MAKING
COMPLEX
EASY

KEPALA BURUNG PSC AND SALAWATI KEPALA BURUNG PSC, WEST PAPUA, INDONESIA

Independent Resources Evaluation
As of January 1, 2020

ECV2359
Independent Resources Evaluation of the Kepala Burung PSC and Salawati Kepala Burung PSC
West Papua, Indonesia
Rev-1
24 February 2020

rpsgroup.com

Document status

Version	Purpose of document	Authored by	Reviewed by	Approved by	Review date
Rev-1	Final	AT, KR, JT	GT	GT	24/02/20
Rev-0	Final	AT, KR, JT	GT	GT	21/02/20

Approval for issue

Gordon Taylor		24 February 2020

Prepared by:

RPS Energy Consultants Limited

Level 5, Menara Chan
138 Jalan Ampang
50450 Kuala Lumpur, Malaysia

Prepared for:

RH Petrogas Limited

20 Harbour Drive,
PSA Vista #06-03/03A
Singapore 117612

Our ref: **ECV2359**

Goldvale House
27-41 Church Street West
Woking, Surrey GU21 6DH
T +44 1483 746 500

Date: 24 February 2020

RH Petrogas Limited
20 Harbour Drive,
PSA Vista #06-03/03A
Singapore 117612

INDEPENDENT RESOURCES EVALUATION OF THE KEPALA BURUNG PSC AND SALAWATI KEPALA BURUNG PSC WEST PAPUA, INDONESIA AS OF JANUARY 1, 2020

In response to your request, RPS Energy Consultants Limited ("RPS") has completed an independent audit of the Kepala Burung Production Sharing Contract (the "Basin PSC") and Salawati Kepala Burung PSC (the "Island PSC") (each a "PSC" or "Property") in which RH Petrogas Limited ("RH Petrogas" or the "Company") holds a working interest. RH Petrogas' participation in the Basin PSC is through its subsidiaries RHP Salawati Basin BV ("RHPSBBV") with 25.936% working interest and Petrogas (Basin) Ltd ("PBL") with 34.064% working interest, while the Company's participation in the Island PSC is through its subsidiaries RHP Salawati Island BV ("RHPSIBV") with 14.5122% working interest and Petrogas (Island) Ltd ("PIL") with 18.702% working interest. Following the signing of the subscription and shareholders' agreements with PT Citra Wahana Abadi ("CWA") in relation to CWA's share subscription in PBL (the "Basin SSHA") and PIL (the "Island SSHA") in July 2018, the Company's effective working interests in the Basin PSC and Island PSC are now 54.0913% and 29.9702% respectively.

RPS undertook this audit following the signing of a Letter of Engagement dated November 8, 2019.

INTRODUCTION

RH Petrogas is currently the Operator of the Basin PSC, located Onshore West Papua and a non-operating partner in the Island PSC, located Onshore and Offshore West Papua, Indonesia (**Figure 1**). The Basin PSC covers an area of around 872 km^2 and contains 18 producing oil and gas fields. RH Petrogas was the non-operating partner in the Basin PSC from 2010 until December 2015 and has been the Operator since January 1, 2016. Previously, PetroChina International (Bermuda) Limited ("PetroChina") was the Operator of the licence. The Island PSC covers an area of around 1,097 km^2 and contains seven producing oil and gas fields. RH Petrogas entered the Island PSC as a non-operating partner in 2010. The Island PSC is currently operated jointly by PetroChina International (Kepala Burung) Limited and PT Pertamina Hulu Energi Salawati as a joint operating body.

In July 2018, the Company signed a new production sharing contract for each of the Basin PSC ("New Basin PSC") and Island PSC ("Salawati PSC") (each a "PSC" or "Property", and together with the Basin PSC and Island PSC, the "PSCs" or "Properties"). The New Basin PSC covers an enlarged area of around 1,030 km^2 which includes essentially the entire existing acreage of the Basin PSC. The Salawati PSC covers an area of around 1,137 km^2 which includes essentially the entire existing acreage of the Island PSC. Both the New

Basin PSC and Salawati PSC are awarded with a new 20-year period and will come into effect when the current Basin PSC and Island PSC expire in 2020. PBL and PIL will each hold a 70% working interest in the New Basin PSC and Salawati PSC respectively and each will be the operator in their respective blocks, with Pertamina holding the remaining 30% working interest. Following the signing of the Basin SSHA and Island SSHA in July 2018, the Company's effective working interest upon commencement of the New Basin PSC and Salawati PSC will each be 57.8578% (before any local government owned company exercised its right to back in for a 10% working interest to be shared by all contractors in proportion to their working interests).

The current producing horizons of the fields in the Basin PSC lie between 2,000 ft and 6,000 ft subsea, and comprise of three main reservoir targets: the Kais Formation limestones, Textularia II Formation, and "U" marker ("UMK") Formation. For the Island PSC, the current producing horizons of the fields lie between 3,000 ft and 6,000 ft subsea, and comprise one main reservoir target; namely the Kais Formation limestones. In addition to the producing fields, the Island PSC contains three undeveloped discoveries. Further, there remains undiscovered exploration potential within the PSCs which has not been reviewed by RPS.

At the request of the Company, RPS has analysed the performance of the producing fields and made forecasts relating to the estimated Low, Best and High future production, costs, prices and cash flow.

Under the Basin PSC and Island PSC, contractors are entitled to receive in kind an amount of the oil and gas volumes for the recovery of their costs and their share of profits in accordance to the terms of the PSC. Under the New Basin PSC and Salawati PSC, contractors are entitled to a share of total production based on an agreed split.

RPS has estimated the volumes of the Proved Reserves ("1P"), Proved plus Probable Reserves ("2P") and Proved plus Probable plus Possible Reserves ("3P") for the producing fields of the PSC (see Appendix I for glossary). These estimates were based on data and information available up to January 2020. This report is based on production data available up to and including December 31, 2019, and has a Reference Date of January 1, 2020.

RPS has applied its expectation of the long term Brent Oil price at the Reference Date of January 1, 2020, which is based on a forward curve (year 2020 to 2025) and US$70 per barrel flat real (at 2% inflation per annum) thereafter.

On the basis of independent assessment and other technical information made available concerning the Properties, RPS has prepared:

- a PSC Reserves Audit Statement (**Table 1**);
- a Contingent Resources Audit Statement (**Table 2**); and
- a SGX Main Board compliance summary table for the Reserves and Resources (**Table 3**).

Our assessment has an effective reference date of January 1, 2020. This letter and the attached Appendices form the integral parts of the RPS report.

Volumes presented in this report have been estimated using the 2018 Petroleum Resources Management System ('PRMS') sponsored by the SPE/WPC/SEG/AAPG/EAGE/SPEE/SPWLA as the standard for classification and reporting (see **Appendix B**). In accordance with SPE-PRMS, RPS has estimated Net Entitlement Reserves for the Properties. A report has been submitted to RH Petrogas which contains Net Entitlement Reserves. However, RH Petrogas has requested this version of the report be prepared for inclusion in their Annual Report and/or announcements. This version excludes Net Entitlement Reserves as RH Petrogas believes such information may risk revealing certain confidential information on the PSC terms when considered together with other publicly available information.

SUMMARY

The audit was completed in February 2020.

This audit was based on technical data, future development plans and resource estimates that have been provided by RH Petrogas to RPS.

RPS's approach in conducting this study has been to focus on validating the Operator's evaluations in regards to the key discipline areas (reservoir and production engineering). Emphasis was placed on the performance of currently producing wells and on workover and infill activities planned for the Property. The aim was to perform an independent audit that is sufficiently detailed to form a robust estimation of the future production and near-term exploration potential of the PSCs.

