JURA ENERGY CORPORATION
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION
AS OF DECEMBER 31, 2022

Dated: May 1, 2023

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DEFINITIONS

In this Statement of Reserves Data and Other Oil and Gas Information, the terms set forth below have the following meanings, unless the context requires or indicates otherwise:

"**2022 Reserves Data**" has the meaning set forth under the heading "Disclosure of Reserves Data".

"**Aminah Lease**" has the meaning as set forth under the heading "Other Oil and Gas Information – Development and Production Leases – Ayesha, Aminah, and Ayesha North Leases".

"**APEL**" means Al Haj Pakistan Exploration Limited (*formerly Premier Oil Pakistan Exploration Limited*).

"**Ayesha Lease**" has the meaning as set forth under the heading "Other Oil and Gas Information – Development and Production Leases – Ayesha, Aminah, and Ayesha North Leases".

"**Ayesha North Lease**" has the meaning as set forth under the heading "Other Oil and Gas Information – Development and Production Leases – Ayesha, Aminah, and Ayesha North Leases".

"**Badar Lease**" has the meaning as set forth under the heading "Other Oil and Gas Information – Development and Production Leases – Badar Lease".

"**Badin IV North Exploration License**" has the meaning as set forth under the heading "Other Oil and Gas Information – Exploration Licenses – Badin IV North Exploration License".

"**Badin IV South Exploration License**" has the meaning as set forth under the heading "Other Oil and Gas Information –Exploration Licenses – Badin IV South Exploration License".

"**Badin IV South Leases**" has the meaning as set forth under the heading "Other Oil and Gas Information – Development and Production Leases – Ayesha, Aminah, and Ayesha North Leases".

"**C&F**" means carriage and freight.

"**COGE Handbook**" means the "Canadian Oil and Gas Evaluation Handbook" prepared jointly by The Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), as amended from time to time.

"**Consortium**" means a consortium of four fertilizer manufacturers consisting of Pak Arab Fertilizers Limited, Agri Tech Limited, DH Fertilizers Limited, and Engro.

"**CPF**" has the meaning as set forth under the heading "Other Oil and Gas Information – Development and Production Leases – Ayesha, Aminah, and Ayesha North Leases".

"**DCQ**" means daily contracted quantity.

"DeGolyer" means DeGolyer and MacNaughton Canada Limited.

"**DGPC**" means the Directorate General of Petroleum Concessions in Pakistan.

"**ECC**" means Economic Coordination Committee of the Federal Cabinet, Government of Pakistan.

"**EEL**" means Energy Exploration Limited, a company formed under the laws of Pakistan.

"**Engro**" means Engro Fertilizers Limited.

"**EWT**" means extended well testing.

"**Exploration License**" means an exclusive right to explore for petroleum within a designated portion of an onshore area under and pursuant to applicable rules.

"**FHL**" means Frontier Holdings Limited, a company formed under the laws of Bermuda and an indirect wholly-owned subsidiary of Jura.

"**GHPL**" means Government Holdings (Private) Limited.

"**GoP**" means the Government of Pakistan including regulatory authorities, governmental departments, agencies, commissions, bureaus, officials, ministers, courts, bodies, boards, tribunals or dispute settlement panels or other law, rule or regulation-making organizations or entities exercising, or entitled or purporting to exercise any administrative, executive, judicial, legislative, policy, regulatory or taxing authority or power in Pakistan.

"**GPA**" means a gas pricing agreement.

"**GPX**" means Gulf Petroleum Exploration Pakistan (GPXP) Limited.

"**GSA**" means a gas sale and purchase agreement.

"**Guddu Exploration License**" has the meaning as set forth under the heading "Other Oil and Gas Information – Exploration Licenses – Guddu Exploration License".

"**Guddu Farm-Out Agreement**" means the farm-out agreement between IPR and Spud dated January 1, 2008, relating to the acquisition by Spud of a 13.5% Working Interest in the Guddu Exploration License.

"**Guddu PCA**" has the meaning as set forth under the heading "Other Oil and Gas Information – Exploration Licenses – Guddu Exploration License".

"**Heritage Oil**" means Heritage Oil & Gas Limited.

"**Hycarbex**" means Hycarbex American Energy Inc.

"**ICC**" means International Chamber of Commerce.

"**IPR**" means IPR Transoil Corporation.

"**IRS**" has the meaning as set forth under the heading "Other Oil and Gas Information – Development and Production Leases - Reti, Maru and Maru South Leases."

"**Jura**" or the "**Corporation**" means Jura Energy Corporation, a corporation existing under the laws of Canada.

"**Kandra Lease**" has the meaning as set forth under the heading "Other Oil and Gas Information – Development and Production Leases – Kandra Lease".

"**KGPL**" means Konnect Gas (Private) Limited.

"**Lease**" means an exclusive right to develop and produce Petroleum from a designated portion of an onshore area under and pursuant to the applicable rules.

"**Marginal Gas Pricing Criteria**" means the Marginal Gas Fields – Gas Pricing Criteria and Guidelines 2013 issued by the Ministry of Petroleum & Natural Resources of the Government of Pakistan.

“**McDaniel**” means McDaniel & Associates Consultants Ltd.

“**McDaniel 2022 Report**” means the independent engineering evaluation of the corporation’s oil, natural gas liquids and natural gas interests prepared by McDaniel effective December 31, 2022, and dated April 10, 2023.

“**MEPD**” means the Ministry of Energy (Petroleum Division).

“**MPCL**” means Mari Petroleum Company Limited.

“**Nareli Exploration License**” has the meaning as set forth under the heading “Other Oil and Gas Information – Exploration Licenses – Nareli Exploration License”.

“**NI 51-101**” means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators.

“**OGDCL**” means Oil and Gas Development Company Limited.

“**OGRA**” means the Pakistan Oil and Gas Regulatory Authority.

“**PEL**” means Petroleum Exploration (Private) Limited.

“**Petroleum**” means all liquid and gaseous hydrocarbons existing in their natural condition, in the strata, as well as all substances, including sulphur, produced in association with such hydrocarbons, but do not include basic sediments and water.

“**Petroleum Concession Agreement**” or “**PCA**” means an agreement pursuant to which the GoP grants to the parties thereto an interest in a Petroleum concession, which interest is subject to the rights, obligations, and liabilities imposed by the applicable Petroleum laws of Pakistan, including the enjoyment of the exclusive right to explore and prospect for, develop, produce, sell and otherwise dispose of Petroleum from the area covered under the Exploration License or the Lease, as the case may be.

“**Petroleum Policy 2001**” means the Pakistan Petroleum (Exploration and Production) Policy, 2001.

“**Petroleum Policy 2009**” means the Pakistan Petroleum (Exploration and Production) Policy, 2009.

“**Petroleum Policy 2012**” means the Pakistan Petroleum (Exploration and Production) Policy, 2012.

“**POL**” means Pakistan Oilfields Limited.

“**President**” means the President of the Islamic Republic of Pakistan.

“**Reti, Maru and Maru South Leases**” have the meaning as set forth under the heading “Other Oil and Gas Information – Development and Production Leases – Reti, Maru, and Maru South Leases”.

“**Rules 1986**” means the Pakistan Petroleum (Exploration and Production) Rules, 1986.

“**Sara and Suri Leases**” has the meaning as set forth under the heading “Other Oil and Gas Information – Development and Production leases – Sara and Suri Leases”.

“**SEDAR**” means the System for Electronic Document Analysis and Retrieval.

“**Settlement Agreement**” means an agreement, dated August 12, 2016, between FHL, Spud and PEL, pursuant to which all the disputes between FHL and PEL were resolved.

"**Sherritt**" means Sherritt International Corporation.

"**Short Term Loan Agreement**" has the meaning as set forth under the headings "General Developments of the Business – History and Recent Business – Developments in 2018 – Short Term Loan Agreement".

"**Sprint**" means Sprint Energy Limited.

"**Spud**" means Spud Energy Pty Limited, a company incorporated pursuant to the Australian Corporations Act 2001 (Cth) and a wholly-owned subsidiary of Jura.

"**SSGCL**" means Sui Southern Gas Company Limited.

"**Statement**" means this Statement of Reserves Data and Other Oil and Gas Information.

"**Tight Gas Policy**" means the Pakistan Tight Gas (Exploration and Production) Policy, 2011.

"**Trakker**" means Trakker Energy (Private) Limited.

"**Tullow**" means Tullow Pakistan (Developments) Limited.

"**WAPDA**" means the Pakistan Water and Power Development Authority.

"**Working Interest**" means all or any undivided interest in the entirety of any Petroleum right, and related obligations and liabilities imposed by the applicable rules in accordance with any Exploration License, Lease or PCA.

"**Working Interest Owner**" means the owner of the applicable Working Interest.

"**Zamzama Farm-Out Agreement**" means the farm-out agreement among Sprint, Spud, and EEL dated April 15, 2009, relating to the acquisition by Spud of a 12% Working Interest in the Zamzama North Exploration License.

"**Zamzama North Exploration License**" has the meaning as set forth under the heading "Other Oil and Gas Information – Exploration Licenses – Zamzama North Exploration License".

"**Zarghun South Lease**" has the meaning as set forth under the heading "Other Oil and Gas Information – Development and Production Leases– Zarghun South Lease".

Words importing the singular number, where the context requires, include the plural and vice versa and words importing any gender include all genders.

CONVENTIONS

Certain other terms used but not defined in this Statement are defined in NI 51-101 and, unless the context otherwise requires, have the same meanings as ascribed to them in NI 51-101. Unless otherwise indicated, references in this Statement to "$" or "dollars" are to United States dollars.

ABBREVIATIONS

The following abbreviations are used in this Statement.

Crude Oil and Natural Gas Liquids		**Natural Gas**	
Bbl	One barrel equalling 34.972 Imperial gallons or 42 U.S. gallons	Bcf	Billion cubic feet
Bbls/d	Barrels per day	Bbl/MMcf	Barrel per million cubic feet

Crude Oil and Natural Gas Liquids		Natural Gas	
Boe	Barrels of oil equivalent	Mcf	Thousand cubic feet
Boe/d	Barrels of oil equivalent per day	Mcf/d	Thousand cubic feet per day
MBoe	Thousand barrels of oil equivalent	MMcf	Million cubic feet
MMBoe	Million barrels of oil equivalent	MMcf/d	Million cubic feet per day
MBbls	Thousand barrels	Btu	British Thermal Units
NGLs	Natural gas liquids, consisting of any one or more of ethane, propane, butane and condensate	MMBtu	Million British Thermal Units
		Btu/Scf	British Thermal Unit per standard cubic feet

The use of the Boe unit of measurement may be misleading, particularly if used in isolation. A Boe conversion ratio of 5.8 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Other	
Km	Kilometer
L.Km	Line kilometer
Sq.Km	Square kilometer
Psi	Pounds per square inch
Md	Millidarcy
$	United States dollars
C$	Canadian dollars
PKR	Pakistan rupee

EQUIVALENCIES

To Convert from	To	Multiply by
Thousand cubic feet	Cubic meters	28.317
Cubic meters	Cubic feet	35.315
Barrels	Cubic meters	0.159
Cubic meters	Barrels	6.293
Feet	Meters	0.305
Meters	Feet	3.281
Miles	Kilometers	1.609
Kilometers	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471
Gigajoules	Thousand cubic feet	1.055

This Statement discloses test rates of production for certain wells over short periods of time, which are preliminary and not determinative of the rates at which those or any other wells will commence production and thereafter decline. Short-term test rates are not necessarily indicative of long-term well or reservoir performance or of ultimate recovery. Although such rates are useful in confirming the presence of hydrocarbons, they are preliminary in nature, are subject to a high degree of predictive uncertainty as a result of limited data availability and may not be representative of stabilized on-stream production rates.

