Krtsanisi Anticline

West Rustavi and Krtsanisi Blocks, Republic of Georgia

Competent Person's Report

as of 31 March 2022

Prepared For:	Block Energy
By:	ERCE
Date:	July 2022

ERCE
Independent Energy Experts

Approved by: Paul Taylor

Date released to client: 29/07/2022

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29 July 2022

The Directors
Block Energy plc
6th Floor, 60 Gracechurch Street
London
United Kingdom
EC3V 0HRT

Dear Sirs,

Re: Competent Person's Report – West Rustavi and Krtsanisi Blocks

In accordance with your instructions, ERC Equipoise Ltd ("ERCE") has prepared a Competent Person's Report ("CPR") for certain hydrocarbon Reserves held by Block Energy plc. ("Block Energy") within the XIb and XIf blocks, located onshore in the Republic of Georgia. The CPR presents ERCE's assessment of the West Rustavi and Krtsanisi field (the "WRK field") which straddles the boundary of the two blocks. Reserves are attributable to current producing wells and to future development activity, which will target a specific area, the KRT Anticline, defined in Section 5 of the report.

The effective date ("Effective Date") of this report is 31 March 2022. For the preparation of this CPR ERCE was provided with data and information by Block Energy up to the Effective Date unless otherwise specified in Section 2.1. Block Energy has provided representations that no new data or information has been acquired between the Effective Date and the publication date of this CPR that would materially affect the opinions expressed in this CPR.

ERCE has carried out this work in accordance with the June 2018 SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Resources Management System (PRMS) as the standard for classification and reporting. A summary of the PRMS is found in Appendix 1: SPE PRMS Guidelines of the report. The full text can be downloaded from:-

https://www.spe.org/en/industry/petroleum-resources-management-system-2018/

Nomenclature that may be used in this CPR and the enclosed report is summarised in Appendix 2: Nomenclature.

Use of the Report

The CPR has been prepared for the sole use of Block Energy to support financing and for reporting on the Alternative Investment Market ("AIM") of the London Stock Exchange. The CPR is prepared in accordance with the AIM Note for Mining and Oil & Gas Companies, June 2009.

Block Energy agrees to ensure that any publication or use of this report which makes reference to ERCE shall be published or quoted in its entirety and Block Energy shall not publish or use extracts of this report or any edited or amended version of this report, without the prior written consent of ERCE. In the case that any part of this report is delivered in digital format, ERCE does not accept any responsibility for edits carried out by the client or any third party or otherwise after such material has been sent by ERCE to the client.

Disclaimer

ERCE has made every effort to ensure that the interpretations, conclusions and recommendations presented in this report are accurate and reliable in accordance with good industry practice. ERCE does not, however, guarantee the correctness of any such interpretations and shall not be liable or responsible for any loss, costs, damages or expenses incurred or sustained by anyone resulting from any interpretation or recommendation made by any of its officers, agents or employees.

ERCE has used standard petroleum evaluation techniques in the generation of this report. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics, production performance and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. In addition, the nature of the reservoirs assessed as part of this CPR are not conventional in oil and gas terms with the storage capacity dependent solely on natural fracturing rather than matrix porosity (Type 1). Reservoirs of this type are more difficult to assess and their performance more uncertain. ERCE has estimated the degree of this uncertainty and determined the range of petroleum initially in place and recoverable hydrocarbon volumes. In applying these procedures and tests, nothing came to the attention of ERCE that would suggest that information provided by Block Energy was not complete and accurate. ERCE reserves the right to review all calculations referred to or included in this report and to revise the estimates in light of erroneous data supplied or information existing but not made available which becomes known subsequent to the preparation of this CPR.

The accuracy of any Reserves and production estimates is a function of the quality and quantity of available data and of engineering interpretation and judgment. While Reserves, and production estimates presented herein are considered reasonable, the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward.

Revenue projections presented in this report are based in part on forecasts of market prices, currency rates, inflation, market demand and government policy which are subject to many uncertainties and may, in future, differ materially from the forecasts utilised herein. Present values of revenues documented in this report do not necessarily represent the fair market value of the Reserves evaluated herein.

No site visits were undertaken in the preparation of this CPR.

Professional Qualifications

ERCE is an independent consultancy specialising in geoscience evaluation, engineering and economic assessment. ERCE will receive a fee for the preparation of this report in accordance with normal professional consulting practices. This fee is not dependent on the findings of this CPR and ERCE will receive no other benefit for the preparation of this CPR.

Neither ERCE nor the Competent Person who is responsible for authoring this CPR, nor any Directors of ERCE have at the date of this report any shareholding in Block Energy. Consequently, ERCE, the Competent Person and the Directors of ERCE consider themselves to be independent of Block Energy, its directors and senior management.

ERCE has the relevant and appropriate qualifications, experience and technical knowledge to appraise professionally and independently the assets.

The preparation of this report has been supervised by Mr. Paul Taylor, Head of Reserves and Resources at ERCE and is the Competent Person. Mr. Taylor has over 30 years of experience in the evaluation of oil and gas fields, preparation of development plans and assessment of reserves and resources. He holds a MEng degree in Chemical Engineering from Nottingham University. He is a Chartered Petroleum Engineer with the UK Engineering Council, a member of the Energy Institute and is a member of and has served on the Board of Directors of the Society of Petroleum Evaluation Engineers. Mr. Taylor therefore possesses the required competencies, being professionally qualified and a member in good standing of an appropriate recognised professional association.

Yours faithfully,

P. Taylor

2022-07-29

Mr. Paul Taylor, CEng

Head of Reserves and Resources, ERCE

1. Executive Summary

ERCE has carried out an evaluation of certain of the hydrocarbon Reserves associated with Blocks XIb and XIf owned by Block Energy, onshore Georgia. The results of ERCE's evaluation are provided in this CPR.

A summary of Block Energy's two licence interests relevant to this CPR is presented in Table 1.1. Both licences are operated by Block Energy.

Table 1.1: Block Energy's Licence Interests

Country	Block	Field(s)	Working Interest	Licence Expiry	Licence Area (sq.km.)
Georgia	Block XIb (Krtsanisi)	West Rustavi-Krtsanisi	100.00%	21-May-39	635
Georgia	Block XIf (West Rustavi)	West Rustavi-Krtsanisi	100.00%	01-Sep-48	37.63

Note

1) Licence expiry based on a 25 year initial term plus a five year extension

The CPR covers both the existing production and the next phase of development of the West WRK field. The field straddles the licence boundary between the two blocks. The planned development covers an up-dip area of the WRK field referred to as the Krtsanisi Anticline ("KRT Anticline"). Further development phases of the WRK field were outside the CPR scope of work.

Reserves

Reserves *are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates as Proved (1P), Proved plus Probable (2P) and Proved plus Probable plus Possible (3P).*

The Reserves associated with the WRK field are presented in Table 1.2 in field units and, at the client's request, in Table 1.3 in metric units. The Reserves estimates include both the field gross estimates and the net entitlement estimates legally accruing to Block Energy under the terms of the respective PSCs.

Table 1.2: Block Energy Reserves in the WRK Field as of 31 March 2022 – Field Units

Commodity	Units	Field Gross Reserves			Net Entitlement Reserves		
		1P	2P	3P	1P	2P	3P
Block XIf							
Oil and Condensate	MMstb	0.13	0.52	1.44	0.10	0.39	1.08
Sales Gas	Bscf	0.12	0.33	0.79	0.09	0.25	0.60
Block XIb							
Oil and Condensate	MMstb	0.06	0.54	1.57	0.05	0.40	1.15
Sales Gas	Bscf	0.22	0.74	1.34	0.16	0.54	0.98
Total							
Oil and Condensate	MMstb	0.19	1.07	3.01	0.14	0.79	2.23
Sales Gas	Bscf	0.34	1.07	2.14	0.25	0.79	1.58

Note

1. Company Net Entitlement Reserves are based on Company share of total Cost and Profit Revenues

Table 1.3: Block Energy Reserves in the WRK Field as of 31 March 2022 – Metric Units

Commodity	Units	Field Gross Reserves			Net Entitlement Reserves		
		1P	2P	3P	1P	2P	3P
Block XIf							
Oil and Condensate	E03m3	21.07	83.29	229.49	15.80	62.47	172.12
Sales Gas	E06sm3	3.43	9.42	22.49	2.57	7.06	16.87
Block XIb							
Oil and Condensate	E06m3	9.84	86.18	249.63	7.18	62.91	182.23
Sales Gas	E06sm3	6.11	20.91	38.05	4.46	15.27	27.77
Total							
Oil and Condensate	E06m3	30.91	169.47	479.12	22.99	125.38	354.35
Sales Gas	E06sm3	9.53	30.33	60.54	7.03	22.33	44.64

Note

1. Company Net Entitlement Reserves are based on Company share of total Cost and Profit Revenues

The Reserves have been evaluated based on ERCE's Brent crude oil price forecast as of 1 April 2022. A differential of $4.50/bbl (real) has been applied based on Block Energy's assumption of future trading arrangements (the actual differential during Q1 2022 was $8.50/bbl). A real terms gas sales price of $4.0/Mscf has been applied based on assumptions from Block Energy; the gas sales agreement specifies that the gas price should be based on a negotiated fair market gas price.

Table 1.4: Hydrocarbon Price Forecasts (Real) as of 1 April 2022

Year	Brent Crude Oil Price	Oil Price Differential	Export Price	Gas Sales Price
	$/bbl	$/bbl	$/bbl	$/Mscf
2022 (9 mo)	97.0	4.5	92.5	4.0
2023	84.8	4.5	80.3	4.0
2024	74.7	4.5	70.2	4.0
2025	71.7	4.5	67.2	4.0
2026	71.7	4.5	67.2	4.0
2027	71.7	4.5	67.2	4.0
2028	71.7	4.5	67.2	4.0
2029	71.7	4.5	67.2	4.0
2030	71.7	4.5	67.2	4.0
2031	71.7	4.5	67.2	4.0
2032+	71.7	4.5	67.2	4.0

Notes

1. ERCE Brent price forecast as of 1 April 2022
2. Oil price differential based on Block Energy's assumed future trading conditions
3. Gas sales price based on Block Energy assumptions

Net present values of the Reserves have been estimated using ERCE's estimates of future production and costs for each licence. Production forecasts have been cut off at the earlier of the licence expiry and the economic limit as defined under PRMS; the licence expiry impacts Block XIf and Block XIb in the 3P case only. The two licences share the Early Production Facility ("EPF") and a consolidated economic limit test ("ELT") was first calculated. Individual ELTs were then applied to each block to account for the different licence expiry dates.

Table 1.5: Block Energy – WRK field Net Present Values of the Reserves as of 31 March 2022

Case	CoP Date	Net Present Value ($ MM)				
		0%	5%	10%	15%	20%
Block XIf						
1P	Sep-2024	0.58	0.51	0.44	0.38	0.32
2P	Feb-2034	4.69	4.76	4.58	4.29	3.97
3P	Sep-2048	33.21	26.18	21.44	18.07	15.55
Block XIb						
1P	Sep-2024	2.93	2.83	2.74	2.65	2.58
2P	Feb-2034	19.06	15.77	13.37	11.57	10.18
3P	May-2039	63.61	46.31	35.54	28.40	23.42
Total						
1P	Sep-2024	3.51	3.34	3.18	3.04	2.90
2P	Feb-2034	23.75	20.53	17.95	15.87	14.15
3P	Sep-48 & May-39	96.82	72.48	56.98	46.47	38.97

Note

1. The NPVs may not represent fair market value.
2. The CoP dates in the 3P case are limited by the individual license expiries for blocks XIb and XIf

2. Introduction

The WRK field is located 12 km south-east of Tbilisi (Figure 2.1). It straddles the licence boundary between Block XIb (Krtsanisi or KRT) and Block XIf (West Rustavi or WR). Hydrocarbon accumulations are present in the Upper Cretaceous, Lower and Middle Eocene stratigraphy. No accumulations have yet been found in the overlying Upper Eocene. This CPR focusses on the Middle Eocene accumulation.

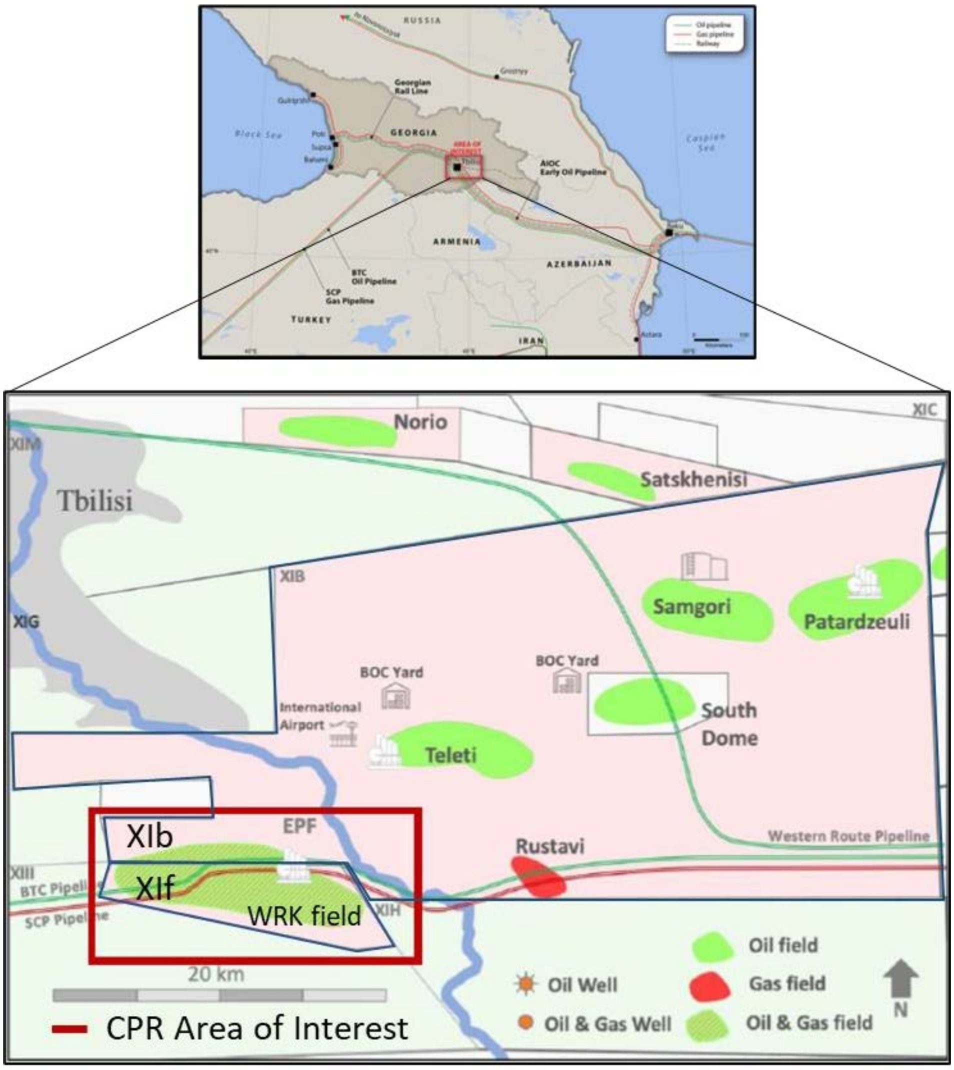

Figure 2.1: Blocks XIb and XIf location map

2.1. Data Provided

ERCE has relied upon data and information made available by Block Energy.

There are 21 wells drilled in the area, however, much of the older data and information was either missing or sparse. Several wells have been drilled and/or sidetracked since 2012 and these have better data sets; this includes two new wells (Wells JKT-01, WR-B01a) and three new sidetracks (Wells JKT-01Z, WR-16aZ and WR-38Z). Well JKT-01 drilled in 2012 is the only recent well with core and FMI data.

Seismic data include two 3D seismic surveys acquired in 2015 and 2019. Block Energy acquired the 2019 survey which covers the entire XIf licence and the Krtsanisi wells in the XIb licence. The 2015 survey was acquired by Jindal Petroleum ("Jindal") and, although it only covers a limited part of the XIf licence, it is useful for tying the data across WRK field to other fields in the XIb licence (Teleti, Patardzeuli, Samgori and South Dome). Block Energy has used various seismic attributes to identify the areas of the WRK field which are likely to be more fractured.

Production data, by well, were provided for the WRK field up to the Effective Date.

Other data comprise details of Block Energy's licence interests, oil and gas sales information, geological and engineering data (including test data), technical reports, and interpreted data (including a reservoir static model and simulation studies). A draft FDP dated May 2022 by Block Energy was provided and although this is dated after the Effective Date it was taken into account as part of the CPR.

No site visit was undertaken in the preparation of this report.