The Basin PSC is almost exclusively onshore and contains two separate blocks; namely the Arar Block to the north, and the Walio Block to the south (**Figure 1**). Within these areas there has been considerable oil and gas activity since the early 1970's, during which many wells have been drilled, multiple 2D seismic lines acquired and local 3D surveys shot over some of the 18 producing fields. The majority of the fields produce from the Tertiary age Kais Formation, which is a carbonate sequence that forms a broad shallow marine platform with localised reefal complexes. Other plays are noted and the Operator will focus near term exploration efforts on Pre-Tertiary clastic sequences that form the likely source rock for hydrocarbons, as well as reservoir hydrocarbons in the combination structural and stratigraphic traps.

The Island PSC is located both onshore and offshore and contains four separate blocks; namely the Salawati Ridge Block (onshore) and the Offshore Walio, and Koi Complex and Sele Strait Blocks (**Figure 1**). Within these areas there has been considerable oil and gas activity since the early 1970's, during which many wells have been drilled, multiple 2D seismic lines and local 3D surveys were acquired. The majority of the fields produce from the Tertiary age Kais Formation, which is a carbonate sequence that forms a broad shallow marine platform with localised reefal complexes. Other plays are noted and the Operator will focus near term exploration efforts on Pre-Tertiary clastic sequences that form the likely source rock for hydrocarbons as well as reservoir hydrocarbons in the combination structural and stratigraphic traps

The **Reserves** for the PSCs are based on the declining trends of current field production, and the Operator's future work plans and programmes to increase hydrocarbon production.

The field production forecasts have been used in a cashflow model with the estimated forecasted Capital Expenditures ("Capex") and Operating Expenses ("Opex"). By modelling the fiscal terms of the PSC, the production profiles are truncated where Opex exceeds revenues and/or at the end of the licence period of the respective PSCs. A summary of the Reserves is presented in **Table 1**.

Oil volumes are reported in Millions of stock tank barrels ("MMstb"). All volumes are reported as gross (100%) interest and effective working interest basis and all lie entirely within the permit boundary of the PSCs.

RPS has not undertaken an assessment of the Stock Tank Oil Initially In-Place ("STOIIP") and Gas Initially In-Place ("GIIP") volumes for the producing fields, as assessment of these more mature fields requires a dynamic assessment of the declining oil and gas production. Decline Curve Analysis ("DCA") was conducted on the producing fields using "type wells" devised from historic production to account for planned infill drilling and other activities. RPS has reviewed the historic production record and devised Low, Best and High "type wells" that reflect the range of performance. This, together with the Operator's 2020 Work Plan and Budget ("WP&B") has allowed the construction of oil production forecasts beyond that of the performance of the current wells.

The work programmes, assumptions regarding "type well" performance and ensuing forecasts have been used in a cashflow model with the estimated forecasted Capex and Opex costs.

The **Contingent Resources** are based on our assessment of developments of undeveloped discoveries. The estimated remaining Contingent Oil Resources volumes are reported in **Table 2**. These are presented on a "Gross 100% Licence Interest Basis" and "Effective Working Interest Basis".

The changes in the effective working interest Reserves and Contingent Resources of the Company as of January 1, 2020 in respect of the Basin and Island blocks as compared with the previous evaluation conducted by RPS with an effective date of January 1, 2019 are shown in **Table 3**. The increases in Oil Reserves from the previous update are due mainly to reserve upgrade in producing fields based on latest production data and reclassification from contingent resources due to improved economics. The increases in Gas Reserves from the previous update are due mainly to the extension of existing gas sales from the Basin block to 2030 based on RPS' updated review of Basin block gas resources and gas demand information from existing and potential new buyers. Gas sold from the Basin block has been increasing over the years and is used mainly for the purposes of power generation to satisfy local electricity requirements.

Based on the audit, it is RPS's opinion that the estimates of total remaining recoverable hydrocarbon volumes form a reasonable representation of the future operation of the PSCs. The reported hydrocarbon resources estimates are based on professional judgment and are subject to future revisions, upward or downward, as a result of future planned operations or as additional information become available.

The data set included historical production data together with reports, presentations and financial information pertaining to the contractual and fiscal terms applicable to the assets. In carrying out this review, RPS has relied solely upon this information.

QUALIFICATIONS

RPS is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. Except for the provision of professional services on a fee basis, RPS does not have a commercial arrangement with any other person or company involved in the Property that is the subject of this report.

The lead professionals involved in this work are RPS Employees and hold degrees in geology, geophysics, petroleum engineering and related subjects; and have relevant experience in the practice of geology, geophysics or petroleum engineering.

Mr. Gordon Taylor, Director, Consulting for RPS Energy, has reviewed this report. He holds a B.Sc. Geological Sciences and M.Sc. Geotechnical Engineering from Birmingham University, United Kingdom. Mr. Taylor is a Chartered Geologist and Chartered Engineer with 40 years' experience in the upstream oil and gas sector, working in the UK and internationally. At RPS, Mr. Taylor has been involved in projects ranging from basin-scale exploration through to field development, reserves reporting, valuations and mergers and acquisition ("M&A") advisory, in the North Sea, India, Southeast Asia and other parts of the world including North and South Americas, Africa and the Atlantic Margin. Mr. Taylor is a Fellow of The Geological Society and Chartered Geologist ("C.Geol"), Member and Chartered Engineer ("C.Eng") of the Institute Materials, Minerals & Mining, Member of the American Association of Petroleum Geologists ("AAPG"), Certified Petroleum Geologist ("CPG") of the Professional Affairs Division of the AAPG, and Member of the Society of Petroleum Engineers ("SPE")

The work was undertaken by a team of professional petroleum engineers, geoscientists and economists and is based on data supplied by RH Petrogas. In estimating Reserves, we have used standard petroleum engineering techniques. These techniques combine geological and production data with detailed information concerning fluid characteristics and reservoir pressure. We have estimated the degree of uncertainty inherent in the measurements and interpretation of the data and have calculated a range of Reserves. We have taken the working interest that RH Petrogas has in the Property as presented by RH Petrogas; we have not investigated, nor do we make any warranty, as to RH Petrogas' interest in the PSC.

BASIS OF OPINION

The evaluation presented in this report reflects our informed judgment, based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to the Property. However, RPS is not in a position to attest to the Property title, financial interest relationships or encumbrances related to the Property. Our estimates of Reserves and Resources are based on data provided by RH Petrogas. We have accepted, without independent verification, the accuracy and completeness of these data.

The report represents RPS's best professional judgment and should not be considered a guarantee or prediction of results. It should be understood that any evaluation, particularly one involving future performance and development activities may be subject to significant variations over short periods of time as new information becomes available. This report relates specifically and solely to the subject Property and is conditional upon various assumptions that are described herein. This report must, therefore, be read in its entirety. This report was provided for the sole use of RH Petrogas and its advisors on a fee basis.

RPS has given its written consent to the issue of this document with its name included within it; and with inclusion of the results presented therein and references thereto in submissions by RH Petrogas to the stock exchanges. Prior to the issuance of this report or sections of this report to a third party, RPS requests that we are able to view the said release in order to check its wording and context. Specifically, excerpts may only be reproduced or published (as required for regulated securities reporting purposes) with the express written permission of RPS.

RPS accepts responsibility for the interpretations and professional opinions contained in this report, as set out in this part of this document; and to the best of our knowledge and belief RPS has taken all reasonable care to ensure that such is the case. The information contained in this report is in accordance with the facts and does not omit anything likely to affect the importance of such information.