FORWARD-LOOKING STATEMENTS

This Statement contains forward-looking statements. These statements relate to future events or future performance of Jura. All statements other than statements of present or historical fact are forward-looking statements. When used in this Statement, the words “may”, “would”, “could”, “will”, “intend”, “plan”, “anticipate”, “believe”, “estimate”, “predict”, “seek”, “propose”, “expect”, “potential”, “continue”, and similar expressions, are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties, and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Jura believes that the expectations reflected in these forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this Statement should not be unduly relied upon. Moreover, Jura does not assume responsibility for the accuracy and completeness of the forward-looking statements. Jura's actual results, performance or achievements could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits Jura will derive therefrom. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this Statement as intended, planned, anticipated, believed, estimated, or expected. Specific forward-looking statements in this Statement include, among others, statements pertaining to the following:

- the level of costs to perform well abandonment and reclamation, including future abandonment and reclamation costs;
- future commodity prices;
- future production rates;
- timing and development of undeveloped reserves;
- future capital expenditure and development plans;
- future tax liability;
- future costs, including operating and production costs, transportations costs, capital costs and administration costs;
- the level of operational cash flows and other internal cash generation;
- anticipated business activities, projected growth and execution of corporate plans and strategies;
- the location and timing of, and the structures to be targeted by, the wells to be drilled in the Guddu, Zamzama North, Nareli, Badin IV South and Badin IV North Exploration Licenses;
- expectations with respect to certain GoP approvals and exemptions and the treatment of Jura and its subsidiaries under governmental regulatory regimes, including future environmental laws and regulations;
- expectations regarding the extension or renewal of Jura's Leases and Exploration Licenses by the GoP and expenses related to the failure to obtain such extensions or renewals;
- expectations regarding the level of production and timing of commencement of commercial production from the Zainab lease pursuant to the Badin IV North Exploration License;
- expectations regarding the execution of deeds of assignments by the GoP in respect of the Zamzama North Exploration License, Mirpur Mathelo Exploration License, Salam Exploration License, Badar Lease and Kandra Lease;
- expectations regarding satisfaction of conditions to completion of the acquisition of EEL and the timing thereof;
- anticipated exploration upside potential in areas covered by the Kandra, Zarghun South and Sara and Suri Leases;
- expected pricing under the Marginal Gas Pricing Criteria and the Petroleum Policy 2012;
- the timing of reprocessing of 3D seismic data obtained under the Guddu Exploration License;
- the timing of approval of amendments in the GSA pursuant to the Zarghun South Lease by SSGCL and the GoP;
- expectations regarding GoP approval of the GPA for the Reti, Maru, and Maru South discoveries under the Guddu Exploration License;
- expectations regarding entitlement of gas pricing under the Marginal Gas Pricing Criteria for the Zainab-1 discovery;

- expectations regarding GoP approval for grant of extension in the Sara and Suri Leases;
- expectations regarding GoP approval of a supplemental GPA under the Tight Gas Policy and a supplemental Lease deed incorporating the Tight Gas Policy terms;
- expectations regarding the grant of waiver from compliance with the financial covenants under Askari Bank syndicated term finance facilities;
- expectations regarding the outcome of arbitration proceedings initiated against PEL;
- expectations regarding the continuity of stay orders granted by Islamabad High Court against PEL's attempt to cause the forfeiture of FHL's 27.5% Working Interest in Badin IV North and South Blocks; and
- expectations regarding obtaining any regulatory/governmental approval.

Statements relating to reserves or resources are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves and resources described can be profitably produced in the future.

With respect to forward-looking statements in this Statement, Jura has made assumptions, regarding, among other things:

- the impact of increasing competition;
- Jura's ability to obtain additional financing on satisfactory terms;
- Jura's ability to attract and retain qualified personnel;
- the stability of global and national economic and political structures;
- the absence of significant project delays, whether as a result of economic, regulatory, environmental or weather conditions; and
- the ability of the Corporation to market oil and natural gas products to new and existing customers.

Jura's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and assumptions set forth above and elsewhere in this Statement:

- the severity and duration of potential public health crises, such as the COVID-19 global pandemic or other medical epidemics or pandemics, including the potential for a temporary suspension of operations impacted by an outbreak of illness and continued weakness and volatility of crude oil and other petroleum products due to decreased global demand due to such events;
- general economic conditions;
- volatility in global market prices for oil and natural gas;
- acts of violence, terrorism and civil unrest affecting Jura's assets and personnel;
- changes of laws in Pakistan affecting foreign ownership, interpretation or renegotiation of existing contracts, government participation, taxation policies, including royalty and tax increases and retroactive tax claims, investment restrictions, working conditions, exploration licensing and government control over domestic oil and gas pricing;
- competition;
- liabilities and risks, including environmental liability and risks, inherent in oil and gas operations;
- volatility in capital markets;
- the availability of capital;

- alternatives to and changing demand for Petroleum products;
- the risk that the GoP may revoke certain approvals;
- the risk that Jura's Exploration Licenses or Leases will expire and will not be renewed, or that Exploration Licenses or Leases that are currently past their term and are pending renewal will not be renewed, on terms acceptable to Jura, or at all;
- the risk of a negative outcome in the arbitration proceedings initiated against PEL with respect to FHL's 27.5% Working Interest in the Badin IV South Leases, the Badin IV South Exploration License and the Badin IV North Exploration License; and
- without limitation, and among other things, the other factors considered under the heading "*Risk Factors*" in Jura's management's discussion and analysis for the year ended December 31, 2022 filed on SEDAR, which risk factors are incorporated by reference herein.

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids (or similar substances) reserves and cash flows to be derived therefrom, including many factors beyond Jura's control. The information concerning reserves and associated cash flow set forth in this Statement represents estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom, are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers, or by the same engineers at different times, may vary. Jura's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. Further, the evaluations are based, in part, on the assumed success of the exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom, contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluation.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material. Many of Jura's producing wells have a limited production history and thus there is less historical production on which to base the reserves estimates. In addition, a significant portion of Jura's reserves may be attributable to a limited number of wells and, therefore, a variation in production results or reservoir characteristics in respect of such wells may have a significant impact upon Jura's reserves.

In accordance with applicable securities laws, McDaniel has used forecast price and cost estimates in calculating reserve quantities. Actual future net cash flows will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs. Actual production and cash flows derived therefrom will vary from the estimates contained in the McDaniel 2022 Report and such variations could be material. The McDaniel 2022 Report is based in part on the assumed success of activities Jura intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom, contained in the McDaniel 2022 Report will be reduced to the extent that such activities do not achieve the level of success assumed in the McDaniel 2022 Report.

The evaluation by McDaniel of the reserves associated with Jura's oil and gas reserves in the McDaniel 2022 Report is effective as of a specific effective date and has not been updated and thus does not reflect changes in Jura's reserves since that date.

Undue reliance should not be placed on forward-looking statements. Such statements are inherently uncertain, are based on estimates and assumptions, and are subject to known and unknown risks and uncertainties (both general and specific) that contribute to the possibility that the future events or circumstances contemplated by the forward-looking statements will not occur. There can be no assurance that the plans, intentions or expectations upon which forward-looking statements are based will, in fact, be realized. Actual results will differ, and the difference may be material and adverse to the Corporation and its shareholders.

These factors should not be considered exhaustive. The reader is cautioned that these factors and risks are difficult to predict and that the assumptions used in the preparation of such information, although considered reasonably accurate at the time of preparation, may prove to be incorrect. Accordingly, readers are cautioned that the actual results achieved by the Corporation will vary from the information provided herein and the variations may be material. Consequently, there are no representations by the Corporation that actual results achieved will be the same in whole or in part as those set out in the forward-looking information. Furthermore, the forward-looking statements contained in this Statement are made as of the date hereof, and the Corporation undertakes no obligation, except as required by applicable securities legislation, to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

DISCLOSURE OF RESERVES DATA

The reserves data set forth below (the "**2022 Reserves Data**") is based upon the evaluation by McDaniel of the reserves associated with Jura's assets and the value of future net revenue attributable to such reserves. The McDaniel 2022 Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101 and the COGE Handbook. The 2022 Reserves Data summarizes the oil, liquids and natural gas reserves associated with Jura's assets and properties and the net present values of future net revenue for these reserves using forecast prices and costs as at December 31, 2022.

All evaluations of future revenue are stated after the deduction of future income tax expenses (unless otherwise noted in the tables), royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables does not represent the fair market value of reserves associated with Jura's assets and properties. There is no assurance that the forecast price and cost assumptions contained in the McDaniel 2022 Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to the following tables. The recovery and reserves estimates for Jura's assets and properties described herein are estimates only and there is no guarantee that the estimated reserves will be recovered. The actual reserves for Jura's assets and properties may be greater or less than those calculated. In the various reserves related tables included herein, columns may not add due to rounding.

All of Jura's oil and natural gas reserves are located onshore in Pakistan. The following table summarizes the reserves evaluated at December 31, 2022 using forecast prices and costs.

Unless otherwise indicated, references herein to "$" or "dollars" are to United States (U.S.) dollars and references herein to "$MM" are to million United States (U.S.) dollars.

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2022

RESERVES CATEGORY	Light and Medium Oil		Heavy Oil		Natural Gas[9]		Natural Gas Liquids	
	Gross (MBbls)	Net (MBbls)	Gross (MBbls)	Net (MBbls)	Gross[10] (MMcf)	Net[11] (MMcf)	Gross[10] (MBbls)	Net[11] (MBbls)
PROVED[1]								
Developed Producing[2]	-	-	-	-	5,380	4,708	12	10
Developed Non-Producing[3]	-	-	-	-	74	64	-	-
Undeveloped[4]	-	-	-	-	1,981	1,733	52	46
TOTAL PROVED	-	-	-	-	**7,435**	**6,506**	**64**	**56**
PROBABLE[5]	-	-	-	-	6,937	6,070	59	52
TOTAL PROVED PLUS PROBABLE[6]	-	-	-	-	**14,372**	**12,575**	**123**	**108**
POSSIBLE[7]	-	-	-	-	12,695	11,108	102	89
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE[8]	-	-	-	-	**27,067**	**23,683**	**225**	**197**

Net Present Value[12] of Future Net Revenue Based on Forecast Prices and Costs:

RESERVES CATEGORY	Before Deducting Income Taxes Discounted at						Unit Value Disc. @ 10%/Yr. (13) ($/Boe)
	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	17.5% ($000s)	20% ($000s)	
PROVED[1]							
Developed Producing[2]	8,363	8,038	7,709	7,398	7,253	7,113	9.38
Developed Non-Producing[3]	63	59	55	52	51	49	5.00
Undeveloped [4]	8,224	7,041	6,076	5,281	4,935	4,618	17.64
TOTAL PROVED	**16,651**	**15,139**	**13,841**	**12,731**	**12,238**	**11,781**	**11.75**
PROBABLE[5]	20,808	17,444	14,863	12,847	11,999	11,237	13.53
TOTAL PROVED PLUS PROBABLE[6]	**37,459**	**32,584**	**28,703**	**25,578**	**24,237**	**23,018**	**12.61**
POSSIBLE[7]	45,031	36,369	29,869	24,907	22,863	21,053	14.90
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE[8]	**82,490**	**68,952**	**58,573**	**50,485**	**47,100**	**44,072**	**13.68**

Net Present Value[12] of Future Net Revenue Based on Forecast Prices and Costs:

RESERVES CATEGORY	After Deducting Income Taxes Discounted at					
	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	17.5% ($000s)	20% ($000s)
PROVED[1]						
Developed Producing[2]	8,363	8,038	7,709	7,398	7,253	7,113
Developed Non-Producing[3]	63	59	55	52	51	49
Undeveloped [4]	8,224	7,041	6,076	5,281	4,935	4,618
TOTAL PROVED	**16,651**	**15,139**	**13,841**	**12,731**	**12,238**	**11,781**
PROBABLE[5]	20,808	17,444	14,863	12,847	11,999	11,237
TOTAL PROVED PLUS PROBABLE[6]	**37,459**	**32,584**	**28,703**	**25,578**	**24,237**	**23,018**
POSSIBLE[7]	34,452	28,345	23,628	19,957	18,427	17,064
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE[8]	**71,911**	**60,929**	**52,332**	**45,535**	**42,664**	**40,082**

Notes to Reserves Data Tables:

(1) "**Proved Reserves**" are those Reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved Reserves. At least a 90% probability that the quantities actually recovered will equal or exceed the estimated Proved Reserves is the target level of certainty.