2.2. Work Completed

ERCE has used standard petroleum evaluation techniques in the generation of this report. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics, production performance and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. The degree of this uncertainty has been estimated to determine the range of petroleum initially in place. Estimates of recovery factors were based on consideration of the results of production performance analysis, reservoir simulation models, classical reservoir engineering calculations and the performances of analogue fields. ERCE has derived independent estimates of Reserves and prepared forecasts of production of oil and gas. ERCE has derived independent cost forecasts and these have been used with the production forecasts to derive the economic limit and estimate net present values. These were derived using an economic model provided by Block Energy which ERCE has confirmed adequately captures the terms of the PSCs and fiscal regime. The economic evaluation does not take into account any outstanding debt, nor future indirect corporate costs.

3. Field Overview

The WRK field is located at the southwestern extent of a Middle Eocene play fairway that also incorporates other fields in the area such as the Ninotsminda, Samgori/Patardzeuil, Samgori South Dome and Teleti fields (Figure 2.1).

Hydrocarbons were discovered in the Middle Eocene of the WRK field by Well WR-16a in 1988. A further seven wells were drilled over the next four years with three wells put on production (Wells WR-16a, WR-38 and KRT-39). Early well results were mixed depending on the degree of natural fracturing encountered. The reservoir is interpreted to be a naturally fractured reservoir with little or no matrix contribution (Type 1 fractured reservoir, Nelson 2001[1]). The matrix comprises volcanic and calcareous tuff with low porosity. The field produces ca. 35°API oil from reservoirs at depths of between approximately 1,400 and 1,800 m TVDSS. Initial pressure was estimated around 190 bar (2,756 psi) in Well WR-16aZ with an initial temperature around 80°C.

A production sharing contract ("PSC") for Block XIb was awarded to a consortium including, Jindal Petroleum in 2009. Jindal drilled Well JKT-01 in 2012 and acquired a 3D seismic survey in 2015. In 2017 the PSC was transferred from Jindal to Schlumberger. In November 2020 Block Energy acquired Schlumberger's 100% interest in the PSC.

Block Energy acquired an initial interest in Block XIf during 2017 which was subsequently increased in stages to 100% by 2019. Together with Block XIb, Block Energy has a 100% working interest in the WRK field and is the field operator. The Block XIb and XIf PSCs have different terms and so for the purposes of determining net entitlement are considered separately.

Since 2019 Block Energy has acquired a 3D seismic survey, drilled new Well WR-B01a and drilled four sidetrack Wells WR-16aZ, WR-38Z and WR-51Z[2] and JKT-01Z. Well JKT-01Z was drilled based on the 2019 3D seismic survey whereas the other wells were drilled based on legacy seismic data. A Middle Eocene top structure map highlighting the location of the recently drilled wells is presented in Figure 3.1.

[1] Nelson, R.A. 2001. Geological Analysis of Naturally Fractured Reservoirs, second edition. Houston: Gulf Publishing Co.

[2] Well WR-51Z was suspended at top Middle Eocene.

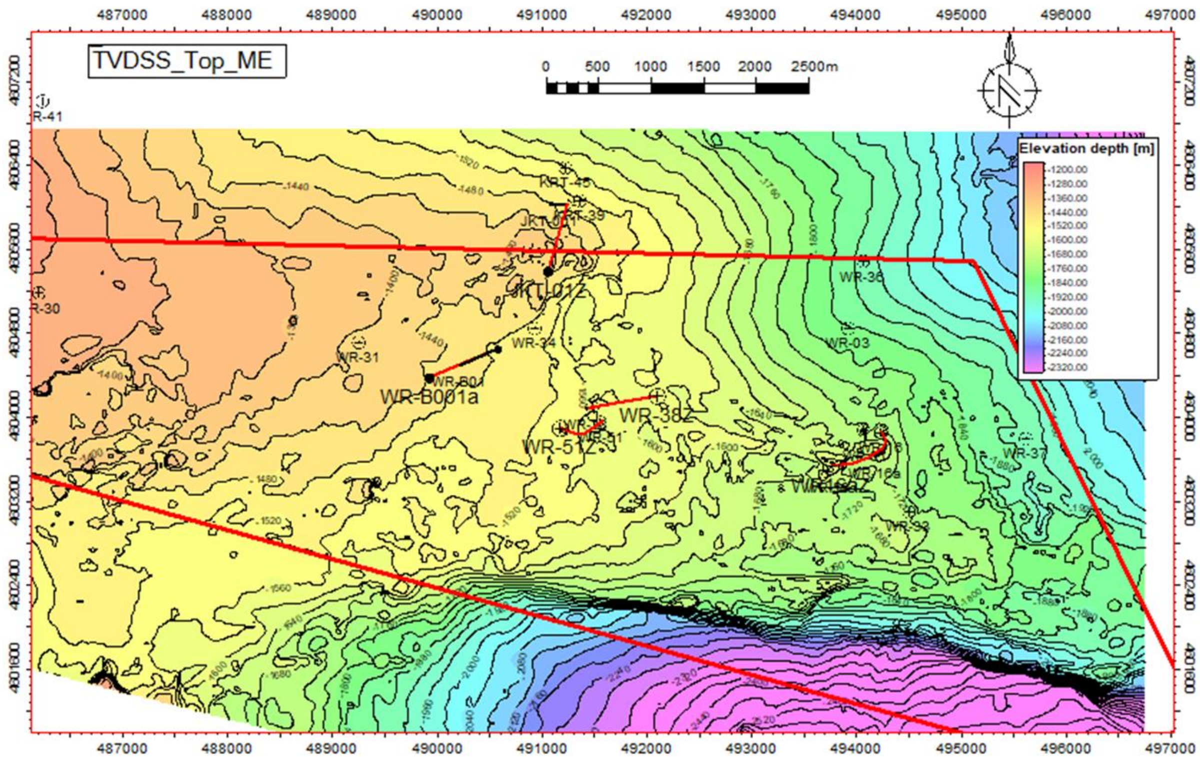

Figure 3.1: Middle Eocene top structure map (m depth)
(Block XIf boundary is shown as a red polygon)

Recent production from the WRK field has been from Wells WR-16aZ, WR-38Z, WR-B01a and JKT-01Z supplemented by Well KRT-39 (located to the north of JKT-01Z). The WRK field oil production history by block is presented in Figure 3.2 together with the total gas production.

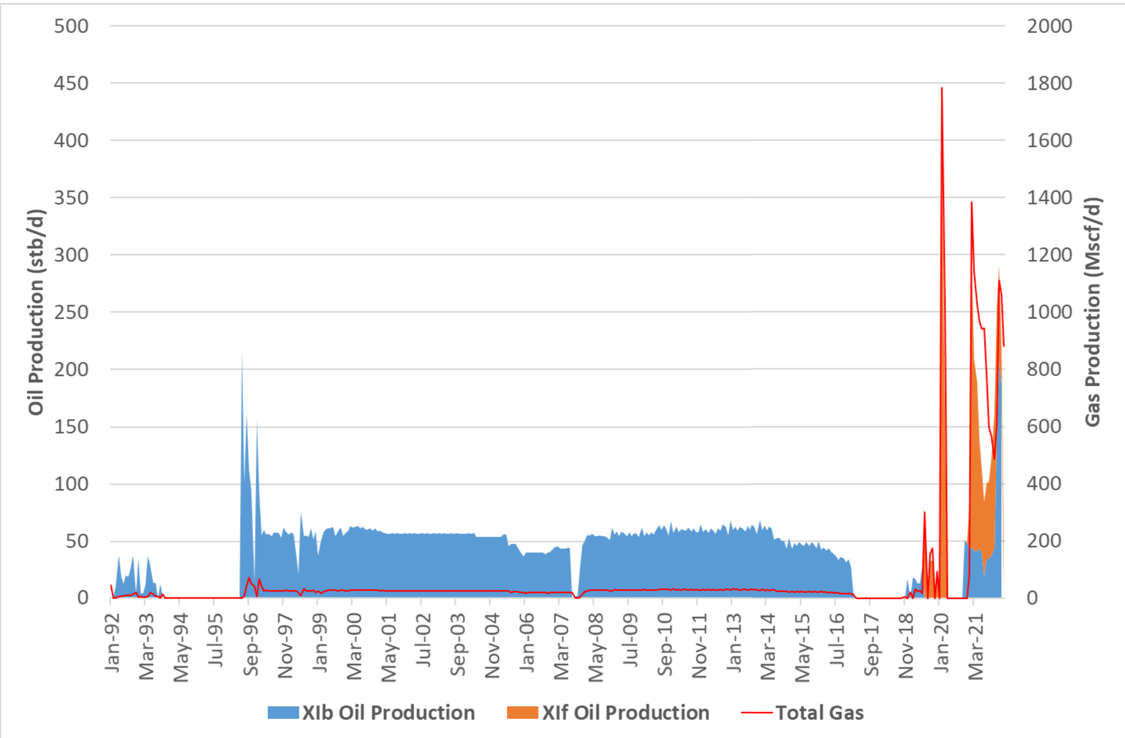

Figure 3.2: Blocks XIb and XIf WRK field oil and gas production history

Well KRT-39 has provided the majority of the production to date and at the Effective Date had produced 454 Mstb of oil and 217 MMscf of gas; the production history is shown in Figure 3.3.

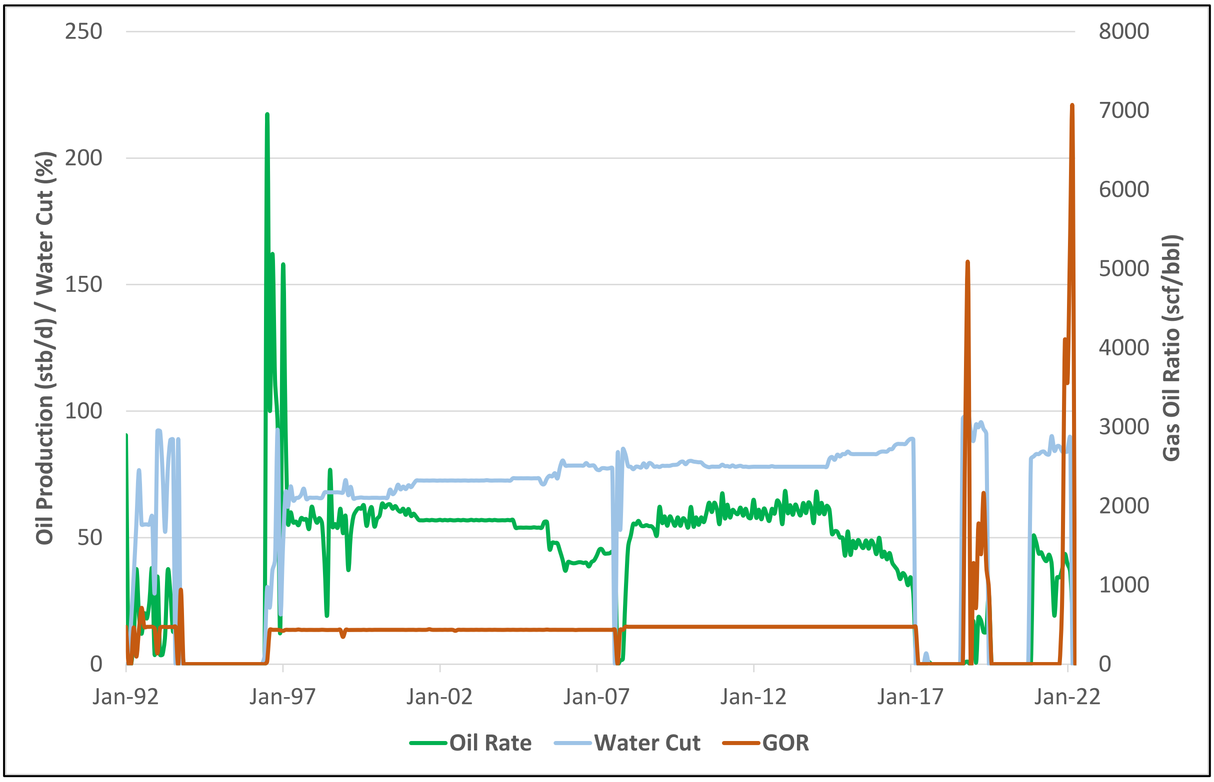

Figure 3.3: Well KRT-39 production history

Production facilities consist of an EPF at the Well WR-16 location and a production separator at the Well KRT-39 location. Multiphase fluids from offsetting wells are sent by flowline to the nearest separator location. A gas flowline links the Well KRT-39 facility to the EPF where all the produced gas is conditioned and compressed before exporting via a 9.5 km gas pipeline to a third-party facility. More details of the facilities are provided in Section 11. The gas is sold under an existing gas sales agreement. Oil is exported via road tanker.

Block Energy plans to drill a further five wells during 2H 2022 to 1H 2023 and has provided ERCE with a draft field development plan ("FDP"). The aim is to replicate the results of recent Well JKT-01Z which, in common with Well KRT-39, is in an area interpreted on seismic to have higher fracture density and therefore better productivity.

4. Geology and Geophysics

The West Rustavi area is located in the Kura Basin of East Georgia, 10 km south-east of Tbilisi (Figure 4.1). The field is the southwestern extent of a Middle Eocene play fairway that also incorporates the Ninotsminda, Samgori/Patardzeuil, Samgori South Dome and Teleti fields.

The Middle Eocene reservoir is characterised by volcanoclastically derived sandstones and shales deposited as submarine gravity flows (Figure 4.2). The thickness of the Middle Eocene section varies from 194 m to 287 m and generally thins in the south. Primary porosity within these rocks is poor with reservoir quality reliant on naturally occurring fractures (Type 1 fractured reservoir – Nelson 2001).

The overlying Upper Eocene Navtlugi Formation is both source and top-seal to the Middle Eocene hydrocarbons.

A clay-rich unit at the base of the Middle Eocene separates it from the underlying, gas-bearing Lower Eocene.

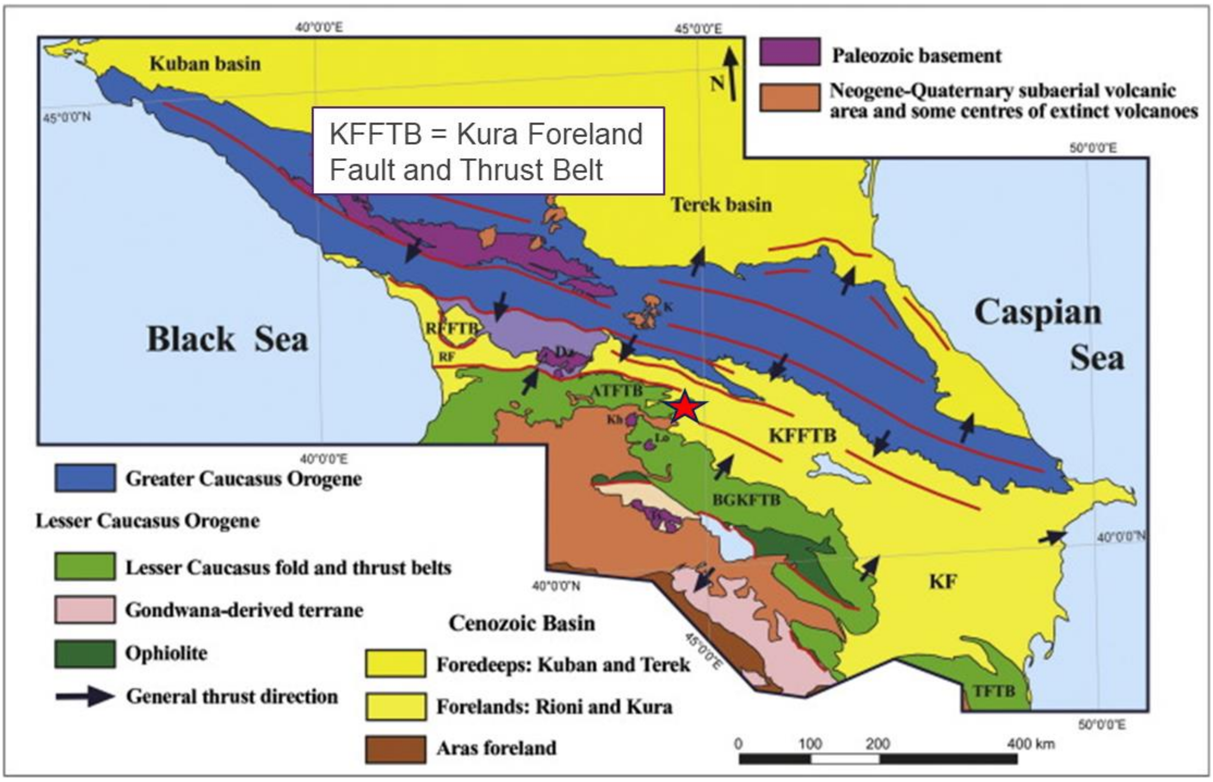

Figure 4.1: Location of the W. Rustavi area within the Kura Basin

The Middle Eocene in the WRK field area is interpreted to be part of a laterally continuous monoclinal structure dipping from west to east. Apart from very small local dip closures there are no obvious structural traps present and it is likely that fault seal and/or lack of faulting are responsible for the containment and distribution of hydrocarbons.

