: The Leviathan Partners' undertaking to supply the Second Tranche is subject to satisfaction of the following conditions: (1) Adoption of a Final Investment Decision (FID) by the Leviathan Partners for the First Phase of the Expansion Project under the Updated Development Plan for the Leviathan Reservoir. This condition was fulfilled on 15 January 2026. For further details about the Expansion Project, see Note 7C1 above; and (2) Engagement by the Leviathan Partners (or another on their behalf) with INGL in a transmission agreement for the Nitzana Pipeline (collectively: the "**Conditions to the Second Tranche**") for the supply of the gas to the buyer at the delivery point on the Israel-Egypt border. This condition was fulfilled on 16 September 2025. Therefore, as of the date of approval of the consolidated financial statements, the Conditions to the Second Tranche have been met. Upon fulfillment of the conditions for the gas supply in the Second Tranche, the daily gas quantity that the Leviathan Partners are committed to supply to Blue Ocean will be increased to 1,150-1,250 MMSCF (approx. 11.9-12.9 BCM per year), according to the mechanism described below. The Amendment to the Export Agreement determines a mechanism for the timing of commencement of the supply of the increased daily quantity (the "**Expansion Date**"), which is primarily based on the Leviathan Partners' estimate regarding the progress of the projects required for expansion of the daily supply quantity, and chiefly completion of the First Phase of the Expansion Project and completion of the project for the construction of the Nitzana Pipeline. The Leviathan Partners' assessment, as of the date of approval of the consolidated financial statements, is that the said projects are expected to be completed in 2029.

4) According to the Amendment to the Export Agreement, on the date of completion of the Ashdod-Ashkelon offshore section and the Third Pipeline Project, the supply period shall be extended until 10 years after such date or until the date on which Blue Ocean shall consume the total contract quantity (i.e., including the First Tranche), whichever is earlier. In addition, on the Expansion Date, the supply period shall be extended until 31 December 2040 or until the date on which Blue Ocean shall consume the total contract quantity (i.e., including the Second Tranche), whichever is earlier. If, at the end of the supply period, Blue Ocean shall not have consumed the total contract quantity, the supply period shall automatically be extended until the date on which Blue Ocean shall consume the total contract quantity, provided that the extension period does not exceed an additional two years.

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.):

5) The Amendment to the Export to Egypt Agreement includes, *inter alia*, the following additional changes:

a) Blue Ocean undertook to take or pay (TOP) for the Additional Quantities according to the mechanisms determined in the Amendment to the Export Agreement.

b) Blue Ocean's right to reduce the TOP quantity in a year in which the average Brent price (as defined in the Export to Egypt Agreement) falls below $50 per barrel, was cancelled.

c) Provisions were determined regarding the price of the gas to be supplied to Blue Ocean under the Export Agreement as well as a price mechanism in relation to the gas quantities to be supplied under the Second Tranche, in accordance with a formula based on the Brent oil barrel price which includes a "floor price".

d) The current price update mechanism, within the meaning thereof in Section (c) above, shall apply to the outstanding quantities to be supplied under the original total contract quantity of the Export to Egypt Agreement, as well as to quantities to be supplied under the First Tranche. With respect to quantities to be supplied under the Second Tranche, a similar mechanism shall apply for updating the price by up to 10% (up or down) after the fifth year (according to the sellers' estimate, in 2035) and after the tenth year from the Expansion Date (according to the sellers' estimate, in 2040). If the parties do not reach agreements on the price update, as detailed above, each one of the parties shall be entitled to reduce the daily gas quantity left to supply under the Amendment to the Agreement, as detailed in Section (c) above, by up to 30% on the first adjustment date and up to 30% on the second adjustment date.

e) Blue Ocean's right to terminate the Export Agreement in the event of termination of the export agreement between Blue Ocean and the holders of the interests in the Tamar project, was canceled.

f) Upon receipt of Blue Ocean's approval of the provisions of the export permit on 15 January 2026, all of the conditions precedent for the Amendment to the Export to Egypt Agreement have been fulfilled, and it took effect.

c. Further to the engagement in the Amendment to the Export to Egypt Agreement, as detailed in Paragraph B above, on 17 December 2025 the leaseholders received the Petroleum Commissioner's approval for export of the Additional Quantities under the Amendment to the Export to Egypt Agreement to Blue Ocean (the "**New Approval**"). In the Partnership's estimation, the New Approval enables compliance with the provisions of the Amendment to the Export to Egypt Agreement, including the supply of the Additional Quantities to Blue Ocean. The New Approval was granted in addition to the export approval granted to the leaseholders on 16 December 2019 (the "**Previous Approval**") and it stipulates that it supersedes any contradictory provision in any other document, including the Amendment to the Export to Egypt Agreement.

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.):

c. (Cont.):

Following is a concise description of the principal conditions of the New Approval:

1) Natural gas quantities under the New Approval may be exported as of the date on which the daily production capacity of the Leviathan reservoir amounts to a minimum of 1,350 MMSCF. The New Approval shall be effective until the earlier of the following: (1) The date on which Blue Ocean consumes the maximum total quantity specified in the New Approval; (2) The date on which the Amendment to the Export to Egypt Agreement comes to an end; (3) The expiration of the Leviathan lease deeds (the "**Term of Export**").
2) The New Approval and its provisions do not derogate from the power conferred on the Minister of Energy pursuant to Section 33 of the Petroleum Law nor from the provisions of the Emergency Regulations.
3) The supply of any quantity to the Buyer shall be subject to supply by the leaseholders of the full gas quantities nominated by the domestic-market consumers (under firm agreements or under binding spot nominations), including at the daily and annual levels.
4) The New Approval was granted for a maximum total quantity to be added to the export quantities pursuant to the Previous Approval, as follows: (a) Until such time as the reservoir's daily production capacity is 1,850 MMSCF (the "**First Expansion**") – the maximum total quantity shall be approx. 20.7 BCM; (b) Until such time as the reservoir's daily production capacity is 2,100 MMSCF (the "**Second Expansion**") – the maximum total quantity shall be approx. 95.6 BCM; and (c) After the Second Expansion – the maximum total quantity shall be approx. 130.9 BCM (in this section: the "**Total Export Quantity**"). The quantities specified in Subsections (b) and (c) above are subject to the recoverability of a volume of natural gas throughout the life of the reservoir (2C+2P categories) of no less than 535 BCM, as shall be determined by the Petroleum Commissioner based on the opinion of professional experts in the field of reserves evaluation, prepared in accordance with generally accepted industry standards. The Petroleum Commissioner may, from time to time, reduce the aforesaid quantities in the event that the quantity recoverable from the reservoir is lower, or if he finds that the development plan is not being implemented with due diligence.
5) The New Approval specifies the maximum daily and annual quantities that may be exported, in accordance with the various expansion phases and the seasonal demand volumes in the domestic market (the "**Maximum Quantities**"). It also provides that in the event of a gap between the total maximum daily quantities in a certain year and the maximum annual quantity determined for that year, the leaseholders may compensate for the shortfall by export on a spot basis, subject to certain conditions as set out in the New Approval. Beginning on 1 January 2036, the Petroleum Commissioner may, by a reasoned decision, reduce the Maximum Quantities by up to 60%, for all or part of the calendar year, in view of a change between the years in the gap between demand and supply in the domestic market, but without thereby affecting the Total Export Quantity. Notice shall be given to the leaseholders at least one year in advance of the anticipated issuance of such a decision. The aforesaid notwithstanding, in the event that such a notice is given, insofar as the Commissioner finds, in proximity to the reduction date, that there is no need for a reduction, he shall inform the leaseholders as soon as possible.

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.):

c. (Cont.):

5) (Cont.):

The New Approval states that, based on the Ministry of Energy's assessments as of the approval grant date, such a gap is indeed expected. Without derogating from the foregoing, where the Petroleum Commissioner finds that the aggregate supply of natural gas delivered to the domestic market from all producing reservoirs has been continuously lower, for a period exceeding 28 days, than the quantities required by the domestic market, he may, after consulting with the Director of the Natural Gas Authority, reduce the Maximum Quantities. The Petroleum Commissioner's decision regarding reduction of the export quantity in these circumstances shall first be examined for the reservoir from which the supply to the domestic market was reduced.

6) In the event that, after the date of the Second Expansion, the actual production capacity of the leases increases and exceeds 2,100 MMSCF per day (in this section: the "**Increase in Production**"), the leaseholders may export one half of the Increase in Production through spot transactions; and in relation to the second half, the leaseholders may submit an application to the Petroleum Commissioner to increase the maximum daily quantity or to increase the excess quantity permitted for export through spot transactions as noted above.

7) The New Approval specifies provisions that regulate the possibility of reducing the Maximum Quantities in the event that the production from the reservoir on a certain day is lower than the full production capacity, as determined in the New Approval, the principal purpose of which is to prioritize allocation to domestic-market consumers while ensuring a minimal daily export quantity subject to certain conditions.

8) In the context of receiving the New Approval, the leaseholders undertook to offer all consumers in the domestic market to enter into binding agreements with them for the purchase of natural gas ("**Firm Contracts**"), for a period of between 1 and 8 years but not beyond expiration of the New Approval (or a longer period insofar as agreed between the parties), for any quantity requested within the difference between the full production capacity at such time, net of the total of (a) the maximum daily quantity specified in the New Approval; and (b) obligations under the leaseholders' existing Firm Contracts, except for the Amendment to the Export to Egypt Agreement. The New Approval includes provisions to ensure the fixed daily quantity that shall be offered in the Firm Contracts, depending on the term of the agreement. In addition, the leaseholders shall offer all consumers in the domestic market to enter into a contract with them for the purchase of natural gas on a spot basis for a period of at least one year (in this section: "**Spot Contracts**"), for any quantity requested within the difference between the Leviathan reservoir's full production capacity on the gas nomination date and the aggregate daily obligations at such time under Firm Contracts they have signed, except for the obligations under the Amendment to the Export to Egypt Agreement. The leaseholders shall offer consumers in the domestic market with which they shall negotiate such Firm Contracts and Spot Contracts, price and linkage formula alternatives, as specified in such obligation.

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.):

Such alternatives include the price and linkage formula alternatives determined in Government Resolution 476 on the Gas Framework, as well as an additional linkage formula that shall be offered to independent power producers, which is based on the household electricity tariff. Notwithstanding the aforesaid, the obligation to offer the price alternatives in relation to Spot Contracts shall only apply until the date of the Second Expansion or until the end of 2030 (whichever is later). If the date of the Second Expansion falls before the end of 2032, such obligation shall continue to apply solely in relation to the peak months (as defined in the New Approval), until the end of 2032. In addition, on 15 February 2026, the Partnership received a request for information from the Competition Authority, pursuant to Section 46(b) of the Economic Competition Law, under which the Partnership was required, *inter alia*, to provide the Competition Authority with a complete copy of the obligations of the leaseholders in the Leviathan reservoir that were given in the context of the New Approval, as well as a final document that was delivered to the Petroleum Commissioner that includes the said obligations in connection with the New Approval.

9) The New Approval sets down provisions whereby, in addition to the foregoing, the leaseholders may export natural gas quantities, in accordance with the New Approval together with the Previous Approval, on a spot basis, subject to all gas quantities that have been nominated by the leaseholders' customers in the domestic market having been supplied and subject to the following limits: Until the date of the Second Expansion or until the end of 2030 (whichever is later) – without any quantitative limit; from the date of the Second Expansion or from the end of 2030 (whichever is later) – up to 2 BCM per year over and above the annual quantity specified in the New Approval, subject to certain daily limits as specified, and also subject to the Commissioner's power to determine additional quantitative limits in certain cases, all up to the Total Export Quantity.

The New Approval sets down additional provisions that address, *inter alia*, the ability to receive approval for the export of gas to the buyer in excess of the Maximum Quantities upon the occurrence of a material change in market conditions; provisions that concern cases in which the export quantity on a certain day is lower than the maximum daily quantity due to nominations received from domestic market consumers; provisions pertaining to reports to the Petroleum Commissioner, disclosure on related agreements, the requirement of the Petroleum Commissioner's approval for any change in the Export Agreement and in related agreements, and provisions on additional matters, including provisions regarding the Commissioner's powers in the case of a breach of the leaseholders' obligations in the context of receipt of the New Approval. Furthermore, concurrently with receipt of the New Approval and at the request of the Ministry of Energy, the leaseholders have confirmed that they shall work together with the Natural Gas Authority on promotion of a platform for the secondary trading of natural gas for natural gas consumers in the Israeli market, and shall also jointly examine various options in connection with the natural gas quantities that may be directed to the trading platform once established, under spot agreements, which quantities shall be purchased in accordance with the standard contractual terms and conditions in sale agreements and shall be carried out according to standard international practice. In this context it is noted that on 25 February 2026, it was posted on the website of the Ministry of Energy that the Natural Gas Authority is promoting the establishment of a natural gas trading platform.

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.):

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.

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.

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.):

On 15 January 2026, an amendment was signed to the Capacity Allocation Agreement for expansion of the capacity reserved for Blue Ocean by an additional 200 MMSCF, to enable the transmission of additional quantities in accordance with the amendment to the export agreement with Blue Ocean. Expansion of the reserved capacity shall take effect on the date on which BOE gives notice to EMED as aforesaid, and shall remain in effect until the end of 2040. The parties undertook to work on extending the term of the Capacity Lease and Operatorship Agreement or finding an alternative to enable the transmission of gas in the EMG pipeline under similar conditions.

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 purchased 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 approx. 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. 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.

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:

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.

As specified in Section 6 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.