(2) "**Developed Producing**" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(3) "**Developed Non-Producing**" reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(4) "**Undeveloped**" reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserve classification (proved, probable, possible) to which they are assigned.

(5) "**Probable Reserves**" means those additional reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus Probable Reserves. At least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable Reserves is the target level of certainty.

(6) "**Proved plus Probable Reserves**" means the aggregate of Proved Reserves and Probable Reserves.

(7) "**Possible Reserves**" means those additional reserves that are less certain to be recovered than Probable Reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated Proved plus Probable plus Possible Reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of Proved plus Probable plus Possible Reserves.
(8) "**Proved plus Probable plus Possible Reserves**" means the aggregate of Proved Reserves, Probable Reserves and Possible Reserves.
(9) Estimates of reserves of natural gas include associated and non-associated gas.
(10) "**Gross Reserves**" are Jura's Working Interest (operating or non-operating) reserves before the deduction of royalties and without including any royalty interests.
(11) "**Net Reserves**" are Jura's Working Interest (operating or non-operating) reserves after deductions of royalty obligations plus Jura's royalty interests.
(12) **Net Present Value of Future Net Revenue** includes all resource income: sale of oil, gas, by-product reserves; processing of third-party reserves; other income.
(13) The unit values are based on net reserve volumes before income tax.
(14) Income taxes include all resource income, appropriate income tax calculations and prior tax pools.
(15) "**Reserves**" or "**reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: (a) analysis of drilling, geological, geophysical and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates.
(16) Numbers may not add exactly due to rounding.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
AS OF DECEMBER 31, 2022
FORECAST PRICES AND COSTS

	Revenue ($000s)	Additional income ($000s) (1)	Royalties ($000s)	Operating Costs ($000s) (2)	Development Costs ($000s)	Abandonment and Reclamation Costs ($000s)	BT Future Net Revenue ($000s) (3)	Income Taxes ($000s)	AT Future Net Revenue ($000s) (3)
Proved	43,933	1,834	5,492	14,954	5,091	3,579	16,651	-	16,651
Proved plus Probable	84,992	2,751	10,624	27,918	7,711	4,031	37,459	-	37,459
Proved plus Probable plus Possible	166,836	4,585	20,855	50,273	12,708	5,095	82,490	10,580	71,911

Notes:
(1) Facilities rental income from Sara Suri
(2) Operating cost less processing and other income.
(3) BT = Before Taxes and AT = After Taxes

NET PRESENT VALUE OF
FUTURE NET REVENUE BY PRODUCTION GROUP
AS OF DECEMBER 31, 2022
FORECAST PRICES AND COSTS

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($000s)	Unit Value Before Income Taxes (discounted at 10%/ year) ($/Boe)
Proved	Light and Medium Crude Oil(1)	-	-
	Heavy Oil	-	-
	Natural Gas	12,550	10.66
Proved plus Probable	Light and Medium Crude Oil(1)	-	-
	Heavy Oil	-	-
	Natural Gas	25,818	11.34
Proved plus Probable plus Possible	Light and Medium Crude Oil(1)	-	-
	Heavy Oil	-	-
	Natural Gas	**52,798**	12.34

Note:
(1) Includes solution gas.

PRICING ASSUMPTIONS

Sale prices used by McDaniel in preparing the 2022 Reserves Data were:

Year	Crude oil price Forecast[(1)]	Badin IV South		Badin IV North		Zarghun South			Guddu	Sara and Suri
		Condensate	Gas	Condensate	Gas	Condensate	Tight	Conventional	Gas	Gas
	$/Bbl	$/Bbl	$/Mcf	$/Bbl	$/Mcf	$/Bbl	$/Mcf	$/Mcf	$/Mcf	$/Mcf
2023	84.00	69.13	5.56	68.95	6.81	84.00	6.41	2.84	3.65	1.72
2024	80.58	67.08	5.48	66.90	6.72	80.58	6.34	2.84	3.60	1.81
2025	79.59	66.61	5.46	66.43	6.69	79.59	6.33	2.84	3.58	1.90
2026	78.53	66.09	5.44	65.92	6.66	78.53	6.31	2.84	3.57	2.00
2027	80.10	67.29	5.47	67.11	6.70	80.10	6.33	2.84	3.59	2.10
2028	81.70	68.51	5.51	68.33	6.75	81.70	6.36	2.84	3.62	2.20
2029	83.34	69.74	5.54	69.57	6.79	83.34	6.39	2.84	3.64	2.31
2030	85.00	71.00	5.58	70.83	6.83	85.00	6.42	2.84	3.67	2.43
2031	86.70	72.28	5.62	72.11	6.88	86.70	6.45	2.84	3.69	2.55
2032	88.44	73.58	5.66	73.41	6.92	88.44	6.49	2.84	3.72	2.67

Note:

(1) Escalation rate of 2% per year applied after 2032.

RECONCILIATION OF CHANGES IN RESERVES

The following tables set forth a reconciliation of the changes in gross total company Working Interest reserve volumes as at December 31, 2022 against such gross reserves as at December 31, 2021, based on the forecast prices and costs assumptions:

	Natural Gas			NGLs		
	Proved	Probable	Proved plus Probable	Proved	Probable	Proved plus Probable
	(MMcf)	(MMcf)	(MMcf)	(MBbls)	(MBbls)	(MBbls)
December 31, 2021	**11,411**	**9,499**	**20,910**	**75**	**70**	**146**
Technical revision	(1,147)	(2,562)	(3,709)	(1)	(11)	(12)
Discoveries	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Extensions	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Production	(2,829)	-	(2,829)	(11)	-	(11)
Economic Factors	-	-	-	-	-	-
December 31, 2022	**7,435**	**6,937**	**14,372**	**64**	**59**	**123**

	Light Crude Oil			Total		
	Proved	Probable	Proved plus Probable	Proved	Probable	Proved plus Probable
	(MBbls)	(MBbls)	(MBbls)	(MBoe)	(MBoe)	(MBoe)
December 31, 2021	**-**	**-**	**-**	**2,043**	**1,708**	**3,701**
Technical revision	-	-	-	(199)	(453)	(651)
Discoveries	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Extensions	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Production	-	-	-	(499)	-	(499)
Economic Factors	-	-	-	-	-	-
December 31, 2022	**-**	**-**	**-**	**1,346**	**1,255**	**2,601**

Notes:

(1) Figures may not add due to rounding.

(2) The Corporation has no unconventional reserves (including, for example, bitumen, synthetic crude oil, coalbed methane), nor any heavy oil.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

The following table sets forth the Proved Undeveloped Reserves and the Probable Undeveloped Reserves, each by product type, attributed to Jura's assets in each of the most recent three financial years based on forecast prices and costs.

		Gross Reserves First Attributed by Year			
Product Type	**Units**	**2020**	**2021**	**2022**	**Total**
Proved Undeveloped					
Light & Medium Oil	MBbls	-	-	-	-
Heavy Oil	MBbls	-	-	-	-
Natural Gas	MMcf	-	-	-	-
Natural Gas Liquids	MBbls	-	-	-	-
Total: Oil Equivalent	MBoe	**-**	**-**	**-**	**-**
Probable Undeveloped					
Light & Medium Oil	MBbls	-	-	-	-
Heavy Oil	MBbls	-	-	-	-
Natural Gas	MMcf	-	-	-	-
Natural Gas Liquids	MBbls	-	-	-	-
Total: Oil equivalent	MBoe	**-**	**-**	**-**	**-**

Undeveloped reserves are attributed by McDaniel in accordance with standards and procedures contained in the COGE Handbook. Proved Undeveloped Reserves are those Reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable Undeveloped Reserves are those Reserves that are less certain to be recovered than Proved Reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

Jura is planning to develop its Proved Undeveloped Reserves over the next two years through commencement of development activities and further drilling of development wells where deemed necessary to achieve optimal depletion of reserves. Jura is planning to develop its Probable Undeveloped Reserves over the next two years through geological and geophysical studies, seismic acquisition/interpretation and the drilling of appraisal/exploratory wells.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geological conditions or production. These revisions can be either positive or negative.

While Jura does not anticipate that any significant economic factors or significant uncertainties will affect any particular components of the reserves data, the reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond the control of Jura. See also "Risk Factors" in Jura's management's discussion and analysis for the year ended December 31, 2022.

Future Development Costs

The following table sets forth the development costs deducted in estimating Jura's future net revenue attributable to the reserve categories set forth below as of December 31, 2022, stated with no discount and a discount rate of 10%, as indicated:

Forecast Prices and Costs			
Year	**Proved Reserves ($000s)**	**Proved Plus Probable Reserves ($000s)**	**Proved Plus Probable Plus Possible Reserves ($000s)**
2023	3,867	6,115	6,115
2024	1,122	1,394	4,331
2025	-	100	2,160
2026	102	102	102
2027	-	-	-
Thereafter	-	-	-
Total Undiscounted	**5,091**	**7,711**	**12,708**
Discounted @ 10%	**4,732**	**7,190**	**11,360**

Note:
(1) Future development costs shown are associated with booked reserves in the McDaniel 2022 Report and do not necessarily represent Jura's full exploration and development budget.

Future development costs are expected to be funded through a combination of funds from operations and future capital injections. Jura's management does not anticipate that costs incurred in connection with future development will have a material adverse impact on the economic viability of the reserves.

OTHER OIL AND GAS INFORMATION

Description of Principal Oil and Gas Properties

The following is a description of the material oil and natural gas properties, pipelines, facilities and installations in which Jura holds Working Interests. Jura's properties are located in the Middle and Lower Indus Basins in Pakistan.

<u>Middle Indus Basin</u>

The Middle Indus Basin or Central Gas Basin is located between the Sargodha, and Khairpur-Jacobabad highs onshore Pakistan. Several gas discoveries have been made in the Middle Indus Basin, some as recently as the early 1950s. The main producing gas reservoirs are Eocene Carbonates (Pirkoh Limestone, Habib Rahi Limestone, Sui Main Limestone, Paleocene Dunghan Carbonates and Ranikot Clastics and deeper Lower Cretaceous Lower Goru Sandstones). The Sui, Mari, Miano, Rehmat, Kandhkot and Qadirpur gas fields are adjacent to FHL's and Spud's Working Interests.

<u>Lower Indus Basin</u>

The Lower Indus Basin is located south of Khairpur-Jacobabad high area to the Arabian Sea. Several oil and gas discoveries have been made in the Lower Indus Basin, some as recently as the mid-1960s. The main producing oil and gas reservoirs are from Paleocene Ranikot and Dunghan Formation, Upper Cretaceous Pab and Mughal Kot Formation and Lower Cretaceous Lower Goru Formation. More than 100 fields have been discovered so far including the largest Khaskheli oilfield and Sari Hundi, Bhit, Badhra and Zamzama gas fields. FHL's Badin blocks are located in the Badin Sub-Basin, the southern part of Lower Indus Basin.

Development and Production Leases

<u>Badar Lease</u>

Ghauspur Block
Spud's Working Interest: 7.89%
(Other Working Interest Owners: PEL 26.32%, OGDCL 50%, Sherritt 15.79%)

Spud is a party to, among other related agreements, the Badar Lease dated September 18, 2003, among the President, Spud, PEL, OGDCL and Sherritt (the "**Badar Lease**"), as amended and supplemented. The Badar Lease covers an area of 123.04 Sq.Km. Spud has a 7.89% Working Interest in the Badar Lease. Pursuant to the terms of the Settlement Agreement, effective August 12, 2016, Spud has agreed to transfer its 7.89% Working Interest in the Badar Lease to PEL.