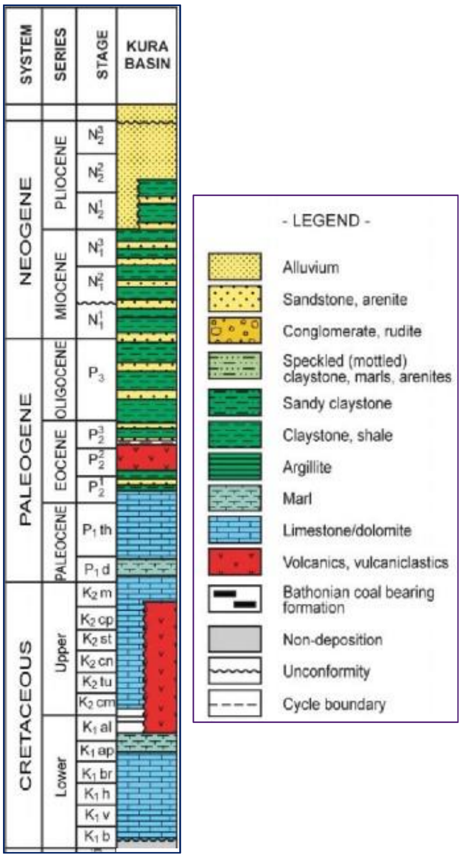

Figure 4.2: Stratigraphic Column covering the reservoir and source intervals

No independent petrophysical analysis work has been undertaken by ERCE as part of this CPR. The volumetric estimates prepared in Section 7 are not dependent on the interpretation of matrix porosity and hydrocarbon saturation; as a Type 1 reservoir, the reservoir capacity is dependent on natural fracturing which cannot be directly measured from wireline log data.

4.1. Seismic attribute analysis

Geometric attributes can be derived from 3D seismic data by comparing each seismic trace to its neighbours and analysing the ways in which they differ. Certain types of seismic attribute such as similarity and curvature are sensitive to discontinuities within the seismic data and so are often used to highlight areas of faulting/fracturing.

Block Energy has employed seismic attribute analysis techniques to identify and delineate fracture intensity within the Middle Eocene of the WRK field. Maximum Positive Curvature ("MPC") was selected as being the most effective at highlighting discontinuities within the seismic volume. The MPC attribute (a measure of how bent a surface is at a particular point) ignores amplitude variations and focuses on geometry variation. In this way, it can also detect faults which show drag or very low displacement which would not register on a similarity/coherency attribute extraction.

Block Energy has further applied Ant-tracking; an edge-enhancement algorithm to the MPC attribute. During the implementation of this algorithm, tracking voxels (volumetric pixels) are placed within the 3D seismic attribute cube. From each starting voxel (or Ant), the algorithm identifies the maximum attribute value within a pre-defined search radius and then moves to that new location, leaving a trail as it goes. The Ants progress in this way, moving to the next, closest maximum value of the attribute and recording their progress as a trail until no further progression is possible. Larger, more persistent attributes will capture more Ant trails and be highlighted by the density of trails which have travelled along their path. This approach enhances the discontinuities in an edge-detection volume because it only captures features that are continuous and likely to be faults.

The resulting Ant-track volume has been used by Block Energy to identify a region of high fracture density in the vicinity of Wells JKT-01 and JKT-01Z which in turn has been used to define the Krtsanisi Anticline ("KRT Anticline") (Figure 4.3). The main trend of the identified fractures in Figure 4.3 is NNE-SSW which is parallel to the principal stress direction of the region (Tsereteli et al. 2016[3]) and hence are in the optimum orientation being "held open" by the prevailing stress field.

This region coincides with Block's mapping of a low-topography four-way dip closure on the eastwards-plunging Middle Eocene surface (Figure 4.4) but it is the area of enhanced fracture density which defines the target area.

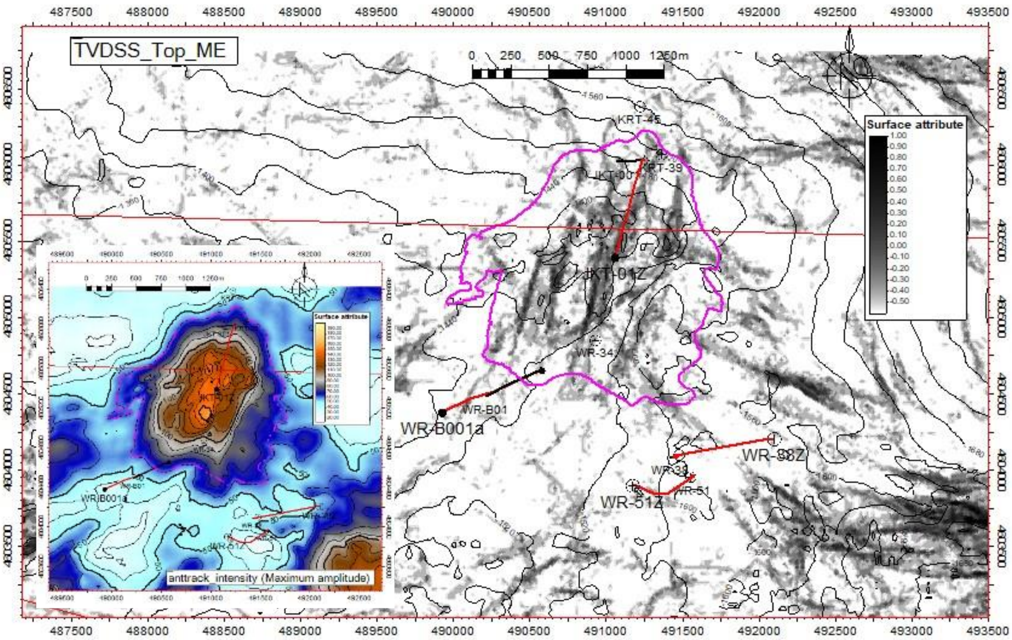

Figure 4.3: KRT Anticline defined using the Ant-track intensity

(Inset is an extraction of maximum intensity)

[3] Tsereteli,N., Tibaldi, A., Alania,V., Gventsadse,A., Enukidze,O., Varazanashvili,O. and Müller, B.I.R. 2016. Active tectonics of central-western Caucasus, Georgia. Tectonophysics, Volume 691, Part B. Pages 328-344

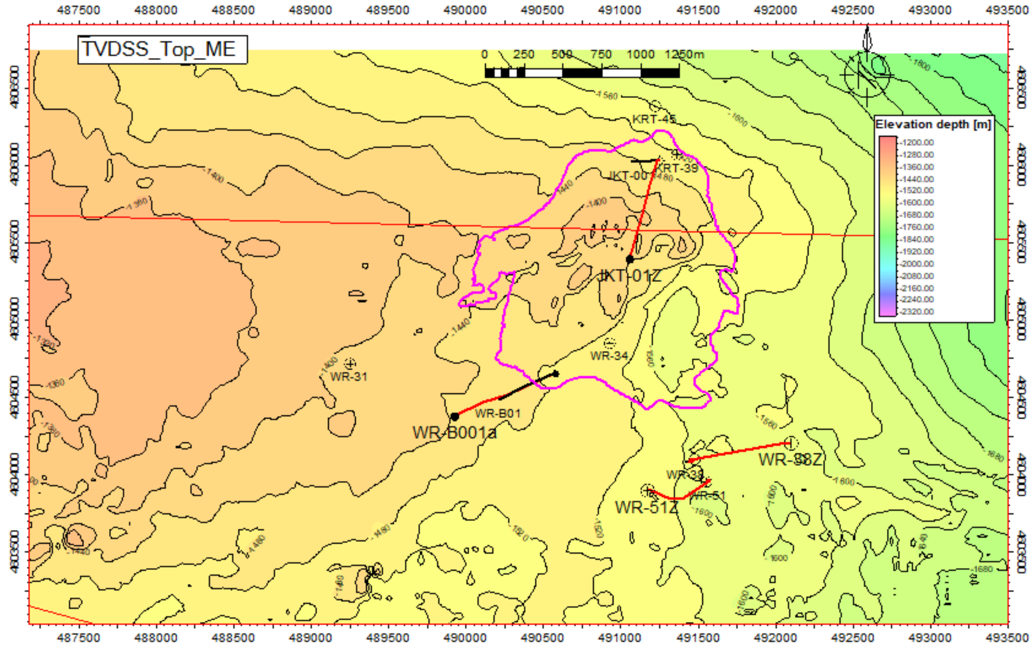

Figure 4.4: KRT Anticline polygon shown on the Middle Eocene top depth structure map

5. KRT Anticline Area

Based on seismic and well results, Block Energy has subdivided the WRK field into eight segments, as shown in Figure 5.1, which are expected to correspond to different areas of developments. Only three segments (namely the KRT Anticline up-dip, the WR-KRT transition and the WR anticline down-dip, all in green shades in the figure) have been produced or are being produced. The Reserves estimates presented in this CPR take account of the production from these three segments.

Block Energy's focus for the next phase of development activity is the KRT Anticline up-dip area. As discussed in Section 4.1, this appears on seismic to be an area of greater fracture intensity and as such a likely development sweet spot. The red polygon area shown on Figure 5.1 delimits the interpreted area of greater fracturing and was used as the basis for the ERCE volumetric calculations presented in Section 7. For the purposes of the CPR this is referred to as the KRT Anticline. Wells KRT-39 and JKT-01Z provide the only production from the area and are assumed to be isolated from the other WRK field wells (Wells WR-16aZ, WR-38Z and WR-B01a) which are in less densely fractured locations.

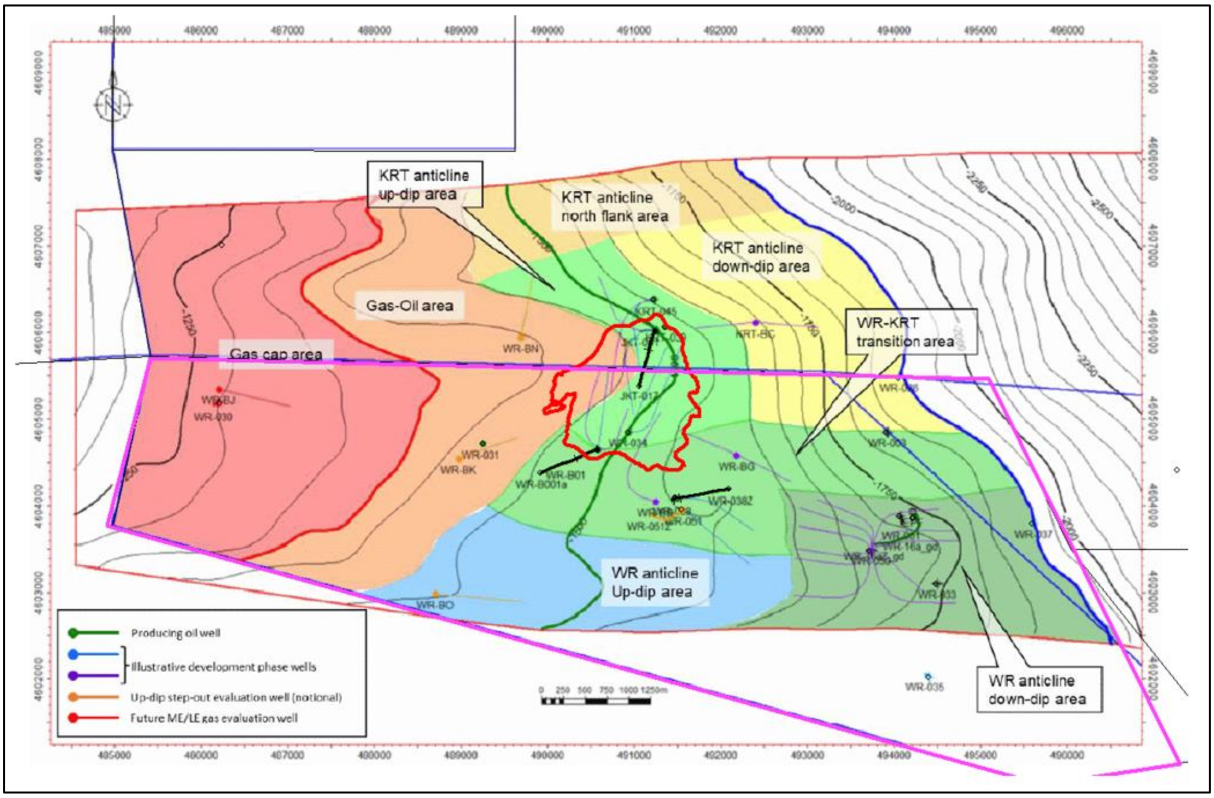

Figure 5.1: Middle Eocene reservoir segments defined by Block Energy

(the red polygon corresponds to the KRT Anticline)

6. Reservoir Engineering

The WRK field contains a light oil (35°API) which, at the Well KRT-39 location, was undersaturated but the field may have contained a primary gas cap. A PVT study was undertaken on behalf of Jindal Petroleum on a bottom hole sample from Well JKT-01 which measured an oil formation volume factor of 1.4 rb/stb, a solution GOR of 525 scf/stb and a bubble point of 140 Bar (2,032 psia). Well KRT-39 produced with a stable GOR of 450 scf/stb from when it commence production in 1992 through to 2010.

The exact trapping mechanism and the distribution of fluids across the WRK field is only partially understood. Block Energy has reviewed the fluids produced during the well tests across the field and derived the hydrocarbon column chart presented in Figure 5.1. Well JKT-01Z observed boundaries during the test which could indicate a GOC at ca. 1,458 m TVDSS and an OWC of 1,528 m TVDSS which would put water at a higher level than shown in Figure 5.1. All the recent wells including Wells WR-B01a, WR-16aZ, WR-38Z and JKT-01Z have produced at GORs which are much greater than 450 scf/stb suggesting free gas is being produced and that the primary/secondary gas cap has increased in size.

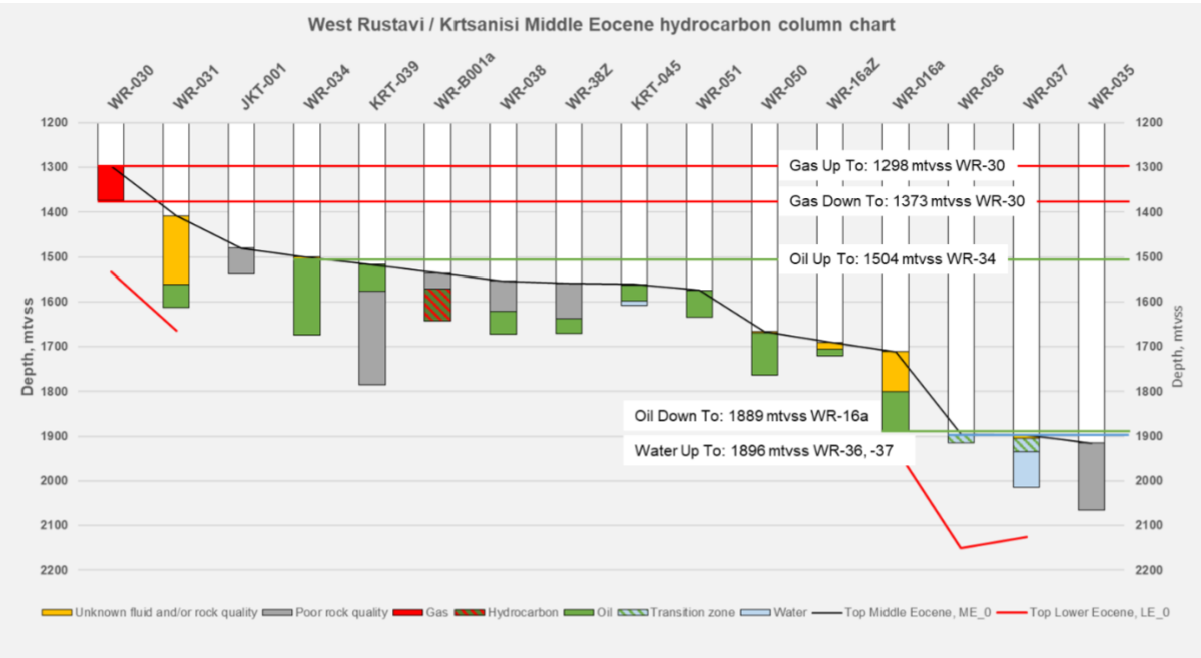

Figure 6.1: WRK field hydrocarbon column chart

(Source: Block Energy)

ERCE has reviewed various work provided by Block Energy including the analysis of the pressure transient analysis of the recent well tests, material balance studies and single well simulation modelling.

Well test information was provided for all the recent wells including WR-B01a, WR-38Z, WR-16aZ and JKT-01Z. The tests are difficult to interpret due to the heterogeneous nature of the reservoir and any results are likely to be non unique. A summary of the well tests is presented in Table 6.1. Water cuts were usually significant and greater than 70% at the end of the tests.