Yours sincerely,
for RPS Energy Consultants Ltd

Gordon Taylor, CEng, CGeol
Director, Consulting

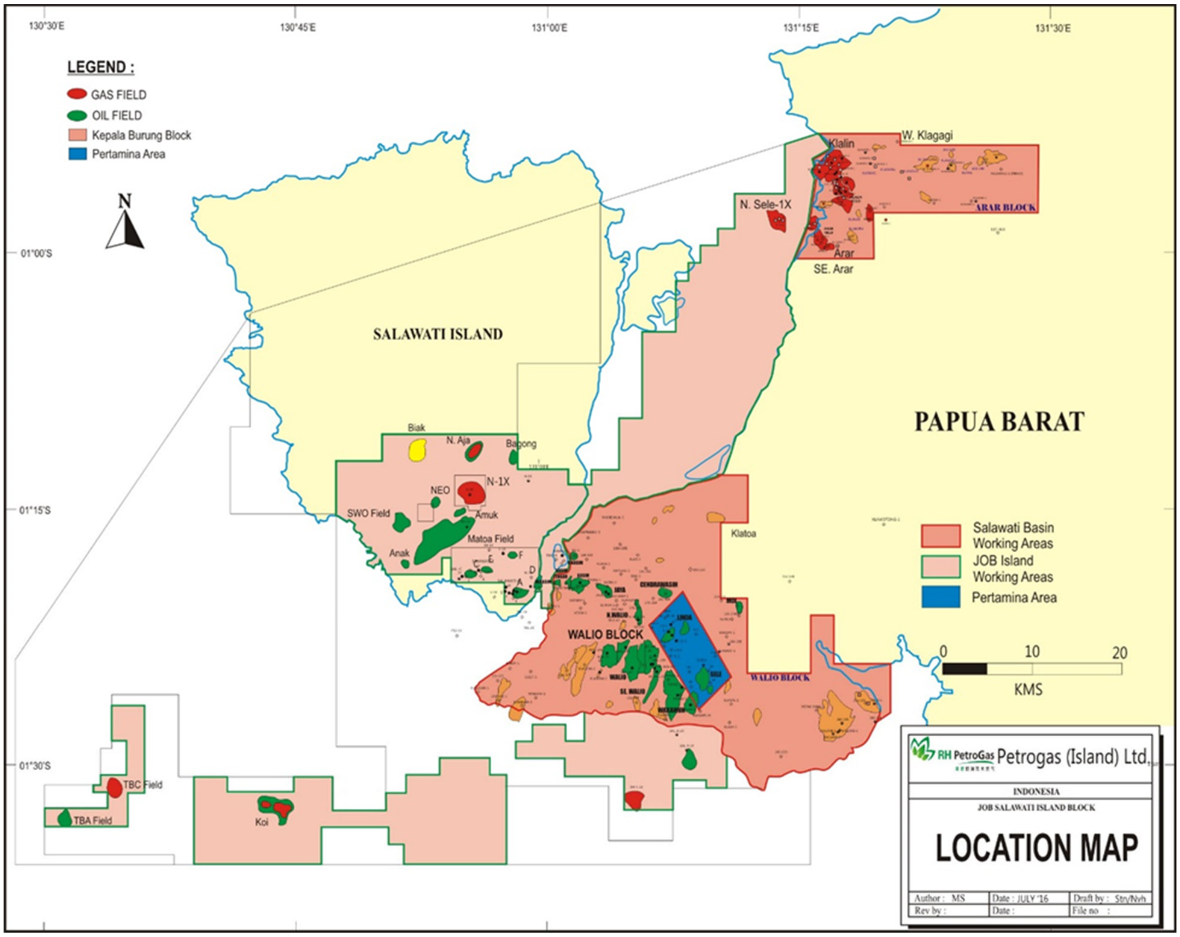

Figure 1: Location of the Basin and Island PSCs, Onshore and Offshore West Papua , Indonesia

Table 1: Combined Oil, Gas and LPG Reserves for the Basin PSC (2020), New Basin PSC (2020-2040), Island PSC (2020) and Salawati PSC (2020-2040)

As of January 1, 2020

	Gross 100% License Basis [1)]			**RH Petrogas's Effective Working Interest Basis [2)]**		
	1P	**2P**	**3P**	**1P**	**2P**	**3P**
Oil Reserves (MMstb) [3)]	39.6	45.5	50.9	22.8	26.2	29.3
Gas Reserves (Bscf) [4)]	35.5	35.5	35.5	20.4	20.4	20.4
LPG Reserves (MT) [5)]	55,869	55,869	55,869	32,171	32,171	32,171

Notes:

1. *All volumes reported below these columns are based on gross (100%) interest as the fields are within the PSCs licence boundary. These volumes include RH Petrogas's and its partner's interests including the Indonesian Government's share.*
2. *The volumes reported under these columns are based on RH Petrogas's effective working interest, which include the Indonesian Government's share under the PSCs.*
3. *Oil Reserves includes Oil Reserves and Condensate Reserves.*
4. *Based on approved sales volumes in WP&B 2020 with similar assumption applied until 2030. Reserves are reported net of inerts and fuel.*
5. *Based on approved sales volumes in WP&B 2020 with similar assumption applied until 2030.*

All Capex and Opex used in the valuation are based on the approved WP&B 2020, as well as RPS in-house estimates.

The Reserves are estimated as of January 1, 2020 until the expiry of the respective PSCs.

The figures presented in this table must be considered only in the context of the comments contained in this report dated February 24, 2020 of which this table forms an integral part.

Table 2: Combined Contingent Oil, Condensate and Gas Resources Attributable to the Basin PSC (2020), New Basin PSC (2020-2040), Island PSC (2020) and Salawati PSC (2020-2040)

As of January 1, 2020

	Gross Contingent Resources 100% License Basis [1)]			RH Petrogas's Effective Working Interest Basis [2)]		
	1C	**2C**	**3C**	**1C**	**2C**	**3C**
Oil and Condensate (MMstb)	33.1	44.5	58.6	19.2	25.8	33.9
Gas (Bscf)	300.4	431.0	619.0	173.6	249.1	357.9

Notes:

1. *All volumes reported below these columns are based on gross (100%) interest as the fields are within the PSCs licence boundary. These volumes include Contractors' and the Indonesian Government's share.*
2. *The volumes reported under these columns are based on RH Petrogas's effective working interest, which include the Indonesian Government's share under the PSCs.*

RPS has estimated a Chance of Commerciality for these Contingent Resources of 70% due to ongoing evaluations of the various projects and the current market conditions.

The volumes presented in this table must be considered only in the context of the comments contained in this report dated February 24, 2020; of which this table forms an integral part.

Table 3: Summary of Combined Oil and Gas Reserves and Resources for the Basin PSC (2020), New Basin PSC (2020-2040), Island PSC (2020) and Salawati PSC (2020-2040)

As of January 1, 2020

Category	Gross Attributable to Licence (MMstb/Bscf)	Net Attributable to Issuer [1] (MMstb/Bscf)	Net Attributable to Issuer [1] Change from Previous Update [2] (%)	Risk Factors [5]	Remarks
RESERVES					
Oil					
1P	39.6	22.8	57% [3]		
2P	45.5	26.2	17% [3]		
3P	50.9	29.3	13% [3]		
Natural Gas					
1P	35.5	20.4	542% [4]		
2P	35.5	20.4	542% [4]		
3P	35.5	20.4	542% [4]		
Natural Gas Liquids					
1P	N/A	N/A	N/A		
2P	N/A	N/A	N/A		
3P	N/A	N/A	N/A		
CONTINGENT RESOURCES					
Oil					
1C	33.1	19.2	-15% [3]	70%	
2C	44.5	25.8	1% [3]	70%	
3C	58.6	33.9	1% [3]	70%	
Natural Gas					
1C	300.4	173.6	6%	70%	
2C	431.0	249.1	1%	70%	
3C	619.0	357.9	2%	70%	
Natural Gas Liquids					
1C	N/A	N/A	N/A		
2C	N/A	N/A	N/A		
3C	N/A	N/A	N/A		

Notes: [1] - Net Attributable to Issuer means the Company's effective working interest share under the respective PSCs. The Company is entitled to a share of these volumes after considering the Indonesian Government's share pursuant to the terms of the PSCs.