<u>Zarghun South Lease</u>

Block No. 2966-1 (Bolan Block)
Spud's Working Interest: 40%
(Other Working Interest Owners: MPCL 35%, GHPL 17.5%, APEL 7.5%)

Spud is a party to, among other related agreements, the Zarghun South Development and Production Lease dated September 16, 2004 among the President, Spud, MPCL, APEL and GHPL (the "**Zarghun South Lease**"), as amended and supplemented. Spud has a 40% Working Interest in the Zarghun South Lease under the November 30, 1994 Bolan Petroleum Concession Agreement. The Zarghun South Lease is operated by MPCL.

The Zarghun South Lease covers an area of 124.22 Sq.Km and is located in the western part of the Sulaiman Fold and Thrust Belt of the Middle Indus Basin and is strategically located near the gas demand center of the city of Quetta. In March 2018, the operator applied to the DGPC for a grant of an additional area of 12.4 Sq.Km in the existing Zarghun South Lease over the Zarghun West area lead under related Rules 1986, which was declined by the DGPC. The Working Interest Owners have requested that the operator take up the matter with the highest level of MEPD.

The discovery well, Zarghun South-1, was drilled in 1998. During production testing, gas from naturally fractured Paleocene and Jurassic carbonates flowed at a rate of 3.5 MMcf/d to 17.7 MMcf/d. The appraisal well, Zarghun South-2, which was drilled in March 2000, tested gas at a rate of 15.6 MMcf/d from the Paleocene carbonates.

In June 2011, the GoP promulgated the Tight Gas Policy, under which tight gas reservoirs, subject to third-party certification, would be eligible for an increased gas price.

Based on the criteria defined in the Tight Gas Policy, Zarghun South Paleocene reservoirs qualify for the incentives under the Tight Gas Policy. Accordingly, DeGolyer was engaged for the purposes of certification and, in its report dated April 30, 2012, DeGolyer certified the Zarghun South gas field reserves as follows: (i) gas initially in place (proved plus probable) of 102 Bcf; (ii) recoverable gas reserves of 68.70 Bcf; (iii) gas reserves eligible for Tight Gas Policy pricing of 58.10 Bcf; and (iv) conventional gas reserves eligible for Petroleum Policy 2001 pricing of 10.60 Bcf.

The tight gas production from Zarghun South is entitled to a price of $5.28 per MMBtu, based on the C&F price of a basket of crude oil priced at $45 per Bbl, as opposed to the price of $2.86 per MMBtu for conventional gas production under the Petroleum Policy 2001.

Following this certification, a supplemental development plan seeking a revised Lease under the Tight Gas Policy was submitted to the GoP for approval in April 2012. In October 2012, the GoP approved the supplemental development plan and granted a tight gas Lease for a period of 17 years from October 10,

2012. A supplemental GPA for gas pricing under the Tight Gas Policy and a supplemental Lease deed incorporating the Tight Gas Policy terms are pending GoP approval, which is expected in the ordinary course. Further, certain amendments to the GSA applicable to sales of production from the Zarghun South Lease are being discussed with the buyer and, following concurrence among the parties thereto, an addendum to the signed GSA will be submitted to the GoP for approval. All other GoP approvals, namely, the current GSA, conventional GPA, pipeline contribution agreement and supplemental PCA have been executed by the relevant parties.

Commercial production from Zarghun South commenced in August 2014 under an Interim Gas Sale Arrangement. The Interim Gas Sale Arrangement was approved by the Working Interest Owners pending installation and commissioning of an amine sweetening unit required for removal of carbon dioxide and hydrogen sulphide from the inlet gas stream. The off-specification gas during the interim arrangement was sold at a discount of 30% to the price that would otherwise be applicable to the gas. Following the full commissioning of the processing facilities in November 2014, the specification gas as stipulated in the GSA is supplied to SSGCL without such discount.

In August 2015, the OGRA issued a provisional gas price notification for tight and conventional gas production from the Zarghun South Lease.

The development well, Zarghun South-3, was drilled in September 2016 to the total depth of 1,820 meters and was completed as a gas producing well in the Dunghan Limestone formation of Palaeocene age. During a short duration post-completion test, the well flowed gas at an average rate of approximately 10.5 MMcf/d at 32/64 inch choke size, having a heating value of approximately 920 Btu/Scf, with an average wellhead flowing pressure of 1,800 Psi. Commercial production from Zarghun South-3 commenced in January 2017.

During 2017, choke performance test and flowing bottom hole pressure ("**BHP**") survey was carried out at Zarghun South-3 well. Based on the results of BHP survey, Zarghun South-3 well was choked-up from 29/64 inch to 36/64 inch.

During July 2018, the first Annual Turn Around ("**ATA**") of the processing facilities was carried out, which include major plant over-hauling. During ATA, a Supervisory Control and Data Acquisition system was installed at the plant and BHP surveys were carried on all three wells.

During 2019, the Zarghun South Working Interest Owners acquired approximately 102 L.Km new in-fill 2D seismic data in order to firm up the drilling location of a fourth development well, Zarghun South-4. The newly acquired data was processed along with 150 L.Km of vintage data.

The drilling of the Zarghun South-4 development well commenced in January 2020. Zarghun South-4 was drilled as a deviated well to a total measured depth of approximately 2022 meters and was successfully completed as a gas producing well in the Dunghan Limestone formation of Paleocene age.

A short duration post-completion testing was conducted after perforating selective intervals of approximately 245 meters. A summary of the well testing results carried out at various choke sizes is as follows:

Choke Size	Average gas flow rates	Wellhead flowing pressure
	MMcf/d	**Psi**
32 / 64"	5.04	1,567
40 / 64"	8.64	1,492
48 / 64"	12.25	1,394
56 / 64"	16.03	1,290

After tie-in with the gas processing facilities the production from Zarghun South-4 commenced in April 2020. During the last quarter of 2021 and 2022, the production from Zarghun South continued to decline as a result of water breakthrough in the Dunghan reservoir. The current average field production is approximately 4.70 MMcf/d and, as of the date of this Statement, the field has produced a volume of approximately 43.71 Bcf of gas.

On February 4, 2021, the Zarghun South Working Interest Owners, including Spud, entered into the Bolan Supplemental PCA with the President, which incorporated provisions for the entitlement of tight gas pricing incentives for the Dunghan Reservoir within the Zarghun South leases.

During 2022, flash floods caused by unusually heavy monsoon rains in Pakistan damaged approximately 10km of Zarghun South's sales gas pipeline. As a result thereof, production from the Zarghun South Lease was suspended for approximately three months. There was no damage to the production facilities installed at field and all field personnel were safely evacuated from the field location. Production from the field resumed in fourth week of December 2022.

Spud has incurred $43,872,943 of capital expenditures related to the Zarghun South Lease to date, of which 35,464 were incurred in the fiscal year 2022.

The Zarghun South Lease will expire in 2029.

<u>Sara and Suri Leases</u>

Block No. East Badin (Extension) Block B
Spud's Working Interest: 60%
(Other Working Interest Owner: OGDCL 40%)

Spud is a party to, among other related agreements, the Sara Development and Production Lease dated July 7, 1996 among the President, Spud and OGDCL and the Suri Development and Production Lease dated June 30, 2000 among the President, Spud and OGDCL (collectively, the "**Sara and Suri Leases**"), each as amended and supplemented.

Following its acquisition of a 38.2% Working Interest from Tullow on August 16, 2012 and a further 21.8% Working Interest from POL and Attock Oil Company on December 24, 2012, Spud has a 60% Working Interest in the Sara and Suri Leases. The Sara and Suri Leases cover a total area of 106.54 Sq.Km located in the Middle Indus Basin, of which 82.72 Sq.Km comprises the Sara Development and Production Lease and 23.82 Sq.Km comprises the Suri Development and Production Lease. Spud acts as the operator of the Sara and Suri Leases.

Two dehydration facilities of 25 MMcf/d are installed at the field. In 2010, the Suri gas field was producing approximately 0.86 MMcf/d of gas, which was supplied to the Guddu thermal power station through the WAPDA. Production from the Sara and Suri Leases was stopped by Tullow in 2010 prior to the acquisition of Leases by Spud. In March 2013, Jura successfully performed rigless operations on three shut-in wells in the Sara and Suri Lease. Rigless operations included pressure and temperature surveys, saturation logs, isolation of various zones, perforations/reperforations, acid stimulation, nitrogen kick off using coil tubing and tests of the wells at various chokes. As a result of rigless operations, gas flow rate from both Suri-1 and Suri-2 wells at a 16/64 inch choke was approximately 1.5 MMcf/d with 160 to 170 Psi wellhead flowing pressure while Sui Upper Limestone in Sara-1 proved to be water wet.

Under the terms of a GSA dated March 26, 1999, production from the Sara and Suri Leases was supplied to the WAPDA. With the cessation of production in October 2010, the GSA is no longer valid and has expired. In May 2014, the GoP approved the allocation of gas from the Sara and Suri Leases to the Central Power Generation Company Limited.

The drilling of development well Sara-4 in the Sara Lease commenced on December 1, 2015. Sara-4 was drilled to a total depth of 1,120 meters. The well was successfully completed in the Sui Upper Limestone formation of Eocene age. During a 7-hour post-completion test on a 20/64 inch choke, the well flowed gas at an average rate of approximately 1.6 MMcf/d with a wellhead flowing pressure of approximately 730 Psi. Sara-4 is located approximately 0.3 km from the existing Sara and Suri gas pipeline infrastructure.

After the drilling of the Sara-4 development well, the available 197 Sq.Km of 3D seismic data was reprocessed in 2016. The seismic data interpretation and mapping carried out at all key horizons and prospect inventory was updated.

In March 2018, the ECC granted an exemption from Rule 43 of Rules 1986 for the Sara and Suri Leases for a period of six months, an extension of the Sara and Suri Leases up to February 2020 and approval for the sale of gas from the Sara and Suri Leases to a third-party at a negotiated price. In April 2018, Spud commenced the bidding process for the sale of gas to a third-party.

The sale of gas from the Sara and Suri Leases to KGPL, an affiliate of Spud, being the sole bidder, was finalised and a summary of commercial terms was submitted to the OGDCL for approval. In August 2018, OGDCL approved the commercial terms for sale of gas to KGPL and GSA was executed on July 11, 2019.

The exemption from Rule 43 of Rules 1986 for Sara and Suri Leases expired on September 8, 2018. On September 7, 2018, Spud submitted an application to DGPC for an exemption under Rule 43 of Rules 1986 for a period of six months from the date of approval. Spud believes that the approval of an exemption under Rule 43 of Rules 1986 will be granted in due course.

The Sara and Suri Leases expired on February 29, 2020. On February 28, 2020, Spud, as operator on behalf of the Working Interest Owners, applied for a further extension in the term of the Sara and Suri Leases for a period of four years effective March 1, 2020 and exemption from the applicability of Rule 43 of Rules 1986 for a period of six months from the date of approval and regularization of an interim period since September 9, 2018.

After completion of necessary field development work, commercial production from the Sara and Suri Leases commenced on October 16, 2020.

Pursuant to the terms of the Sara and Suri GSA, the minimum DCQ by the buyer is 1.105 MMcf/d. However, due of closure of international borders as a result of the COVID-19 pandemic, the buyer was unable to procure the necessary equipment and logistic facilities required to offtake the DCQ. The buyer requested the Sara and Suri Working Interest Owners to reduce the DCQ to 0.25 MMcf/d for a period of six months up to April 2020, which was declined by OGDCL, and as a result, OGDCL instructed the operator to suspend supply of gas to the buyer effective March 1, 2021.