Well WR-16aZ initially flowed at dry oil rates around 600 stb/d but after a week both the water cut and GOR increased sharply. Build ups during the testing of Well WR-38Z were influenced by production from offset wells. Well productivity indices are of the order of 1 – 2 bbl(liquid)/day/psi. There appears to be a declining initial pressure measured in each subsequent well. Common themes appear to be negative skin and permeability anisotropy. Generally vertical permeability is estimated to be much greater than horizontal permeability and this together with the negative skin (typically ca. -2) is indicative of the natural fracturing.

Table 6.1: Well Test Summary for recent wells

Well	Date	Avg. Liquid Rate (bbl/d)	Final WCUT	Initial Pressure (psia)	K_{hor} (mD)	K_{vert} (mD)	Skin	PI (bbl/d/psia)
WR-16aZ	Mar-19	600	70%	2,756	1	681	-2.25	2.4
WR-38Z	Dec-19	623	76%	2,518	2.2	0.001	-2.5	1.3
WR-B01a	Sep-21	500	85%	2,460	0.3	?	-4.02	1.0
JKT-01Z	Jan-22	435	70%	2,147	1.4	206.5	-2.9	1.1

Block Energy has undertaken material balance analysis based on the performance of Well KRT-39. Well KRT-39 produced at a relatively stable GOR of ca. 450 scf/stb until 2011 when the GOR increased, most likely as a result of the reservoir pressure dropping below the bubble point (ca. 2,200 psia). Block Energy achieved a match assuming a connected STOIIP of 10 MMstb with a small aquifer. ERCE has undertaken similar work and has found the analysis very sensitive to the assumed aquifer size and, for example, was able to obtain a match with a much smaller STOIIP of 1 MMstb but a larger aquifer. Given it is difficult to determine what the aquifer size might be, ERCE believes Block Energy's connected STOIIP of 10 MMstb would be at the high end of the STOIIP range.

Block Energy has undertaken simulation work using a coarse gridded single well model of Well JKT-01Z to guide production forecasting. The model input selection was partly based on data from the well test interpretation. The model includes a small gas cap and an oil column of 45 m based on the pressure boundaries interpreted from the well test. A model porosity of 0.5% was used to represent the fracture porosity. A horizontal permeability of 1-2 mD with a Kv/Kh of 10 was used to capture the permeability anisotropy. The model assumes an initial water saturation of 20% and a residual oil saturation to water of 25%, which in turn implies a maximum microscopic sweep of 68.75%. The model was initialised with a STOIIP of 0.6 MMstb based on Block Energy's estimate of the mapped KRT Anticline STOIIP of 4.2 MMstb divided equally between Wells KRT-39, JKT-01Z and a further five development wells. A plot of the first two years of forecast production from Well JKT-01Z is presented in Figure 6.2 and includes the first 2.5 months of actual historical data. To honour the rapid build up in water cut, two columns of high permeability grid blocks were included in the model to mimic fracture performance. The model was produced with a minimum flowing bottom hole pressure of 1,740 psia (120 Bara) and a maximum oil rate of 630 stb/d. Over a 13 year production life the well recovers 0.15 MMstb which corresponds to a recovery factor of 25%.

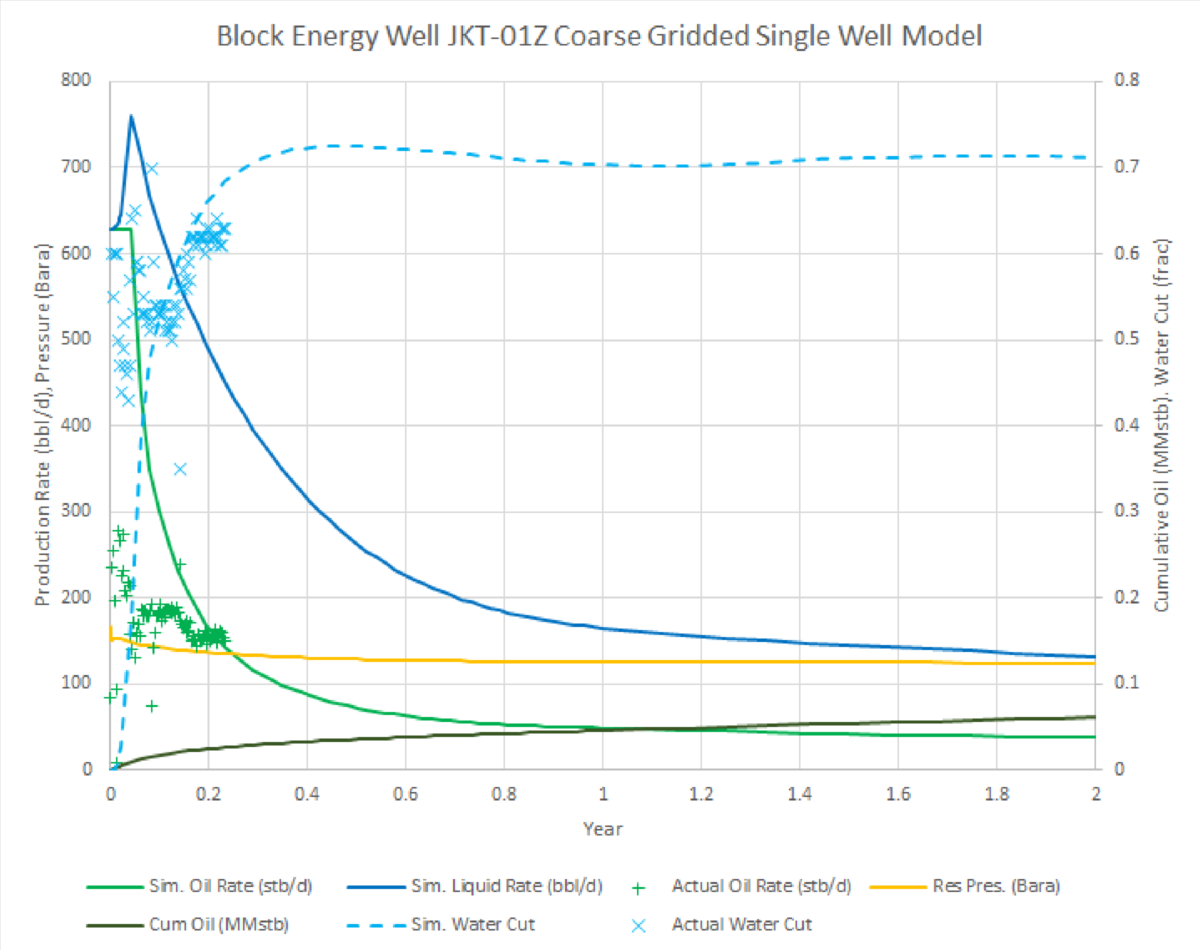

Figure 6.2: Block Energy Well JKT-01Z coarse model production forecast (two years)

ERCE is of the opinion, following a review of the model, that it should not be used as the basis for generating the production forecasts used in this CPR. The longer term recovery is limited in the model by the decline in the reservoir pressure which at the end of the run is 1914 psia (132 Bara), however, it may be that water cut development will be the more important factor. The distribution of the fracture network relative to the well and the gas/water legs, plus the degree of aquifer support will be key to deciding what controls future performance but these are very uncertain. ERCE believes the model has too many degrees of freedom to make it a useful predictive tool at this stage. ERCE has instead decided to use decline curve analysis for production forecasting purposes and this is discussed in more detail in Section 9.

7. Estimation of Hydrocarbons in Place

ERCE has estimated the oil initially in place within the KRT Anticline to guide the future recovery estimates for the development wells targeting this area. The volumes were estimated probabilistically using input distributions for the various input parameters.

The volumetric polygon was defined based on the seismic Ant-tracking work undertaken by Block Energy (Section 4.1). An OWC of 1,528 m TVDSS (based on the Well JKT-01Z well test) was used to estimate the gross rock volume ("GRV") within the polygon area in the low case. In the high case a depth of 1,594m TVDSS was used on the basis of the oil down to ("ODT") in Well KRT-39. A number of small structural closures were assumed to contain perched gas with GOCs ranging between 1,414 and 1,429 m TVDSS. (The GOC of 1,458 m TVDSS interpreted from the Well JKT-01Z well test interpretation was considered too inaccurate to use as the basis of an initial GOC.)

The net to gross ("NTG") was assumed to be 1.0 for the purposes of estimating the fracture volume. The oil saturation in the fractures is also expected to be very high. The fracture porosity is the key parameter which unfortunately cannot be directly measured. Normally data such as core photographs, borehole image logs, well test interpretations, and mud losses from drilled wells would be integrated together with the structural setting and history to get a qualitative understanding of how fractured this area is compared to possible analogues. In the case of the KRT Anticline these data are very limited which compounds the problems in estimating fracture porosity. Based on ERCE experience of Type 1 reservoirs elsewhere in the world, a fracture porosity of 0.7% was considered to be a high case. A low case of 0.175% was used as lower values would not be consistent with the recovery to date. A mid case (P50) estimate of 0.35% was then determined by using a log-normal distribution. A mid case oil formation volume factor (Bo) of 1.4 rb/stb was used in line with the PVT data; the distribution was skewed to lower values as the Samgori-Patardzeuli field has a Bo of 1.2.

The parameters used as input to the probabilistic volumetric calculations are presented in Table 7.1. Log-normal distributions were used for GRV and fracture porosity; triangular distributions were used for the other parameters with the low, mid and high values corresponding to P90, P50 and P10 estimates respectively.

Table 7.1: KRT Anticline volumetric input parameters

GRV (MM m3)			NTG (frac)			Fracture Porosity (%)			So (frac)			Bo (rb/stb)		
Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
127	179	251	1.00	1.00	1.00	0.175%	0.350%	0.700%	0.95	0.98	1.00	1.20	1.40	1.45

The resulting STOIIP estimates are presented in Table 7.2. This represents the oil in the fracture system that will be developed by existing Wells KRT-39 and JKT-01Z and the future development wells. Based on the fracture intensity maps it was considered unlikely that Wells WR-16aZ, WR-38Z and WR-B01a will be draining this volume as they lie outside the volumetric polygon.

Table 7.2: KRT Anticline STOIIP estimates

STOIIP (MMstb)		
Low	Mid	High
1.3	2.9	6.2

8. Development Plans

A Block Energy draft FDP dated May 2022 was provided to ERCE and forms the basis of the development plans for the WRK field. The document describes a first phase ("First Phase") of activities which are focused on the KRT Anticline. This phase is considered firm and deemed the most mature. The FDP document also mentions, but does not discuss future phases of development, which would target the remainder of the eight different areas shown in Figure 5.1 of Section 5; these were not assessed as part of this CPR.

The First Phase of the development plan requires five new wells in best estimate (2P) case as follows:

- The first three wells will be drilled as sidetracks from existing wellbores: Wells WR-B01a (a donor well currently on production), WR-34 and KRT-45; and
- Two new wells will be drilled from existing pads of Wells JKT-01Z and WR-34 respectively

The low (1P) case assumes that only two of the three sidetracks will be required (with no new wells). The high (3P) case assumes an additional three new wells will be required in addition to the five 2P wells making the total number of wells equal to eight.

All wells are planned to be drilled with a 6" horizontal hole through the Middle Eocene and completed barefoot with 2-7/8" tubing. The wells will require beam pumps to provide artificial lift. The sidetracks are estimated to take 45 days to drill, complete and hook up whereas the new wells will take 60 days (both estimates include the time for moving the rig). The first well will be the sidetrack of Well WR-B01a and is scheduled to commence in June 2022.

Developed Reserves are attributable to the current stock of five producing wells (Wells WR-B01a, WR-16aZ, WR-38Z, JKT-01Z and KRT-39); Well WR-B01a will cease production when the sidetrack operations commence in June 2022.

Undeveloped Reserves were assigned to the new production associated to the First Phase of development. Locations of the new wells (Wells WR-B01_ST, WR-34_ST, KRT-45_ST, JKT-BB and WR-34_BS) for the 2P case are shown in Figure 8.1.

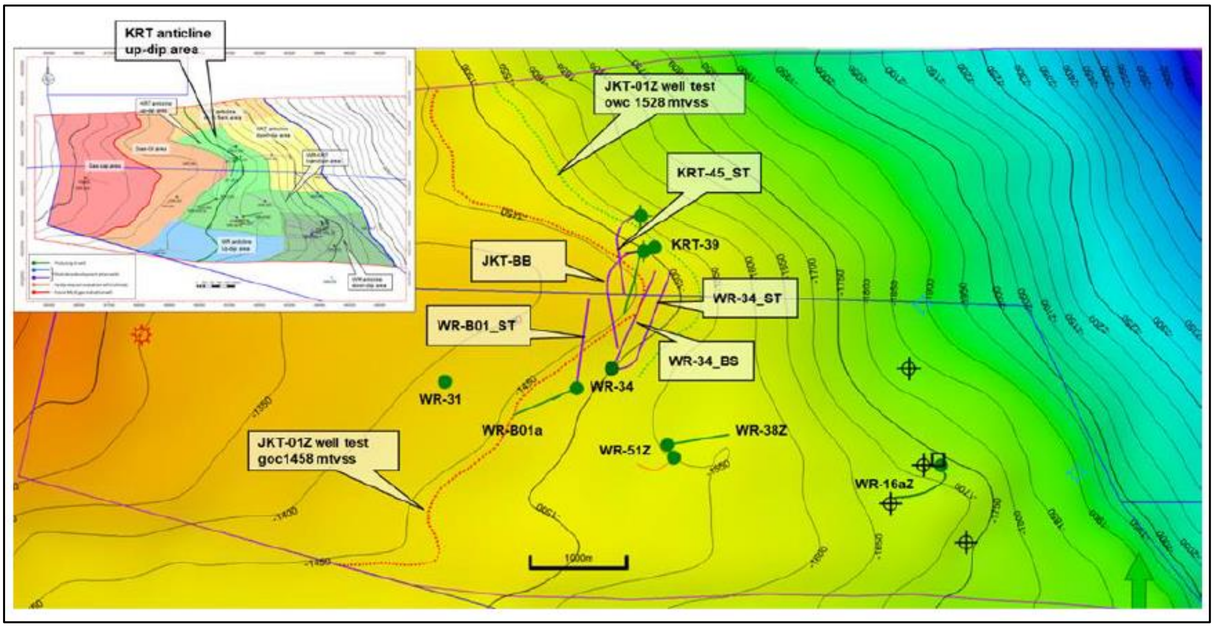

Figure 8.1: KRT Anticline new development well locations (2P case)

For the purposes of economic modelling, production was allocated to each licence on the basis of the surface well location. Hence Wells WR-B01_ST, WR-34_BS and WR-34_ST are within Licence XIf and Wells KRT-45_ST and JKT-BB are within Licence XIb.

9. Technically Recoverable Resources

ERCE has assessed the Technically Recoverable Resources of the KRT Anticline by considering the performance of the existing wells (Wells JKT-01Z and KRT-39) as well as deriving volumetric estimates of the likely recovery. Recovery factors were applied probabilistically to the volumetric STOIIP estimates presented in Section 7. Based on analogue performance of Type 1 reservoirs, recovery within the fracture system is likely to be high assuming water sweep from an underlying aquifer. Given the recovery to date, a low (P90) case recovery factor of at least 60% was required to avoid negative remaining volumes. In the high (P10) case a recovery factor of 90% was considered feasible based on ERCE experience of other Type 1 reservoirs. A mid (P50) case recovery factor of 75% was used as the average of the two. The resulting technically recoverable resources are presented in Table 9.1

Table 9.1: TRR and remaining TRR of the KRT Anticline as of 31 March 2022

Source	STOIIP (MMstb)			TRR (MMstb)			Np 31 Mar 22	Remaining TRR (MMstb)		
	Low	Best	High	Low	Best	High	MMstb	Low	Best	High
ERCE	1.3	2.9	6.2	0.9	2.1	5.0	0.5	0.5	1.7	4.6

These ERCE estimates of TRR are not conditioned to any specific development plan (e.g. schedule or locations) or constrained by any timeframe (e.g. related to licence duration or facilities life). ERCE estimates that two, five and eight new oil wells will be required to develop these TRR at the different levels of confidence. With the inclusion of Well JKT-01Z , which is currently flowing, but excluding Well KRT-39, ERCE estimates a remaining TRR/well of 0.12, 0.25 and 0.47 MMstb at the different levels of confidence. These volumes have been calibrated to the Well JKT-01Z performance and are likely to be recovered over an extended timeframe; ERCE has assumed that this could be up to 100 years, however given the nature of the production decline, the volumes in the tail are not significant.

ERCE has also assessed the TRR associated with Wells WR-B01a, WR-16aZ and WR-38Z which lie within Licence XIf but are considered to be separate from the KRT Anticline. The TRR estimates are presented in Table 9.2 and were derived using decline curve analysis (DCA). ERCE estimates of TRR are not conditioned to any specific development plan but based on the production extrapolation of current producers. ERCE has not prepared an independent volumetric estimate of the STOIIP for the West Rustavi area and therefore no reconciliation with hydrocarbon in place volumes was possible.