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. **Agreement for the supply of natural gas between the Leviathan partners and the Yam Tethys partners:**

   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. As of the date of approval of the consolidated financial statements, the Leviathan partners are considering the possibility of exporting condensate from the Leviathan project using existing third-party systems. In this context, consideration is being given to the possibility of adapting the existing transmission and storage infrastructure for transportation of condensate from the Leviathan project, storage and loading thereof onto vessels for export. In addition, the Leviathan partners are considering the possibility of engaging in agreements for the sale of condensate to potential international customers. The export of condensate from the Leviathan project may depend on commercial, technical, operational, regulatory and other factors.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

C. Engagements for the supply of natural gas and condensate (Cont.):

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.

10. **Dependence on a customer:**
    As of 31 December 2025, 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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)

D. 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.):

D. 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.

a) **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 approx. 600 MMCF per day (approx. 6 BCM per year) to approx. 650 MMCF per day (approx. 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 approx. 850 MMCF per day (approx. 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, including another postponement due to Operation Roaring Lion, and as of the date of approval of the consolidated financial statements, the commencement of flow is expected in Q3/2026.

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 25 December 2024, Chevron and INGL signed an addendum to the 2019 Agreement, whereby the agreement was extended at such date until the earlier of: (1) The expiration date of the agreement according to its terms and conditions; (b) The Piping Commencement Date as defined in the agreement for transmission on a firm basis, which is described below, and as part of the settlement agreement signed between Chevron and INGL regarding the 2019 Agreement and the 2021 agreement, was set for 5 August 2025. 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 in this section: the "**Transmission Agreement**" or, in this section: the "**Agreement**").

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

D. 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 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 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. On 11 May 2025 and 18 September 2025, the General Partner's Board approved an additional budget of approx. $29 million (100%, for the Leviathan Partners, the Partnership's share – approx. $13 million) and approx. $7.6 million (100% for the Leviathan Partners, the Partnership's share – approx. $3.5 million), respectively, for completion of the said work, as a result of the war and the delay in the timetable for completion of the work consequently thereto, such that, as of the date of approval of the consolidated financial statements, the approved budget totals approx. $139 million (100% for the Leviathan Partners, the Partnership's share – approx. $63 million).

   In Chevron's estimation, the dates of completion of construction of the Combined Section and the commencement of gas transmission are expected in Q3/2026.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

D. 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. Furthermore, it was agreed that allocation of the construction costs among the partners in the Leviathan and Tamar projects will be carried out based on the actual transmission rates. In July 2024 the ratio of allocation between the Leviathan partners and the Tamar partners was updated to 72.04% and 27.96%, respectively.

7) 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.

8) 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.

9) 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 12J8 below.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

D. 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.):

10) On 25 December 2025, and further to Chevron's engagement with INGL in a settlement agreement as provided in Note 12J8 below (the "**Settlement Agreement**"), the parties entered into an amendment to the 2019 Agreement, whereby the agreement was extended until the earlier of: (a) The agreement expiration date in accordance with its terms; or (b) 1 January 2027 (in lieu of 1 January 2026); or (c) the Transmission Commencement Date, as defined in the transmission agreement on a firm basis described in Section (1) above (scheduled for 5 August 2025), at which time the Transmission Agreement would enter into force on the terms specified in the Settlement Agreement, which include, *inter alia*, Chevron's obligation to pay for the transmission of gas in a quantity no lower than 4 BCM per year.

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 transmission capacity (through Chevron) under the Transmission Agreement, and will be responsible for the performance of Chevron's obligations and its bearing of the costs 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 Note 12C3D above. 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 in which case the allocation will be carried out based on actual use. See paragraph 6 in connection with an update to the allocation ratio between the Leviathan partners and the Tamar partners.

b) **Project for the onshore connection between the Israeli transmission system and the Egyptian transmission system in the area of Nitzana:**

On 16 September 2025 Chevron entered into an agreement for the provision of transmission services with INGL for the purpose of piping natural gas from the Leviathan reservoir to Egypt through the Nitzana Project (the "**Transmission Agreement**"). The project for the onshore connection between the Israeli transmission system and the Egyptian transmission system in the area of Nitzana (the "**Nitzana Project**"), includes a pipeline and the construction of a compressor station in the area of Ramat Hovav. On 23 October 2025, the Leviathan Partners received notice from the Gas Authority, whereby the rate of the Nitzana Project allocated to the Leviathan project has been revised to 41.8% (the "**Updated Allocated Rate**"). Of note, to the best of the Partnership's knowledge, the remaining capacity of the Nitzana Project will be allocated to the partners in the Tamar project (41.8%) and to Energean (16.4%).

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

D. 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.):

Further to this notice, on 23 October 2025, Chevron, on behalf of the Leviathan Partners, signed an amendment to the Transmission Agreement intended to reflect the Updated Allocated Rate (the "**Amendment to the Agreement**"). Furthermore, to the best of the Partnership's knowledge, concurrently therewith, the said other two exporters also signed transmission agreements with INGL in respect of the share allocated to them in the project, thereby satisfying the conditions precedent that had been stipulated for the Transmission Agreement's entry into force and effect.

Pursuant to Resolution No. 3/2023 of the Natural Gas Commission regarding the financing and allocation of capacity in the export lines, the capacity of the Nitzana Project is estimated by the Gas Authority at approx. 6 BCM per year. According to such resolution, 70% of the capacity allocated to each exporter shall be on a firm transmission basis and the remainder shall be on an interruptible transmission basis. Further to the Amendment to the Agreement as aforesaid, the allocation to the Leviathan Partners is 41.8%, and the daily firm transmission capacity guaranteed to the Leviathan Partners shall be approx. 175,560 MMBTU (the "**Basic Capacity**").

Below is a summary description of key points of the Transmission Agreement and the related agreements signed in connection therewith, between the Leviathan Partners:

1. The Transmission Agreement regulates INGL's undertaking to construct the Nitzana Project and supply natural gas transmission services from the Leviathan reservoir, pursuant to Resolution No. 3/2023 and Resolution No. 2/2014 of the Natural Gas Commission regarding the financing of export projects through the Israeli transmission system.
2. The flow of gas under the Transmission Agreement shall commence no later than 36 months from the date of fulfillment of the conditions precedent, as set forth in Section 8 below (the "**Flow Commencement Date**").
3. In consideration for the transmission services regarding the Basic Capacity, Chevron shall pay a transmission tariff comprising a capacity fee and a throughput fee for the gas quantity actually transmitted, in accordance with the standard transmission tariffs in Israel, as may be updated from time to time. In addition, INGL undertook to provide interruptible transmission services of additional quantities of gas over and above the Basic Capacity, subject to the capacity available in the transmission system, in a minimum scope no less than 1.8 BCM per year (for all of the exporters that shall engage in the Transmission Agreement). For the transmission of such additional quantities, Chevron shall pay a transmission tariff for interruptible transmission services in respect of the actual quantities transmitted, as shall be determined by the Gas Authority. In addition, Chevron shall bear its proportionate share (according to Leviathan Partners' allocation rate) of the operating costs of the Nitzana Project facilities, including the fixed costs of the Project facilities, including the compressor station and variable costs for electricity consumption for operating the compressor station, based on the actual rate of use.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

D. 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.):

4. The Transmission Agreement shall terminate upon the earlier of: (a) the date on which the agreement is terminated pursuant to its terms and conditions; (b) 15 years following the Flow Commencement Date; or (c) the expiry of INGL's transmission license. In addition, Chevron may extend the term of the agreement by up to 5 additional years by advance notice, or to terminate the agreement by advance notice, following the earlier of: (a) 8 years after the Flow Commencement Date; or (b) the date on which the overall transmitted quantity reaches approx. 11.4 BCM.
5. The agreement further provides that in the event of a halt in the majority of natural gas exports from Israel to Egypt (at least 90%, and excluding secondary trade exports and exports through the EMG pipeline), not resulting from a breach of the relevant export agreement by Chevron, Chevron shall be entitled, one time during the period of the Transmission Agreement, to terminate the same by advance notice. If, after such termination and until the end of 15 years from the Flow Commencement Date, exports to Egypt resume, the Transmission Agreement shall be reinstated in accordance with the capacity to be available in the transmission system at that time.
6. Pursuant to the principles set out in Resolution 3/2023, Chevron's share (for the share of the Leviathan Partners in the Nitzana Project) in the total financing of the construction of the Nitzana Project shall be according to Leviathan's allocation rate. The Transmission Agreement determines an estimated budget for construction of the Nitzana Project of approx. $608 million (the Partnership's share – approx. $115 million). The Transmission Agreement further determines that INGL shall be entitled to update the estimated budget by up to another approx. 12% during the course of the Project, according to the actual costs of the Project. Payment shall be made according to milestones set out in the agreement, with 40% of the amount to be paid shortly after the fulfillment of the conditions precedent as set forth in Section 8 below, and the balance to be paid according to the progress of construction of the Nitzana Project. In addition, Chevron and/or the Leviathan Partners (according to their proportionate share in the Leviathan Project) are required to provide guarantees to INGL to secure Chevron's undertakings for financing the Nitzana Project and for payments for transmission under the agreement, see Section E(10) below.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

D. 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.):

7. During the period until the Flow Commencement Date, Chevron shall be entitled to divert the Basic Capacity or any part thereof to the Jordan North line, subject to the terms and conditions set forth in the Transmission Agreement. In addition, after the Flow Commencement Date, and throughout the term of the Agreement, in the event that transmission of gas through the Nitzana Project is not possible for whatever reason, Chevron shall be entitled to divert the Basic Capacity or any part thereof to the Jordan North line, subject to the terms and conditions set forth in the Transmission Agreement.
8. The validity of the Transmission Agreement is subject to the fulfillment of the following two conditions precedent by the allocation determination date: (1) approval of the Transmission Agreement by the Gas Authority; and (2) the signing of gas transmission agreements with the other exporters covering the full construction costs of the Nitzana Project. With respect to this second condition, the agreement provides that it shall be deemed fulfilled also if, before the allocation determination date, one or more of the three exporters signs a transmission agreement and undertakes to bear the entire construction budget. In such case, the proportionate share of the undertaking exporters shall be determined by equal division of the total capacity, and they shall be subject to milestone payments and provision of collateral according to their share. As of the date of approval of the Consolidated Interim Financial Statements, the aforesaid conditions precedent for the Transmission Agreement have been satisfied.
   In addition, to the best of the Partnership's knowledge, following all the exporters' signing of the Transmission Agreement, the Transmission Agreement took effect on 23 October 2025. Moreover, to the best of the Partnership's knowledge, on 5 November 2025, Chevron and INGL signed an agreement for the performance of design work, procurement and construction of a compression system and valve station for the Nitzana Project (the "**Compressor Station**"), which provides for the terms and conditions of construction of the Compressor Station.
9. Concurrently with the signing of the Transmission Agreement, Chevron and the other Leviathan partners signed a services agreement (the "**Services Agreement**"), under which it was determined that the Leviathan Partners shall be entitled to transmit natural gas (through Chevron) under the Transmission Agreement, and be responsible for the fulfillment of Chevron's undertakings under the Transmission Agreement on a back-to-back basis, as if the Leviathan Partners were a party to the Transmission Agreement instead of Chevron, each according to its proportionate share in the Leviathan Project. For the purpose of regulating the partners' activities under the Transmission Agreement, the Services Agreement determines approval procedures and authorizations required from the partners for various actions.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

D. 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.):

The Services Agreement further determines that each partner shall bear its proportionate share of the costs related to the Transmission Agreement, including the connection fees (construction costs of the Nitzana Project), transmission fees, and operating costs of the Nitzana Project. The Services Agreement also provides that each partner shall be required to provide bank guarantees in favor of INGL in the amount of its proportionate share of the guarantees required under the Transmission Agreement.

10. In addition to the Services Agreement, Chevron and the other Leviathan partners signed another services agreement (the "**EPC Services Agreement**"). This agreement was signed since Chevron is expected to engage in an engineering, procurement and construction agreement (EPC) with INGL for the construction of the Compressor Station in the Nitzana Project, for a lump sum of approx. $285 million, which is included in the estimated budget for the Nitzana Project as provided in Section 6 above (the "**Fixed Consideration**"), reflecting the cost estimated for the compressor station in December 2024. Under the EPC Services Agreement, the Leviathan Partners undertook, each according to its proportionate share in the Leviathan Project, to bear the Leviathan Partners' share of any excess costs, if any, in the event that Chevron's actual execution costs for the compressor station exceed the Fixed Consideration.
11. According to the Operator's estimate, the completion of the Nitzana pipeline construction and the gas flow commencement date are expected during Q4/2028.

c) **Export of natural gas to Egypt through the Jordan-North Export Pipeline**

1. 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 (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 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, concurrently with the flow through the EMG pipeline.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

D. 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.):

2. In view of the delay in the completion of the project for the construction of the combined section, in February 2022, 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. 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. 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 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 set of agreements so signed includes the following agreements:

   a. 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.

   b. 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.):

D. 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.):

c. 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 2027, as part of an amendment signed on 25 December 2025 between Chevron and INGL, under which Chevron undertook to pay for the piping of a gas quantity of no less than 0.25 BCM per year.

d. 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. In a letter dated 28 December 2025, the Natural Gas Authority informed, *inter alia*, that the annual available transmission capacity for 2026 through the Jordan-North pipeline was 4.2 BCM. 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.

e. The Leviathan Partners and Blue Ocean signed an amendment to the agreement for export to Egypt as specified in Section 12C3B above.
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, it is not certain on the date of approval of the consolidated financial statements, 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 and which are not transmitted via the EMG pipeline.

d) **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 (b) above for the local transmission company (in this section: the "**Project**", "**Transmission System**" and "**Transmission Company**", respectively), as specified below.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

D. 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.):

d) (Cont.):

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.

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.):

D. 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.):

d) (Cont.):

2) 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.