In January 2022, the buyer and sellers agreed to revise the terms of Sara and Suri GSA, pursuant to which the DCQ was reduced to up to 0.5 MMcf/d for a period of two months from the date of recommencement of production and up to 1 MMcf/d thereafter. The production from Sara and Suri Leases resumed on January 25, 2022.

Spud has incurred $5,218,461 of capital expenditures related to the Sara and Suri Leases to date, of which $nil were incurred in the fiscal year 2022.

<u>Kandra Lease</u>

Block No. 2768-6
FHL's Working Interest 37.5%
(Other Working Interest Owners: PEL 37.5%, GHPL 25%)

FHL is a party to, among other related agreements, the Kandra Development and Production Lease dated January 5, 2006, among the President, FHL, PEL and GHPL (the "**Kandra Lease**"), as amended and supplemented. The Kandra Lease covers an area of 314.43 Sq.Km. FHL has a 37.5% Working Interest in the Kandra Lease under the Kandra Petroleum and Concession Agreement dated March 27, 1999. The Kandra

Lease is operated by PEL and is currently under development. Pursuant to the terms of the Settlement Agreement, effective August 12, 2016, FHL has agreed to transfer its 37.5% Working Interest in the Kandra Lease to PEL.

Reti, Maru and Maru South Leases

Block No. 2869-9 (Reti-Maru and Maru South Leases)
Spud's Working Interest: 10.66%
(Other Working Interest Owners: OGDCL 57.76%, IPR 9.08%, GHPL 22.50%)

Spud is a party to, among other related agreements, the Reti, Maru and Maru South Development and Production Leases dated June 25, 2013, June 28, 2013 and June 18, 2013, respectively, among the President, Spud, OGDCL, IPR and GHPL (the "**Reti, Maru, and Maru South Leases**"). The Reti, Maru and Maru South Leases cover an area of 8.6 Sq.Km, 15.41 Sq.Km and 6.64 Sq.Km respectively.

A combined document of commerciality of the Reti, Maru and Maru South gas fields was approved by the DGPC on May 17, 2012. In January 2013, the GoP allocated the gas from the Reti, Maru and Maru South discoveries to the Consortium. Development plans for the Reti, Maru and Maru South gas discoveries were submitted to the GoP for approval on February 11, 2013. On March 15, 2013, the Working Interest Owners executed a GSA with the Consortium. Pursuant to the GSA, the Consortium constructed a 26 Km sale gas pipeline for supply of gas to Engro. Further to the execution of the GSA for the supply of untreated gas, the GoP communicated a provisional price of $6.0 per MMBtu, subject to a quality discount of 10%, in accordance with the Petroleum Policy 2012. However, the GoP issued the following clarifications in March 2013: (i) the gas price would be in accordance with applicable Petroleum policies/relevant gas pricing agreements or equal to gas sale price of other fertilizers plants, whichever is higher and (ii) the applicability of the Petroleum Policy 2012 price will be subject to execution of a supplemental PCA. On September 18, 2013, the operator submitted a draft GPA for the Reti, Maru, and Maru South gas fields with the GoP for approval. On December 11, 2013, the GoP advised that Reti, Maru and Maru South Leases are entitled to a gas price under the Petroleum Policy 2009 and requested OGDCL to submit a draft GPA in line with the Petroleum Policy 2009 for conversion of the regime.

Commercial production under the Maru and Maru South Leases commenced on December 26, 2013 and commercial production under the Reti Lease commenced on January 4, 2014.

To effectively drain the reservoir and to increase gas production from the Reti Lease, the Working Interest Owners approved the drilling of the Reti-2 development well. The drilling of the Reti-2 development well commenced on February 7, 2015. The total depth of the well was 700 meters, which targeted the Pirkoh Limestone formation of Eocene age. During a short duration post-stimulation test on a 48/64 inch choke, the well flowed gas at the rate of approximately 6.22 MMcf/d at a wellhead flowing pressure of 400 Psi. Production from development well Reti-2 commenced in May 2015.

In August 2018, the operator submitted the revised GPA to the MEPD for approval. The gas pricing mechanism under the revised GPA is in line with the clarifications issued by the GoP in March 2013, pursuant to which the gas price is required to be the higher of the following: (i) the Petroleum Policy 2009 or Petroleum Policy 2012 price as applicable; and (ii) the notified consumer gas price for the fertilizer sector as published by OGRA. The approval of a revised GPA is expected in due course.

In August 2018, an acid stimulation job was carried out at the Maru-2 and Khamiso-1 wells. The results showed slight improvement in the flow rates and wellhead flowing pressures. Further, in February and March 2019, BHP surveys were carried out at all wells except the Reti-2 and Maru-2 wells. An Integrated Reservoir Study ("**IRS**") was carried out, which indicated the requirement to install front end compression facility. The front end compression facility was successfully commissioned in September 2022.

The current average production from Reti, Maru and Maru South Leases is approximately 4.26 MMcf/d, and as of the date of this Statement, the cumulative production from the Reti, Maru and Maru South Leases is approximately 25.94 Bcf.

Spud has incurred $5,876,958 of capital expenditures related to the Reti, Maru and Maru South Leases to date, of which $24,253 were incurred in the fiscal year 2022.

The Reti, Maru and Maru South Leases will expire in 2023, 2029 and 2026 respectively.

Ayesha, Aminah, and Ayesha North Leases

Block No. 2468-5
FHL's Working Interest 27.5%
(Other Working Interest Owners: PEL 47.5%, GPX 25%)

FHL is a party to, among other related agreements, the Ayesha Development and Production Lease (the "**Ayesha Lease**") dated September 16, 2014 and the Aminah Development and Production Lease (the "**Aminah Lease**") and Ayesha North Development and Production Lease (the "**Ayesha North Lease**") each dated February 21, 2017, among the President, FHL, PEL and GPX (collectively, the "**Badin IV South Leases**"). The Ayesha, Aminah and Ayesha North Leases cover an area of 19.71 Sq.Km, 13.67 Sq.Km and 6.11 Sq.Km respectively.

The drilling of the exploration well Ayesha-1, targeting the Upper Sands of the Lower Goru formation, commenced on December 31, 2013. On January 27, 2014, the Ayesha-1 exploration well achieved a total depth of 2,400 meters. Gas shows were observed over a 50-meter section in the Lower Goru "A" and "B" Sands. The Ayesha-1 discovery well was completed in the 'B' Sands of the Lower Goru Formation of the Cretaceous age. During a short test on a 32/64 inch choke, the well flowed gas with a heating value of approximately 1,000 Btu/Scf at a rate of 11.34 MMcf/d with a wellhead flowing pressure of 1,998 Psi. The condensate to gas ratio was in the range of 10-12 Bbl/MMcf.

On July 16, 2020, the GoP approved gas prices for Badin IV South Leases under the Marginal Gas Pricing Criteria. The price for Ayesha gas field is expected to be $4.51 per MMBtu, based on the C&F price of a basket of crude oil priced at $45 per Bbl.

On September 16, 2014, the GoP approved the declaration of commercial discovery and field development plan of the Ayesha gas field and granted the Ayesha Lease over the discovery area for a period of six years commencing September 16, 2014.

The drilling of the Aminah-1 exploration well commenced on January 6, 2016 and reached the targeted depth of 2,297 meters on February 1, 2016. The well was logged and completed in the Lower Goru "A" Sands of Cretaceous age. Post-completion surface well testing was conducted in July 2016 after selective perforations of 15 meters in the Lower Goru "A" Sands. During the ten-hour test on 48/64 inch fixed choke, the well flowed gas at an average rate of approximately 19 MMcf/d with an average wellhead flowing pressure of 1,607 Psi and having an average heating value of approximately 1,000 Btu/Scf. The average condensate to gas ratio was approximately 3.8 Bbl/MMcf with the water rate of 24.5 barrels per day.

On May 26, 2017 and August 11, 2017, the GoP approved the declaration of commercial discovery over Aminah gas field and the field development plan for the Aminah-1 gas field respectively and granted the Aminah Lease over the discovery area for a period of seven years commencing February 21, 2017.

The drilling of the Ayesha North-1 exploration well commenced on March 25, 2016 and reached the targeted depth of 2,820 meters on May 10, 2016. The well was logged and completed in the Lower Goru "A" Sands of Cretaceous age. Post-completion surface well testing was conducted in July 2016 after perforating 18 meters interval in the Lower Goru "A" Sands. During the eight-hour test on 48/64 inch fixed choke, the well flowed gas at an average rate of approximately 8.7 MMcf/d with an average wellhead flowing pressure of 771 Psi and having an average heating value of approximately 970 Btu/Scf. The average condensate to gas ratio was approximately 8.17 Bbl/MMcf with the water rate of 28 barrels per day. The gas rate and wellhead pressures are expected to improve after planned stimulation to remove the formation damage.

On June 13, 2017 and on August 11, 2017, the GoP approved the declaration of commercial discovery over Ayesha North gas field and the field development plan for the Ayesha North-1 gas field respectively and granted the Ayesha North Lease over the discovery area for a period of eight years commencing February 21, 2017. On November 30, 2017, the GoP allocated 8.0 and 6.8 MMcf/d gas from the Aminah Lease and Ayesha North Lease respectively to SSGCL.

On July 30, 2018, the operator submitted a draft GPA to the DGPC for approval. The approval of the GPA is expected in due course.

The Working Interest Owners approved a fast track development of Badin IV South gas and condensate discoveries. The development plan envisages construction of a 30 MMcf/d Central Processing Facility (the "**CPF**") at the wells under the Ayesha, Aminah and Ayesha North Leases to be tied into the CPF through gathering flow lines. Processed gas from the CPF shall be transported through an approximately 28 km gas sale pipeline for tie-in into the SSGCL transmission system.

After successful testing and commissioning of production facilities, the commercial production from the Ayesha, Aminah and Ayesha North Leases in the Badin IV South block commenced in February 2020. The gas production is sold to SSGCL, whereas the condensate production is sold to refineries in Pakistan.

A GSA has been finalized with SSGCL. Pursuant to the terms of the GSA, SSGCL has granted a waiver from the applicability of 20% "quality discount", due to higher CO2 contents, for a period of six months from the date of commencement of commercial production. The grant of waiver from the applicability of quality discount is subject to the condition that The Working Interest Owners under the Badin IV South Leases shall install an amine sweeting unit within the waiver period, failing which, the quality discount shall apply retrospectively from the date of commencement of commercial production.

The Working Interest Owners approved the installation of an amine sweeting unit, on a rental basis. The efficient and cost-effective use of the amine sweeting unit required certain modifications to the amine sweeting unit including installation of aerial coolers. The import of the aerial cooler was delayed due to closure of international borders.

As a result of delay in import of the aerial cooler, the operator was unable to achieve installation and commissioning of the amine sweeting unit within the waiver period stipulated in the GSA. After completion of necessary modifications, the installation and commissioning of the amine sweetening unit was completed in February 2021. Effective August 14, 2021, the Working Interest Owners completed the buyout of the amine sweetening unit.

During the year, production from Aminah well was suspended due to excessive water production. The Working Interest Owners are evaluating various options to resume production from Aminah Well.

In January 2023, PEL, the operator of Badin IV South Leases, attempted to invoke the forfeiture of FHL's 27.5% Working Interest in such leases for alleged non-payment of cash calls, which FHL maintains were improper. Jura, Spud and FHL dispute PEL's actions, and Spud and FHL have commenced ICC arbitration against PEL in respect of this matter. FHL has also obtained a stay order from Islamabad High Court restraining the DGPC from approving the forfeiture of FHL's 27.5% Working Interest.

FHL has incurred $9,612,812 of capital expenditures related to the Badin IV South Leases to date, of which $458,921 were incurred in the fiscal year 2022.

The Ayesha lease expired on September 26, 2020. The operator, on behalf of the Working Interest Owners, applied for an extension in the term of the Ayesha Lease for a period of five years effective September 17, 2020, which FHL believes will be granted in the ordinary course of business.

Aminah and Ayesha North Leases will expire in 2024 and 2025 respectively.