Table 9.2: TRR and remaining TRR from Wells WR-B01a, WR-16aZ and WR-38Z as of 31 March 2022

TRR (MMstb)			Np 31 Mar 22	Remaining TRR (MMstb)		
Low	Mid	High	MMstb	Low	Mid	High
0.11	0.15	0.20	0.09	0.02	0.06	0.10

10. Production Forecasts

ERCE has prepared TRR production forecasts as part of the Reserves estimation process.

For the current producing wells, DCA was used to derive the production forecasts. ERCE's DCA was performed on individual wells based on water-oil ratio (WOR) and/or operating rate versus cumulative oil analysis. This included recent Well JKT-01Z which was brought online in January 2022 and for which initial performance was analysed using daily data, and Well WR-B01a, which will be sidetracked in June 2022.

For the future wells ERCE has used Well JKT-01Z as a type well to generate production forecasts at the different levels of confidence. ERCE understands that Well JKT-01Z is currently choked back due to a gas constraint on an inter-field pipeline to the EPF; Block Energy believes, based on the single well modelling work (Section 6), that higher offtake should be possible in future wells. ERCE accepts that it may be possible to increase the gross production rates in the new wells but does not believe the impact on the water cut and GOR can be reliably modelled; for the purposes of estimating Reserves, ERCE has assumed that the new wells will produce at similar rates to Well JKT-01Z. For forecasting purposes ERCE has assumed the wells will decline harmonically in line with a water drive mechanism. Individual wells were forecast down to a final technical oil rate of 1 stb/d over up to 100 years cognoscente that an economic limit would apply much earlier.

Secondary phase production volumes were also estimated by ERCE. Gas production volumes were forecast using decreasing trends of GOR, derived from historic production data. Gas is currently being produced at rates which are greater than the estimated solution GOR. Reasons for this are poorly understood but could be because there are small, perched gas caps present (this was accounted for when estimating the STOIIP in Section 7). In time GORs are likely to reduce back to levels closer to the solution GOR of 450 scf/stb. For the new wells it was assumed they will produce with a GOR of 450 scf/stb throughout their lives.

The individual well and project profiles were aggregated to field production forecasts making allowances for production efficiency. ERCE has assumed an average production efficiency of 95% for the entire forecast period at all levels of confidence. During the aggregation of well profiles, surface facilities flow capacities have been accounted for to simulate possible constraints to production. For the purpose of Reserves calculation, the aggregation was carried out up to the licence level, with the generation of two distinct production forecasts for each of the XIb and XIf blocks as they have slightly different fiscal terms.

A description and a schematic of the production system (Figure 11.1) are included in the draft FDP. All existing and future multiphase flowlines in-place have nominal capacities of 453 m^3/d (2,850 bbl/d) of fluid and 144,000 sm^3/d (5 MMscf/d) of gas. Work to upgrade the production separator at Well KRT-39 is currently on going and is expected to be completed before development drilling starts. The separator is being upgraded to be able to handle the production from the existing KRT-39 and JKT-01Z wells plus the future production from two new wells. A significant upgrade is also planned for the EPF where the dehydration unit will be upgraded so that its gas capacity will be the same as the export pipeline of 100,000 sm^3/d (3.5 MMscf/d) of gas. ERCE understands that a possible constraint to production may exist in the gas capacity of the flowline between the KRT-39 facility and the EPF, nominally of 27,000 sm^3/d (0.9 MMscf/d). This constraint is not reached in the ERCE production forecasts, but this flowline may require an upgrade if any of the new wells produce at higher than expected GORs.

The oil production forecasts are presented with the historical production since 2017 for the total field in Figure 10.1.

All ERCE gas production forecasts have been generated as wellhead volumes which in this case are assumed to be equivalent to the sales gas volumes; the field facilities are electrified from the national grid and the fuel and flare requirements are not considered material. The associated gas production forecasts are presented in Figure 10.2.

The forecasts are also shown in tabular form on an annual basis in Table 10.1 and in line with the economic input are shown to end 2049. The totals in the last row of Table 10.1 are lower than the sum of the TRR estimates presented in Table 9.1 and Table 9.2 because of the more limited forecast period.

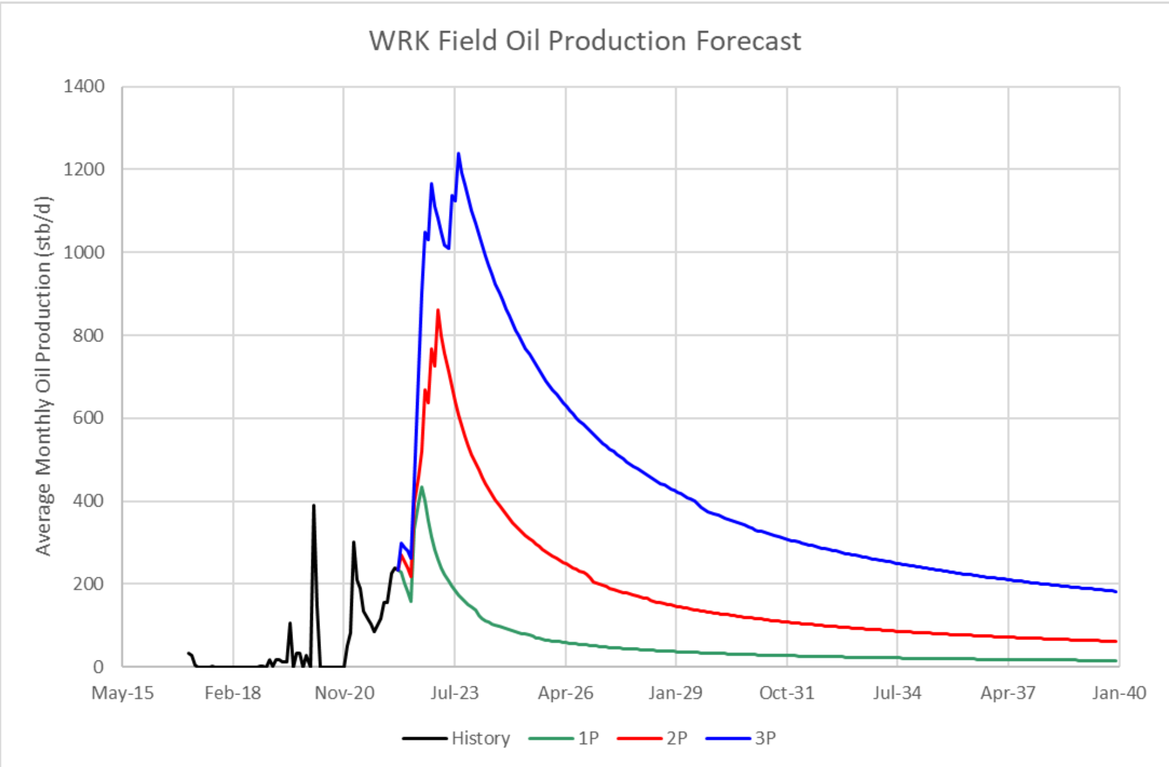

Figure 10.1: WRK Field Oil Production Forecast – Existing plus First Phase Wells

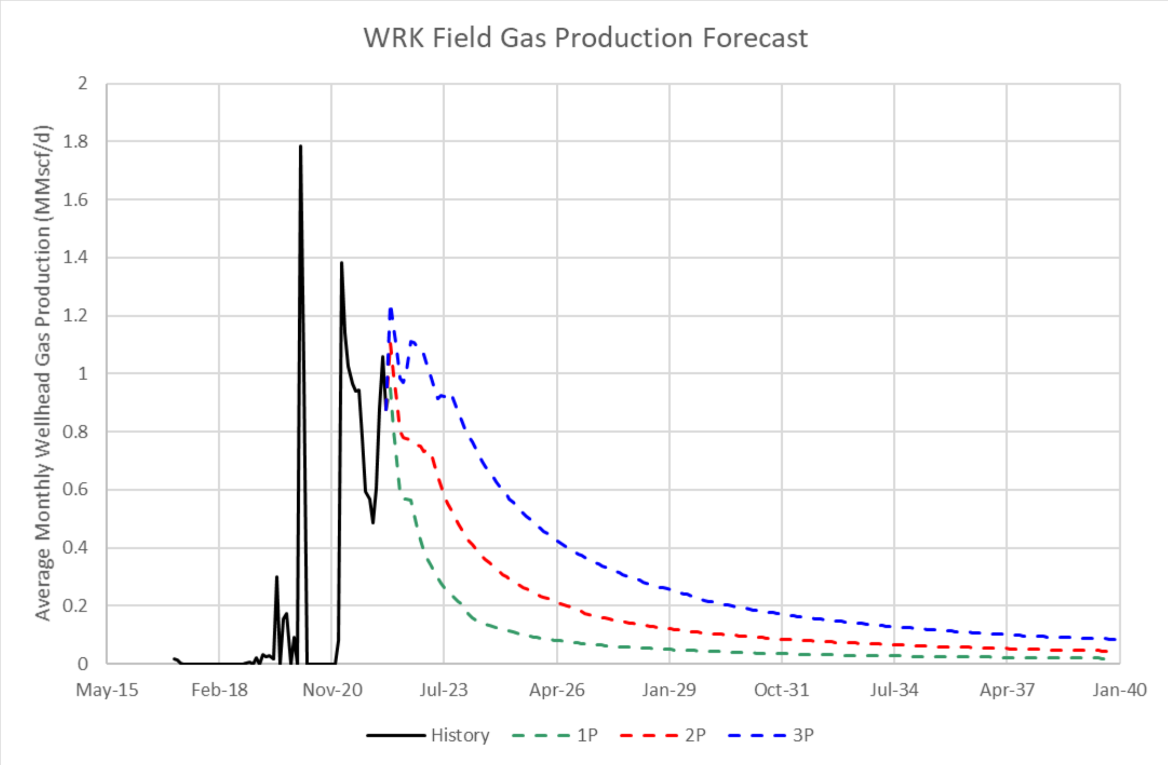

Figure 10.2: WRK Field Gas Production Forecast – Existing plus First Phase Wells

Table 10.1: WRK Field Oil and Gas Production Forecasts – Existing plus First Phase Wells

Year	Oil Production Rate (stb/d)			Gas Production Rate (MMscf/d)		
	1P	2P	3P	1P	2P	3P
2022 (9 mo)	299	407	584	0.64	0.85	1.08
2023	212	684	1,118	0.30	0.63	0.96
2024	110	426	963	0.15	0.38	0.72
2025	75	308	750	0.10	0.27	0.53
2026	57	242	616	0.08	0.21	0.41
2027	47	189	523	0.06	0.16	0.34
2028	40	161	455	0.05	0.13	0.28
2029	35	139	400	0.05	0.11	0.24
2030	31	124	352	0.04	0.10	0.20
2031	28	112	318	0.04	0.09	0.18
2032	26	102	292	0.03	0.08	0.16
2033	23	94	270	0.03	0.07	0.14
2034	22	87	251	0.03	0.07	0.13
2035	20	81	235	0.03	0.06	0.12
2036	19	75	220	0.02	0.06	0.11
2037	18	71	208	0.02	0.05	0.10
2038	17	67	197	0.02	0.05	0.09
2039	16	63	187	0.02	0.05	0.09
2040	15	60	178	0.02	0.04	0.08
2041	14	57	170	0.02	0.04	0.08
2042	13	55	162	0.02	0.04	0.08
2043	13	52	156	0.02	0.04	0.07
2044	13	50	149	0.02	0.03	0.07
2045	12	48	144	0.01	0.03	0.07
2046	12	46	139	0.01	0.03	0.06
2047	12	44	134	0.00	0.01	0.02
2048	12	43	129	0.00	0.00	0.00
2049	11	38	114	0.00	0.00	0.00
Total (Mstb, Bscf)	**419**	**1,397**	**3,385**	**0.61**	**1.27**	**2.24**

11. Facilities and Costs

ERCE has prepared future cost forecasts to support the production profiles set out in Section 10. This consists of costs associated with the developed producing profile, through existing surface facilities and the incremental costs for the First Phase wells and operations.

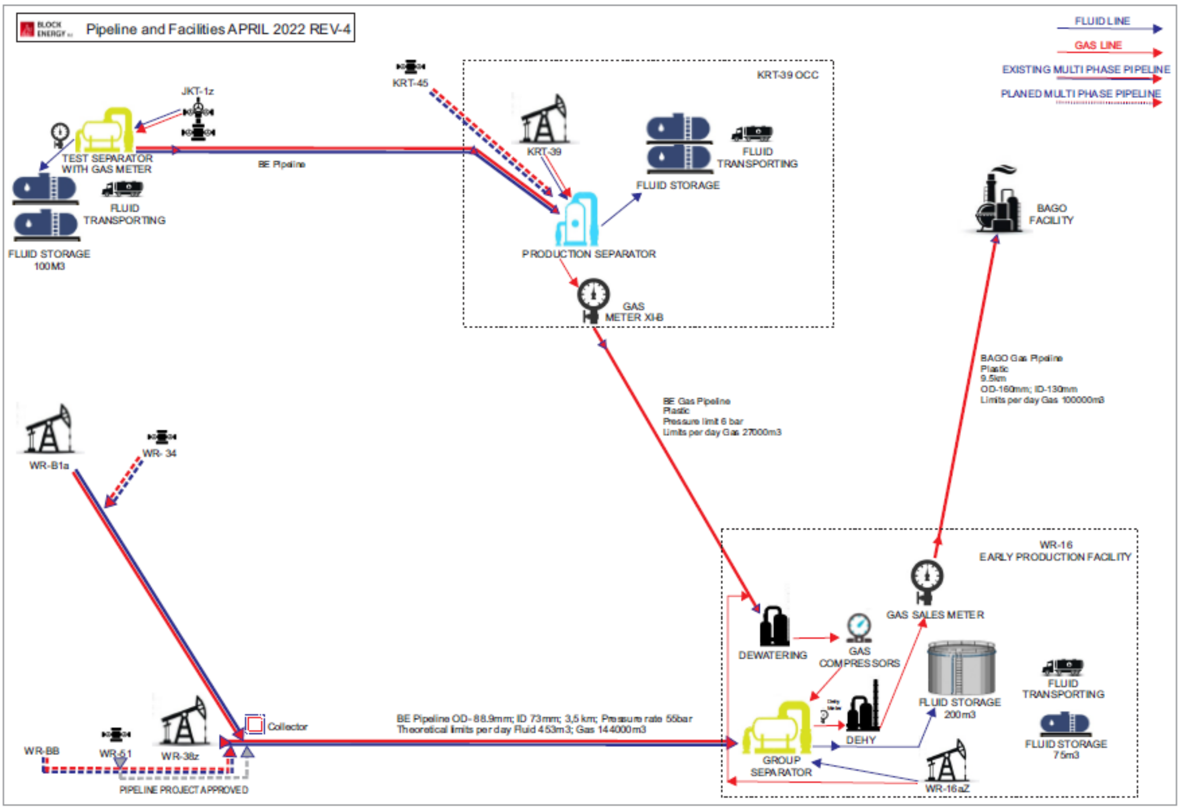

Figure 11.1: Facilities Schematics

Capital costs are driven primarily by additional First Phase wells that are required to support the production profiles at each level of confidence. The existing facilities shown in Figure 11.1 will be utilised for the incremental production from the First Phase wells, with minor facilities upgrades.

In the 1P case, two sidetracks are each drilled at a cost of $1.42 MM. Draft AFE documentation for these wells has been provided to ERCE. At the 2P level of confidence, three sidetracks and two new wells are also drilled, at a cost of $2.72MM. At the 3P level of confidence, three sidetracks and five new wells are drilled. The first well in the drilling programme, Well WR-B01_ST, has a forecast cost of $1.02MM as approximately $400,000 has been sunk to date and as such are excluded from the ERCE forecasts. In addition to the drilling costs there are some one-off purchases, for example pump jack, transformers and operator cabins. The final well costs are shown in Table 11.1.

Table 11.1: Well Costs (Drilling, Completion and Hook Up)

Well	Name	Block	Drilling ($M)	Equipment ($M)	Cost ($M)	Reserves Case
Well 1	WR-B01_ST	XIf	$1,020	$0	$1,020	1P, 2P, 3P
Well 2	WR-34_ST	XIf	$1,420	$78	$1,498	1P, 2P, 3P
Well 3	KRT-45_ST	XIb	$1,420	$78	$1,498	2P, 3P
Well 4	JKT-BB	XIb	$2,720	$71	$2,791	2P, 3P
Well 5	WR-34_BS	XIf	$2,720	$62	$2,782	2P, 3P
Well 6	Well 6	XIf	$2,720	$67	$2,787	3P
Well 7	Well 7	XIb	$2,720	$67	$2,787	3P
Well 8	Well 8	XIb	$2,720	$67	$2,787	3P

Remaining CAPEX is limited to minor upgrades of existing facilities and pipelines; a total of $400,000. This includes:

- Remaining work on the Well KRT-39 separator upgrade (parts on order – sunk cost);
- East Production Facility glycol unit upgrade, based on a vendor quotation; and
- Infield and tie-in pipelines.