[2] - Previous evaluation was conducted by RPS with an effective date of January 1, 2019.

[3] - The increases in Oil Reserves from the previous update are due mainly to reserve upgrade in producing fields based on latest production data and reclassification from contingent resources due to improved economics.

[4] - The increases in Gas Reserves from the previous update are due mainly to the extension of existing gas sales from the Basin block to 2030 based on RPS' updated review of Basin block gas resources and gas demand information from existing and potential new buyers. Gas sold from the Basin block has been increasing over the years and is used mainly for the purposes of power generation to satisfy local electricity requirements.

[5] - Applicable to Resources. "Risk Factor" for Contingent Resources means the estimated chance, or probability, that the volumes will be commercially extracted.

1P: Proved
2P: Proved + Probable
3P: Proved + Probable + Possible
1C: Low Estimate Contingent Resource
2C: Best Estimate Contingent Resource
3C: High Estimate Contingent Resource

MMstb: Millions of Stock Tank Barrels
Bscf: Billions of Standard Cubic Feet

Name of Qualified Person: Gordon Taylor
Date: 24-Feb-20

Professional Society Membership: Fellow, Geological Society, Chartered Geologist (C.Geol)
Member, Institute Materials, Minerals & Mining, Chartered Engineer (C.Eng)

Appendix A
Glossary

1C	The low estimate of Contingent Resources. There is estimated to be a 90% probability that the quantities actually recovered could equal or exceed this estimate
2C	The best estimate of Contingent Resources. There is estimated to be a 50% probability that the quantities actually recovered could equal or exceed this estimate
3C	The high estimate of Contingent Resources. There is estimated to be a 10% probability that the quantities actually recovered could equal or exceed this estimate
1P	The low estimate of Reserves (proved). There is estimated to be a 90% probability that the quantities remaining to be recovered will equal or exceed this estimate
2P	The best estimate of Reserves (proved+probable). There is estimated to be a 50% probability that the quantities remaining to be recovered will equal or exceed this estimate
3P	The high estimate of Reserves (proved+probable+possible). There is estimated to be a 10% probability that the quantities remaining to be recovered will equal or exceed this estimate
1U	The unrisked low estimate of Prospective Resources
2U	The unrisked best estimate of Prospective Resources
3U	The unrisked high estimate of Prospective Resources
AVO	Amplitude versus Offset
B	Billion
bbl(s)	Barrels
bbls/d	Barrels per day
Bcm	Billion cubic metres
B_g	Gas formation volume factor
B_{gi}	Gas formation volume factor (initial)
B_o	Oil formation volume factor
B_{oi}	Oil formation volume factor (initial)
B_w	Water volume factor
boe	Barrels of oil equivalent
stb/d	Barrels of oil per day
BHP	Bottom hole pressure
Bscf	Billions of standard cubic feet
bwpd	Barrels of water per day
condensate	A mixture of hydrocarbons which exist in gaseous phase at reservoir conditions but are produced as a liquid at surface conditions
cP	Centipoise
Eclipse	A reservoir modelling software package
E_{gi}	Gas Expansion Factor
EMV	Expected Monetary Value
EUR	Estimated Ultimate Recovery
FBHP	Flowing bottom hole pressure
FTHP	Flowing tubing head pressure
ft	Feet
FWHP	Flowing well head pressure
FWL	Free Water Level

GDT	Gas Down To
GIIP	Gas Initially in Place
GOC	Gas oil Contact
GOR	Gas/oil ratio
GRV	Gross rock volume
GWC	Gas water contact
IPR	Inflow performance relationship
IRR	Internal rate of return
KB	Kelly Bushing
k_a	Absolute permeability
k_h	Horizontal permeability
km	Kilometres
LPG	Liquefied Petroleum Gases
m	Metres
m^3	Cubic metres
m^3/d	Cubic metres per day
ma	Million years
M	Thousand
M$	Thousand US dollars
MBAL	Material balance software
Mbbls	Thousand barrels
mD	Permeability in millidarcies
MD	Measured depth
MDT	Modular formation dynamics tester tool
MM	Million
MMbbls	Million barrels
MMscf/d	Millions of standard cubic feet per day
MMstb	Million stock tank barrels (at 14.7 psi and 60° F)
MMt	Millions of tonnes
MM$	Million US dollars
MPa	Mega pascals
m/s	Metres per second
msec	Milliseconds
MT	Metric Tonnes
mV	Millivolts
NTG or N:G	Net to gross ratio
NGL	Natural Gas Liquids
NPV	Net Present Value
OWC	Oil water contact
P_{90}	There is estimated to be at least a 90% probability (P_{90}) that this quantity will equal or exceed this low estimate
P_{50}	There is estimated to be at least a 50% probability (P_{50}) that this quantity will equal or exceed this best estimate
P_{10}	There is estimated to be at least a 10% probability (P_{10}) that this quantity will equal or exceed this high estimate
PDR	Physical data room
Petrel	A geoscience and reservoir engineering software package

petroleum	Naturally occurring mixtures of hydrocarbons which are found beneath the Earth's surface in liquid, solid or gaseous form
phi	Porosity
p_i	Initial reservoir pressure
PI	Productivity index
ppm	Parts per million
psi	Pounds per square inch
psia	Pounds per square inch (absolute)
psig	Pounds per square inch (gauge)
p_{wf}	Flowing bottom hole pressure
PSDM	Pre-stack depth migrated seismic data
PSTM	Pre-stack time migrated seismic data
PVT	Pressure volume temperature
rb	Barrel(s) at reservoir conditions
rcf	Reservoir cubic feet
REP™	A Monte Carlo simulation software package
RF	Recovery factor
RFT	Repeat formation tester
RKB	Relative to kelly bushing
rm^3	Reservoir cubic metres
SCADA	Supervisory control and data acquisition
SCAL	Special Core Analysis
scf	Standard cubic feet measured at 14.7 pounds per square inch and 60° F
scf/d	Standard cubic feet per day
scf/stb	Standard cubic feet per stock tank barrel
SGS	Sequential Gaussion Simulation
SIBHP	Shut in bottom hole pressure
SIS	Sequential Indicator Simulation
sm^3	Standard cubic metres
S_o	Oil saturation
S_{oi}	Initial oil saturation
S_{or}	Residual oil saturation
S_{orw}	Residual oil saturation relative to water
sq. km	Square kilometers
stb	Stock tank barrels measured at 14.7 pounds per square inch and 60° F
stb/d	Stock tank barrels per day
STOIIP	Stock tank oil initially in place
S_w	Water saturation
S_{wc}	Vonnate water saturation
$	United States Dollars
t	Tonnes
THP	Tubing head pressure
Tscf	Trillion standard cubic feet
TVDSS	True vertical depth (sub-sea)
TVT	True vertical thickness
TWT	Two-way time
US$	United States Dollar

VDR	Virtual data room
VLP	Vertical lift performance
V_{sh}	Shale volume
VSP	Vertical Seismic Profile
W/m/K	Watts/metre/° K
WC	Water cut
WUT	Water Up To
Z	A measure of the "non-idealness" of gas
ϕ	Porosity
μ	Viscosity
μ_g	Viscosity of gas
μ_o	Viscosity of oil
μ_w	Viscosity of water

Appendix B
Summary of Reporting Guidelines

The following is extracted from the 2018 SPE/WPC/SEG/AAPG/EAGE/SPEE/SPWLA PRMS using the section numbering and spelling from PRMS.