3) 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, which is expected to increase the transmission capacity to approx. 11 BCM, is expected to occur during H2/2026.

e) The Jordan-South export pipeline, connects the Israeli transmission system in the Southern Dead Sea are to Jordanian industrial plants.

E. Pledges and guarantees:

1. Short-term (dollar) bank deposits as of 31 December 2025 in the sum of approx. $49.6 million used for debt service and current payments in the context of the issue of the Leviathan Bond bonds (see Note 10B above).
2. Long-term bank deposits as of 31 December 2025 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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

E. Pledges and guarantees (Cont.):

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 venture operator 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 via the Ashdod-Ashkelon pipeline (see Section D2A) 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. To secure a transmission agreement for the export of gas to Egypt via the Nitzana pipeline (see Section D2b), as part of the Partnership's activity in the Leviathan project, the Partnership provided bank guarantees and corporate guarantees in favor of INGL. As of the date of approval of the consolidated financial statements, the total sum is approx. ILS 135.3 million and approx. ILS 95.4 million, respectively.
11. In the context of the Partnership's operations in Morocco, the Partnership provided, as of the date of approval of the consolidated financial statements, a bank guarantee in the sum of approx. $1.75 million to ONHYM (see Note 7C4 above).
12. As part of the Partnership's activity in Bulgaria, the Partnership provided bank guarantees which, as of the date of approval of the consolidated financial statements, total approx. EUR 2.25 million, to the Bulgarian Ministry of Energy (see Note 7C6 above).
13. As of the date of approval of the consolidated financial statements, the Partnership provided guarantees in the sum of approx. $54.3 million to the Ministry of Energy in connection with its rights in the oil and gas assets, see Section G3 below.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

F. Engagement for renewable energy collaboration

1) 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 (CO2), with the carbon dioxide captured and stored in 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.

2) 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, under the collaboration with Enlight and according to the TASE Rules, for a period of 3 years (the "**First Period**"), with the First Period being extendable for additional periods of 3 years each, subject to the approval of the general meeting of participation unit holders by the required majority under the TASE Rules. The aforesaid notwithstanding, follow-on investments and/or investments in renewable energy projects in which the Partnership had (directly or indirectly) invested and/or committed to invest in the First Period, are not limited to such period, and shall be made out of the Investment Facility (as defined below) and/or from the internal sources of the Co-Owned Corporations and/or the project corporations. The said authorization to carry out renewable energy projects was limited 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) (the "**Investment Facility**"), 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. The First Period ended on 21 September 2025.
The collaboration with Enlight (as detailed below) with respect to the projects commenced before such date continues, up to the Investment Facility in accordance with the general meeting's approval, and according to the Collaboration Agreement. Collaboration with Enlight according to the Addendum to the Agreement (as defined below) with respect to additional projects, in which no investment was made, directly or indirectly, or an investment commitment, until the end of the First Period, will be subject to approval by the Partnership's meeting of unit holders.

b) As of the date of approval of the consolidated financial statements, the Partnership's renewable energy operations are conducted in collaboration with Enlight, as amended from time to time, as specified below:

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

F. Engagement for renewable energy collaboration (Cont.):

2) The Partnership's renewable energy operations are conducted in collaboration with Enlight (Cont.):

On 13 March 2023, the Partnership engaged with Enlight in a detailed agreement regarding exclusive collaboration for a 3-year 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). On 16 February 2026 the parties entered into an addendum to the agreement, in which they agreed to extend the Term of Exclusivity for the collaboration for an additional 3-year period (i.e., until 31 March 2029) which, in certain circumstances, may be extended up to a period of 5 years from the date of signing of the addendum to the agreement (in this section: the "**Addendum to the Agreement**").

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.

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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

F. Engagement for renewable energy collaboration (Cont.):

2) The Partnership's renewable energy operations are conducted in collaboration with Enlight (Cont.):

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.

c) 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. 234 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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

F. Engagement for renewable energy collaboration (Cont.):

2) The Partnership's renewable energy operations are conducted in collaboration with Enlight (Cont.):

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.

d) On 12 March 2025, MedLight engaged with a local partner in Egypt (a third party unaffiliated with the Partnership or Enlight, in this section: the "**Partner**") in an MOU for the development and construction of a renewable energy project in the Sinai peninsula, with the aim of exporting electricity to the State of Israel, the Palestinian Authority and the Gaza Strip. In this context, land was identified with an estimated production potential of approx. 4-5 GW, and certain geographic areas for construction of the production facilities were considered. The project is expected to be carried out in stages, with consideration being given in the first stage to a potential onshore connection in the Nitzana area, close to the existing gas pipeline route, and later, with the increase of the output, consideration will be given to laying a submarine cable along the route of the EMG pipeline infrastructure, enabling significant electricity transmission, relatively close to the consumption areas in Israel. It is clarified that implementation of the project (if promoted) is subject, *inter alia*, to completion of feasibility studies, engagement in binding agreements, receipt of approvals and permits from third parties and relevant authorities, commercial regulation of the sale of the electricity and the provision of financing, and arrangement/construction of transmission infrastructures and connection.

e) 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. 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 2030.
5) With respect to their past 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) Satisfaction of specific restrictions that will apply to new natural gas supply agreements

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 in effect, other than the restrictions below:

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

G. Regulation (Cont.):

1. The Gas Framework (Cont.):

c) (Cont.):

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. 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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

G. Regulation (Cont.):

2. Environmental Regulation (Cont.):

b) (Cont.):

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 E13 above).

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. 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. Over the years 2022-2025, INGL revised the project's budget several times. As of the date of approval of the consolidated financial statements, the budget is approx. $138.9 million (100% Leviathan partners; the Partnership's share – approx. $63 million).

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

G. Regulation (Cont.):

4. Projects for export through the national transmission system: (Cont.):

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 12D2(a) above.

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 (the "**Commission**") adopts resolutions that update the rates of the various transmission services.

b. According to the Commission's resolution no. 1/2020 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. In this context, on 26 November 2025, the Commission released a draft resolution for public comment on the criteria and tariffs regarding balancing the pressure in the transmission system. The draft resolution proposes amending the flow control balancing regime set forth in Commission resolution no. 8/2019, whereby transmission system users were required to maintain a balance between the gas quantities they nominated at the points of entry to the transmission system, and the quantities actually consumed at the points of exit. In the draft resolution, the Commission proposes transitioning to a daily balancing regime only, which is based on the purchase and sale of gas at market-based prices. Such balancing transactions would be carried out via a gas trading platform.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

G. Regulation (Cont.):

5. Natural Gas Commission resolution on the regulation of criteria and rates relating to the operation of the transmission system (Cont.):

c. On 4 June 2024, the 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% to ILS 0.5871 per MMBTU, and the natural gas flow tariff by approx. 7.6% to ILS 0.1071 per MMBTU.

d. On 20 December 2022, the Commission released resolution no. 4/2022, which determines a system-wide tariff that is due from consumers of the natural gas transmission system, to fund projects of infrastructures, development, backup, redundancy of system-wide needs of the natural gas sector, or actions a license holder is required to take under the Natural Gas Sector Law. According to Commission resolution no. 4/2025 of 24 December 2025, the system-wide tariff for 2026 is ILS 0.0038 per MMBTU.

e. On 24 December 2025, the Commission issued resolution no. 5/2025 regarding tariffs for interruptible transmission services in projects for natural gas export to neighboring countries. According to this resolution, the interruptible transmission tariff for export shall be calculated according to a formula combining the capacity component and the transmission component in the general transmission tariff, using a designated export load factor. The resolution distinguishes between two situations and sets a load factor of 0.95 when the exporter cannot sign a firm transmission agreement due to a regulatory decision or operational constraints (which are not the exporter's), and a load factor of 0.45 when the exporter chooses, for its own reasons, to sign an interruptible transmission agreement. It was also determined that interruptible transmission agreements for export shall be signed for a period of one year or more. It was further determined that this resolution would replace the interim order set forth in resolution 2/2019 and in the resolutions that amended it.

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.)

G. 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.):

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 12D2B 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.)

G. 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.

7. On 16 September 2025, Chevron, on behalf of the Leviathan Partners, entered into an agreement with INGL for the provision of transmission services, for the transmission of natural gas from the Leviathan reservoir to Egypt via the Nitzana Project (in this section: the "**Transmission Agreement**").

On 23 October 2025, the Leviathan Partners received a notice on behalf of the Gas Authority according to which the allocation rate for the Leviathan project in the Nitzana Project has been updated and will be 41.8% (the "**Updated Allocation Rate**"), and further to this notice, on 23 October 2025, Chevron signed, on behalf of the Leviathan Partners, an amendment to the Transmission Agreement intended to reflect the Updated Allocation Rate.

On 23 October 2025, Energean entered into a transmission agreement with INGL in connection with the Nitzana Pipeline for the transmission of 1 BCM per year for a period of 15 years, and its share in the pipeline's construction costs is 16.4%.

To the best of the Partnership's knowledge, due to the signing of the Transmission Agreement by all of the exporters, the Transmission Agreement took effect on 23 October 2025. Moreover, to the best of the Partnership's knowledge, on 5 November 2025, an agreement was signed between Chevron and INGL for the performance of work on planning, purchase and construction of a compressor system and valve station for the Nitzana Project (the "**Compressor Station**"), which regulates the terms and conditions of construction of the Compressor Station.

8. 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. On 4 June 2023 Chevron submitted its position on this document, as part of the public comments. On 18 February 2026 Chevron received a detailed response to its comments, which it is now studying. 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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.)
G. Regulation (Cont.):

9. **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 12I 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 12E(13) 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.

H. 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, the Partnership's operations in the Block 12 joint venture in Cyprus is carried out by Chevron Cyprus, and the Partnership's operations in the Bulgaria License is carried out by OMV Bulgaria. Under the joint operation agreements (in this section: the "**JOAs**") in such joint ventures and licenses, it was agreed that Chevron, Chevron Cyprus and OMV Bulgaria, 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, Chevron Cyprus and OMV Bulgaria, are entitled to reimbursement of indirect expenses which are calculated as a percentage of the direct expenses, as specified below:

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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

H. Reimbursement of indirect expenses to project operators (Cont.):

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%.

The Bulgaria License

OMV Bulgaria is entitled to reimbursement of any and all direct expenses it incurs in connection with its role as operator, as well as reimbursement of indirect expenses derived from the joint venture's expenditure rate, depending on the type of activity in the block as specified below (provided that in any event, the annual payment for indirect expenses shall be no less than €200,000): In the exploration stage, the rate of indirect expenses shall be 2% of direct expenses; in the development stage, the rate of indirect expenses shall be 1.5% of direct expenses; and in the production stage, the rate of indirect expenses shall be 1% of direct expenses.

I. 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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

I. Agreement for the grant of usage rights in the facilities of the Yam Tethys project (Cont.)

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 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. 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.

J. 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 2025, 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 2025 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 17 May 2026. 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 $8.0 million (of which approx. $2.4 million to related parties).

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):
J. Legal Proceedings (Cont.):

1. (Cont.):

   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.

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 3 August 2026.
   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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

J. Legal Proceedings (Cont.):

3. (Cont.):

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. 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, the Respondents' summations were filed with the court in August 2025, and the Petitioners' responding summations were filed with the court in 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 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 (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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

J. Legal Proceedings (Cont.):

4. (Cont.):

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.

Trial hearings took place in November 2022. On 10 December 2023, the Petitioner filed closing arguments on his behalf, on 13 March 2025, the Respondents filed closing arguments on their behalf, and on 3 August 2025, the Petitioner filed responding arguments on his behalf. On 12 August 2025, the Petitioner filed a motion to submit a new document as evidence in the proceeding, and on 30 October 2025, the Respondents filed their response to the said motion. On 9 November 2025, the court accepted the Petitioner's proposal whereby each party address the evidence to be filed, and according to the court's decision, on 11 November 2025, the Petitioner filed the additional evidence on his behalf, on 8 December 2025, the Partnership filed its response to the new evidence, and on 16 December 2025 the Petitioner filed his reply. The court also ruled in its decision of 18 December 2025 that the Certification Motion is to be decided. On 10 December 2023, the Petitioner filed closing arguments on his behalf, on 13 March 2025, the Respondents filed closing arguments on their behalf, and on 3 August 2025, the Petitioner filed responding arguments on his behalf. On 12 August 2025, the Petitioner filed a motion to submit a new document as evidence in the proceeding, and on 30 October 2025, the Respondents filed their response to the said motion. On 9 November 2025, the court accepted the Petitioner's proposal whereby each party address the evidence to be filed, and according to the court's decision, on 11 November 2025, the Petitioner filed the additional evidence on his behalf, on 8 December 2025, the Partnership filed its response to the new evidence, and on 16 December 2025 the Petitioner filed his reply. The court also ruled in its decision of 18 December 2025 that the Certification Motion is to be decided. In the Partnership's estimation, based on an opinion of its legal counsel, chances of the motion being granted are lower than 50%.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

J. Legal Proceedings (Cont.):

5. 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. 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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

J. Legal Proceedings (Cont.):

5. (Cont.):

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. On 10 March 2025, the final pretrial hearing and the hearing of Haifa Port's motion to summon the customs representative for testimony were held, and dates were scheduled for the trial hearings in the months of September through November 2025. In the court's decision of 20 March 2025, Haifa Port's motion to summon the customs representative for testimony was denied. Further thereto, the parties agreed to refer the case to mediation, and in September, several mediation sessions in the proceeding were held before the Hon. Justice (Ret.) Zvi Zylbertal. Accordingly, some of the trial hearings that were scheduled in the proceeding were canceled. On 14 December 2025, the court entered a judgment on the mediation agreement on which the parties had agreed, according to which the claims were mutually dismissed, with no order for costs. 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.

6. 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); 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**").