Operational expenditure for the existing production is based on actual costs incurred throughout 2021. This is split into fixed and variable costs across Blocks XIb and XIf. Fixed costs of $9,592 per month for Block XIb were allocated based on the two current active wells in the KRT field out of the total of 22 across the whole block. Variable operating costs are as follows (6 Mscf = 1 boe):

- XIf - $7.87/boe
- XIb - $6.19/boe

An incremental fixed OPEX is applied to each block to account for additional operating personnel at new well sites.

Overall asset G&A costs across Block XIb and XIf of $51,718 per month were allocated to the licences on a unit of production basis. The G&A costs for XIb were allocated based on the two current active wells in the WRT field out of a total of 22 across the whole block. This excludes UK G&A costs.

A high level abandonment estimate has been adopted by ERCE of $75,000 for new wells. An abandonment provision for existing facilities and wells has already been set aside and is considered a sunk cost and hence excluded from the ERCE forecasts.

12. Economic Evaluation

ERCE has reviewed Block Energy's economic model and made minor modifications where appropriate. The CoP and Net Present Values ("NPVs") at various discount rates were determined at the 1P/2P/3P levels of uncertainty based on the relevant fiscal regime, production and cost profiles generated by ERCE and several economic assumptions listed below. The results are presented in this report both on a 100% field gross basis and a net entitlement basis for all Reserves and cost cases. The NPVs are presented based on Block Energy's net entitlement.

The economic limit test was initially carried out on a consolidated basis and ELTs later applied to individual blocks taking into account the expiry dates. Forecasts were prepared on a monthly basis and the CoP dates coincide with the end of the final period with the maximum cumulative cash flow. For both Block XIf and Block XIb, the CoP dates in the 3P case correspond to the licence expiry including a 5-year extension period. The CoP dates for each licence are presented in Table 12.1.

Table 12.1: Cessation of Production Dates

Case	Cessation of Production Date		
	Block XIf	Block XIb	Combined
1P	Sep-2024	Sep-2024	Sep-2024
2P	Feb-2034	Feb-2034	Feb-2034
3P	Sep-2048	May-2039	Sep-48 & May-39

The licences are operated under the terms of PSCs. Main elements include 50% cost recovery (both blocks) and contractor profit share of 50% in Block XIf and 46% in Block XIb. The Contractor is not liable for Georgian income tax.

ERCE's 1 April 2022 price forecast of Brent crude oil was used for the evaluation and is presented in Table 1.4 (in the Executive Summary). Crude oil differential and natural gas prices were based on assumptions from Block Energy. Prices are escalated at 2.0% per annum inflation.

Capital and operating costs have been determined in 2022 real terms and are inflated at 2.0% per annum.

The NPVs are presented in Table 1.5 of the Executive Summary. Though NPVs form an integral part of fair market value estimations, without consideration for other economic criteria they are not to be construed as ERCE's opinion of fair market value. There is no assurance that the forecast production and cost profiles contained in this CPR will be attained and variances could be material.

Appendix 1: SPE PRMS Guidelines

This report references the SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Reserves and Resources Classification System and Definitions, as revised in June 2018 (PRMS). The full text of the PRMS document can be viewed at:

https://www.spe.org/en/industry/petroleum-resources-management-system-2018/

Definitions of the key PRMS Reserves and Resource classes, categories and a glossary of related terms can be found at the above address.

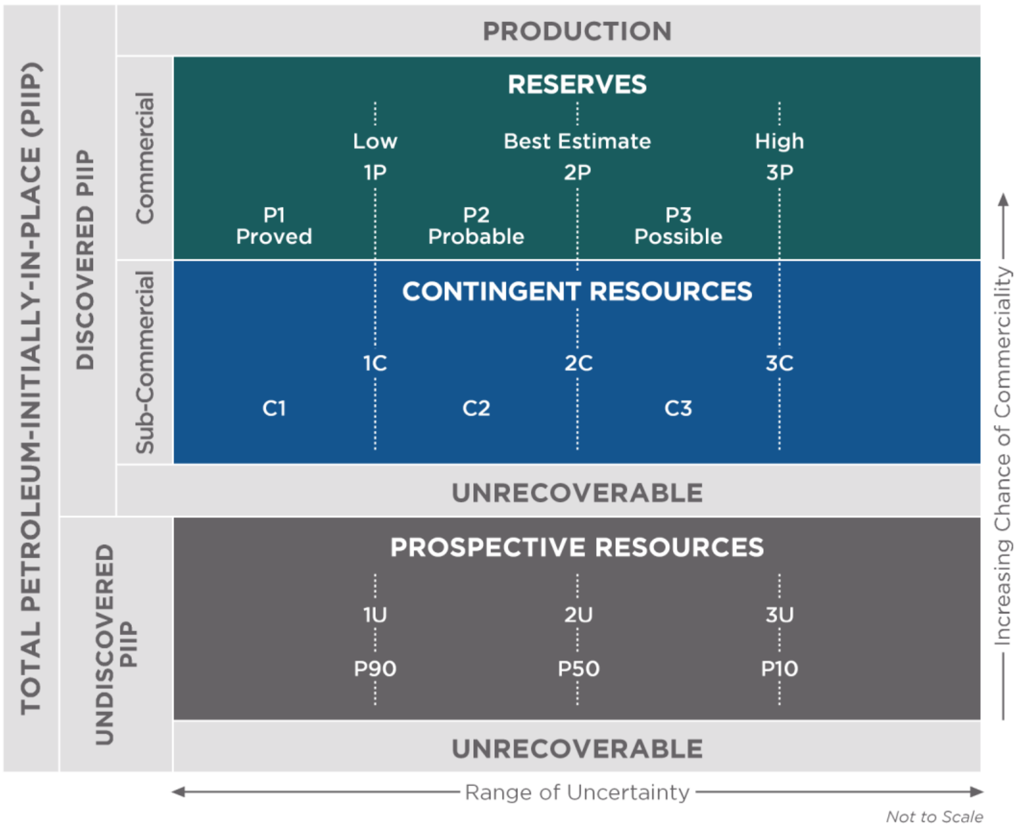

Figure A: PRMS Resources classification framework

(Modified from Petroleum Resources Management System (PRMS) Revised June 2018, page 8, Figure 1.1)

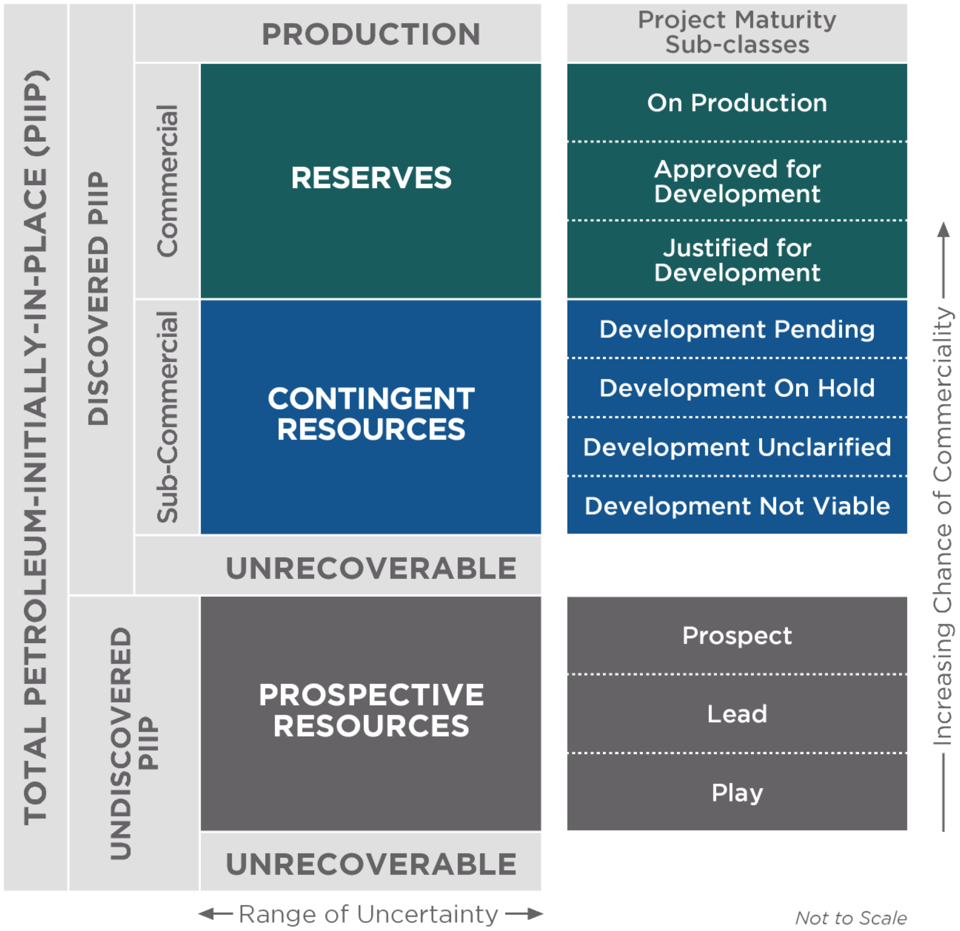

Figure B: PRMS Resources sub-classes

(Modified from Petroleum Resources Management System (PRMS) Revised June 2018, page 8, Figure 2.1)

Table 1: PRMS Recoverable Resources Classes and Sub-Classes

Classes/Sub-classes	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market- related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.

Classes/Sub-classes	Definition	Guidelines
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame}) There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub- classified based on project maturity and/or characterized by the economic status.

Classes/Sub-classes	Definition	Guidelines
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.

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

Table 2: PRMS Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3: PRMS Reserves Category Definitions and Guidelines

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

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

Table 4: Glossary of Terms Used in PRMS

Term	Definition
1C	Denotes low estimate of Contingent Resources.
2C	Denotes best estimate of Contingent Resources.
3C	Denotes high estimate of Contingent Resources.
1P	Denotes low estimate of Reserves (i.e., Proved Reserves). Equal to P1.
2P	Denotes the best estimate of Reserves. The sum of Proved plus Probable Reserves.
3P	Denotes high estimate of reserves. The sum of Proved plus Probable plus Possible Reserves.
1U	Denotes the unrisked low estimate qualifying as Prospective Resources.
2U	Denotes the unrisked best estimate qualifying as Prospective Resources.
3U	Denotes the unrisked high estimate qualifying as Prospective Resources.
Abandonment, Decommissioning, and Restoration (ADR)	The process (and associated costs) of returning part or all of a project to a safe and environmentally compliant condition when operations cease. Examples include, but are not limited to, the removal of surface facilities, wellbore plugging procedures, and environmental remediation. In some instances, there may be salvage value associated with the equipment removed from the project. ADR costs are presumed to be without consideration of any salvage value, unless presented as "ADR net of salvage."
Accumulation	An individual body of naturally occurring petroleum in a reservoir.
Aggregation	The process of summing well, reservoir, or project-level estimates of resources quantities to higher levels or combinations, such as field, country or company totals. Arithmetic summation of incremental categories may yield different results from probabilistic aggregation of distributions.
Appraisal	The phase that may follow successful exploratory drilling. Activities to further evaluate the discovery, such as seismic acquisition, geological studies, and drilling additional wells may be conducted to reduce technical uncertainties and commercial contingencies.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is underway. A project maturity sub-class of Reserves.
Analog	Method used in resources estimation in the exploration and early development stages (including improved recovery projects) when direct measurement is limited. Based on evaluator's assessment of similarities of the analogous reservoir(s) together with the development plan.
Analogous Reservoir	Reservoirs that have similar rock properties (e.g., petrophysical, lithological, depositional, diagenetic, and structural), fluid properties (e.g., type, composition, density, and viscosity), reservoir conditions (e.g., depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide insight and comparative data to assist in estimation of recoverable resources.

Assessment	See Evaluation.
Associated Gas	A natural gas found in contact with or dissolved in crude oil in the reservoir. It can be further categorized as gas cap gas or solution gas.
Basin-Centered Gas	An unconventional natural gas accumulation that is regionally pervasive and characterized by low permeability, abnormal pressure, gas-saturated reservoirs, and lack of a down dip water leg.
Barrel of Oil Equivalent (BOE)	The term allows for a single value to represent the sum of all the hydrocarbon products that are forecast as resources. Typically, condensate, oil, bitumen, and synthetic crude barrels are taken to be equal (1 bbl = 1 BOE). Gas and NGL quantities are converted to an oil equivalent based on a conversion factor that is recommended to be based on a nominal heating content or calorific value equivalent to a barrel of oil.
Basis for Estimate	The methodology (or methodologies) and supporting data on which the estimated quantities are based. (Also referenced as basis for the estimation.)
Behind-Pipe Reserves	Reserves that are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion before the start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling and completing a new well including hook-up to allow production.
Best Estimate	With respect to resources categorization, the most realistic assessment of recoverable quantities if only a single result were reported. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
C1	Denotes low estimate of Contingent Resources. C1 is equal to 1C.
C2	Denotes Contingent Resources of same technical confidence as Probable, but not commercially matured to Reserves.
C3	Denotes Contingent Resources of same technical confidence as Possible, but not commercially matured to Reserves.
Chance	Chance equals 1-risk. Generally synonymous with likelihood. (See Risk)
Chance of Commerciality	The estimated probability that the project will achieve commercial maturity to be developed. For Prospective Resources, this is the product of the chance of geologic discovery and the chance of development. For Contingent Resources and Reserves, it is equal to the chance of development.
Chance of Development	The estimated probability that a known accumulation, once discovered, will be commercially developed.
Chance of Geologic Discovery	The estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum.
Coalbed Methane (CBM)	Natural gas contained in coal deposits. Coalbed gas, although usually mostly methane, may be produced with variable amounts of inert or even non-inert gases. [Also called coal-seam gas (CSG) or natural gas from coal (NGC).]

Commercial	A project is commercial when there is evidence of a firm intention to proceed with development within a reasonable time-frame. Typically, this requires that the best estimate case meet or exceed the minimum evaluation decision criteria (e.g., rate of return, investment payout time). There must be a reasonable expectation that all required internal and external approvals will be forthcoming. Also, there must be evidence of a technically mature, feasible development plan and the essential social, environmental, economic, political, legal, regulatory, decision criteria, and contractual conditions are met. .
Committed Project	Project that the entity has a firm intention to develop in a reasonable time-frame. Intent is demonstrated with funding/financial plans, but FID has not yet been declared (See also Final Investment Decision.)
Completion	Completion of a well. The process by which a well is brought to its operating status (e.g., producer, injector, or monitor well). A well deemed to be capable of producing petroleum, or used as an injector, is completed by establishing a connection between the reservoir(s) and the surface so that fluids can be produced from, or injected into, the reservoir.
Completion Interval	The specific reservoir interval(s) that is (are) open to the borehole and connected to the surface facilities for production or injection, or reservoir intervals open to the wellbore and each other for injection purposes.
Concession	A grant of access for a defined area and time period that transfers certain entitlements to produced hydrocarbons from the host country to an entity. The entity is generally responsible for exploration, development, production, and sale of hydrocarbons that may be discovered. Typically granted under a legislated fiscal system where the host country collects taxes, fees, and sometimes royalty on profits earned. (Also called a license.)
Condensate	A mixture of hydrocarbons (mainly pentanes and heavier) that exist in the gaseous phase at original temperature and pressure of the reservoir, but when produced, are in the liquid phase at surface pressure and temperature conditions. Condensate differs from NGLs in two respects: (1) NGL is extracted and recovered in gas plants rather than lease separators or other lease facilities, and (2) NGL includes very light hydrocarbons (ethane, propane, or butanes) as well as the pentanes-plus that are the main constituents of condensate.
Confidence Level	A measure of the estimated reliability of a result. As used in the deterministic incremental method, the evaluator assigns a relative level of confidence (high/moderate/low) to areas/segments of an accumulation based on the information available (e.g., well control and seismic coverage). Probabilistic and statistical methods use the 90% (P90) for the high confidence (low value case), 50% (P50) for the best estimate (moderate value case), and 10% (P10) for the low (high value case) estimate to represent the chances that the actual value will equal or exceed the estimate.
Constant Case	A descriptor applied to the economic evaluation of resources estimates. Constant-case estimates are based on current economic conditions being those conditions (including costs and product prices) that are fixed at the evaluation date and held constant, with no inflation or deflation made to costs or prices throughout the remainder of the project life other than those permitted contractually.
Consumed in Operations (CiO)	That portion of produced petroleum consumed as fuel in production or lease plant operations before delivery to the market at the reference point. (Also called lease fuel.)