PRMS is a fully integrated system that provides the basis for classification and categorization of all petroleum reserves and resources.

B.1 Basic Principles and Definitions

A classification system of petroleum resources is a fundamental element that provides a common language for communicating both the confidence of a project's resources maturation status and the range of potential outcomes to the various entities. The PRMS provides transparency by requiring the assessment of various criteria that allow for the classification and categorization of a project's resources. The evaluation elements consider the risk of geologic discovery and the technical uncertainties together with a determination of the chance of achieving the commercial maturation status of a petroleum project.

The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. Quantities of petroleum and associated products can be reported in terms of volumes (e.g., barrels or cubic meters), mass (e.g., metric tonnes) or energy (e.g., Btu or Joule). These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

The use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios. The application of PRMS must consider both technical and commercial factors that impact the project's feasibility, its productive life, and its related cash flows.

B.2 Petroleum Reserves Classification Framework

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid state. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content can be greater than 50%.

The term resources as used herein is intended to encompass all quantities of petroleum naturally occurring within the Earth's crust, both discovered and undiscovered (whether recoverable or

unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered as conventional or unconventional resources.

Figure B.1 graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Petroleum.

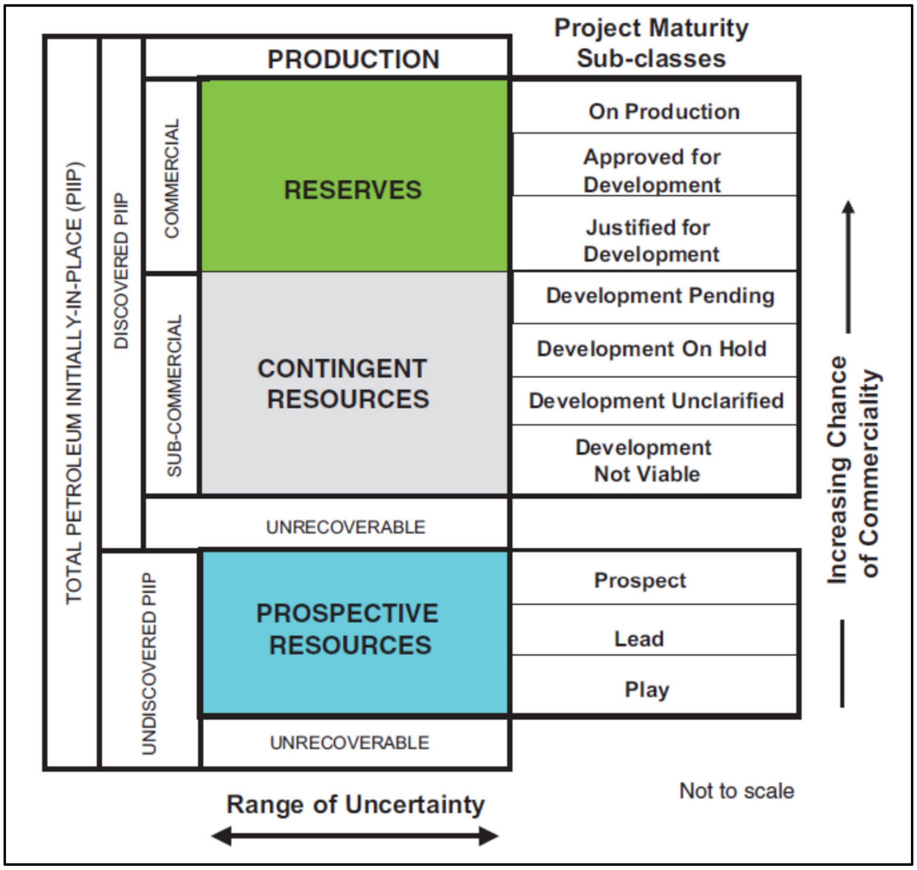

Figure B.1: Resources classification framework

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

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

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

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

- **Production** is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see PRMS 2018 Section 3.2, Production Measurement).

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

- **Reserves** are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied. Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) (see PRMS 2018 Section 3.2.2), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves. Reserves are further categorized in accordance with the range of uncertainty and should be sub- classified based on project maturity and/or characterized by development and production status.

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

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

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

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

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

Other terms used in resource assessments include the following:

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

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

Whenever these terms are used, the conditions associated with their usage must be clearly noted and documented.

B.3 Project Based Resource Evaluations

The resources evaluation process consists of identifying a recovery project or projects associated with one or more petroleum accumulations, estimating the quantities of PIIP, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on maturity status or chance of commerciality.

The concept of a project-based classification system is further clarified by examining the elements contributing to an evaluation of net recoverable resources (see Figure B.2).

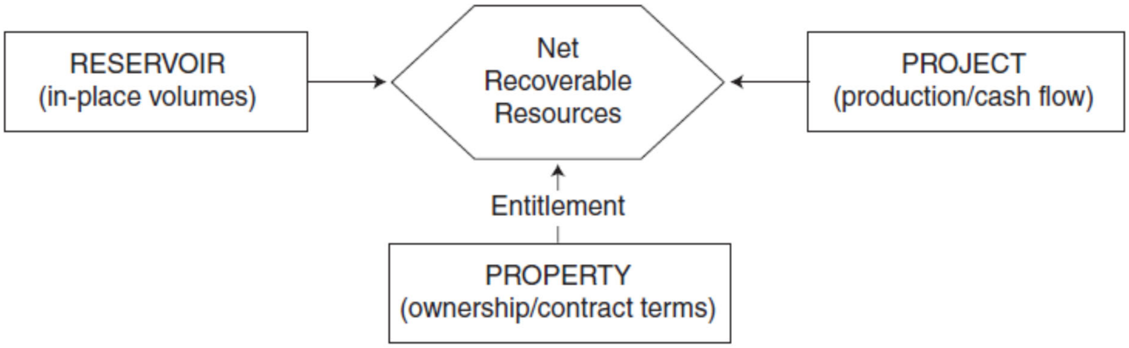

Figure B.2: Resources Evaluation

The reservoir (contains the petroleum accumulation): Key attributes include the types and quantities of PIIP and the fluid and rock properties that affect petroleum recovery.

The project: A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty.

The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

The property (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations that may be spatially unrelated to a potential single field designation.

An entity's net recoverable resources are the entitlement share of future production legally accruing under the terms of the development and production contract or license.

In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See PRMS 2018 Section 2.1.3.5, Project Maturity Sub-Classes) at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project (See PRMS 2018 Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

An accumulation or potential accumulation of petroleum is often subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resources classes simultaneously. When multiple options for development exist early in project maturity, these options should be reflected as competing project alternatives to avoid double counting until decisions further refine the project scope and timing. Once the scope is described and the timing of decisions on future activities established, the decision steps will generally align with the project's classification. To assign recoverable resources of any class, a project's development plan, with detail that supports the resource commercial classification claimed, is needed.

The estimates of recoverable quantities must be stated in terms of the production derived from the potential development program even for Prospective Resources. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be based largely on analogous projects. In-place quantities for which a feasible project cannot be defined using current or reasonably forecast improvements in technology are classified as Unrecoverable.

Not all technically feasible development projects will be commercial. The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see PRMS 2018 Section 3.1, Assessment of Commerciality).

Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions (e.g., inflation, market factors, and contingencies), exchange rates, transportation and processing infrastructure, fiscal terms, and taxes.