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

J. Legal Proceedings (Cont.):

6. (Cont.):

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 Partnership filed its closing arguments in October 2025, and the Petitioner filed a responding arguments on his behalf in December 2025. The court further ruled that the Attorney General is required to file her position on the status of the institutional bodies in overrulings, such as those contemplated in the Discovery Motion, by 5 February 2026 and accordingly, on 15 February 2026, the Attorney General filed a notice with the court whereby she did not see fit to add to the statements made in the positions filed by her behalf in the proceeding to date. On 25 June 2025, the Petitioner filed a motion for the adjudication of a fee in the sum of ILS 950,000 (plus VAT) for his counsel, and according to the court's decision, on 7 August 2025, the Partnership filed its response to the motion. On 10 August 2025, the court ordered dismissal of the said motion, with no order for costs. In the Partnership's estimation, based on an opinion of its legal counsel, chances of the Discovery Motion being granted are lower than 50%.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

J. Legal Proceedings (Cont.):

7. 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. 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.

Note 12 – Contingent Liabilities, Engagements and Pledges (Cont.):

J. Legal Proceedings (Cont.):

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 Note 12D2(a) below, 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). Concurrently with the said arbitration proceeding, the parties have referred the case to mediation with the aim of attempting to reach agreements without an arbitration award. On 6 May 2025, a third mediation session in the proceeding was held, at the end of which the parties reached an in-principle agreement, which was subject to final approval by INGL and the partners in the Leviathan and Tamar projects, in connection with a settlement arrangement whereby, *inter alia*, INGL shall credit Chevron (and consequently the partners in the Leviathan and Tamar projects) with part of the transmission fees paid to INGL for the transmission to EMG's terminal in Ashkelon, and in connection with several changes to the transmission agreement, including the transmission fees that Chevron shall pay in 2025-2026, and extension of the transmission agreement by two years. The reimbursement expected to be received by the Partnership is in a non-material amount. On 5 August 2025, the parties signed a settlement agreement that is based on the principles on which they agreed as aforesaid, and on 19 August 2025, an arbitration award was entered on the said settlement agreement, with each party bearing its own costs.

Note 13 – The Partnership's 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 2025: 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 20C.

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 ($)
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
19.3.2024	11.4.2024	60	0.05112
24.5.2024	20.6.2024	60	0.05112
8.8.2024	5.9.2024	65	0.05538
20.11.2024	12.12.2024	65	0.05538
10.3.2025	3.4.2025	60	0.05112
12.5.2025	5.6.2025	60	0.05112
8.8.2025	28.8.2025	60	0.05112
10.11.2025	4.12.2025	60	0.05112
15.3.2026	31.3.2026	70	0.05963

Notes to the Consolidated Financial Statements as of 31 December 2025 (Dollars in millions)

Note 13 – The Partnership's 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).

c) On 11 May 2025 and 4 September 2025, 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. Equity composition attributable to the holders of the Partnership's participation units as of 31 December 2025 is as follows:

	The Limited Partner	The General Partner	Total
The Partnership's equity	154.8	-[44]	154.8
Capital reserves	(26.7)	-[44]	(26.7)
Retained earnings	1,763.1	0.2	1,763.3
Balance as of 31 December 2025	**1,891.2**	**0.2**	**1,891.4**

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).

E. On 12 May 2025, 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.

F. With respect to the equity instrument-based payment of the Partnership and the Partnership's subsidiaries granted to the Partnership's CEO, see Note 20C below.

[44] Less than $0.1 million.

Notes to the Consolidated Financial Statements as of 31 December 2025 (Dollars in millions)

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 are affected mainly by the volume of natural gas consumption by the domestic market, Egypt and Jordan (the "**Regional Market**"), by the production and transmission capacity and from the gas price, which is partly linked to the price of Brent oil barrel. 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 period of the consolidated financial statements from the Leviathan project:

	For the year ended		
	31.12.2025	31.12.2024	31.12.2023
Revenues from the sale of natural gas and condensate:			
Natural gas	992.2	1,119.5	1,094.4
Condensate	20.5	16.8	-
	1,012.7	**1,136.3**	**1,094.4**
Domestic market	170.5	141.9	168.6
Regional market	842.2	994.4	925.8
	1,012.7	**1,136.3**	**1,094.4**
Quantities of natural gas (BCM)			
Domestic market	0.83	0.67	0.93
Regional market	4.11	4.41	4.05
	4.94	**5.08**	**4.98**
Quantities of condensate (MMBBL)[45]	388.5	254.5	-

Note 15 – Royalties:

A. Composition:

	For the year ended		
	31.12.2025	31.12.2024	31.12.2023
Royalties to the State	107.4	120.0	117.5
Royalties to interested parties	12.9	14.4	14.1
Royalties to third parties	25.8	28.8	28.2
Total	**146.1**	**163.2**	**159.8**

[45] Excluding condensate that was sold under the agreement specified in Note 12C5 above.

Notes to the Consolidated Financial Statements as of 31 December 2025 (Dollars in millions)

Note 15 – Royalties (Cont.):

Effective rate of royalties in the Leviathan project:

	For the year ended		
	31.12.2025	31.12.2024	31.12.2023
Effective rate of the royalties in Leviathan project:			
To the State	10.61%	10.57%	10.73%
To interested parties	1.27%	1.27%	1.29%
To a third party	2.55%	2.54%	2.57%

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 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, upon the fulfillment of the cumulative conditions: 1. P2 Reserves balance in the Leviathan field according to an updated resources report is less than 125 BCM. 2. The abandonment plan has been approved by the Commissioner.

On 1 September 2022, the Operator submitted, on behalf of the Leviathan Partners, 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 2025 at the rate of 11.06%. According to a letter received from the Ministry of Energy in January 2026, the rate of the advance payments on account of State royalties in respect of the revenues from the Leviathan Project in 2026 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, 2021, 2022 and 2023, whereby the rate of the royalty value at the wellhead in the Leviathan project is 9.58%, 10.17%, 10.08% and 9.34%, respectively. The royalty rate on which the Partnership based its consolidated financial statements is approx. 10.6% (2024: 10.6%, 2023: 10.7%,).

   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 and which are presented in the 'Other Long-Term Assets' and 'Trade and other receivables' items.

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. $26.4 million (2024: approx. $27.0 million).

Notes to the Consolidated Financial Statements as of 31 December 2025 (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 calculation of the market value at the wellhead of the State royalties is also used for calculation 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 calculation of the market value at the wellhead of the overriding royalties on which the Partnership relied in its consolidated 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. $9.1 million (2024: approx. $8.3 million) and is included under the 'other long-term assets' item.
7. In 2024, the Ministry of Energy's audit of the royalty reports 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. Accordingly, the Partnership has received all of the advance payments paid in excess (including interest and indexation) from the Ministry of Energy and from the overriding royalty interest owners. The audit for years 2019-2020 is in an advanced stage.

Note 16 – Cost of Natural Gas and Condensate Production[46]:

Composition:	For the year ended		
	31.12.2025	31.12.2024	31.12.2023
Salaries and social benefits	25.7	25.2	19.6
Guarding and security	1.2	1.4	0.9
Insurance	20.0	19.0	17.5
Delivery, transmission and transportation costs	53.6	74.0	69.3
Operation management and operator fee	21.8	22.6	17.6
Maintenance	18.5	19.7	18.1
Others	8.9	6.5	5.6
Total	**149.7**	**168.4**	**148.6**

[46] Mostly through the joint ventures.

Notes to the Consolidated Financial Statements as of 31 December 2025 (Dollars in millions)

Note 17 – G&A Expenses:

Composition:	For the year ended		
	31.12.2025	31.12.2024	31.12.2023
Salaries and social benefits	8.4	6.7	6.5
Cost of equity instrument-based payment to the CEO (see Note 20C below)	0.4	0.5	2.7
Professional services, net	4.4	3.7	7.2
Other	4.4	6.0	4.4
Total	**17.6**	**16.9**	**20.8**

Note 18 – Financial Expenses and Income:

Composition:

	For the year ended		
	31.12.2025	31.12.2024	31.12.2023
Expenses:			
For bonds (Notes 10B and 10C above)	91.7	113.0	126.9
For liability to banking corporations (Note 10D above)	12.6	1.7	2.4
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 12E4 above and 20D below)	0.4	0.4	0.4
For changes in oil and gas asset retirement obligation due to lapse of time	4.9	3.5	3.2
Other	2.0	1.5	1.1
Net of financing costs capitalized[47]	(20.8)	(6.3)	(5.2)
Total expenses	**90.8**	**113.8**	**133.8**
Income:			
From deposits in banks and short-term investments	14.4	17.5	13.1
Revaluation of future production-based royalties from the Karish and Tanin leases (see Note 8B above)	25.8	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
Update of amounts receivable from a company accounted for at equity (see Note 21G3 below)	4.4	5.5	7.1
Other	13.3	5.8	2.6
Total income	**57.9**	**90.9**	**28.7**
Total financial expenses, net	**(32.9)**	**(22.9)**	**(105.1)**

[47] The cap rate used for determining the borrowing costs capitalized in 2025 is approx. 7.1% (2024: approx. 6.6%).

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, up to 31 December 2021 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%). Accordingly, such advance tax payments were carried directly to the Partnership's equity. 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), according to the judgment, 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, 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. \$143.0 million and approx. \$129.7 million, respectively (*in lieu* of approx. \$121.8 million and approx. \$108.5 million, respectively, as stated in the Partnerships' tax reports filed with the Tax Authority). The Partnerships' capital gain for 2016 is approx. \$56.1 million and approx. \$76.3 million, respectively (*in lieu* of approx. \$8.6 million and approx. \$20.6 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 2025. 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. $66.4 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.

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 interests in the Tamar and Dalit Leases held by the Partnership. 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. $391.3 million (*in lieu* of approx. $233.6 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. $830.3 million (*in lieu* of approx. $674.8 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 2025. 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.

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. $147.1 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. $205.3 million (*in lieu* of approx. $156.7 million, as stated in the Partnership's tax report filed with the Tax Authority) and the Partnership's capital gain for 2018 is approx. $18.1 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 2025. 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. $18.3 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. In accordance with the court's decision, an update notice regarding the method in which the proceedings shall continue is required to be filed by 30 March 2026.
6. On 14 July 2021, the Partnership released a temporary tax certificate for entitled holders in respect of the holding of a participation unit of the Partnership for the 2019 tax year. In view of the disputes which arose between the Partnership and the Tax Authority and disagreements regarding the amount of the Partnership's taxable income for 2019, on 31 December 2025 a non-agreed assessment was received from the Tax Authority according to Section 145(a)(2)(b) of the Income Tax Ordinance (in this section: the "**Tax Assessment**"), the Partnership intends to file an objection to the Tax Assessment, in accordance with the extension granted by the Assessing Officer by 31 March 2026. According to the Tax Assessment, the Partnership's taxable business income for 2019 is approx. $405.3 million (in lieu of approx. $169.8 million, as stated in the Partnership's tax report filed with the Tax Authority), and the Partnership's capital gains for 2019 are approx. $10.6 million, as declared in the report filed thereby as aforesaid. The said amounts were translated from ILS to USD according to the dollar rate known as of 31 December 2025.

Note 19 – Taxes on Income and Oil and Gas Profit Levy (Cont.):

B. Income tax assessments and tax certificates (Cont.):

6. (Cont.):

The main disputes pertain to the interpretation of the method of recognition of financial income and other expenses actually borne by the Partnership, similarly to the disputes for which assessments to the best of judgment were issued for the years 2016 and 2018, as detailed above, and the recording of financial income for negative exchange rate differences, the method of depreciation of assets according to the provisions of the law, and recognition of other expenses in accordance with the provisions of the Income Tax Ordinance. As of the date of consolidated financial statements, and according to the Tax Assessment, and insofar as all of the Tax Authority's claims are granted, the Partnership will be required to pay additional tax (including linkage differences and interest), at the expense of the Partnership's participation unit holders, in the sum of approx. $90.1 million.

7. On 12 April 2022, the Partnership released a temporary tax certificate for entitled holders in respect of participation unit-holding for the 2020 tax year. In view of the disputes which arose between the Partnership and the Tax Authority and disagreements regarding the amount of the Partnership's taxable income for 2020, on 31 December 2025 a non-agreed assessment was received from the Tax Authority according to Section 145(a)(2)(b) of the Income Tax Ordinance (in this section: the "**Tax Assessment**"), the Partnership intends to file an objection to the Tax Assessment, in accordance with the extension granted by the Assessing Officer by 31 March 2026. In accordance with the Tax Assessment, the Partnership's taxable business income for 2020 is approx. $369.1 million (in lieu of approx. $87 million, as stated in the Partnership's tax report filed with the Tax Authority). The said amounts were translated from ILS to USD according to the dollar rate known as of 31 December 2025. The main disputes pertain to the interpretation of the method of recognition of financial income and other expenses actually borne by the Partnership, including expenses similar to those for which assessments to the best of judgment were issued for the years 2016-2018, as detailed above, and the recording of financial income for negative exchange rate differences, the method of depreciation of assets according to the provisions of the law, and recognition of other expenses in accordance with the provisions of the Income Tax Ordinance. As of the date of the consolidated financial statements, and according to the Tax Assessment, and insofar as all of the Tax Authority's claims are granted, the Partnership will be required to pay additional tax (including linkage differences and interest), at the expense of the Partnership's participation unit holders, in the sum of approx. $107.7 million.

8. In the Partnership's estimation, based on the opinion of its professional advisors, the chances of the Partnership's key arguments being granted, and at the very least, allowing the deduction of the expenses contemplated in the disputes for the tax years 2016-2020 in those years and/or in subsequent years, are higher than 50%. Accordingly, the Partnership has not included a provision in its consolidated financial statements in respect of these tax assessments.