Contingency	A condition that must be satisfied for a project in Contingent Resources to be reclassified as Reserves. Resolution of contingencies for projects in Development Pending is expected to be achieved within a reasonable time period.
Contingent Project	A project that is not yet commercial owing to one or more contingencies that have not been resolved.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.
Continuous-Type Deposit	A petroleum accumulation that is pervasive throughout a large area and that generally lacks well-defined OWC or GWC. Such accumulations are included in unconventional resources. Examples of such deposits include “basin-centered” gas, tight gas, tight oil, gas hydrates, natural bitumen, and oil shale (kerogen) accumulations.
Conventional Resources	Resources that exist in porous and permeable rock with buoyancy pressure equilibrium. The PIIP is trapped in discrete accumulations related to a localized geological structural feature and/or stratigraphic condition, typically with each accumulation bounded by a down dip contact with an aquifer and is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water.
Cost Recovery	Under a typical production-sharing agreement, the contractor is responsible for the field development and all exploration and development expenses. In return, the contractor recovers costs (investments and operating expenses) out of the production stream. The contractor normally receives an entitlement interest share in the petroleum production and is exposed to both technical and market risks.
Crude Oil	Crude oil is the portion of petroleum that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric conditions of pressure and temperature (excludes retrograde condensate). Crude oil may include small amounts of non-hydrocarbons produced with the liquids but does not include liquids obtained from the processing of natural gas.
Cumulative Production	The sum of petroleum quantities that have been produced at a given date. (See also Production). Production is measured under defined conditions to allow for the computation of both reservoir voidage and sales quantities and for the purpose of voidage also includes non-petroleum quantities.
Current Economic Conditions	Economic conditions based on relevant historical petroleum prices and associated costs averaged over a specified period. The default period is 12 months. However, in the event that a step change has occurred within the previous 12-month period, the use of a shorter period reflecting the step change must be justified and used as the basis of constant-case resources estimates and associated project cash flows.
Defined Conditions	Forecast of conditions to exist and impact the project during the time period being evaluated. Forecasts should account for issues that impact the commerciality, such as economics (e.g., hurdle rates and commodity price); operating and capital costs; and technical, marketing, sales route, legal, environmental, social, and governmental factors.
Deposit	Material laid down by a natural process. In resources evaluations, it identifies an accumulation of hydrocarbons in a reservoir. (See Accumulation.)

Deterministic Incremental Method	An assessment method based on defining discrete parts or segments of the accumulation that reflect high, moderate, and low confidence regarding the estimates of recoverable quantities under the defined development plan.
Deterministic Method	An assessment method based on discrete estimate(s) made based on available geoscience, engineering, and economic data and corresponds to a given level of certainty.
Deterministic Scenario Method	Method where the evaluator provides three deterministic estimates of the quantities to be recovered from the project being applied to the accumulation. Estimates consider the full range of values for each input parameter based on available engineering and geoscience data, but one set is selected that is most appropriate for the corresponding resources confidence category. A single outcome of recoverable quantities is derived for each scenario.
Developed Reserves	Reserves that are expected to be recovered from existing wells and facilities. Developed Reserves may be further sub-classified as Producing or Non- Producing.
Developed Producing Reserves	Developed Reserves that are expected to be recovered from completion intervals that are open and producing at the effective date. Improved recovery reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Developed Reserves that are either shut-in or behind-pipe. (See also Shut-In Resources and Behind-Pipe Reserves.)
Development On Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. A project maturity sub-class of Contingent Resources.
Development Not Viable	A discovered accumulation for which there are contingencies resulting in there being no current plans to develop or to acquire additional data at the time due to limited commercial potential. A project maturity sub-class of Contingent Resources.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. A project maturity sub-class of Contingent Resources.
Development Plan	The design specifications, timing, and cost estimates of the appraisal and development project(s) that are planned in a field or group of fields. The plan will include, but is not limited to, well locations, completion techniques, drilling methods, processing facilities, transportation, regulations, and marketing. The plan is often executed in phases when involving large, complex, sequential recovery and/or extensive areas.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information. This sub-class requires appraisal or study and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity. A project maturity sub-class of Contingent Resources.

Discovered	A petroleum accumulation where one or several exploratory wells through testing, sampling, and/or logging have demonstrated the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In this context, “significant” implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for technical recovery. (See also Known Accumulation.)
Discovered Petroleum Initially-In-Place	Quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production. Discovered PIIP may be subdivided into commercial, sub-commercial, and the portion remaining in the reservoir as Unrecoverable.
Discovered Unrecoverable	Discovered petroleum in-place resources that are evaluated, as of a given date, as not able to be recovered by the commercial and sub-commercial projects envisioned.
Dry Gas	Natural gas remaining after hydrocarbon liquids have been removed before the reference point. It should be recognized that this is a resources assessment definition and not a phase behavior definition. (Also called lean gas.)
Economic	A project is economic when it has a positive undiscounted cumulative cash flow from the effective date of the evaluation, the net revenue exceeds the net cost of operation (i.e., positive cumulative net cash flow at discount rate greater than or equal to zero percent).
Economic Interest	Interest that is possessed when an entity has acquired an interest in the minerals in-place or a license and secures, by any form of legal relationship, revenue derived from the extraction of the mineral to which he must look for a return.
Economic Limit	Defined as the time when the maximum cumulative net cash flow (see Net Entitlement) occurs for a project.
Economically Not Viable Contingent Resources	Those quantities for which development projects are not expected to yield positive cash flows under reasonable forecast conditions. May also be subject to additional unsatisfied contingencies.
Economically Viable Contingent Resources	Those quantities associated with technically feasible projects where cash flows are positive under reasonable forecast conditions but are not Reserves because it does not meet the other commercial criteria
Economically Producible	Refers to the situation where the net revenue from an ongoing producing project exceeds the net expenses attributable to a certain entity’s interest. The ADR costs are excluded from the determination.
Effective Date	Resource estimates of remaining quantities are “as of the given date” (effective date) of the evaluation. The evaluation must take into account all data related to the period before the "as of date.”
Entitlement	That portion of future production (and thus resources) legally accruing to an entity under the terms of the development and production contract or license.
Entity	A legal construct capable of bearing legal rights and obligations. In resources evaluations, this typically refers to the lessee or contractor, which is some form of legal corporation (or consortium of corporations). In a broader sense, an entity can be an organization of any form and may include governments or their agencies.
Established Technology	Methods of recovery or processing that have proved to be successful in commercial applications.

Estimated Ultimate Recovery (EUR)	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities that have been already produced. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.
Evaluation	The geosciences, engineering, and associated studies, including economic analyses, conducted on a petroleum exploration, development, or producing project resulting in estimates of the quantities that can be recovered and sold and the associated cash flow under defined forward conditions. (Also called assessment.)
Evaluator	The person or group of persons responsible for performing an evaluation of a project. These may be employees of the entities that have an economic interest in the project or independent consultants contracted for reviews and audits. In all cases, the entity accepting the evaluation takes responsibility for the results, including its resources and attributed value estimates.
Exploration	Prospecting for undiscovered petroleum using various techniques, such as seismic surveys, geological studies, and exploratory drilling.
Field	In conventional reservoirs, a field is typically an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impermeable rock, laterally by local geologic barriers, or both. The term may be defined differently by individual regulatory authorities. For unconventional reservoirs without hydrodynamic influences, a field is often defined by regulatory or ownership boundaries as necessary.
Final Investment Decision (FID)	Project approval stage when the participating companies have firmly agreed to the project and the required capital funding.
Flare Gas	The total quantity of gas vented and/or burned as part of production and processing operations (but not as fuel).
Flow Test	An operation on a well designed to demonstrate the existence of recoverable petroleum in a reservoir by establishing flow to the surface and/or to provide an indication of the potential productivity of that reservoir (such as a wireline formation test). May also demonstrate the potential of certain completion techniques, particularly in unconventional reservoirs.
Fluid Contacts	The surface or interface in a reservoir separating two regions characterized by predominant differences in fluid saturations. Because of capillary and other phenomena, fluid saturation change is not necessarily abrupt or complete, nor is the surface necessarily horizontal.
Forecast Case	A descriptor applied to a scenario when production and associated cash-flow estimates are based on those conditions (including costs and product price schedules, inflation indexes, and market factors) forecast by the evaluator to reasonably exist throughout the evaluation life (i.e., defined conditions). Inflation or deflation adjustments are made to costs and revenues over the evaluation period.
Gas Balance	In gas production operations involving multiple working interest owners, maintaining a statement of volumes attributed to each, depending on each owner's portion received. Imbalances may occur that must be monitored over time and eventually balanced in accordance with accepted accounting procedures.
Gas Cap Gas	Free natural gas that overlies and is in contact with crude oil in the reservoir. It is a subset of associated gas.

Gas Hydrates	Naturally occurring crystalline substances composed of water and gas, in which a solid water lattice accommodates gas molecules in a cage-like structure or clathrate. At conditions of standard temperature and pressure, one volume of saturated methane hydrate will contain as much as 164 volumes of methane gas. Gas hydrates are included in unconventional resources, but the technology to support commercial maturity has yet to be developed.
Gas/Oil Ratio	Ratio that is calculated using measured natural gas and crude oil volumes at stated conditions. The gas/oil ratio may be the solution gas/oil ratio, Rs ; produced gas/oil ratio, Rp ; or another suitably defined ratio of gas production to oil production.
Geostatistical Methods	A variety of mathematical techniques and processes dealing with the collection, methods, analysis, interpretation, and presentation of large quantities of geoscience and engineering data to (mathematically) describe the variability and uncertainties within any reservoir unit or pool, specifically related here to resources estimates.
High Estimate	With respect to resources categorization, this is considered to be an optimistic estimate of the quantity that will actually be recovered from an accumulation by a project. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.
Hydrates	See Gas Hydrates.
Hydrocarbons	Hydrocarbons are chemical compounds consisting wholly of hydrogen and carbon molecules.
Improved Recovery	The extraction of additional petroleum, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural forces in the reservoir. It includes waterflooding and gas injection for pressure maintenance, secondary processes, tertiary processes, and any other means of supplementing natural reservoir recovery processes. Improved recovery also includes thermal and chemical processes to improve the in-situ mobility of viscous forms of petroleum. (Also called enhanced recovery.)
Injection	The forcing, pumping, or natural flow of substances into a porous and permeable subsurface rock formation. Injected substances can include either gases or liquids.
Justified for Development	A development project that has reasonable forecast commercial conditions at the time of reporting and there are reasonable expectation that all necessary approvals/contracts will be obtained. A project maturity sub-class of Reserves.
Kerogen	The naturally occurring, solid, insoluble organic material that occurs in source rocks and can yield oil upon heating. Kerogen is also defined as the fraction of large chemical aggregates in sedimentary organic matter that is insoluble in solvents (in contrast, the fraction that is soluble in organic solvents is called bitumen). (See also Oil Shales.)
Known Accumulation	An accumulation that has been discovered.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect. A project maturity sub-class of Prospective Resources.

Learning Curve	Demonstrated improvements over time in performance of a repetitive task that results in efficiencies in tasks to be realized and/or in reduced time to perform and ultimately in cost reductions.
Likelihood	Likelihood (the estimated probability or chance) is equal (1- risk). (See Probability and Risk.)
Low/Best/High Estimates	Reflects the range of uncertainty as a reasonable range of estimated potentially recoverable quantities.
Low Estimate	With respect to resources categorization, this is a conservative estimate of the quantity that will actually be recovered from the accumulation by a project. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
Lowest Known Hydrocarbons (LKH)	The deepest documented occurrence of a producible hydrocarbon accumulation as interpreted from well log, flow test, pressure measurement, core data, or other conclusive and reliable evidence.
Market	A consumer or group of consumers of a product that has been obtained through purchase, barter, or contractual terms.
Marketable Quantities	Those quantities of hydrocarbons that are estimated to be producible from petroleum accumulations and that will be consumed by the market. (Also referred to as marketable products.)
Mean	The sum of a set of numerical values divided by the number of values in the set.
Measurement	The process of establishing quantity (volume, mass, or energy content) and quality of petroleum products delivered to a reference point under conditions defined by delivery contract or regulatory authorities.
Mineral Lease	An agreement in which a mineral owner (lessor) grants an entity (lessee) rights. Such rights can include (1) a fee ownership or lease, concession, or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of the lease; (2) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and/or (3) those agreements with foreign governments or authorities under which a reporting entity participates in the operation of the related properties or otherwise serves as producer of the underlying reserves (as opposed to being an independent purchaser, broker, dealer, or importer).
Monte Carlo Simulation	A type of stochastic mathematical simulation that randomly and repeatedly samples input distributions (e.g., reservoir properties) to generate a resulting distribution (e.g., recoverable petroleum quantities).
Multi-Scenario Method	An extension of the deterministic scenario method. In this case, a significant number of discrete deterministic scenarios are developed by the evaluator, with each scenario leading to a single deterministic outcome. Probabilities may be assigned to each discrete input assumption from which the probability of the scenario can be obtained; alternatively, each outcome may be assumed to be equally likely.

Natural Bitumen	The portion of petroleum that exists in the semi-solid or solid phase in natural deposits. In its natural state, it usually contains sulfur, metals, and other non- hydrocarbons. Natural bitumen has a viscosity greater than 10,000 mPa·s (or 10,000 cp) measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural viscous state, it is not normally recoverable at commercial rates through a well and requires the implementation of improved recovery methods such as steam injection. Natural bitumen generally requires upgrading before normal refining.
Natural Gas	Portion of petroleum that exists either in the gaseous phase or is in solution in crude oil in a reservoir, and which is gaseous at atmospheric conditions of pressure and temperature. Natural gas may include some amount of non- hydrocarbons.
Natural Gas Liquids (NGLs)	A mixture of light hydrocarbons that exist in the gaseous phase in the reservoir and are recovered as liquids in gas processing plants. NGLs differ from condensate in two principal respects: (1) NGLs are extracted and recovered in gas plants rather than lease separators or other lease facilities, and (2) NGLs include very light hydrocarbons (ethane, propane, or butanes) as well as the pentanes-plus that are the main constituents of condensates.
Net Entitlement	That portion of future production (and thus resources) legally accruing to an entity under the terms of the development and production contract or license. Under the terms of PSCs, the producers have an entitlement to a portion of the production. This entitlement, often referred to as "net entitlement" or "net economic interest" is estimated using a formula based on the contract terms incorporating costs and profits.
Net Pay	The portion (after applying cutoffs) of the thickness of a reservoir from which petroleum can be produced or extracted. Value is referenced to a true vertical thickness measured.
Net Revenue Interest	An entity's revenue share of petroleum sales after deduction of royalties or share of production owing to others under applicable lease and fiscal terms. (See also Entitlement and Net Entitlement)
Netback Calculation	Term used in the hydrocarbon product price determination at reference point to reflect the revenue of one unit of sales after the costs associated with bringing the product to a market (e.g., transportation and processing) are removed.
Non-Hydrocarbon Gas	Associated gases such as nitrogen, carbon dioxide, hydrogen sulfide, and helium that are present in naturally occurring petroleum accumulations.
Non-Sales	That portion of estimated recoverable or produced quantities that will not be included in sales as contractually defined at the reference point. Non-sales include quantities CiO, flare, and surface losses, and may include non- hydrocarbons.
Oil Sands	Sand deposits highly saturated with natural bitumen. Also called "tar sands." Note that in deposits such as the western Canada oil sands, significant quantities of natural bitumen may be hosted in a range of lithologies, including siltstones and carbonates.
Oil Shales	Shale, siltstone, and marl deposits highly saturated with kerogen. Whether extracted by mining or in-situ processes, the material must be extensively processed to yield a marketable product (synthetic crude oil). (Often called kerogen shale.)

On Production	A project maturity sub-class of Reserves that reflects the operational execution phase of one or multiple development projects with the Reserves currently producing or capable of producing. Includes Developed Producing and Developed Non-Producing Reserves.
Overlift/Underlift	Production entitlements received that vary from contractual terms resulting in overlift or underlift positions. This can occur in annual records because of the necessity for companies to lift their entitlement in parcel sizes to suit the available shipping schedules as agreed upon by the parties. At any given financial year- end, a company may be in overlift or underlift. Based on the production matching the company's accounts, production should be reported in accord with and equal to the liftings actually made by the company during the year and not on the production entitlement for the year.
P1	Denotes Proved Reserves. P1 is equal to 1P.
P2	Denotes Probable Reserves.
P3	Denotes Possible Reserves.
Penetration	The intersection of a wellbore with a reservoir.
Petroleum	Defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbon compounds, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content of petroleum can be greater than 50%.
Petroleum Initially-in-Place (PIIP)	The total quantity of petroleum that is estimated to exist originally in naturally occurring reservoirs, as of a given date. Crude oil in-place, natural gas in-place, and natural bitumen in-place are defined in the same manner.
Pilot Project	A small-scale test or trial operation used to assess technology, including recovery processes, for commercial application in a specific reservoir.
Play	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation to define specific Leads or Prospects. A project maturity sub-class of Prospective Resources.
Pool	An individual and separate accumulation of petroleum in a reservoir within a field.
Possible Reserves	An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. Possible Reserves are those additional reserves that analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.
Primary Recovery	The extraction of petroleum from reservoirs using only the natural energy available in the reservoirs to move fluids through the reservoir rock to other points of recovery.
Probability	The extent to which an event is likely to occur, measured by the ratio of the favorable cases to the whole number of cases possible. PRMS convention is to quote cumulative probability of exceeding or equaling a quantity where P90 is the small estimate and P10 is the large estimate. (See also Uncertainty.)