The resources being estimated are those quantities producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see PRMS 2018 Section 3.2.1, Reference Point) and may permit forecasts of CiO quantities (see PRMS 2018 Section 3.2.2., Consumed in Operations). The cumulative production forecast from the effective date forward to cessation of production is the remaining recoverable resources quantity (see PRMS 2018 Section 3.1.1, Net Cash-Flow Evaluation).

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

B.4 Project Classification

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

B.4.1 Determination of Discovery Status

A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs (see PRMS 2018 Section 4.1.1, Analogs). In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.

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

B.4.2 Determination of Commerciality

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

1. Evidence of a technically mature, feasible development plan.

2. Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.

3. Evidence to support a reasonable time-frame for development.

4. A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see PRMS 2018 Section 3.1.1, Net Cash-Flow Evaluation).

5. A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, CO_2) can be sold, stored, re-injected, or otherwise appropriately disposed.

6. Evidence that the necessary production and transportation facilities are available or can be made available.

7. Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

8. The commerciality test for Reserves determination is applied to the best estimate (P_{50}) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the 2P Reserves. Stricter cases [e.g., low estimate (P_{90})] may be used for decision purposes or to investigate the range of commerciality (see PRMS 2018 Section 3.1.2, Economic Criteria). Typically, the low- and high-case project scenarios may be evaluated for sensitivities when considering project risk and upside opportunity.

To be included in the Reserves class, a project must be sufficiently defined to establish both its technical and commercial viability as noted in PRMS 2018 Section 2.1.2.1. There must be a reasonable expectation that all required internal and external approvals will be forthcoming and evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where justifiable; for example, development of economic projects that take longer than five years to be developed or are deferred to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

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

B.4.3 Project Status and Chance of Commerciality

Evaluators have the option to establish a more detailed resources classification reporting system that can also provide the basis for portfolio management by subdividing the chance of commerciality axis according to project maturity. Such sub-classes may be characterized qualitatively by the project maturity level descriptions and associated quantitative chance of reaching commercial status and being placed on production.

As a project moves to a higher level of commercial maturity in the classification (see Figure 1.1 vertical axis), there will be an increasing chance that the accumulation will be commercially developed and the project quantities move to Reserves. For Contingent and Prospective Resources, this is further expressed as a chance of commerciality, Pc, which incorporates the following underlying chance component(s):

The chance that the potential accumulation will result in the discovery of a significant quantity of petroleum, which is called the "chance of geologic discovery," Pg.

Once discovered, the chance that the known accumulation will be commercially developed is called the "chance of development," Pd.

There must be a high degree of certainty in the chance of commerciality, Pc, for Reserves to be assigned; for Contingent Resources, Pc = Pd; and for Prospective Resources, Pc is the product of Pg and Pd.

Contingent and Prospective Resources can have different project scopes (e.g., well count, development spacing, and facility size) as development uncertainties and project definition mature.

B.5 Project Maturity Sub-classes

As Figure B-1 illustrates, development projects and associated recoverable quantities may be sub- classified according to project maturity levels and the associated actions (i.e., business decisions) required to move a project toward commercial production.

Maturity terminology and definitions for each project maturity class and sub-class are provided in PRMS 2018 Table I. This approach supports the management of portfolios of opportunities at various stages of exploration, appraisal, and development. Reserve sub-classes must achieve commerciality while Contingent and Prospective Resources sub-classes may be supplemented by associated quantitative estimates of chance of commerciality to mature.

Resources sub-class maturation is based on those actions that progress a project through final approvals to implementation and initiation of production and product sales. The boundaries between different levels of project maturity are frequently referred to as project "decision gates."

Projects that are classified as Reserves must meet the criteria as listed in PRMS 2018 Section 2.1.2, Determination of Commerciality. Projects sub-classified as Justified for Development are agreed upon by the managing entity and partners as commercially viable and have support to advance the project, which includes a firm intent to proceed with development. All participating entities have agreed to the project and there are no known contingencies to the project from any official entity that will have to formally approve the project.

Justified for Development Reserves are reclassified to Approved for Development after a FID has been made. Projects should not remain in the Justified for Development sub-class for extended time periods without positive indications that all required approvals are expected to be obtained without undue delay. If there is no longer the reasonable expectation of project execution (i.e., historical track record of execution, project progress), the project shall be reclassified as Contingent Resources.

Projects classified as Contingent Resources have their sub-classes aligned with the entity's plan to manage its portfolio of projects. Thus, projects on known accumulations that are actively being studied, undergoing feasibility review, and have planned near-term operations (e.g., drilling) are placed in Contingent Resources Development Pending, while those that do not meet this test are placed into either Contingent Resources On Hold, Unclarified, or Not Viable.

Where commercial factors change and there is a significant risk that a project with Reserves will no longer proceed, the project shall be reclassified as Contingent Resources.

For Contingent Resources, evaluators should focus on gathering data and performing analyses to clarify and then mitigate those key conditions or contingencies that prevent commercial development. Note that the

Contingent Resources sub-classes described above and shown in Figure 2.1 are recommended; however, entities are at liberty to introduce additional sub-classes that align with project management goals.

For Prospective Resources, potential accumulations may mature from Play, to Lead and then to Prospect based on the ability to identify potentially commercially viable exploration projects. The Prospective Resources are evaluated according to chance of geologic discovery, Pg, and chance of development, Pd, which together determine the chance of commerciality, Pc. Commercially recoverable quantities under appropriate development projects are then estimated. The decision at each exploration phase is whether to undertake further data acquisition and/or studies designed to move the Play through to a drillable Prospect with a project description range commensurate with the Prospective Resources sub-class.

B.5.1 Reserves Status

Once projects satisfy commercial maturity (criteria given in Table 1), the associated quantities are classified as Reserves. These quantities may be allocated to the following subdivisions based on the

funding and operational status of wells and associated facilities within the reservoir development plan (PRMS 2018 Table 2 provides detailed definitions and guidelines):

- **Developed Reserves** are quantities expected to be recovered from existing wells and facilities.
- **Developed Producing Reserves** are expected to be recovered from completion intervals that are open and producing at the time of the estimate.
- **Developed Non-Producing Reserves** include shut-in and behind-pipe reserves with minor costs to access.
- **Undeveloped Reserves** are quantities expected to be recovered through future significant investments.

The distinction between the “minor costs to access” Developed Non-Producing Reserves and the “significant investment” needed to develop Undeveloped Reserves requires the judgment of the evaluator taking into account the cost environment. A significant investment would be a relatively large expenditure when compared to the cost of drilling and completing a new well. A minor cost would be a lower expenditure when compared to the cost of drilling and completing a new well.

Once a project passes the commercial assessment and achieves Reserves status, it is then included with all other Reserves projects of the same category in the same field for estimating combined future production and applying the economic limit test (see PRMS 2018 Section 3.1, Assessment of Commerciality).

Where Reserves remain Undeveloped beyond a reasonable time-frame or have remained Undeveloped owing to postponements, evaluations should be critically reviewed to document reasons for the delay in initiating development and to justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay (see PRMS 2018 Section 2.1.2, Determination of Commerciality) is justified, a reasonable time-frame to commence the project is generally considered to be less than five years from the initial classification date.

Development and Production status are of significant importance for project portfolio management and financials. The Reserves status concept of Developed and Undeveloped status is based on the funding and operational status of wells and producing facilities within the development project. These status designations are applicable throughout the full range of Reserves uncertainty categories (1P, 2P, and 3P or Proved, Probable, and Possible). Even those projects that are Developed and On Production should have remaining uncertainty in recoverable quantities.