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 7C9 above) is approx. ILS 1,868 million, and the deferred capital gain for the sale of the Partnership's holdings in Tamar Petroleum 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 and/or objection and appeal proceedings have not yet been completed, 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. Part of 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 2025, 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 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) 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.
6) 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. On 9 April 2025, the Leviathan Partners received an assessment to the best of judgment for the Leviathan levy for 2020, which includes interpretive disputes with regards to the implementation of the provisions of the Law in the levy reports of the Leviathan Leases, issues that are heard also in the appeal for 2019, and the method of classification of some of the investments made by the holders of the interests in Leviathan for purposes of the Law. On 14 May 2025, an appeal was filed with the Tel Aviv District Court in respect of a levy assessment order for 2020, which was served on the Leviathan Partners as specified above, and on 2 November 2025, the TALE's grounds for the assessment in the said appeal were received.

Note 19 – Oil and Gas Profit Levy and Taxes (Cont.):

C. The Levy Law (Cont.):

6) (Cont.)

According to the court's decision, notice of the grounds for the appeal should be filed by 15 March 2026. On 30 December 2025, the Leviathan Partners received levy assessments to the best of judgment for 2021-2022 that include issues that are also discussed in the 2019-2020 assessments, as well as other interpretive disputes regarding the classification and recognition of various components in the Leviathan Project's levy reports. 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%. 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.

7) 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 to disputes that arose between the parties. The disputes regarding the levy reports for the years 2013-2020 were discussed between the parties within the framework of appeals conducted before the Tel Aviv District Court. 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 12J1 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. On 30 December 2024, TALE issued an assessment to the best of judgment for the tax year 2021, which chiefly pertains to the same disputes as emerged between the years 2013 and 2020. On 22 February 2026, an agreement was signed between the Assessing Officer and the Tamar Venture (through Chevron, which serves as the 'Reporting Partner' in the venture, within the meaning of this term in the Law), under which all disputes contemplated in the said appeals were settled. According to the assessments agreement, the Partnership recorded in its financial statements an additional expense in the sum of approx. $17.4 million for the period until the sale of its rights in the Tamar Project (see Note 7C9 above).

8) 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. $2.0 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%.

Notes to the Consolidated Financial Statements as of 31 December 2025 (Dollars in millions)

Note 19 – Oil and Gas Profit Levy and Taxes (Cont.):

D. Income taxes included in the statement of comprehensive income as part of the continued operations

	For the year ended		
	31.12.2025	31.12.2024	31.12.2023
Current taxes	(111.3)	(109.4)	(97.4)
Current taxes due to previous years	(0.5)	30.4[48]	(1.8)
Deferred taxes	(5.2)	(77.6)	(44.1)
Total income taxes	**(117.0)**	**(156.6)**	**(143.3)**
Taxes attributed to discontinued operations	(4.5)	*)	0.5
Total taxes attributed to continuing operations	**(121.5)**	**(156.6)**	**(142.8)**

***) Less than $0.1 million in expenses.**

[48] 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 2025 (Dollars in millions)

Note 19 – Oil and Gas Profit Levy and Taxes (Cont.):

E. Deferred taxes

1. **Composition:**

	31.12.2025	31.12.2024
Deferred tax liabilities		
Trade and other receivables	-	1.4
Costs of bond issue	-	0.1
Oil and gas assets	363.7	355.5
Other long-term assets	34.6	35.0
Total	**398.3**	**392.0**
Deferred tax assets		
Trade and other receivables	(0.5)	-
Costs of bond issue	(0.1)	-
Provision for oil and gas levy and social benefits	(1.0)	(0.5)
Total	**(1.6)**	**(0.5)**
Deferred tax liabilities, net	**396.7**	**391.5**

2. Deferred taxes are calculated according to a tax rate of 23% (2024 – identical) based on the tax rate expected to apply on the reversal date.
3. The movement in deferred taxes was carried to the statement of comprehensive income.
4. Deferred tax liabilities were not recognized in respect of temporary differences totaling approx. $1.6 million (2024: approx. $1.4 million) which relate to investments in associates as these investments are not expected to be liquidated in the foreseeable future.
5. No deferred tax assets were recognized in respect of tax losses in NewMed Morocco and NewMed Balkan since, as of the date of approval of the consolidated financial statements, the Partnership does not anticipate taxable income against which these losses may be utilized.

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 2025 (Dollars in millions)

Note 19 – Oil and Gas Profit Levy and Taxes (Cont.):

F. Theoretical Tax (Cont.):

	For the year ended		
	31.12.2025	31.12.2024	31.12.2023
Profit before income taxes from continuing operations	**479.5**	**681.2**	**574.3**
Statutory tax rate	23%	23%	23%
Tax calculated according to the statutory tax rate	**(110.3)**	**(156.7)**	**(132.1)**
Decrease (increase) in income taxes due to the following factors:			
Difference between the income measurement basis as reported for tax purposes (ILS) and the income measurement basis as reported in the financial statements ($)	9.2	(0.6)	(7.3)
Tax losses for which no deferred taxes were recognized (see Section E5 above)	(19.1)	-	-
Taxes due to previous years	(0.5)	-	(1.8)
Others	(0.8)	0.7	(1.6)
Income taxes	**(121.5)**	**(156.6)**	**(142.8)**

Note 20 – Transactions and Balances vis-à-vis Interested Parties, Related Parties and Control Holders:

A. Balances:

	31 December 2025		31 December 2024	
	Parent Companies	Related Parties and Other Interested Parties	Parent Companies	Related Parties and Other Interested Parties
Trade and other receivables	-	16.3	-	17.6
Other long-term assets	0.3	2.7	0.3	12.0
Trade and other payables	2.8	1.5	2.4	1.5
The highest current debt balance this year	0.2	-	0.2	-

Notes to the Consolidated Financial Statements as of 31 December 2025 (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:

	Note	Parent Companies	Related parties and Other Interested Parties
For the year ended 31 December 2025			
Overriding royalty expenses (continued operations)	**15**	-	12.9
Overriding royalty expenses (discontinued operations)	**7C9**	0.1	-
Equity instrument-based payment to the CEO	**20C**	-	0.4
Directors' remuneration		-	0.4
Delek Group guarantee fee	**20D, 12D4**	0.4	-
Rent	**20E2**	0.4	-
For the year ended 31 December 2024			
Overriding royalty expenses (continued operations)	**15**	*)	14.4
Overriding royalty expenses (discontinued operations)	**7C9**	0.8	-
Equity instrument-based payment to the CEO	**20C**	-	0.5
Directors' remuneration		-	0.3
Delek Group guarantee fee	**20D, 12D4**	0.4	-
Rent	**20E2**	0.3	-
For the year ended 31 December 2023			
Gas sale revenues	**14, 12C7**	*)	-
Overriding royalty expenses (continued operations)	**15**	-	14.1
Overriding royalty revenues (discontinued operations)	**7C9**	1.1	-
Equity instrument-based payment to the CEO	**20C**	-	2.7
Directors' remuneration		-	0.5
Delek Group guarantee fee	**20C, 12D4**	0.4	-
Rent	**20E2**	0.4	-

**) Less than $0.1 million

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"):

Mr. Abu has served as CEO of the General Partner in a full-time position (100%) since 1 April 2011. On 21 September 2022, the meeting of the holders of the participation units decided not to approve the previous compensation policy for officers of the Partnership and of the General Partner. 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 previous compensation policy for a period of 3 years, including the 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 terms of office and employment by the compensation committee and the board of directors by way of "overruling", see Note 12J6 above. On 25 January 2026, the participation unit holders meeting, following the recommendation of the compensation committee of 18 December 2025 and the General Partner's Board resolution of the same day, decided to re-approve the previous compensation policy for a period of 3 years from the date of the meeting's approval (the "**New Compensation Policy**"). The New Compensation Policy includes updates to the previous compensation policy, and approves updates terms of office and employment to Mr. Abu.

Below is a brief description of the main updated terms of office and employment:

1. The CEO's monthly salary as of 31 December 2025 is ILS 222.6 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. 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, 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.

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.)**

3. The term of Mr. Abu's employment is until 30 April 2030.
4. In May 2025, Mr. Abu received an annual bonus for 2024 in the sum of approx. ILS 3,407 thousand (in 2024, Mr. Abu received an annual bonus for 2023 in the sum of approx. ILS 3,282 thousand).
   In addition, in September 2025 a special bonus was approved for Mr. Abu in the sum of 6 monthly salaries gross, for the investment of irregular and extraordinary efforts in the promotion and implementation of a project in the work plan, and according to the compensation policy as being in effect at such time.
5. On 27 July 2022 the CEO was granted (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 previous 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 were vested in 3 equal annual tranches, commencing from 1 August 2022. The exercise price of the first tranche 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 tranches 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.
   In addition, on 5 February 2026, Mr. Abu was allotted, for no consideration, 1,541,233 non-marketable options exercisable for 1,541,233 participation units. The allotment was performed in accordance with the New Compensation Policy and the option plan (the "**Additional Options**"). The Additional Options will vest in 3 equal annual tranches, commencing from 18 December 2025 (the "**Approval Date**"). The exercise price of the first tranche was ILS 16.709, which was equal to the average closing price of the participation units on TASE at the close of the 30 trading days that preceded the Approval Date. The exercise price of the remaining two tranches will increase by 5% each year relative to the previous year.

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.)**

5. (Cont.)

According to a valuation received by the Partnership, the economic value of the Additional Options on the Approval Date totaled approx. ILS 8.1 million and the annual economic value (i.e. the economic value of the Additional Options on the Approval Date, divided by 3) totaled approx. ILS 2,700 thousand. The economic value of the Additional Options as aforesaid, was calculated using the Black-Scholes model, based on the following assumptions: (a) participation unit price, as of the Approval Date, of ILS 16.67; (b) exercise price of each option (adjusted for profit distribution) was calculated according to ILS 16.709 for the first tranche, ILS 17.544 for the second tranche, and ILS 18.422 for the third tranche; (c) expiration date – 18 December 2029; (d) vesting date – as specified in this section above; (e) standard deviation rate of 35.85%; and (f) risk-free interest rate of approx. 3.67%.

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 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.):

C. Terms of Employment of the CEO of the General Partner, Mr. Yossi Abu ("Mr. Abu" or the **"CEO") (Cont.)**

6. (Cont.)

On 20 October 2025, a detailed agreement was signed, setting forth the terms and conditions of the Equity Compensation and providing, *inter alia*, that: (1) the shares (5% of the issued share capital of New Med Balkan) shall be allotted to a trustee in favor of Mr. Abu; (2) the shares are subject to a reverse vesting mechanism with a vesting period of 36 months, ending on 8 March 2028; (3) the Partnership shall provide, in favor of Mr. Abu, financing for his pro rata share (5%) of the Initial Investment up to a cap of $100 million, plus annual interest at the rate of 7.5%; (4) insofar as any tax liability shall be imposed on Mr. Abu for the grant of the Equity Compensation before the exercise and sale of the shares, the Partnership shall provide Mr. Abu with financing to cover such tax liability; (5) until full repayment of the financing, the shares shall be pledged in favor of the Partnership in a first ranking fixed charge; (6) until the end of the vesting period, Mr. Abu shall not be entitled to perform any disposition of the shares; (7) until the end of the vesting period, the voting rights for the shares shall be exercised in accordance with the Partnership's instructions, whereas from the end of the vesting period forth, the voting rights for the shares shall be exercised in accordance with Mr. Abu's instructions (through the trustee, insofar as the shares are still held in trust); (8) in the event of termination of Mr. Abu's employment: before the end of the vesting period – in certain circumstances, the Partnership shall have the right to buy the shares for no consideration/in consideration for their par value, and in other circumstances, the Partnership shall have the right (but not an obligation) to buy the shares for a consideration to be determined on a DCF basis (net of the outstanding financing); after the end of the vesting period – in any event of termination of employment, the Partnership shall have the right (but not an obligation) to buy the shares for a consideration to be determined on a DCF basis.

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 12E4 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;

Note 20 – Transactions and Balances vis-à-vis Interested Parties, Related Parties and Control Holders (Cont.):

D. (Cont.)

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 audit committee and the Board approved the Partnership's engagement with Delek Group in a lease agreement in connection with the offices used by the General Partner and the Partnership. In 2025, the Partnership recorded approx. $0.4 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.
   On 4 September 2025, the compensation committee and the board of the General Partner of the Partnership, in accordance with the compensation policy as being in effect at such time, 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 15 months from 1 September 2025 to 30 November 2026, with a total limit of liability of $300 million per claim and in total for the insurance period, all under terms and conditions which comply with the compensation policy.
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. In March 2025, such pledge has been removed.
6. On 15 March 2026 the Chairman of the Board, Mr. Gabi Last ("**Mr. Last**") gave the Partnership notice that he was stepping down on 31 March 2026. On the same date, the compensation committee and the Board approved for Mr. Last an actual advance notice of 3 months. It is clarified that Mr. Last will continue to serve as a director.

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.):

7. Regarding the renewable energy collaboration with Enlight and the personal interest of Mr. Abu in the engagement, see Note 12F2 above.
8. 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 7C6 and Section C.5 above.
9. 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 12J4).