Probabilistic Method	The method of estimation of resources is called probabilistic when the known geoscience, engineering, and economic data are used to generate a continuous range of estimates and their associated probabilities.
Probable Reserves	An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.
Production	The cumulative quantities of petroleum that have been recovered at a given date. Production can be reported in terms of the sales product specifications, but project evaluation requires that all production quantities (sales and non-sales), as measured to support engineering analyses requiring reservoir voidage calculations, are recognized.
Production Forecast	A forecasted schedule of production over time. For Reserves, the production forecast reflects a specific development scenario under a specific recovery process, a certain number and type of wells and particular facilities and infrastructure. When forecasting Contingent or Prospective Resources, more than one project scope (e.g., wells and facilities) is frequently carried to determine the range of the potential project and its uncertainty together with the associated resources defining the low, best, and high production forecasts. The uncertainty in resources estimates associated with a production forecast is usually quantified by using at least three scenarios or cases of low, best, and high, which lead to the resources classifications of, respectively, 1P, 2P, 3P and 1C, 2C, 3C or 1U,2U and 3U.
Production-Sharing Contract (PSC)	A contract between a contractor and a host government in which the contractor typically bears the risk and costs for exploration, development, and production. In return, if exploration is successful, the contractor is given the opportunity to recover the incurred investment from production, subject to specific limits and terms. Ownership of petroleum in the ground is retained by the host government; however, the contractor normally receives title to the prescribed share of the quantities as they are produced. (Also termed production-sharing agreement (PSA).
Project	A defined activity or set of activities that provides the link between the petroleum accumulation's resources sub-class and the decision-making process, including budget allocation. A project may, for example, constitute the development of a single reservoir or field, an incremental development in a larger producing field, or the integrated development of a group of several fields and associated facilities (e.g. compression) with a common ownership. In general, an individual project will represent a specific maturity level (sub-class) at which a decision is made on whether or not to proceed (i.e., spend money), suspend, or remove. There should be an associated range of estimated recoverable resources for that project. (See also Development Plan.)
Property	A defined portion of the Earth's crust wherein an entity has contractual rights to extract, process, and market specified in-place minerals (including petroleum). In general, defined as an area but may have depth and/or stratigraphic constraints. May also be termed a lease, concession, or license.

Prospect	A project associated with an undrilled potential accumulation that is sufficiently well defined to represent a viable drilling target. A project maturity sub-class of Prospective Resources.
Prospective Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.
Proved Reserves	An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. Proved Reserves are those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term “reasonable certainty” is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.
Pure Service Contract	Agreement between a contractor and a host government that typically covers a defined technical service to be provided or completed during a specific time period. The service company investment is typically limited to the value of equipment, tools, and expenses for personnel used to perform the service. In most cases, the service contractor’s reimbursement is fixed by the contract’s terms with little exposure to either project performance or market factors. No Reserves or Resources can be attributed to these activities.
Qualified Reserves Auditor	A reserves evaluator who (1) has a minimum of ten years of practical experience in petroleum engineering or petroleum production geology, with at least five years of such experience being in responsible charge of the estimation and evaluation of Reserves information; and (2) either (a) has obtained from a college or university of recognized stature a bachelor’s or advanced degree in petroleum engineering, geology, or other discipline of engineering or physical science or (b) has received, and is maintaining in good standing, a registered or certified professional engineer’s license or a registered or certified professional geologist’s license, or the equivalent, from an appropriate governmental authority or professional organization. (see SPE 2007 “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information”)
Qualified Reserves Evaluator	A reserves evaluator who (1) has a minimum of five years of practical experience in petroleum engineering or petroleum production geology, with at least three years of such experience being in the estimation and evaluation of Reserves information; and (2) either (a) has obtained from a college or university of recognized stature a bachelor’s or advanced degree in petroleum engineering, geology, or other discipline of engineering or physical science or (b) has received, and is maintaining in good standing, a registered or certified professional engineer’s license or a registered or certified professional geologist’s license, or the equivalent, from an appropriate governmental authority or professional organization. (modified from SPE 2007 “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information”)
Range of Uncertainty	The range of uncertainty of the in-place, recoverable, and/or potentially recoverable quantities; may be represented by either deterministic estimates or by a probability distribution. (See Resources Categories.)
Raw Production	All components, whether hydrocarbon or other, produced from the well or extracted from the mine (hydrocarbons, water, impurities such as non-hydrocarbon gases, etc.).

Reasonable Certainty	If deterministic methods for estimating recoverable resources quantities are used, then reasonable certainty is intended to express a high degree of confidence that the estimated quantities will be recovered. Typically attributed to Proved Reserves or 1C Resources quantities.
Reasonable Expectation	Indicates a high degree of confidence (low risk of failure) that the project will proceed with commercial development or the referenced event will occur. (Differs from reasonable certainty, which applies to resources quantity technical confidence, while reasonable expectation relates to commercial confidence.).
Recoverable Resources	Those quantities of hydrocarbons that are estimated to be producible by the project from either discovered or undiscovered accumulations.
Recovery Efficiency	A numeric expression of that portion (expressed as a percentage) of in-place quantities of petroleum estimated to be recoverable by specific processes or projects, most often represented as a percentage. It is estimated using the recoverable resources divided by the hydrocarbons initially in-place. It is also referenced to timing; current and ultimate (or estimated ultimate) are descriptors applied to reference the stage of the recovery. (Also called recovery factor.)
Reference Point	A defined location within a petroleum extraction and processing operation where quantities of produced product are measured under defined conditions before custody transfer (or consumption). Also called point of sale, terminal point, or custody transfer point.
Report	The presentation of evaluation results within the entity conducting the assessment. Should not be construed as replacing requirements for public disclosures under guidelines established by regulatory and/or other government agencies.
Reserves	Those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied.
Reservoir	A subsurface rock formation that contains an individual and separate natural accumulation of petroleum that is confined by impermeable barriers, pressure systems, or fluid regimes (conventional reservoirs), or is confined by hydraulic fracture barriers or fluid regimes (unconventional reservoirs).
Resources	Term used to encompass all quantities of petroleum (recoverable and unrecoverable) naturally occurring in an accumulation on or within the Earth's crust, discovered and undiscovered, plus those quantities already produced. Further, it includes all types of petroleum whether currently considered conventional or unconventional. (See Total Petroleum Initially-in-Place.)
Resources Categories	Subdivisions of estimates of resources to be recovered by a project(s) to indicate the associated degrees of uncertainty. Categories reflect uncertainties in the total petroleum remaining within the accumulation (in-place resources), that portion of the in-place petroleum that can be recovered by applying a defined development project or projects, and variations in the conditions that may impact commercial development (e.g., market availability and contractual changes). The resource quantity uncertainty range within a single resources class is reflected by either the 1P, 2P, 3P, Proved, Probable, Possible, or 1C, 2C, 3C or 1U, 2U, 3U resources categories.

Resources Classes	Subdivisions of resources that indicate the relative maturity of the development projects being applied to yield the recoverable quantity estimates. Project maturity may be indicated qualitatively by allocation to classes and sub-classes and/or quantitatively by associating a project's estimated likelihood of commerciality.
Resources Type	Describes the accumulation and is determined by the combination of the type of hydrocarbon and the rock in which it occurs.
Revenue-Sharing Contract	Contracts that are very similar to the PSCs with the exception of contractor payment in these contracts, the contractor usually receives a defined share of revenue rather than a share of the production.
Risk	The probability of loss or failure. Risk is not synonymous with uncertainty. Risk is generally associated with the negative outcome, the term "chance" is preferred for general usage to describe the probability of a discrete event occurring.
Risk and Reward	Risk and reward associated with oil and gas production activities are attributed primarily from the variation in revenues cause by technical and economic risks. The exposure to risk in conjunction with entitlement rights is required to support an entity's resources recognition. Technical risk affects an entity's ability to physically extract and recover hydrocarbons and is usually dependent on a number of technical parameters. Economic risk is a function of the success of a project and is critically dependent on cost, price, and political or other economic factors.
Risk Service Contract (RSC)	Agreements that are very similar to the production-sharing agreements in that the risk is borne by the contractor but the mechanism of contractor payment is different. With a RSC, the contractor usually receives a defined share of revenue rather than a share of the production.
Royalty	A type of entitlement interest in a resource that is free and clear of the costs and expenses of development and production to the royalty interest owner. A royalty is commonly retained by a resources owner (lessor/host) when granting rights to a producer (lessee/contractor) to develop and produce that resource. Depending on the specific terms defining the royalty, the payment obligation may be expressed in monetary terms as a portion of the proceeds of production or as a right to take a portion of production in-kind. The royalty terms may also provide the option to switch between forms of payment at discretion of the royalty owner.
Sales	The quantity of petroleum and any non-hydrocarbon product delivered at the custody transfer point (reference point) with specifications and measurement conditions as defined in the sales contract and/or by regulatory authorities.
Shale Gas	Although the terms shale gas and tight gas are often used interchangeably in public discourse, shale formations are only a subset of all low-permeability tight formations, which include sandstones and carbonates, as well as shales, as sources of tight gas production
Shale Oil	Although the terms shale oil and tight oil are often used interchangeably in public discourse, shale formations are only a subset of all low-permeability tight formations, which include sandstones and carbonates, as well as shales, as sources of tight oil production
Shut-In Resources	Resources planned to be recovered from (1) completion intervals that are open at the time of the estimate, but which have not started producing; (2) wells that were shut-in for market conditions or pipeline connections; or (3) wells not capable of production for mechanical reasons that can be remediated at a limited cost compared to the cost of the well.

Split Classification	A single project should be uniquely assigned to a sub-class along with its uncertainty range, For example, a project cannot have quantities categorized as 1C, 2P, and 3P. This is referred to as "split classification." If there are differing commercial conditions, separate sub-classes should be defined.
Split Conditions	The uncertainty in recoverable quantities is assessed for each project using resources categories. The assumed commercial conditions are associated with resource classes or sub-classes and not with the resources categories. For example, the product price assumptions are those assumed when classifying projects as Reserves, and a different price would not be used for assessing Proved versus Probable reserves. That would be referred to as "split conditions."
Stochastic	Adjective defining a process involving or containing a random variable or variables or involving likelihood or probability, such as a stochastic simulation.
Sub-Commercial	A project subdivision that is applied to discovered resources that occurs if either the technical or commercial maturity conditions of project have not yet been achieved. A project is sub-commercial if the degree of commitment is such that the accumulation is not expected to be developed and placed on production within a reasonable time-frame. Sub-commercial projects are classified as Contingent Resources.
Sunk Cost	Money spent before the effective date and that cannot be recovered by any future action. Sunk costs are not relevant to future business decisions because the cost will be the same regardless of the outcome of the decision. Sunk costs differ from committed (obligated) costs, where there is a firm and binding agreement to spend specified amounts of money at specific times in the future (i.e., after the effective date).
Synthetic Crude Oil	A mixture of hydrocarbons derived by upgrading (i.e., chemically altering) natural bitumen from oil sands, kerogen from oil shales, or processing of other substances such as natural gas or coal. Synthetic crude oil may contain sulfur or other non-hydrocarbon compounds and has many similarities to crude oil.
Taxes	Obligatory contributions to the public funds, levied on persons, property, or income by governmental authority.
Technical Forecast	The forecast of produced resources quantities that is defined by applying only technical limitations (i.e., well-flow-loading conditions, well life, production facility life, flow-limit constraints, facility uptime, and the facility's operating design parameters). Technical limitations do not take into account the application of either an economic or license cut-off. (See also Technically Recoverable Resources).
Technical Uncertainty	Indication of the varying degrees of uncertainty in estimates of recoverable quantities influenced by the range of potential in-place hydrocarbon resources within the reservoir and the range of the recovery efficiency of the recovery project being applied.
Technically Recoverable Resources	Those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial or accessibility considerations.
Technology Under Development	Technology that is currently under active development and that has not been demonstrated to be commercially viable. There should be sufficient direct evidence (e.g., a test project/pilot) to indicate that the technology may reasonably be expected to be available for commercial application.

Tight Gas	Gas that is trapped in pore space and fractures in very low-permeability rocks and/or by adsorption on kerogen, and possibly on clay particles, and is released when a pressure differential develops. It usually requires extensive hydraulic fracturing to facilitate commercial production. Shale gas is a sub-type of tight gas.
Tight Oil	Crude oil that is trapped in pore space in very low-permeability rocks and may be liquid under reservoir conditions or become liquid at surface conditions. Extensive hydraulic fracturing is invariably required to facilitate commercial maturity and economic production. Shale oil is a sub-type of tight oil.
Total Petroleum Initially-in-Place	All estimated quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.
Uncertainty	The range of possible outcomes in a series of estimates. For recoverable resources assessments, the range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities for an individual accumulation or a project. (See also Probability.)
Unconventional Resources	Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and lack well-defined OWC or GWC (also called “continuous-type deposits”). Such resources cannot be recovered using traditional recovery projects owing to fluid viscosity (e.g., oil sands) and/or reservoir permeability (e.g., tight gas/oil/CBM) that impede natural mobility.Moreover, the extracted petroleum may require significant processing before sale (e.g., bitumen upgraders).
Undeveloped Reserves	Those quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling and completing a new well) is required to recomplete an existing well.
Undiscovered Petroleum Initially-in-Place	That quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.
Unrecoverable Resources	Those quantities of discovered or undiscovered PIIP that are assessed, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered owing to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.
Upgrader	A general term applied to processing plants that convert extra-heavy crude oil and natural bitumen into lighter crude and less viscous synthetic crude oil. While the detailed process varies, the underlying concept is to remove carbon through coking or to increase hydrogen by hydrogenation processes using catalysts.
Wet Gas	Natural gas from which no liquids have been removed before the reference point. The wet gas is accounted for in resources assessments, and there is no separate accounting for contained liquids. It should be recognized that this is a resources assessment definition and not a phase behavior definition.
Working Interest	An entity’s equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms.

Appendix 2: Nomenclature

3D	three dimensional
ABEX	abandonment cost
API	American Petroleum Institute
bbl	barrel (42 US gallons)
Bg	gas formation volume factor, in scf/rcf
BH	bottom hole
BHA	bottom hole assembly
Bo	oil formation volume factor, in rb/stb
Bscf	thousands of millions of standard cubic feet
C&P	cased and perforated
CGR	condensate gas ratio
CO_2	carbon dioxide
CoP	cessation of production
COS	geological chance of success
CPI	computer processed interpretation
d	day
DCA	decline curve analysis
DST	drill stem test
Eg	gas expansion factor
ELT	economic limit test
EPF	early production facility
FBHP	flowing bottom hole pressure
FDP	field development plan
FMB	flowing material balance
ft	feet
FTHP	flowing tubing head pressure
FVF	formation volume factor
FWL	free water level
GDT	gas down to
GEF	gas expansion factor
GIIP	gas initially in place
GOC	gas oil contact
GOR	gas oil ratio

GRV	gross rock volume
GSA	gas sales agreement
GWC	gas water contact
H_2S	hydrogen sulphide
HIIP	hydrocarbons initially in place
HLV	Heavy Lift Vessel
ICV	interval control valve
kh	permeability thickness
km	kilometres
Kr	relative permeability
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LTC	long term compression
m	metre
M MM	thousands and millions respectively
MD	measured depth
md or mD	millidarcy
MDRKB	measured depth below Kelly Bushing
MDT	modular dynamic tester
MPC	Maximum Positive Curvature
MSL	mean sea level
mss	metres subsea
N_2	nitrogen
NAG	non-associated gas
Np	cumulative oil production
NPV xx	net present value at xx discount rate
NTG	net to gross ratio
ODT	oil down to
OPEX	operating cost
OWC	oil water contact
P90	low case (probabilistic) estimate (there should be a 90% probability of exceeding this estimate)
P50	mid or best case (probabilistic) estimate (there should be a 50% probability of exceeding this estimate)
P10	high case (probabilistic) estimate (there should be a 10% probability of exceeding this estimate)

Pb	saturation, or bubble point, pressure
PBU	pressure-build-up
Phi	porosity
Phie	effective porosity
Phit	total porosity
PI	productivity index, in stb/d/psi for oil or MMscf/d/psi or Mscf/d/psi for gas
POD	plan of development
PSA	production sharing agreement
PSC	production sharing contract
psi	pressure, measured in pounds per square inch
psia	absolute pressure, measured in pounds per square inch
psig	gauge pressure which is the pressure above atmospheric pressure, measured in pounds per square inch
PSDM	post stack depth migration
PSTM	post stack time migration
PVT	pressure volume temperature experiment
rb	reservoir barrels
RCA	routine core analysis
rcf	cubic feet at reservoir conditions
RFT	repeat formation tester
Rs	solution gas oil ratio
scf	standard cubic feet measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
ss	sub-sea
stb	stock tank barrel (42 US gallons measured at 14.7 pounds per square inch and 60 degrees Fahrenheit)
STOIIP	stock tank oil initially in place
Sw	water saturation
Swc	connate water saturation
TD	total depth
THP	tubing head pressure
TVD	true vertical depth
TVDSS	true vertical depth sub-sea
TWT	two way time
WGR	water gas ratio
WOR	water oil ratio
WUT	water up to