Independent Technical Report (ITR)

Project: Cory Moruga block and resource potential of the Snowcap Discovery, Trinidad

On behalf of

Predator Oil & Gas Holdings PLC

11th January, 2024

Author: Dr Timothy Wright FGS, FSEG and MIMMM

Scorpion Geoscience Ltd

201 The Darwin Rooms

1 Worcester Road, Great Malvern WR14 4QY

United Kingdom, Company Reg: 12638818

T: +44(0)7890399512 | E: timw@scorpiongeoscience.co.uk

Contents

Table of Figures

Reference Tables

Disclaimer

This report, including any enclosures and attachments, has been prepared for the exclusive use and benefit of the addressee(s) and solely for the purpose for which it is provided which is to provide an independent technical assessment of the Cory Moruga Licence and Snowcap Discovery based on relevant proprietary and published data. This report and all opinions expressed herein are subject to the terms of the Master Service Agreement between Predator Oil and Gas PLC and Scorpion Geoscience Limited. No part of this report should be reproduced, distributed or communicated to any third party without prior consent. No liability will be accepted for the outcomes of any investments or operational activities resulting from recommendations or opinions expressed in this report. Scorpion Geoscience does not accept any liability if this report is used for an alternative purpose from which it is intended, nor to any third party in respect of this report.