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 2025 (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 consolidated statement of financial position:

	31.12.2025			
	Level 1	Level 2	Level 3	Total
Financial assets at fair value through profit or loss:				
Investment in a joint project with Airovation Technologies (See Note 12F1)	-	-	2.0	**2.0**
Future production-based royalties from the Karish and Tanin leases (see Note 8B above)	-	-	251.1	**251.1**
Total financial assets at fair value through profit or loss:	-	-	253.1	**253.1**

	31.12.2024			
	Level 1	Level 2	Level 3	Total
Financial assets at fair value through profit or loss:				
Investment in a joint project with Airovation Technologies (See Note 12F1)	-	-	1.0	**1.0**
Future production-based royalties from the Karish and Tanin leases (see Note 8B above)	-	-	278.0	**278.0**
Total financial assets at fair value through profit or loss:	-	-	279.0	**279.0**

Adjustment due to fair value measurements classified as Level 3 under the fair value hierarchy of future production-based royalties from the Karish and Tanin leases (see Note 8B above):

	For the year ended 31 December	
	2025	2024
Balance as of January 1	**278.0**	**273.2**
Proceeds	(52.6)	(55.0)
Changes in proceeds receivable	(0.1)	(1.1)
Remeasurement recognized in profit or loss	25.8	60.9
Balance as of December 31	**251.1**	**278.0**

Notes to the Consolidated Financial Statements as of 31 December 2025 (Dollars in millions)

Note 21 – Financial Instruments (Cont.):

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 above:

	Fair Value	Book Value
As of 31 December 2025	1,139.3	1,117.3
As of 31 December 2024	1,589.6	1,625.6

D. Groups of financial instruments:

	As of 31 December	
	2025	2024
Financial assets:		
Cash and cash equivalents	107.7	51.2
Deposits	50.6	333.8
Trade receivables	181.5	209.6
Trade and other receivables	54.2	40.0
Receivables from a company accounted for at equity	16.3	27.4
Future production-based royalties from the Karish and Tanin leases (see Note 8B above)	260.5	287.3
Total financial assets	**670.8**	**949.3**
Financial liabilities:		
Trade and other payables	8.0	2.0
Bonds (see Note 10B above)	1,117.3	1,625.6
Long-term loan from a banking corporation (see Note 10D3 above)	275.0	-
Total financial liabilities	**1,400.3**	**1,627.6**

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.

Notes to the Consolidated Financial Statements as of 31 December 2025 (Dollars in millions)

Note 21 – Financial Instruments (Cont.):

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. Part of the Partnership's credit facilities, as provided in Note 10D above, are based on the SOFR interest.

The following table presents tests of sensitivity to a change in capitalized interest, with the other variables remaining constant:

	As of 31 December 2025				
	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)	(24.2)	(12.6)	**251.1**	13.8	28.9

	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

Note 21 – Financial Instruments (Cont.):

F. Market risks (Cont.):

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. In this regard, under the export to Egypt permit, as mentioned in Note 12C3C above, the Leviathan Partners have undertaken to offer several price formulas, including a formula linked to the general Electricity Production Tariff, which does not include a price floor. 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. It is further 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 2025 (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 2025								
Profit (Loss) from Change in the Natural Gas Price								
30%	20%	10%	5%	Fair Value	-5%	-10%	-20%	-30%
40.5	26.0	15.6	7.9	**251.1**	(7.8)	(11.5)	(2.8)	(19.5)

As of 31 December 2025								
Profit (Loss) from Change in the Condensate Price								
30%	20%	10%	5%	**Fair Value**	-5%	-10%	-20%	-30%
15.8	10.6	5.1	2.5	**251.1**	(2.5)	(5.0)	(10.1)	(10.5)

As of 31 December 2024								
Profit (Loss) from Change in the Natural Gas Price[49]								
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[49]								
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)

[49] 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 2025 (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 2025 is a current balance. The Partnership's principal customers in the report period are Blue Ocean which accounted for approx. 54% of the sales in the report period, and NEPCO which accounted for approx. 29% of the sales in the report period (62% and 26% of the sales in 2024, respectively, 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. Furthermore, as of the date of approval of the consolidated financial statements, the Partnership has received all payments from its customers that were recorded in the trade receivables as of the date of the consolidated financial statements.

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 2025		
	Ended 31 December 2025	Total	Current Balance	Disputed Balance
NEPCO	292.8	51.1	51.1	-
Blue Ocean	546.9	109.7	109.7	-
Other customers	173.0	20.7	20.7	-
Total	**1,012.7**	**181.5**	**181.5**	**-**

	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**	**-**

Note 21 – Financial Instruments (Cont.):

G. Credit risks (Cont.):

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.
3) The Partnership has amounts receivable from a company accounted for at equity in the sum of approx. $16.3 million (2024: approx. $27.3 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[50] 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:

[50] The cap rate used in determining the fair value of the receivables was estimated at 20.8% as of 31 December 2025 (31 December 2024: 22.0%).

Notes to the Consolidated Financial Statements as of 31 December 2025 (Dollars in millions)

Note 21 – Financial Instruments (Cont.):
H. Liquidity risk (Cont.):

2025	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	8.0	-	-	-	-	8.0
Long-term loan from a banking corporation	-	16.7	73.9	81.7	184.1	356.4
Bonds	-	76.1	730.9	568.6	-	1,375.6
Total	8.0	92.8	804.8	650.3	184.1	1,740.0

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

Notes to the Consolidated Financial Statements as of 31 December 2025 (Dollars in millions)

Note 21 – Financial Instruments (Cont.):

H. Liquidity risk (Cont.):

Changes in liabilities deriving from financing activity:

	Balance as of 31 Dec. 2024	Cash Flow	Effect of Changes in Amortized Cost	Other Changes	Balance as of 31 Dec. 2025
Bonds	1,625.6	(511.5)	3.3	-	1,117.3
Distributable profit distributed	-	(240.3)	-	240.3	-
Long-term loan from a banking corporation	-	275.0	-	-	**275.0**
Total liabilities deriving from financing activity	**1,625.6**	**(476.8)**	**3.3**	**240.3**	**1,392.3**

	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 distributed	-	(250.3)		250.3	-
Short-term loan from 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**

Note 22 – Material Subsequent Events:

A. For details about Operation Roaring Lion and the cessation of the natural gas production from the Leviathan reservoir, see Note 1D.

B. For details about the receipt of tax assessments not by agreement, for the tax years 2019 and 2021, see Notes 19B6 and 19B7, respectively.

C. For details about the approval of an additional buy-back plan for the purchase of Leviathan Bond bonds, see Note 10C.

D. For details about the completion of the Third Pipeline project, see Note 7C1B(2).

E. For details about the fulfillment of conditions precedent in the natural gas export to Egypt agreement, see Note 12C3B.

F. For details about the adoption of a FID in the Expansion Project of the Leviathan Project, see Note 7C1E.

G. For details about a report on reserves and contingent resources in the Leviathan Leases, see Note 7C1F.

H. For details about a report on contingent and prospective resources in the Aphrodite reservoir, see Note 7C2F.

I. For details about the engagement of the Partnership and OMV Bulgaria in an agreement for the sale of 10% of the interests in the Bulgaria License to BEH, see Note 7C6B.

J. For details about the results of the drill in the Vinekh prospect in the Bulgaria License, see Note 7C6C.

K. For details about the granting of a participation unit-based payment to the Partnership's CEO, see Note 20C.

L. For details about the withdrawal of loans from credit facilities, see Notes 10D3 and 10D4.

M. For details about the Partnership's engagement in an agreement for the provision of credit facilities of $500 million, see Note 10D4.

N. For details about the approval of profit distribution by the board of directors of the General Partner of the Partnership in the sum of $70 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 2025	**Report Date**:	15 March 2026

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 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 Report (Chapter B of this Report) and Note 8B to the Financial Statements (Chapter C 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 2025 and for Y2025**

See Section 2B of Part One of the Board Report (Chapter B of this Report).

Regulation 10C: **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), which are incorporated herein by reference.

On 12 May 2025, the Partnership released a shelf prospectus, under which securities may be offered until 12 May 2027. For further details, see the Partnership's immediate report dated 12 May 2025 (Ref.: 2025-01-033082), 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.

Regulation 11: List of the Partners2hip's investments in subsidiaries and companies accounted for at equity thereof[2]

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 2025	Price of the shares listed on TASE as of 31 December 2025 (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 2025 (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	-	-	-	-
EMED Pipeline B.V. ("EMED B.V.")[8]	Ordinary shares	5,000	$5,000	$75,005,000	-	25	7,347	_[9]	Dollar	-
EMED Pipeline[10]	Ordinary shares	5,000	€5,000	-	-	100	-	-	-	-
Eastern Mediterranean Gas Company S.A.E	Ordinary shares	57,330,000	$57,330,000	-	-	9.75	-	-	-	-

[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 Notes 1G5 and 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 Report (Chapter B of this Report).

[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.

[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.

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 2025	Price of the shares listed on TASE as of 31 December 2025 (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 2025 (U.S. Dollars ("$") in thousands)	Main terms of the loans		
								Final maturity date	Linkage terms	Additional details
("EMG")[11]										
NewMed Energy UK Limited ("NewMed Morocco")[12]	Ordinary shares	1	£1	-	-	100	Approx. 4,000	September 2029	ILS	-[13]
NewMed Energy Balkan Limited ("NewMed Balkan")[14]	Ordinary shares	1	£1	-	-	95[15]	-	-	-	-
Enlight-NewMed Development, Limited Partnership[16]	Participation units	-	-	-	-	33.33%	Approx. 1,296	_[17]	_	_
Enlight-NewMed Development (UK) Ltd.[18]	Ordinary shares	100	£100	-	-	33.33	-	-	-	-

[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.

[14] An SPC which was incorporated in England and holds 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.

[15] Mr. Yossi Abu, the Partnership's CEO ("**Mr. Abu**" or the "**CEO**") holds 5% of the issued share capital of NewMed Balkan, allotted to him as equity compensation. For further details see Regulation 21(b)(2) below.

[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 2025	Dividends received (or receivable by the Partnership) after 31 December 2025	Dividend payment dates after 31 December 2025	Management fees received as of 31 December 2025	Management fees received (or receivable by the Partnership) after 31 December 2025	Management fee payment dates after 31 December 2025	Interest	Interest payment dates
Leviathan Bond	(430)	-	(430)	-	-	-	-	-	-	-	-
EMED Pipeline	(41)	-	(41)	-	-	-	-	-	-	-	-
EMED B.V.	(9,992)	-	(10,066)	-	-	-	-	-	-	-	-
EMG	27,057	-	18,084	-	-	-	-	-	-	-	-

Regulation 20: **listed securities**

In 2025, until the report approval date, no new securities of the Partnership were listed 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 2025, 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 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 2025:

[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.

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%	1,030,819	1,355,808	447,337[20]	-	-	-	-	-	-	147,221	2,981,184
Gabi Last	Executive Chairman of the Board	100%	0.00%[21]	609,249	130,800								83,012	823,061
Tzachi Habusha	VP Finance	100%	-	484,542	183,569	-	-	-	-	-	-	-	89,226	757,337
Sari Singer Kaufman	General Counsel, EVP	100%	-	494,835	154,377	-	-	-	-	-	-	-	102,215	751,427
Zvi Karcz	VP Exploration	100%	-	486,566	148,727	-	-	-	-	-	-	-	94,621	729,915
Interested parties of the Partnership and/or the GP														
External directors and an independent director[22]	-	-	-	429.2	-	-	-	-	-	-	-	-	-	429.2

[20] For details regarding Mr. Abu's holdings in options that are exercisable for the Partnership's Participation Units and about the grant of equity compensation to Mr. Abu at the rate of 5% of the issued share capital of NewMed Balkan, see Regulation 21(b)(2) below.
[21] Mr. Last holds 12,109.60 Participation Units.
[22] 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) <u>Compensation policy</u>

On 21 September 2022, the meeting of the holders of participation units of the Partnership (the "**Participation Units**"), decided not to approve the Previous 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), which are incorporated herein by reference.

Consequently, on 28 September 2022, the Compensation Committee and the Board of Directors of NewMed Energy Management Ltd., the Partnership's General Partner (the "**Board**" and the "**GP**", respectively) decided, after further discussion on the matter, to approve the Previous 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 "**Previous Compensation Policy**"). For further details, see the Partnership's immediate report of 29 September 2022 (Ref.: 2022-01-121942), which is incorporated herein by reference.

On 25 January 2026, the Participation Unit holders meeting, following the recommendation of the Compensation Committee of 18 December 2025 and the Board resolution of the same day, decided to re-approve the Previous Compensation Policy, with certain modifications, for a period of three years from the date of the Meeting's approval (the "**New Compensation Policy**"). For further details about the New Compensation Policy, including the main differences between it and the Previous Compensation Policy, see the Partnership's immediate reports of 18 December 2025 and 25 January 2026 (Ref. 2025-01-101197 and 2026-01-009438, respectively), which are incorporated herein by reference.

(2) <u>Yossi Abu</u>

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 GP.

On 21 September 2022, the meeting of the Participation Unit holders decided not to approve the 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), which are incorporated herein by reference.

Consequently, on 28 September 2022, the compensation committee and the Board decided, after further discussion on the matter, to approve the said terms of office and employment for Mr. Abu, notwithstanding the objection of the meeting of the Participation Unit holders, until 30 April 2027. For further details, see the Partnership's immediate report of 29 September 2022 (Ref.: 2022-01-121942), 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 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.

On 25 January 2026, the Participation Unit holders meeting, following the approval of the Compensation Committee of 18 December 2025 and the Board resolution of the same day, and after approval of the New Compensation Policy, decided to approve the renewal of the terms of office and employment of Mr. Abu as CEO of the Partnership until 30 April 2030, with certain modifications, and to grant him equity compensation. For further details, including the changes to Mr. Abu's employment agreement, see the Partnership's immediate reports of 18 December 2025 and 25 January 2026 (Ref. 2025-01-101197 and 2026-01-009438, respectively), which are incorporated herein by reference.

Accordingly, Mr. Abu's updated terms of office and employment are as follows (the "**Terms of Office and Employment**"):

Mr. Abu's monthly salary is approx. ILS 222.6 thousand gross (100%)[23] (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, 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

[23] As of 31 December 2025.