<u>Maru East Gas Field</u>

Block No. 2869-9 (Maru East Gas Field)
Spud's Working Interest: 10.66%
(Other Working Interest Owners: OGDCL 57.76%, IPR 9.08%, GHPL 22.50%)

The drilling of exploration well, Maru East-1 commenced on January 26, 2014 to test the potential of hydrocarbons of the Pirkoh Limestone formation of Eocene age. Total depth of 770 meters was achieved on February 6, 2014. During a short duration, post-stimulation test on a 32/64 inch choke, the well flowed gas at a rate of 3 MMcf/d with wellhead flowing pressure of 450 Psi and a heating value of approximately 700 Btu/Scf. The Maru East-1 well was completed in the Pirkoh Limestone Formation of Eocene age.

Effective September 26, 2014, the GoP granted a provisional approval for EWT of Maru East-1 for a period of six months. In March 2015, the GoP allocated production from Maru East-1 to Engro, the existing buyer of the Reti-Maru gas. Production from Maru East gas field commenced in June 2015.

On September 26, 2017, the GoP approved the declaration of commerciality for the Maru East-1 discovery effective April 4, 2017 in accordance with Article-6 of the Guddu PCA and under Rules 24(1) & 52(d) of Rules 1986. The GoP also regularized the production under EWT from August 15, 2015 until April 4, 2017.

On November 14, 2017, the GoP allocated approximately 3 MMcf/d of gas from Maru East gas field to Engro during the EWT period.

The Maru East gas field is currently shut-in. As of the date of this Statement, the cumulative production from the Maru East gas field is approximately 2.02 Bcf.

Spud has incurred $385,572 of expenditures related to the Maru East gas field to date, of which $nil were incurred in the fiscal year 2022.

<u>Khamiso Gas Field</u>

Block No. 2869-9 (Khamiso Gas Field)
Spud's Working Interest: 10.66%
(Other Working Interest Owners: OGDCL 57.76%, IPR 9.08%, GHPL 22.50%)

The drilling of exploration well Khamiso-1 commenced on June 30, 2016 to test the potential of hydrocarbons of the Pirkoh Limestone formation of Eocene age. Total depth of 753 meters was achieved on July 28, 2016. During a short duration pre-stimulation test on a 32/64 inch choke, the well flowed gas at an average rate of 2.95 MMcf/d, having a heating value of approximately 697 Btu/Scf, with an average wellhead flowing pressure of 505 Psi. The Khamiso-1 well was completed in the Pirkoh Limestone Formation of Eocene age.

On June 23, 2017, the GoP approved the allocation of gas up to approximately 2.9 MMcf/d from Khamiso-1 to Engro, the existing buyer of the Reti-Maru gas. Production from Khamiso-1 commenced on June 29, 2017 under the EWT arrangement for a period of 4 months.

On January 10, 2018, the production from Khamiso-1 recommenced after the GoP's approval of a six-month extension under the EWT arrangement. On November 20, 2018, the GoP approved the declaration of commerciality for the Khamiso discovery in accordance with Article-6 of the Guddu PCA and under Rules 24 and 52(d) of Rules 1986.

The current average production from Khamiso gas field is approximately 2.20 MMcf/d, and as of the date of this Statement, the cumulative production from the Khamiso gas field is approximately 6.26 Bcf.

Spud has incurred $333,265 of expenditures related to the Khamiso gas field to date, of which $nil were incurred in the fiscal year 2022.

<u>Umair Gas Field</u>

Block No. 2869-9 (Umair Gas Field)
Spud's Working Interest: 10.66%
(Other Working Interest Owners: OGDCL 57.76%, IPR 9.08%, GHPL 22.50%)

The drilling of exploratory well Umair-1 commenced in January 2018. Umair-1 was drilled to the total depth of 790 meters, to target the Pirkoh Limestone and Habib Rahi Limestone formations. During a short-duration pre-stimulation test on a 36/64 inch choke, the well flowed commingled gas from the Pirkoh Limestone and Habib Rahi Limestone formations at an average rate of 2.47 MMcf/d, having a heating value of approximately 755 Btu/Scf, and a wellhead flowing pressure of approximately 330 Psi. The well has been completed as a gas producer in the Pirkoh Limestone and Habib Rahi limestone formations.

The production from the Umair-1 well is expected to be entitled to a gas price of $3.84 per MMBtu, based on the C&F crude oil price of $45 per barrel, under the Petroleum Policy 2012. DGPC approved the declaration of commerciality for the Umair-1 well on June 20, 2019.

On December 11, 2020, the GoP approved the allocation of gas up to approximately 2.9 MMcf/d from Umair-1 to Engro, the existing buyer of the Reti-Maru gas. Production from Umair-1 commenced on December 12, 2020.

The current average production from the Umair gas field is approximately 1.30 MMcf/d, and as of the date of this Statement, the cumulative production from the Khamiso gas field is approximately 1.33 Bcf.

Spud has incurred $346,235 of expenditures related to the Umair gas field to date, of which $nil were incurred in the fiscal year 2022.

Exploration Licenses

<u>Guddu Exploration License</u>

Block 2869-9
Spud's Working Interest: 13.5%
(Other Working Interest Owners: OGDCL 70%, IPR 11.5%, GHPL 5%)

Spud is a party to, among other related agreements, the Guddu Exploration License No.272/Pak/1999 (the "**Guddu Exploration License**"), which provides Spud with a 13.5% Working Interest in the PCA related to the Guddu Exploration License (the "**Guddu PCA**"). The Guddu Exploration License and the Guddu PCA grant exploration rights with respect to an area located in the Sindh and Punjab Provinces in Pakistan, which covers an area of 2,093.40 Sq.Km. The Guddu block contains the Reti, Maru, Maru South, Maru East, and Khamiso gas fields and recent Umair-1 gas discovery. The Guddu block lies close to gas markets in the prolific Middle Indus Basin which contain Pakistan's major gas fields.

Spud entered into the Guddu Farm-Out Agreement after acquiring Working Interests under the Guddu Exploration License from IPR in 2008. Prior to the Guddu Farm-Out Agreement, the Working Interest Owners to the Guddu Exploration License purchased 337 L.Km and acquired 981 L.Km 2D of seismic data.

Based on interpretation and mapping, the first exploratory well, Reti-1, was drilled in January 2008 and showed the presence of gas on the logs in Pirkoh (Eocene) Limestone, whereas, the results from the primary objective, the Cretaceous 'C' Sands reservoirs, were found to be water-bearing. In order to exploit Pirkoh gas, a replacement well "Reti-1A" was drilled which was the first declared gas discovery under the Guddu Exploration License.

The Working Interest Owners acquired and interpreted an additional 244 L.Km of seismic data in 2009. Subsequently, the Maru, Maru South, Maru East, Khamiso and Umair gas fields were discovered in shallow ±650 meters Pirkoh formation carbonate build-ups by drilling of the Reti-1A, Maru-1, Maru South-1, Maru East-1, Ismail-1 and Khamiso-1 exploratory wells in August 2009, January 2010, August 2011, January 2014, November 2014, July 2016 and February 2018 respectively.

In order to fully explore the prospectively of the Guddu Exploration License, the Working Interest Owners for the Guddu Exploration License approved the acquisition of approximately 545 Sq.Km of 3D seismic data in the southern part of block. The processing and interpretation of 3D seismic data is in progress.

The drilling of exploratory well Umair NW-1 commenced in July 2020. The projected depth of the well was approximately 800 meters to target the Pirkoh Limestone and Habib Rahi Limestone formations of Eocene age.

The exploratory well, Umair NW-1, was drilled to the total depth of 804 meters. Based on the hydrocarbon shows during drilling, log results, and interpretations, it was concluded that gas accumulations existed in the targeted Pirkoh Limestone and Habib Rahi Limestone formations. Testing did not, however, yield commercial quantities of gas from both formations. Consequently, the well is plugged and abandoned.

The drilling of exploration well Umair SE-01 commenced on May 13, 2022. The projected depth of the well is 785 meters, which will target the Pirkoh and Habib Rahi Limestone formations of Eocene age. The well achieved target depth on May 23, 2022. The well is currently shut-in for pressure built-up. The Guddu JV Partners are planning to carry out post-acid stimulation test, which is expected to occur in second week of May 2023.

The GoP has approved Spud's application for the replacement of its Guddu block bank guarantee with the hypothecation of its reserves in the Zarghun South Lease.

Spud has incurred $3,434,272 of expenditures related to the Guddu Exploration License to date, of which $296,474 were incurred in the fiscal year 2022.

The Guddu Exploration License expired on December 31, 2021. The operator, on behalf of the Working Interest Owners, applied for an extension in the term of the Guddu Exploration License up to June 30, 2025, which Spud believes will be granted in the ordinary course of business.

<u>Zamzama North Exploration License</u>

Block No. 2667-8
Spud's Working Interest: 24%
(Other Working Interest Owners: Heritage Oil 48%, Trakker 8%, Hycarbex 20%)

Spud is a party to, among other related agreements, the Zamzama North Exploration License No. 396/Pak/2007 (the "**Zamzama North Exploration License**") which provides Spud with a 24% Working Interest in the December 15, 2007 PCA. Pursuant to the terms of the Zamzama Farm-Out Agreement, Spud has a carry obligation of 3% towards Hycarbex, meaning Spud is responsible for 27% of the exploration costs in the Zamzama North block. Additionally, upon the declaration of commerciality and approval from the DGPC, Hycarbex may elect to acquire an additional 3% full-paying Working Interest from Spud, the acquisition of which will be subject to the reimbursement by Hycarbex of past costs incurred on exploration and development attributable to such 3% Working Interest. The Zamzama North Exploration License pertains to a 1,229.23 Sq.Km block located in the Sindh province of Pakistan and in the Kirthar foredeep geological formation. The Zamzama North Exploration License is operated by Heritage Oil.

Of Spud's 24% Working Interest in the Zamzama North Exploration License, 12% is directly held by Spud and the remaining 12% Working Interest is held by EEL for the benefit of Spud pursuant to the terms of a related trust agreement. The trust arrangement between Spud and EEL is in place to satisfy Pakistani regulations requiring that local Pakistani entities must hold certain minimum ownership in Pakistani Petroleum concessions. Spud has entered into an agreement to purchase EEL. Closing of the transaction is subject to the following conditions precedent: (i) the receipt of duly executed deeds of assignment evidencing the assignment by Sprint of its 12% Working Interests in the Zamzama North Exploration License to EEL; (ii) the approval by the State Bank of Pakistan of Spud's investment in EEL; and (iii) the issuance of a share transfer deed. These conditions have not been fulfilled as of the date of this Statement.

Formal assignment of Working Interests in Pakistan is subject to the execution of a deed of assignment by the GoP. Spud and EEL submitted their respective deeds of assignment relating to the acquisition of their Working Interests in the Zamzama North Exploration License to the GoP on November 14, 2011; however, these remain outstanding as of the date of this Statement.

The Zamzama North Exploration License Working Interest Owners purchased 750 L.Km 2D vintage seismic and adjacent wells data. In 2009 the Working Interest Owners acquired, processed and interpreted 340 L.Km of 2D seismic data. The mapping resulted in the delineation of an approximately 12 Sq.Km low relief four-way dip closed robust structure named the "Khairpur Prospect". Although the Khairpur-1 exploratory well was initially planned to be drilled in 2013, drilling of this well has been delayed due to the expiry of the license term. The Khairpur Prospect is located within 10 Km of existing pipeline infrastructure, which could allow for early commercialization of gas discovery.

The Zamzama North Exploration License has been converted to the Petroleum Policy 2012 and therefore, any gas sales from future discoveries in the Zamzama North Exploration License will be entitled to gas pricing under the Petroleum Policy 2012.

The Zamzama North Exploration License reached the end of its initial term on December 14, 2011. On February 22, 2016, the DGPC issued a notice to the operator for the fulfillment of outstanding work obligations stipulated in the Zamzama North PCA within a period of 60 days. The Working Interest Owners are pursuing the matter with the DGPC.