B.5.2 Economic Status

Projects may be further characterized by economic status. All projects classified as Reserves must be commercial under defined conditions (see PRMS 2018 Section 3.1, Assessment of Commerciality Assessment). Based on assumptions regarding future conditions and the impact on ultimate economic viability, projects currently classified as Contingent Resources may be broadly divided into two groups:

- **Economically Viable Contingent Resources** are those quantities associated with technically feasible projects where cash flows are positive under reasonably forecasted conditions but are not Reserves because it does not meet the commercial criteria defined in PRMS 2018 Section 2.1.2.

- **Economically Not Viable Contingent Resources** are those quantities for which development projects are not expected to yield positive cash flows under reasonable forecast conditions.

The best estimate (or P_{50}) production forecast is typically used for the economic evaluation for the commercial assessment of the project. The low case, when used as the primary case for a project decision, may be used to determine project economics. The economic evaluation of the project high case alone is not permitted to be used in the determination of the project's commerciality.

For Reserves, the best estimate production forecast reflects a specific development scenario recovery process, a certain number and type of wells, facilities, and infrastructure.

The project's low-case scenario is tested to ensure it is economic, which is required for Proved Reserves to exist (see PRMS 2018 Section 2.2.2, Category Definitions and Guidelines). It is recommended to evaluate the low case and the high case (which will quantify the 3P Reserves) to convey the project downside risk and upside potential. The project development scenarios may vary in the number and type of wells, facilities, and infrastructure in Contingent Resources, but to recognize Reserves, there must exist the reasonable expectation to develop the project for the best estimate case.

The economic status may be identified independently of, or applied in combination with, project maturity sub-classification to more completely describe the project. Economic status is not the only qualifier that allows defining Contingent or Prospective Resources sub-classes. Within Contingent Resources, applying the project status to decision gates (and/or incorporating them in a plan to execute) more appropriately defines whether the project is placed into the sub-class of either Development Pending versus On Hold, Not Viable, or Unclarified.

Where evaluations are incomplete and it is premature to clearly define the associated cash flows, it is acceptable to note that the project economic status is "undetermined."

B.6 Resources Categorization

The horizontal axis in the resources classification in Figure B.1 defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project or group of projects. These estimates include the uncertainty components as follows:

- The total petroleum remaining within the accumulation (in-place resources).

- The technical uncertainty in the portion of the total petroleum that can be recovered by applying a defined development project or projects (i.e., the technology applied).

- Known variations in the commercial terms that may impact the quantities recovered and sold (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) are part of project's scope and are included in the horizontal axis, while the chance of satisfying the commercial terms is reflected in the classification (vertical axis).

The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P_1), Probable (P_2), Possible (P_3), 1C, 2C, 3C, C1, C2, and C3; or 1U, 2U, and 3U resources categories. The commercial chance of success is associated with resources classes or sub-classes and not with the resources categories reflecting the range of recoverable quantities.

There must be a single set of defined conditions applied for resource categorization. Use of different commercial assumptions for categorizing quantities is referred to as "split conditions" and are not allowed. Frequently, an entity will conduct project evaluation sensitivities to understand potential implications when making project selection decisions. Such sensitivities may be fully aligned to resource categories or may use single parameters, groups of parameters, or variances in the defined conditions.

Moreover, a single project is uniquely assigned to a sub-class along with its uncertainty range. For example, a project cannot have quantities classified in both Contingent Resources and Reserves, for instance as 1C, 2P, and 3P. This is referred to as “split classification.”

B.6.1 Range of Uncertainty

Uncertainty is inherent in a project’s resources estimation and is communicated in PRMS by reporting a range of category outcomes. The range of uncertainty of the recoverable and/or potentially recoverable quantities may be represented by either deterministic scenarios or by a probability distribution (see PRMS 2018 Section 4.2, Resources Assessment Methods).

When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

- There should be at least a 90% probability (P_{90}) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (P_{50}) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P_{10}) that the quantities actually recovered will equal or exceed the high estimate.

In some projects, the range of uncertainty may be limited, and the three scenarios may result in resources estimates that are not significantly different. In these situations, a single value estimate may be appropriate to describe the expected result.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental method, quantities for each confidence segment are estimated discretely (see PRMS 2018 Section 2.2.2, Category Definitions and Guidelines).

Project resources are initially estimated using the above uncertainty range forecasts that incorporate the subsurface elements together with technical constraints related to wells and facilities. The technical forecasts then have additional commercial criteria applied (e.g., economics and license cutoffs are the most common) to estimate the entitlement quantities attributed and the resources classification status: Reserves, Contingent Resources, and Prospective Resources.

While there may be significant chance that sub-commercial and undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable quantities independent of such likelihood when considering what resources class to assign the project quantities.

B.6.2 Category Definitions and Guidelines

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental method, the deterministic scenario (cumulative) method, geostatistical methods, or probabilistic methods (see PRMS 2018 Section 4.2, Resources Assessment Methods). Also, combinations of these methods may be used.

Use of consistent terminology (Figure B.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high forecasts are used to estimate the resulting 1P/2P/3P quantities, respectively. The associated incremental quantities are termed Proved (P_1), Probable (P_2) and Possible (P_3). Reserves are a subset of, and must be viewed within the context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, the criteria can be equally applied to Contingent and Prospective Resources. Upon satisfying the commercial maturity criteria for discovery and/or development, the project quantities will then move to the appropriate resources sub-class. PRMS 2018 Table 3 provides criteria for the Reserves categories determination.

For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.

For Prospective Resources, the general cumulative terms low/best/high estimates also apply and are used to estimate the resulting 1U/2U/3U quantities. No specific terms are defined for incremental quantities within Prospective Resources.

Quantities in different classes and sub-classes cannot be aggregated without considering the varying degrees of technical uncertainty and commercial likelihood involved with the classification(s) and without considering the degree of dependency between them (see PRMS 2018 Section 4.2.1, Aggregating Resources Classes).

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

All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see PRMS 2018 Section 3.1, Assessment of Commerciality).

PRMS 2018 Tables 1, 2, and 3 present category definitions and provide guidelines designed to promote consistency in resources assessments. The following summarize the definitions for each Reserves category in terms of both the deterministic incremental method and the deterministic scenario method, and also provides the criteria if probabilistic methods are applied. For all methods (incremental, scenario, or probabilistic), low, best and high estimate technical forecasts are prepared at an effective date (unless justified otherwise), then tested to validate the commercial criteria, and truncated as applicable for determination of Reserves quantities.

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 known reservoirs and under defined technical and commercial conditions. 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.

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate 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.

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) Reserves, 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. Possible Reserves that are located outside of the 2P area (not upside quantities to the 2P scenario) may exist only when the commercial and technical maturity criteria have been met (that incorporate the Possible development scope). Stand- alone Possible Reserves must reference a commercial 2P project (e.g., a lease adjacent to the commercial project that may be owned by a separate entity), otherwise stand-alone Possible is not permitted.

One, but not the sole, criterion for qualifying discovered resources and to categorize the project's range of its low/best/high or $P_{90}/P_{50}/P_{10}$ estimates to either 1C/2C/3C or 1P/2P/3P is the distance away from known productive area(s) defined by the geoscience confidence in the subsurface.

A conservative (low-case) estimate may be required to support financing. However, for project justification, it is generally the best-estimate Reserves or Resources quantity that passes qualification because it is considered the most realistic assessment of a project's recoverable quantities. The best estimate is generally considered to represent the sum of Proved and Probable estimates (2P) for Reserves, or 2C when Contingent Resources are cited, when aggregating a field, multiple fields, or an entity's resources.

It should be noted that under the deterministic incremental method, discrete estimates are made for each category and should not be aggregated without due consideration of associated confidence. Results from the deterministic scenario, deterministic incremental, geostatistical and probabilistic methods applied to the same project should give comparable results (see PRMS 2018 Section 4.2, Resources Assessment Methods).

If material differences exist between the results of different methods, the evaluator should be prepared to explain these differences.