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) (the "**Grant Date**")[24]. The allotment was performed in accordance with the Previous 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 "**Option Plan**").

The Options vested in 3 equal annual tranches, commencing from 1 August 2022. The exercise price of the first tranche was 866 Agorot, which was equal to the average closing price of the Participation Units on TASE at the close of the 30 trading days that preceded the Grant Date. The exercise price of the remaining two tranches increased 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), which are 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 tranche, ILS 9.10 for the second tranche, and ILS 9.55 for the third tranche; (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%.

In addition, on 5 February 2026, Mr. Abu was allotted, for no consideration, 1,541,233 non-marketable options exercisable for 1,541,233 Participation Units, which constitute approx. 0.13% 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 New Compensation Policy and the Option Plan (the "**Additional Options**").

The Additional Options will vest in 3 equal annual tranches, commencing from 18 December 2025 (the "**Approval Date**"). The exercise price of the first tranche was ILS 16.709, which was equal to the average closing price of the Participation Units on TASE at the close of the 30 trading days that preceded the Approval Date. The

[24] 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.

[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.

exercise price of the remaining two tranches will increase by 5% each year relative to the previous year.

For further details, see the Partnership's immediate reports of 18 December 2026, 25 January 2026 and 5 February 2026 (Ref. 2025-01-101197, 2025-01-009438, 2026-01-012695 and 2026-01-012870, respectively), which are incorporated herein by reference.

According to a valuation received by the Partnership, the economic value of the Additional Options on the Approval Date totaled approx. ILS 8.1 million and the annual economic value (i.e. the economic value of the Additional Options on the Approval Date, divided by 3) totaled approx. ILS 2,700 thousand. The economic value of the Options as aforesaid, was calculated using the Black-Scholes model, based on the following assumptions: (a) Participation Unit price, as of the Approval Date, of ILS 16.67; (b) exercise price of each option (adjusted for profit distribution) was calculated according to ILS 16.709 for the first tranche, ILS 17.544 for the second tranche, and ILS 18.422 for the third tranche; (c) expiration date – 18 December 2029; (d) vesting date – as specified in this section above; (e) standard deviation rate of 35.85%; and (f) risk-free interest rate of approx. 3.67%.

According to the Terms of Office and Employment, Mr. Abu received an annual bonus for 2024, which was approved in May 2025, in the sum of approx. ILS 3,407.2 thousand, in accordance with the Previous Compensation Policy and based on the following components:

(a) <u>A business target-dependent component (55%)</u> – Mr. Abu met the business targets specified below, and was therefore entitled, in respect of this component, to the sum of approx. ILS 1,873.9 thousand: (1) performance of a profit distribution of no less than $150 million; (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; (3) Long Lead Items commitment of at least $300 million (100%); (4) agreement with INGL for development of the Nitzana Pipeline; (5) update of the development plan for the Aphrodite reservoir; and (6) entry into the blue hydrogen sector; (b) <u>A component dependent on the quantitative tests specified below (20%)</u>: (1) change in adjusted net profit (5%)[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 124%, and therefore he was entitled for this criterion to the sum of approx. ILS 170.4 thousand; (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, or fundraising where the Partnership's share is no less than $200 million or the signing of binding gas sale agreements at a volume of over 25 BCM or the signing of export agreements. Mr. Abu met this criterion due to the making of actual investments by the Partnership in a petroleum asset in an amount of

[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.

no less than $50 million and due to the signing of an export agreement, and therefore he was entitled in respect of this criterion to the sum of approx. ILS 511.1 thousand; and (c) The Board's discretionary component (25%): the sum of approx. ILS 851.8 thousand.

In addition, in September 2025 a special bonus was approved for Mr. Abu in the sum of 6 monthly salaries gross, for the investment of irregular and extraordinary efforts in the promotion and implementation of a project in the work plan, and according to the Previous Compensation Policy.

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 of the costs of the initial investment that includes the first two wells to be drilled in the petroleum asset known as Block 1-21 Han Asparuh, located in the EEZ of the Republic of Bulgaria in the Black Sea (the "**Bulgaria License**"), 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 Previous 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), which are 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.

Accordingly, on 20 October 2025, a detailed agreement was signed, setting forth the terms and conditions of the Equity Compensation and providing, *inter alia*, that: (1) the shares (5% of the issued share capital of New Med Balkan) shall be allotted to a trustee in favor of Mr. Abu; (2) the shares are subject to a reverse vesting mechanism with a vesting period of 36 months, ending on 8 March 2028; (3) the Partnership shall provide, in favor of Mr. Abu, financing for his pro rata share (5%) of the Initial Investment up to a cap of $100 million, plus annual interest at the rate of 7.5%; (4) insofar as any tax liability shall be imposed on Mr. Abu for the grant of the Equity Compensation before the exercise and sale of the shares, the Partnership shall provide Mr. Abu with financing to cover such tax liability; (5) until full repayment of the financing, the shares shall be pledged in favor of the Partnership in a first ranking fixed charge; (6) until the end of the Vesting Period (as defined in the agreement), Mr. Abu shall not be entitled to perform any disposition of the shares; (7) until the end of the Vesting Period, the voting rights for the shares shall be exercised in accordance with the Partnership's instructions, whereas from the end of the Vesting Period forth, the voting rights for the shares shall be exercised in accordance with Mr. Abu's instructions (through the trustee, insofar as the shares are still held in trust); (8) in the event of termination of Mr. Abu's employment: before the end of the Vesting Period – in certain circumstances, the Partnership shall have the right to buy the shares for no consideration/in consideration for their par value, and in other circumstances, the Partnership shall have the right (but not an obligation) to buy the shares for a consideration to be determined on a DCF basis (net of the outstanding financing); after the end of the Vesting Period – in any event of termination of employment, the Partnership shall have the right (but not an obligation) to buy the shares for a consideration to be determined on a DCF basis.

In addition, Mr. Abu is entitled to be included in a D&O insurance policy to be taken out by the Partnership and/or the control holder, from time to time, in accordance with the approvals required by law. Accordingly, Mr. Abu received letters of indemnification and exemption from liability, in the language attached to the immediate report released by the Partnership on 4 June 2012 (Ref. 2012-01-147513). In addition, Mr. Abu was granted letters of exemption and indemnification for officers in the language attached as Annex C to the Notice of Meeting report released by the Partnership on 3 July 2019 (Ref. 2019-01-057213), which do not derogate from the validity of the letters of exemption from liability and indemnification he received in 2012.

(3) Gabi Last

Mr. Gabi Last ("**Mr. Last**") has served as Executive Chairman of the Board in a full-time position since April 2022 (prior to which, from May 2001, he held office as a director, and from January 2020, he held office as Chairman of the Board).

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 133.5 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 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

[27] As of 31 December 2024.

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 an annual bonus for 2024, which was approved in May 2025, in the sum of approx. ILS 466 thousand, in accordance with the Previous Compensation Policy, and based on the following components:

(a) A business target-dependent component (55%) – Mr. Last met the business targets specified below, and was therefore entitled, in respect of this component, to the sum of approx. ILS 256.3 thousand: (1) performance of a profit distribution of no less than $150 million; (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; (3) Long Lead Items commitment of at least $300 million (100%); (4) agreement with INGL for development of the Nitzana Pipeline; (5) update of the development plan for the Aphrodite reservoir; and (6) entry into the blue hydrogen sector; (b) A component dependent on the quantitative tests specified below (20%): (1) change in adjusted net profit (5%)[28]. Mr. Last 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 124%, and therefore he was entitled for this criterion to the sum of approx. ILS 23.3 thousand; (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, or fundraising where the Partnership's share is no less than $200 million or the signing of binding gas sale agreements at a volume of over 25 BCM or the signing of export agreements. Mr. Last met this criterion due to the making of actual investments by the Partnership in a petroleum asset in an amount of no less than $50 million and due to the signing of an export agreement, and therefore he was entitled in respect of this criterion to the sum of approx. ILS 69.9 thousand; and (c) The Board's discretionary component (25%): the sum of approx. ILS 116.5 thousand.

On 15 March 2026, Mr. Last gave notice to the partnership that he was stepping down as Chairman of the Board on 31 March 2026. On the same date, the Compensation Committee and the Board approved for Mr. Last actual advance notice of 3 months and an adjustment bonus of 6 gross monthly salaries, all in accordance with the Employment Agreement and the New Compensation Policy. It is clarified that Mr.

[28] 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.

Last will continue to hold office as a director, will be classified as an expert director, as this term is defined in the Companies Regulations (Conditions and Tests for a Director with Accounting and Financial Expertise and for a Director with Professional Qualifications), 5766-2005 (the "**Qualification Regulations**"), and will be entitled to annual compensation and participation compensation in the maximum amounts as specified in the Compensation Regulations, according to the Partnership's ranking as being from time to time.

(4) 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 102.9 thousand[29] (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 on behalf of the Partnership. The Partnership may grant Mr. Habusha, each year, an annual bonus for the previous calendar year, provided that he is employed by the Partnership for 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 an annual bonus for 2024, which was approved in May 2025, in the sum of ILS 654 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 legal counsel at the Partnership).

Ms. Singer's gross monthly salary is approx. ILS 102.9 thousand[30] (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

[29] As of 31 December 2025.

[30] As of 31 December 2025.

encashment), 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 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 is employed by the Partnership for 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 an annual bonus for 2024, which was approved in May 2025, in the sum of ILS 550 thousand.

(6) 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 102.9 thousand[31] (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 encashment), 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 Partnership. The Partnership may grant Mr. Karcz, each year, an annual bonus for the previous calendar year, provided that he is employed by the Partnership for 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

[31] As of 31 December 2025.

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 grant to Mr. Karcz of a one-time retention bonus in the sum total of ILS 270 thousand. The retention bonus was paid in 3 equal installments, as follows: 3 monthly salaries gross were paid together with the salary for February 2024, February 2025 and February 2026.

Mr. Karcz received an annual bonus for 2024, which was approved in May 2025, in the sum total of ILS 440 thousand.

(7) Salary of directors of the GP

On 1 April 2025 Mr. Efraim Sadka ceased to hold office as an external director on the Board. For further details, see the Partnership's immediate reports of 1 April 2025 (Ref. 2025-01-023722 and 2025-01-023725), which are incorporated herein by reference.

On 6 May 2025 a special general meeting of the Participation Unit holders was held, which approved the appointment of Mr. Eran Yaacov as an external director on the Board, for a 3-year term of office, commencing on the date of the meeting's resolution, as well as his terms of office. For further details, see the Partnership's immediate reports of 1 April 2025 and 6 May 2025 (Ref. 2025-01-023733, 2025-01-031707, 2025-01-031710 and 2025-01-031719, respectively), which are incorporated herein by reference.

The two external directors and the independent director on the Board, who are classified as expert directors, as defined in the Qualification Regulations, 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 Executive Chairman of the Board are specified in Regulation 21(b)(3) above. The remaining directors on the Board are officers in Delek Group Ltd. ("**Delek Group**"), 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 69.2 thousand per month[32] (plus VAT). The monthly fee is updated every 3 months in accordance with changes in the CPI relative to the April 2020 CPI rate.

[32] As of 31 December 2025.

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 GP 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 GP's management and to meetings with the representatives of the GP 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 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 November 2024, 3 December 2024 and 30 December 2024 (Ref. 2024-01-618247, 2024-01-621633 and 2024-01-628464, respectively), which are 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 a 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 the Partnership's Periodic Report for 2024, as released on 10 March 2025 (Ref. 2025-01-015633) (the "**BP-ADNOC Transaction**" and the "**2024 Periodic Report**", respectively), 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 the 2024 Periodic 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), which are 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
817.6	134.4	-	0.8	48.8	1,001.6

(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 GP, and through an indirect holding in Avner Oil & Gas Ltd. approx. 54.66% of the issued unit capital of the Partnership.

Regulation 22: **Transactions of the Partnership with the GP or transactions in which the GP's controlling shareholder has a personal interest**

Below are details, to the best of the Partnership's knowledge, regarding any transaction with the GP or the GP's controlling shareholder, or in the approval of which the GP'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 Report (Chapter B of this Report):

(a) According to the Partnership Agreement, the GP 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 GP, 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 GP, 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 GP or Delek Group any management fees or operator fees.

Furthermore, according to this decision, the Partnership bears the costs of the compensation of the CEO and of all of the directors on the Board and the fees of the Executive 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 GP does not bear the Partnership's management expenses, insofar as the GP 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 GP 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 GP, 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 GP.

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), which are 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 2025, the Partnership recorded expenses in respect of royalties to Delek Overriding Royalty for the Leviathan project in the sum total of approx. $12.9 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 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

[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.

Guarantee fee that the Partnership paid Delek Group in 2025 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 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

[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.

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

[37] To the best of the Partnership's knowledge, Chevron Cyprus is a wholly owned subsidiary of Chevron Corporation ("**Chevron Corp.**").

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.

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) in Chapter D of the 2020 periodic report, as released on 17 March 2021 (Ref.: 2021-01-036588) (the "**2020 Periodic Report**").

(e) The Partnership pays rent to Delek Group for the Partnership's offices in Herzliya. The audit committee, for the sake of caution, and the Board first approved the said engagement on 28 June 2017 and determined that it was at arm's length, in accordance with an opinion of an independent appraiser which reviewed rent for similar properties with similar characteristics in the region. 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 2025, the Partnership paid Delek Group, in respect of the said engagement, the sum of approx. $387 thousand.

Negligible transactions – 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 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 GP as of 31 March 2025, see the Partnership's immediate report of 7 April 2025 (Ref.: 2025-01-025630), which is incorporated herein by reference.
On 4 February 2026, Mr. Abu was allotted 1,541,233 non-marketable options, and on 5 February 2026 Harel Investments in Insurance and Financial Services Ltd. commenced being an interest holder in the Partnership. For further details, see the Partnership's immediate reports of 5 February 2026 (Ref. 2026-01-012695 and 2026-01-012885), which are incorporated herein by reference.