On May 20, 2016, the DGPC issued a Show Cause Notice to the operator to explain within a period of 30 days from the issuance of the notice, as to why the Zamzama North Exploration License and the Zamzama North PCA may not be revoked. The operator and Working Interest Owners are pursuing the matter with the DGPC.

Spud has incurred $898,272 of capital expenditures related to the Zamzama North Exploration License to date, of which $6,277 were incurred in the fiscal year 2022.

<u>Nareli Exploration License</u>

Block No. 3068-9
Spud's Working Interest: 27.75%
(Other Working Interest Owners: MPCL 37.05%, POL 30.4%, GHPL 2.5%, BECL carried 2.5%)

Spud is a party to, among other related agreements, the Nareli Exploration License No. 502/Pak/2021 (the "**Nareli Exploration License**"), which provides Spud with a 29% Working Interest in the October 13, 2021 Petroleum Concession Agreement.

In February 2022, GHPL and BECL exercised their rights to acquire a 2.5% working interest in the Nareli

Block. The GHPL 2.5% working interest is on a full participation basis, whereas BECL 2.5% is carried working interest to be proportionality borne by MPCL, Spud and POL.

In order to exploit the resource potential of the Nareli Exploration License, the Working Interest Owners have approved the acquisition of 456 Sq. Km of 2D seismic data.

Spud has incurred $103,513 of capital expenditures related to the Nareli Exploration License to date, of which $85,006 were incurred in the fiscal year 2022.

The Nareli Exploration License will expire on October 12, 2024.

Kandra – Exploration Activities

Block No. 2768-6
FHL's Working Interest 35%
(Other Working Interest Owners: PEL 35%, GPX 25%, GHPL carried 5%)

Pursuant to the Kandra Lease, the Working Interest Owners have exclusive rights to carry out exploration activities in the Lease area. Accordingly, the 2007 seismic program for the Kandra Lease also covered the deeper Lower Goru formation at Kandra. The Kandra Lease is operated by PEL.

In 2009, the Working Interest Owners under the Kandra Lease acquired new 2D seismic data of 361.3 L.Km which was processed along with re-processing of vintage purchased data of 107.7 L.Km 2D seismic. Based on interpretation and mapping of the seismic data a location was selected for the new Kandra-4 Deep exploratory well to target the Lower Goru Massive Sandstone Formation. On August 16, 2008, drilling of the Kandra-4 Deep well began. It was drilled to a total depth of 2,229 meters on October 26, 2008 and tested during November 2008. Although significant quantities of high-Btu gas were flared from both the Lower Goru Massive Sandstone and the underlying Chiltan Limestone Formation, which appears fractured, the flares were followed by water influx and the well tested non-commercial quantities of gas from both targets. The well was temporarily suspended on December 5, 2008, pending further technical studies, which were inconclusive. The well has not been plugged and abandoned since it may be possible to recomplete the well as a producer in the future. Geochemical study on samples of Kandra-4 Deep well shows promising source potential in the Sembar and Lower Goru formations.

In 2016-2017, additional 2D seismic of 229 L.Km has been purchased along with data on one well, Jhatpat-1. The purpose of the data was to evaluate the hydrocarbon potential in the deeper Triassic reservoirs.

Badin IV North Exploration License

Block No. 2468-6
FHL's Working Interest 27.5%
(Other Working Interest Owners: PEL 47.5%, GPX 25%)

FHL is a party to, among other related agreements, the Badin IV North Exploration License among the President, FHL, PEL and GPX (the "**Badin IV North Exploration License**"), as amended and supplemented. The Badin IV North Exploration License lies in the Lower Indus Basin and covers an area of 872.94 Sq.Km. FHL has a 27.5% Working Interest in the Badin IV North Exploration License under the Badin IV North Petroleum Concession Agreement dated January 5, 2006. The Badin IV North Exploration License is operated by PEL.

Initial geological and geophysical evaluation commenced with the purchase of 3D seismic data of 993 Sq.Km and vintage 2D seismic data of 4493 L.Km. As a result of mapping, new 2D seismic data of 301 L.Km was acquired in 2007 which was processed along with re-processing of 595 L.Km 2D vintage seismic data. Based on revised interpretation and mapping, Jamali Deep-1 and Wahid-1 exploration wells were drilled.

The Jamali Deep-1 well was drilled to test the Jamali Deep Prospect, at the Lower Goru Basal Sandstone level. On December 31, 2008, drilling of the Jamali Deep-1 well began. It was drilled to a total depth of 3,862 meters on May 5, 2009 and tested during May and June 2009. Although hydrocarbon shows were encountered during drilling from the Lower Goru Basal and Massive Sandstones, the well tested non-commercial quantities of gas from both targets. The well was temporarily suspended on June 8, 2009, pending further technical studies and subsequently plugged and abandoned. Post well analysis indicated that Lower Goru Upper Sands were faulted in well supported by seismic and FMI data while Basal and Massive Sands were tight and hydrocarbon bearing. These sands did not flow because of their tight nature. Several other prospects exist under the Badin IV North Exploration License within the main established hydrocarbon fairway at Upper Sand, Middle, Basal and Massive Sand levels, and ranking of these on a technical and economic basis is being finalized for future drilling priority.

Drilling of the Wahid-1 well began in May 2011. The well was drilled to a total depth of 2,300 meters. The target sands within the Lower Goru were encountered close to prognosis. Based on the open hole logs, the target Upper Sands were water bearing. Consequently, the well was plugged and abandoned without testing in June 2011.

After the negative drilling results of Jamil Deep-1 and Wahid-1 exploration wells, another seismic data re-processing campaign was launched in 2011 after test re-processing from various vendors. Total of 536 L.Km 2D seismic was re-processed.

The drilling of exploration well, Zainab-1 commenced on June 5, 2017, and reached the targeted depth on June 28, 2017. The well was logged and completed in the Lower Goru "B" Sands of Cretaceous age. Post-completion surface well testing was conducted after perforating selective intervals of approximately 16.5 meters. A summary of the well testing results at various choke sizes is as follows.

Choke Size	Test duration	Average gas flow rates	Condensate rate	Water rate	Wellhead flowing pressure
	Hours	MMcf/d	Bbl/d	Bbl/d	Psi
32 / 64"	12	10.20	451	72	2,133
40 / 64"	12	14.30	500	130	2,026
48 / 64"	12	19.04	500	130	1,861
56 / 64"	24	23.04	772	54	1,724

The operator has submitted the declaration of commerciality, field development plan and the application for grant of development and production lease for gas and condensate discovery in the Zainab gas fields for a period of ten years.

After fulfilling the Phase-I commitments, the operator submitted an application to DGPC for the grant approval for entering into Phase-II of the license term effective December 6, 2017. On August 30, 2018, DGPC granted approval of entering into Phase-II of the initial term of the Badin IV North Exploration License for a period of 2 years.

The Phase-II of the license term expired on December 6, 2019. On December 4, 2019, the operator on behalf of the Working Interest Owners of the Badin IV North Exploration License applied for the regularization the eight-month period from December 6, 2017 to August 30, 2018 along with an extension in license term up to August 30, 2020. This decision is pending with the GoP as of the date of this Statement.

In October 2022, PEL, the operator of Badin IV North Exploration License, attempted to invoke the forfeiture of FHL's 27.5% Working Interest in such exploration license for alleged non-payment of cash calls, which FHL maintains were improper. Jura, Spud and FHL dispute PEL's actions, and Spud and FHL have commenced ICC arbitration against PEL in respect of this matter. FHL has also obtained a stay order from Islamabad High Court restraining the DGPC from approving the forfeiture of FHL's 27.5% Working Interest.

FHL has incurred $9,265,058 of capital expenditures related to the Badin IV North block to date, of which $154,000 were incurred in the fiscal year 2022.

<u>Badin IV South Exploration License</u>

Block No. 2468-5
FHL's Working Interest 27.5%
(Other Working Interest Owners: PEL 47.5%, GPX 25%)

FHL is a party to, among other related agreements, the Badin IV South Exploration License among the President, FHL, PEL and GPX (the "**Badin IV South Exploration License**"), as amended and supplemented. The Badin IV South block lies in lower Indus basin and covers an area of 864.41 Sq.Km. FHL has a 27.5% Working Interest in the Badin IV South Exploration License under the Badin IV South Petroleum Concession Agreement dated January 5, 2006. The Badin IV South Exploration License is operated by PEL.

Exploration activities commenced with the purchase of vintage data. The vintage data set includes 3D seismic data of 626 Sq.Km, 2D seismic data of 3175 L.Km and adjacent wells data of 29 wells. After initial interpretation and mapping, new 2D seismic data of 484 L.Km was acquired in 2007 which was processed along with re-processing of approximately 622 L.Km of vintage data. The interpretation and mapping of the new data set resulted in numerous prospects and leads but unfortunately, could not be drilled due to failure in areas captured under the Badin IV North Exploration License. Another seismic re-processing campaign commenced in 2011 and a total of 729 L.Km 2D of data was re-processed. After the interpretation and mapping of the full data set, four prospects were firmed up for drilling to target shallow reservoirs in the Lower Goru Upper Sands. These prospects were drilled in two drilling campaigns, which resulted in three gas and condensate discoveries and one dry hole.

In 2013, the Working Interest Owners in the Badin IV South Exploration License approved the drilling of two exploratory wells, Ayesha-1 and Haleema-1.

On December 31, 2013, the Working Interest Owners commenced drilling of Ayesha-1, targeting the Upper Sands of the Lower Goru Formation. For further information, see "Development and Production Leases – Ayesha, Aminah and Ayesha North Leases".

On February 27, 2014, drilling commenced at Haleema-1. On March 17, 2014, Haleema-1 reached the total depth of 1,849 meters. The target Lower Goru Upper Sands were encountered deeper than forecasted. Based on the interpretation of open hole logs the formations were found to be water bearing. Consequently, the well was plugged and abandoned without testing.

The second drilling campaign started with the drilling of Aminah-1 exploration well commenced on January 6, 2016. For further information see "Development and Production Leases – Ayesha, Aminah and Ayesha North Leases".

The drilling of Ayesha North-1 exploration well commenced on March 25, 2016. For further information see "Development and Production Leases – Ayesha, Aminah and Ayesha North Leases".

Based on the interpretation and mapping along with the integration of data from newly drilled wells, five prospects and a number of leads have been identified.

On November 3, 2016, the GoP approved the entering into of Phase-II of the initial term of the Badin IV South Exploration License effective July 5, 2016.

The Badin IV South Exploration License will expire on February 2, 2024. The outstanding commitment will be one shallow exploration well up to 1600 meters or 50 meters inside the Lower Goru Upper Sands.

The GoP approved FHL's request for replacement of its share of bank guarantee against the hypothecation of FHL's share of gas reserves in Ayesha, Aminah and Ayesha North (Badin South block).

On August 13, 2021, the Working Interest Owners in the Badin IV South Exploration License, including FHL, entered into the Badin IV South Supplemental PCA for the Badin IV South Leases with the President, which incorporated provisions for the entitlement of gas pricing incentives under the Marginal Gas Pricing Criteria for Ayesha, Aminah and Ayesha North leases.

In January 2023, PEL, the operator of Badin IV South Exploration License, attempted to invoke the forfeiture of FHL's 27.5% Working Interest in such exploration license for alleged non-payment of cash calls, which FHL maintains were improper. Jura, Spud and FHL dispute PEL's actions, and Spud and FHL have commenced ICC arbitration against PEL in respect of this matter. FHL has also obtained a stay order from Islamabad High Court restraining the DGPC from approving the forfeiture of FHL's 27.5% Working Interest.

FHL has incurred $8,213,080 of expenditures related to the block to date, of which $221,000 were incurred in the fiscal year 2022.