B.6.3 Incremental Projects

The initial resources assessment is based on application of a defined initial development project, even extending into Prospective Resources. Incremental projects are designed to either increase recovery efficiency, reduce costs, or accelerate production through either maintenance of or changes to wells, completions, or facilities or through infill drilling or by means of improved recovery. Such projects are classified according to the resources classification framework (Figure B.1), with preference for applying project maturity sub-classes (Figure B.1). Related incremental quantities are similarly categorized on the range of uncertainty of recovery. The projected recovery change can be included in Reserves if the degree of commitment is such that the project has achieved commercial maturity (See PRMS 2018 Section 2.1.2, Determination of Commerciality). The quantity of such incremental recovery must be supported by technical evidence to justify the relative confidence in the resources category assigned.

An incremental project must have a defined development plan. A development plan may include projects targeting the entire field (or even multiple, linked fields), reservoirs, or single wells. Each incremental project will have its own planned timing for execution and resource quantities attributed to the project. Development plans may also include appraisal projects that will lead to subsequent project decisions based on appraisal outcomes.

Circumstances when development will be significantly delayed and where it is considered that Reserves are still justified should be clearly documented. If there is no longer the reasonable expectation of project execution (i.e., historical track record of execution, project progress), forecast project incremental recoveries are to be reclassified as Contingent Resources (see PRMS 2018 Section 2.1.2, Determination of Commerciality).

B.6.3.1 Workovers, Treatments and Changes of Equipment

Incremental recovery associated with a future workover, treatment (including hydraulic fracturing stimulation), re-treatment, changes to existing equipment, or other mechanical procedures where such projects have routinely been successful in analogous reservoirs may be classified as Developed Reserves, Undeveloped Reserves, or Contingent Resources, depending on the associated costs required (see PRMS 2018 Section 2.1.3.2, Reserves Status) and the status of the project's commercial maturity elements.

Facilities that are either beyond their operational life, placed out of service, or removed from service cannot be associated with Reserves recognition. When required facilities become unavailable or out of service for longer than a year, it may be necessary to reclassify the Developed Reserves to either Undeveloped Reserves or Contingent Resources. A project that includes facility replacement or restoration of operational usefulness must be identified, commensurate with the resources classification.

B.6.3.2 Compression

Reduction in the backpressure through compression can increase the portion of in-place gas that can be commercially produced and thus included in resources estimates. If the eventual installation of compression meets commercial maturity requirements, the incremental recovery is included in either Undeveloped Reserves or Developed Reserves, depending on the investment on meeting the Developed or Undeveloped classification criteria. However, if the cost to implement compression is not significant, relative to the cost of one new well in the field, or there is reasonable expectation that compression will be implemented by a third party in a common sales line beyond the reference point, the incremental quantities may be classified as Developed Reserves. If compression facilities were not part of the original approved development plan and such costs are significant, it should be treated as a separate project subject to normal project maturity criteria.

B.6.3.3 Infill Drilling

Technical and commercial analyses may support drilling additional producing wells to reduce the wells spacing of the initial development plan, subject to government regulations. Infill drilling may have the combined effect of increasing recovery and acceleration production. Only the incremental recovery (i.e. recovery from infill wells less the recovery difference in earlier wells) can be considered as additional Reserves for the project; this incremental recovery may need to be reallocated.

B.6.3.4 Improved Recovery

Improved recovery is the additional petroleum obtained, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural reservoir energy. It includes secondary recovery (e.g., waterflooding and pressure maintenance), tertiary recovery processes (thermal, miscible gas injection, chemical injection, and other types), and any other means of supplementing natural reservoir recovery processes.

Improved recovery projects must meet the same Reserves technical and commercial maturity criteria as primary recovery projects.

The judgment on commerciality is based on pilot project results within the subject reservoir or by comparison to a reservoir with analogous rock and fluid properties and where a similar established improved recovery project has been successfully applied.

Incremental recoveries through improved recovery methods that have yet to be established through routine, commercially successful applications are included as Reserves only after a favorable production response from the subject reservoir from either (a) a representative pilot or (b) an installed portion of the project, where the response provides support for the analysis on which the project is based. The improved recovery project's resources will remain classified as Contingent Resources Development Pending until the pilot has demonstrated both technical and commercial feasibility and the full project passes the Justified for Development "decision gate."

B.6.3.5 Unconventional Resources

The types of in-place petroleum resources defined as conventional and unconventional may require different evaluation approaches and/or extraction methods. However, the PRMS resources definitions, together with the classification system, apply to all types of petroleum accumulations regardless of the in- place characteristics, extraction method applied, or degree of processing required.

Conventional resources exist in porous and permeable rock with pressure equilibrium. The PIIP is trapped in discrete accumulations related to a local geological structure feature and/or stratigraphic condition. Each conventional accumulation is typically bounded by a down dip contact with an aquifer, as its position is controlled by hydrodynamic interactions between buoyancy of petroleum in water versus capillary force. The petroleum is recovered through wellbores and typically requires minimal processing before sale.

Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and are not significantly affected by hydrodynamic influences (also called "continuous-type deposit"). Usually there is not an obvious structural or stratigraphic trap. Examples include coalbed methane (CBM), basin-centered gas (low permeability), tight gas and tight oil (low permeability), gas hydrates, natural bitumen (very high viscosity oil), and oil shale (kerogen) deposits. Note that shale gas and shale oil are sub-types of tight gas and tight oil where the lithologies are predominantly shales or siltstones. These accumulations lack the porosity and permeability of conventional reservoirs required to flow without stimulation at economic rates. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, hydraulic fracturing stimulation for tight gas and tight oil, steam and/or solvents to mobilize natural bitumen for in-situ recovery, and in some cases, surface mining of oil sands). Moreover, the extracted petroleum may require significant processing before sale (e.g., bitumen upgraders).

For unconventional petroleum accumulations, reliance on continuous water contacts and pressure gradient analysis to interpret the extent of recoverable petroleum is not possible. Thus, there is typically a need for increased spatial sampling density to define uncertainty of in-place quantities, variations in reservoir and hydrocarbon quality, and to support design of specialized mining or in-situ extraction programs. In addition, unconventional resources typically require different evaluation techniques than conventional resources.

Extrapolation of reservoir presence or productivity beyond a control point within a resources accumulation must not be assumed unless there is technical evidence to support it. Therefore, extrapolation beyond the immediate vicinity of a control point should be limited unless there is clear engineering and/or geoscience evidence to show otherwise.

The extent of the discovery within a pervasive accumulation is based on the evaluator's reasonable confidence based on distances from existing experience, otherwise quantities remain as undiscovered. Where log and core data and nearby producing analogs provide evidence of potential economic viability, a successful well test may not be required to assign Contingent Resources. Pilot projects may be needed to define Reserves, which requires further evaluation of technical and commercial viability.

A fundamental characteristic of engagement in a repetitive task is that it may improve performance over time. Attempts to quantify this improvement gave rise to the concept of the manufacturing progress function commonly called the "learning curve." The learning curve is characterized by a decrease in time and/or costs, usually in the early stages of a project when processes are being optimized. At that time, each new improvement may be significant. As the project matures, further improvements in time or cost savings are typically less substantial. In oil and gas developments with high well counts and a continuous program of activity (multi-year), the use of a learning curve within a resources evaluation may be justified to predict improvements in either the time taken to carry out the activity, the cost to do so, or both. While each development project is unique, review of analogs can provide guidance on such predictions and the range of associated uncertainty in the resulting recoverable resources estimates (see also Section 3.1.2 Economic Criteria).

Source: Petroleum Resources Management System (revised June 2018), Version 1.01, Society of Petroleum Engineers