Regulation 24A: **Authorized capital, issued capital and convertible securities**

For details, see the Partnership's immediate report of 5 February 2026 (Ref.: 2026-01-012870), 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 5 February 2026 (Ref.: 2026-01-012870), 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 GP:	Executive 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	Member of the Investment Committee
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 GP, a subsidiary, an affiliate or of an interested party?	Executive Chairman of the Board, member of the Partnership's donations committee (the "**Donations Committee**"), a director of a private subsidiary 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 Executive Chairman of the Board[40]	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.

[40] On 15 March 2026 Mr. Last gave notice that he was stepping down as Chairman of the Board on 31 March 2026. For further details, see Regulation 21(b)(3) above.

Details	Gabi Last	Leora Pratt Levin	Idan Wallace	Tamir Polikar
Occupation in the last five years:	Executive Chairman of the Board of the GP, a director of Med-Enlight, Chairman of the Board of Delek Group and the Delek Foundation for Education, Culture and Science (CIC) ("**Delek Foundation**"), a director of subsidiaries of Delek Group, a director of a private subsidiary of the Partnership and a member of management of various NPOs	A director of the GP, EVP, Chief Legal Counsel and Corporate Secretary of Delek Group, a director of subsidiaries of Delek Group and a board member in the Suzanne Dellal Center Association	A director of the GP, CEO of Delek Group, a director of subsidiaries of Delek Group, and a director of private companies owned by him	A director of the GP, deputy CEO and CFO at Delek Group, a director of subsidiaries of Delek Group, a director of private companies in which he is a shareholder, and member of the executive committee and chairman of committees at Shenkar Engineering Design Art (CIC)
<u>Other</u> directorships:	A private subsidiary 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, Isracard Ltd. and an observer on the board of Ithaca Energy Plc	Delek Energy, Ithaca Energy Plc, Mehadrin Ltd., Isracard 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., Isracard Ltd., Polikar Holdings Ltd., Gallipoli Real Estate Investments Ltd., Briza Lgyrp Ltd., Elysee Downtown Ltd., Ithaca Energy Plc and Inplay Oil Corp
Relative of another interested party of the GP?	No	No	No	No
Deemed by the GP as having accounting and financial expertise for purposes of compliance with the minimum number determined by the Board pursuant to Section 92(a)(12) of the Companies Law?	No	No	No	Yes

Details	Yair Neumann	Eli Zamir	Yoram Cohen	Eran Yaacov
I.D. number:	038127833	024570582	022107098	022976187
Position at the GP:	Director	Independent director	External director	External director
Date of birth:	17 January 1986	8 January 1970	7 November 1965	24 April 1967
Address for service of process:	19 Abba Eban Blvd., Herzliya	5 Aharon David Gordon St., Tel Aviv	48 Medinat Hayehudim St., Herzliya	4 Tiroche St., Ramat Hasharon
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, Chairman	Audit Committee member Finance Committee member, Chairman Compensation Committee member Investment Committee member	Audit Committee member, Chairman Finance Committee member Compensation Committee member, Chairman Investment Committee member
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?[41]	-	-	Yes	Yes
Employee of the GP, a subsidiary, an affiliate or of an interested party?	VP Business Development at Delek Group, CEO and director 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	6 May 2025
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, mediation course	B.A. in Management and Economics from the Open University, LL.B. in Law from the Netanya Academic College, M.B.A. in law from Bar Ilan University

[41] Within the meaning of the term in Section 1 of the Compensation Regulations.

Details	Yair Neumann	Eli Zamir	Yoram Cohen	Eran Yaacov
Occupation in the last five years:	Director of the GP, VP Business Development at Delek Group, CEO, VP Finance and director at private companies of Tshuva Group and an advisor on capital raising and mergers at Delek Group	Director at the GP, CEO of Jeffs' Brands, CEO of Invest-Pro – Shukai Hon Ltd., Independent Director and member of the Audit Committee at AI Systems Communications Ltd., and External Director at Formula Systems (1985) Ltd.	Director at the GP, CEO of Noga – Electricity System Management Ltd., CEO of Rani Zim Renewable Energy (2022) Ltd., and Director at Trans Israel Ltd.	External director of the GP, economics and tax advisor, Interim Director General of the Ministry of Finance, Director of the Tax Authority at the Ministry of Finance, and a lecturer at Tel Aviv University and the College of Management
Other directorships:	Mehadrin Ltd., El-Ad National (2023) U.S. Holdings Ltd, and an observer on the board of Ithaca Energy Plc	IMCannabis Corp		Chairman of the Board at Orion Properties Ltd.
Relative of another interested party of the GP?	No	No	No	No
Deemed by the GP as having accounting and financial expertise for purposes of compliance with the minimum number determined by the Board 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[42]

Officer	I.D. number	Date of Birth	Date of commencement of office	Position at the Partnership, the GP, a subsidiary, affiliate or interested party	Interested party of the Partnership and/or the GP?	Relative of another senior officer or of an interested party of the Partnership and/or the GP?	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 of the Partnership, a director of Med-Enlight and in Yes-Enlight General Partner Ltd., 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), and the holder of shares of NewMed Balkan (which were allotted to him as equity compensation, as detailed in Regulation 21(b)(2) above).	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 and in Yes-Enlight General Partner Ltd., limited partner of Yes-Enlight Holdings, Limited Partnership, a director of private subsidiaries of the Partnership and private companies of which he is a shareholder, 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, a director of Med-Enlight 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 Med-Enlight, a director of a private subsidiary of the Partnership, and an independent director of Steakholder Foods Ltd.

[42] 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 GP, a subsidiary, affiliate or interested party	Interested party of the Partnership and/or the GP?	Relative of another senior officer or of an interested party of the Partnership and/or the GP?	Education	Experience in the last 5 years
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
Tzachi Habusha	027268317	23 March 1974	1 January 2022	CFO of the Partnership, member of the Donations Committee, a director of a private subsidiary 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 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 GP
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

Officer	I.D. number	Date of Birth	Date of commencement of office	Position at the Partnership, the GP, a subsidiary, affiliate or interested party	Interested party of the Partnership and/or the GP?	Relative of another senior officer or of an interested party of the Partnership and/or the GP?	Education	Experience in the last 5 years
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
Guil Bashan	031403264	13 September 1978	12 May 2025 – VP Corporate Development and Investor Relations 1 June 2016 – Chief Analyst and Head of Investor Relations	VP Corporate Development and Investor Relations	No	No	B.A. in Economics and Business Administration from the Tel Aviv-Jaffa Academic College, M.B.A. in Philosophy from Tel Aviv University	VP Corporate Development and Investor Relations and Chief Analyst and Head of Investor Relations 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
Gali Gana	059674770	2 June 1965	1 February 2016	Internal auditor of the Partnership and the GP, 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 GP, 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 2025, and as of the report approval date, there are no independent authorized signatories at the Partnership or the GP.

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, adding the Bulgaria License 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), which is incorporated herein by reference.

Regulation 29: **Recommendations and decisions of the directors**

Regulation 29(a):

(a) For details on the partial prepayment of the bonds that were issued by Leviathan Bond (the "**Leviathan Bond Bonds**"), see the Partnership's immediate report of 12 May 2025 (Ref.: 2025-01-032975), which is incorporated herein by reference. For further details, see Section (e) of Part One of the Board Report (Chapter B of this Report).

(b) For details on the Board's decision to approve another plan to buy back Leviathan Bond bonds, see the Partnership's immediate report of 6 January 2026 (Ref. 2026-01-002487), which is incorporated herein by reference. For further details, see Section E of the Part One of the Board Report (Chapter B of this Report).

(c) On 9 March 2025, 11 May 2025, 7 August 2025 and 9 November 2025, the Board decided, after receiving the recommendation of the Finance Committee, to approve profit distributions in the sum of $60 million each. The record dates for the said distributions were 20 March, 2025, 21 May 2025, 19 August 2025, and 4 December 2025, respectively. The distribution dates were 3 April 2025, 5 June 2025, 28 August 2025 and 4 December 2025, respectively. For further details, see the Partnership's immediate reports of 10 March 2025, 12 May 2025, 7 August 2025 and 10 November 2025 (Ref. 2025-01-015639, 2025-01-032989, 2025-01-058657 and 2025-01-085259, respectively), which are incorporated herein by reference. In addition, on 15 March 2026, the Board decided, after receiving the recommendation of the Finance Committee, to approve a $70 million profit distribution, with the record date for the said distribution being 24 March 2026, and the date of the said distribution being 31 March 2026.

(d) 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 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 GP, 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 its decision 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 or bear 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), which are incorporated herein by reference.

(b) For details on the decision of the meeting of the Participation Unit holders of 6 May 2025 to approve the appointment of Mr. Eran Yaacov as an external director on the Board, for a term of office of 3 years beginning on the date of the meeting's decision, and to approve his terms of office, see the Partnership's immediate reports of 1 April 2025 and 6 May 2025 (Ref. 2025-01-023733, 2025-01-031707, 2025-01-031710 and 2025-01-031719, respectively), which are incorporated herein by reference.

(c) For details on the decision of the Participation Unit holders of 25 January 2026 to approve a new compensation policy for officers of the Partnership and the GP, and to approve the renewal of the terms of office and employment of Mr. Abu, including the grant of equity compensation, see the Partnership's immediate reports of 18 December 2025 and 25 January 2026 (Ref. 2025-01-101197 and 2026-01-009438, respectively), which are incorporated herein by reference.

Regulation 29A: **Decisions of the Partnership**

(a) The outline for the collaboration between the Partnership and Enlight 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) which are incorporated herein by reference. On 16 February 2026, the parties engaged in an addendum to the agreement, in which it was agreed to extend the exclusive collaboration for an additional period of 3 years (i.e., until 31 March 2029), which in certain circumstances may be extended up to a period of five years from the date of signing with the addendum to the agreement. The Audit Committee and the Board approved the extension of the exclusivity period, in consideration of Mr. Abu's personal interest as aforesaid. For further details see Section 7.10 of Chapter A of this report.

(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) On 17 July 2012, the Participation Unit holders meeting approved an amendment to the Partnership Agreement to include the granting of letters of indemnification undertaking exemption from liability to directors of the GP who are not control holders of the GP and/or of the Partnership and/or their relatives, who serve from time to time in the GP and/or in subsidiaries of the Partnership (and who are not external directors). Pursuant to the amendments made to the Partnership Agreement as resolved by the meeting on 17 July 2012, the Board decided on 19 July 2012 to approve the granting of exemption and indemnification letters to officers of the GP and of the Partnership.

On 30 June 2019, the Compensation Committee and the Board decided to approve the granting of letters of indemnification undertaking and exemption from liability to officers serving in the GP and/or the Partnership, without derogating from the validity of exemption and indemnification letters previously granted to officers of the Partnership and/or the GP. On 10 July 2019, the Participation Unit holders meeting approved an amendment to Section 11 of the Limited Partnership Agreement dated 1 July 1993, as amended from time to time, regarding exemption, indemnification and insurance of officers of the Partnership and the GP. For further details, see the Partnership's immediate reports of 3 July 2019 and 10 July 2019 (Ref. 2019-01-057213 and 2019-01-059625, respectively), which are incorporated herein by reference.

On 4 August 2020, the Board approved authorizing the Partnership's management to sign, on behalf of the Partnership as the sole shareholder of Leviathan Bond, a written resolution to grant exemption and indemnification letters to the officers serving in Leviathan Bond and those who will serve therein from time to time. For details regarding letters of indemnification undertakings and exemptions from liability that were granted to directors and officers of the Partnership, the GP and Leviathan Bond, see Regulation 29A(4) of Chapter D of the 2020 Periodic Report.

(b) On 25 September 2024, the Compensation Committee and the Board confirmed the granting of letters of exemption and indemnification undertakings to the directors and officers of the Partnership, as well as their inclusion in the D&O liability insurance policy of the GP and of the Partnership, as being from time to time. 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 17 months from 1 July 2024, see Regulation 29A(4)(d) of Chapter D of the 2024 Periodic Report.

(d) On 4 September 2025, 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 GP, the Partnership and its subsidiaries, including the Partnership's CEO, for a period of 15 months from 1 September 2025, with a total limit of liability of $300 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 4 September 2025 (Ref.: 2025-01-067133), which is incorporated herein by reference.

(e) On 6 May 2025, the Participation Unit holders meeting, after approval by the Compensation Committee and the Board, approved the granting of letters of exemption and indemnification to the director Mr. Eran Yaacov, and his inclusion in the D&O insurance policy of the GP and the Partnership, as it shall be from time to time.

(f) On 11 May 2025, the Compensation Committee and the Board approved the granting of letters of exemption and indemnification to an office of the Partnership, and his inclusion in the D&O insurance policy of the GP and the Partnership, as being from time to time.

NewMed Energy - Limited Partnership

by the General Partner, NewMed Energy Management Ltd.

Names and positions of signatories: Gabi Last, Chairman of the Board
Yossi Abu, CEO

Date: 15 March 2026

Part E

Report on the effectiveness of internalcontrol 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

2025 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 "**Board**"), 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 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 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 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 the GP, as provided above, the Board 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 2025 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 2025 (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 and the audit and financial statements review committees of NewMed Energy Management Ltd., the general partner in the Partnership (the "**GP**"), 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 the GP 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.

15 March 2026	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 2025 (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 and the audit and financial statement review committees of NewMed Energy Management Ltd, the general partner of the Partnership (the "**GP**"), 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 the GP 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.

15 March 2026	Tzachi Habusha, CPA	VP Finance	
Date	Full name	Title	Signature