Oil and Gas Wells

The following table sets out the number and status of oil and gas wells associated with the properties in which Jura held a Working Interest and which were producing, or considered to be capable of production, as at December 31, 2022.

	Oil		Natural Gas	
	Gross	Net	Gross	Net
Zarghun South				
Producing	-	-	3	1.20
Non-producing	-	-	1	0.40
Guddu				
Producing	-	-	7	0.75
Non-producing	-	-	1	0.11
Badin IV South				
Producing	-	-	3	0.83
Non-producing	-	-	-	-
Badin IV North				
Producing	-	-	-	-
Non-producing	-	-	1	0.28
Sara and Suri				
Producing	-	-	1	0.60
Non-producing	-	-	2	1.20
Total				
Producing	-	-	14	3.38
Non-producing	-	-	5	1.99

Properties with no Attributed Reserves

The following table sets information concerning Jura's assets with no attributed reserves as at December 31, 2022.

Unproved Properties	Gross Acres (1)	Net Acres (2)
Zamzama North Exploration License	303,749	72,898
Badin IV North Exploration License	215,708	59,320
Badin IV South Exploration License	213,600	58,740
Guddu Exploration License	517,290	55,143
Nareli Exploration License	596,747	173,056

Notes:

(1) "**Gross Acres**" are the total acres in which Jura has or had an interest.

(2) "**Net Acres**" is the aggregate of the total acres in which Jura has or had an interest multiplied by Jura's Working Interest percentage held therein.

Jura expects that all Exploration Licenses in respect of its unproven properties will be renewed. Accordingly, it does not expect that any of its rights to explore, develop and exploit its unproven properties will expire within one year.

The following tables set out the nature, timing, and cost of outstanding minimum work commitments under Exploration Licenses for the above properties:

Zamzama North Exploration License			
Phase I – Year	**Work Program**	**Minimum Financial Commitment Gross ($MM)**	**Minimum Financial Commitment Net ($MM)**
Three	Three exploratory wells (firm) to a depth of 3,700 meters or 100 meters in Pab Sandstone, whichever is shallower	5.1	1.2
	Total	**5.1**	**1.2**

Award date: December 15, 2007

Exploration License Status: Phase I of the exploration license for the Zamzama North Exploration License expired on December 14, 2011. On February 22, 2016 and DGPC has issued a notice to the operator for the fulfillment of outstanding work obligations stipulated in the Zamzama North PCA within a period of 60 days.

Badin IV South Exploration License			
Phase II – Year	**Work Program**	**Minimum Financial Commitment Gross ($MM)**	**Minimum Financial Commitment Net ($MM)**
One	One exploratory well to test the potential of the Upper sands of lower Goru	1.25	0.34
	Total	**1.25**	**0.34**

Award date: January 5, 2006

Exploration License Status: The GoP approved the extension in Phase II of the initial term of Badin IV South Exploration License with effect from September 2, 2021. The Exploration License will now expire on February 2, 2024.

Badin IV North Exploration License			
Phase II – Year	**Work Program**	**Minimum Financial Commitment Gross ($MM)**	**Minimum Financial Commitment Net ($MM)**
One	One exploratory well to test the potential of the lower Goru	3.6	1.0
	Total	**3.6**	**1.0**

Award date: January 5, 2006

Exploration License Status: The Badin IV North Exploration License expired on December 6, 2019. On December 4, 2019, the operator on behalf of Badin IV North Exploration License Working Interest Owners applied for the regularization of the eight-month period from December 6, 2017 to August 30, 2018 along with an extension in license term up to August 30, 2020. This decision is pending with the GoP.

Guddu Exploration License			
Phase II – Year	**Work Program**	**Minimum Financial Commitment Gross ($MM)**	**Minimum Financial Commitment Net ($MM)**
Three	One exploratory well to test the potential of the lower Goru	3.0	0.4
	Total	**3.0**	**0.4**

Award date: February 2, 2000

Exploration License Status: The Guddu Exploration License expired on December 23, 2021. The operator has submitted an application for an extension in license term to June 30, 2025. This decision is pending with the GoP.

Nareli Exploration License			
Phase I – Year	**Work Program**	**Minimum Financial Commitment Gross ($MM)**	**Minimum Financial Commitment Net ($MM)**
One to Three	The JV Partners are in the process of finalizing the work program to discharge minimum work commitments	12.81	3.62
	Total	**12.81**	**3.62**

Award date: October 13, 2021

Exploration License Status: The Nareli Exploration License will expire on October 12, 2024.

Significant Factors or Uncertainties Relevant to Properties with no Attributed Reserves

The development of properties with no attributed reserves can be affected by a number of factors including, but not limited to, project economics, forecasted commodity price assumptions, cost estimates and access to infrastructure. These and other factors could lead to the delay or the acceleration of projects related to these properties.

Except as otherwise disclosed in this Statement with respect to PEL's attempt to invoke the forfeiture of FHL's 27.5% Working Interest in the Badin IV South Leases, the Badin IV South Exploration License and the Badin IV North Exploration License and the potential negative outcome of arbitration in respect of such matter, there are no significant economic factors or uncertainties that may affect the anticipated development or production of Jura's properties with no attributed reserves.

The Zamzama North concession is located in the immediate vicinity of existing pipeline infrastructure.

Forward Contracts

There are no contracts under which Jura may be precluded from fully realizing, or may be protected from the full effect of, future market prices for oil or gas.

Jura is under no transportation obligations or commitments for future physical deliveries of oil or gas which exceed Jura's expected related future production from its proved reserves.

Tax Horizon

As at December 31, 2022, Jura had cumulative assessed tax losses totalling $2.65 million and unclaimed exploration expenditures totalling $30.44 million. Based on these figures and Jura's expected future revenue stream, it is expected that Jura will not be in a tax-paying situation until 2026.

Costs Incurred

The following table summarizes capital expenditures made by Jura for the financial year ended December 31, 2022.

	($000s)
Property Acquisition Costs:	
Proved Properties	-
Unproved Properties	-
Exploration Costs	795
Development Costs	1,250
Total	**2,045**

Exploration and Development Activities

For the financial year ended December 31, 2022, Jura participated in the following exploration and development wells.

Number of Wells Drilled						
	Exploration		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil	-	-	-	-	-	-
Natural gas	1	0.11	-	-	1	0.11
Service	-	-	-	-	-	-
Stratigraphic Test	-	-	-	-	-	-
Dry	-	-	-	-	-	-
Total	**1**	**0.11**	**-**	**-**	**1**	**0.11**

For details in respect of the important current and likely exploration and development activities, see "Other Oil and Gas Information – Description of Principal Oil and Gas Properties".

Abandonment and Reclamation Costs

Jura has estimated the cost to perform well abandonment and reclamations by taking into account well depths, geographical location, existing well status and tangible assets. A well's abandonment is scheduled to occur after the total Proved plus Probable production forecast deems the well no longer capable of production. Where possible, a well's abandonment is scheduled as part of a multi-well program to achieve an economy of scale. The expected cost to be incurred in respect of Proved Reserves, net of salvage value, is $3,570,000 without discount and $2,210,000 using a discount rate of 10%. The expected cost to be incurred in respect of Proved plus Probable Reserves, net of salvage value, is $4,031,000 without discount and $1,807,000 using a discount rate of 10%.

The following tables sets forth the abandonment costs deducted in the estimation of Jura's future net revenue:

Year	Proved Reserves ($000s)	Proved Plus Probable Reserves ($000s)
2023	-	-
2024	-	-
2025	-	-
2026	2,108	-
2027	-	-
Thereafter	1,472	4,031
Total Undiscounted	**3,579**	**4,031**
Discounted @ 10%	**2,210**	**1,807**

Production Estimates

The following table is a summary of the gross volume of Jura's share of estimated production for 2023.

	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Oil Equivalent (Boe/d)
Proved					
Badin IV South	-	-	1,925	15	347
Badin IV North	-	-	855	9	156
Zarghun South	-	-	2,010	1	347
Guddu	-	-	1,021	-	176
Sara and Suri	-	-	172	-	30
Total Proved	-	-	**5,983**	**24**	**1,055**
Proved plus Probable					
Badin IV South	-	-	2,774	22	500
Badin IV North	-	-	965	10	176
Zarghun South	-	-	2,131	1	368
Guddu	-	-	1,061	-	183
Sara and Suri	-	-	185	-	32
Total Proved plus Probable	-	-	**7,116**	**32**	**1,258**

Production History

The following table summarizes Jura's average daily production before deduction of royalties, for the periods indicated.

Product	Q1 2022	Q2 2022	Q3 2022	Q4 2022
Light and Medium Crude Oil (Bbls/d)	-	-	-	-
NGLs (Bbls/d)	36	25	22	16
Natural Gas (Mcf/d)	9,711	7,417	5,564	3,391
Total (Boe/d)	1,710	1,306	983	603

Netback History

The following table sets forth certain production information in respect of product prices received, royalties paid, operating expenses and resulting netback associated with Jura's assets for the periods indicated.

Product Type	Period	$per unit of production			
		Price Received	Royalties Paid	Production Costs	Netbacks
Light & Medium Crude Oil ($/Bbl)	Q1 2022	-	-	-	-
	Q2 2022	-	-	-	-
	Q3 2022	-	-	-	-
	Q4 2022	-	-	-	-
Heavy Oil ($/Bbl)	Q1 2022	-	-	-	-
	Q2 2022	-	-	-	-
	Q3 2022	-	-	-	-
	Q4 2022	-	-	-	-
Natural Gas ($/Mcf)	Q1 2022	5.76	0.71	1.02	4.30
	Q2 2022	5.75	0.78	1.67	3.30
	Q3 2022	5.75	0.67	1.18	3.90
	Q4 2022	6.16	0.96	3.56	1.65
Natural Gas Liquid ($/Bbl)	Q1 2022	80.42	9.65	8.04	62.73
	Q2 2022	90.57	10.87	9.06	70.64
	Q3 2022	76.01	9.12	7.60	59.29
	Q4 2022	70.16	8.42	7.02	54.72

Production by Area

The table below indicates the production volumes by area from Jura's important oil and natural gas properties for the financial year ended December 31, 2022.

Area	Conventional Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)
Guddu	-	-	7,975	
Zarghun South	-	-	5,120	1.95
Badin IV South	-	-	12,574	4.78
Sara Suri	-	-	275	
Total	**-**	**-**	**25,944**	**6.73**

APPENDIX A
FORM 51-101F2
REPORT OF RESERVES DATA BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Jura Energy Corporation (the "**Corporation**"):

1. We have evaluated the Corporation's reserves data as at December 31, 2022. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2022 estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated for the year ended December 31, 2022, and identifies the respective portions thereof that we have evaluated and reported on to the Corporation's board of directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	**Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - $000s)**			
			Audited	Evaluated	Reviewed	**Total**
McDaniel and Associates	December 31, 2022	Pakistan	-	28,703	-	28,703

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report.

8. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

EXECUTED as to our report referred to above:

McDaniel and Associates Consultants Ltd, Calgary, Alberta, Canada, April 10, 2023.

(signed)" C. T. Boulton"
Cameron T. Boulton, P. Eng.
Executive Vice President

APPENDIX B
FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS
ON RESERVES DATA AND OTHER INFORMATION

Management of Jura Energy Corporation (the "**Corporation**") is responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator is presented herein.

The Reserves Committee of the board of directors of the Corporation has:

a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;
b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation and, in the event of a proposal to change the independent qualified reserves evaluator, to inquire whether there had been disputes between the previous independent qualified reserves evaluator; and
c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved:

a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and
c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Dated: May 1, 2023

(signed) "Nadeem Farooq"
Nadeem Farooq
Chief Executive Officer and Director

(signed) "Mehran Inayat Mirza"
Mehran Inayat Mirza
Director

(signed) "Stephen C. Smith"
Stephen C. Smith
Director

(signed) "Arif Siddiq"
Arif Siddiq
Chief Financial Officer