Overview of resources

Status: Production Licence

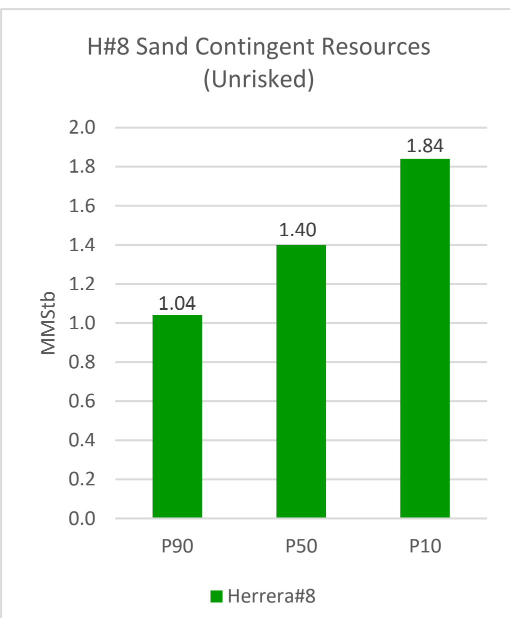
Herrera #8 Sand Contingent Resources

Net 83.8% to PRD

Workovers Snowcap-1 and 2ST1 wells

Applying wax treatment and

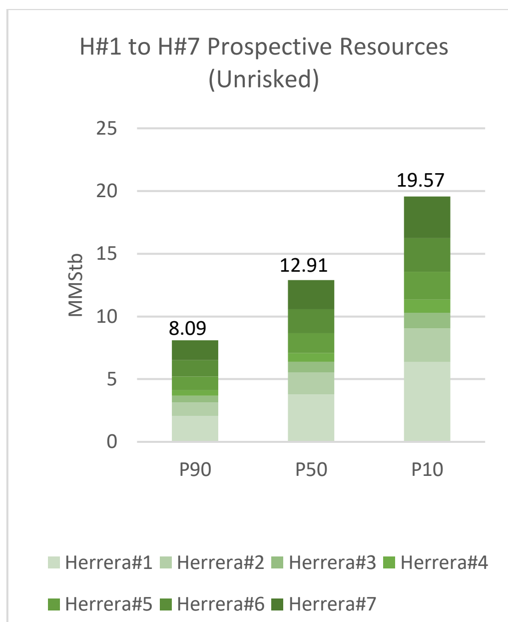
Sand jet perforating technology



Herrera #1-7 Sands Prospective Resources

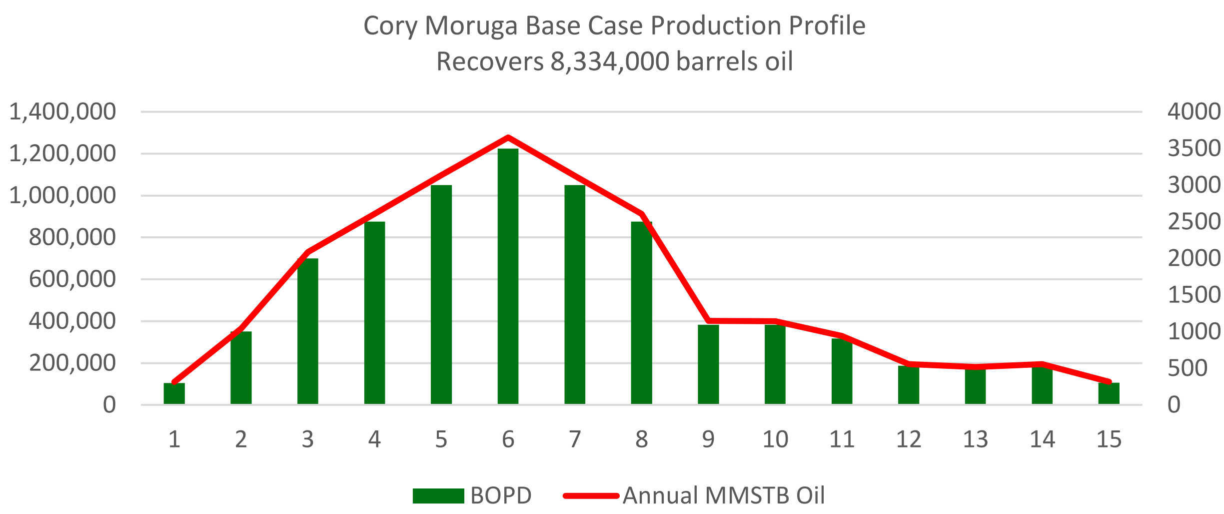
Net 83.8% to PRD

Snowcap-3 appraisal/development well



Base Case 15-Year Production Profile being considered for Snowcap Development

Using 58.2% of P50 Contingent and Prospective Resources



Undiscounted Gross Revenues Forecast

Workover of Snowcap-1 and 2ST1 wells Contingent Resources

	30th Jun 24	31st Jul 24	31st Aug 24	30th Sep 24	31st Oct 24	30th Nov 24	31st Dec 24	31st Jan 25	28th Feb 25	31st Mar 25	30th Apr 25	31st May 25
Net profit £ (100%)	308,339	299,579	290,819	282,059	273,299	264,539	255,739	246,001	236,263	226,525	216,787	207,524

Snowcap-3 appraisal/development well Prospective Resources – First 8 months from start-up

	30th Jun 24	31st Jul 24	31st Aug 24	30th Sep 24	31st Oct 24	30th Nov 24	31st Dec 24	31st Jan 25	28th Feb 25	31st Mar 25	30th Apr 25	31st May 25
Net profit £ (100%)					729,510	707,930	686,350	664,770	643,190	621,610	600,030	578,450

Company's Base Case project economic model gives following economic indicators

WTI spot price (flat)	US$76/bo
Undiscounted operating profit (100%)	US$202.12 million
NPV @10%	US$ 85.14 million
IRR 240.9%	

Executive Summary

Scorpion Geoscience Limited acting as a Qualified Reserves Evaluator has been contracted by Predator Oil & Gas PLC (LSE Standard List: PRD) to provide an independent assessment of exploration and development potential associated with the Cory Moruga exploration and production licence situated onshore in southern Trinidad which hosts the *Snowcap Discovery* drilled by Parex Resources Inc. in 2011. PRD holds an 83.8% interest in the Cory Moruga licence following acquisition of T-Rex Resources (Trinidad) and the Cory Moruga asset from Challenger Energy Group (AIM: CEG) in November 2023. T-Rex resources remain the Trinidadian Ministry of Energy and Energy Industries (MEEI) approved operator of a new Joint Venture operating committee with a 16.2% non-operating participating interest held by Touchstone Exploration.

- Snowcap is a virgin undeveloped oil field onshore Trinidad granted to PRD by MEEI in the form of a production licence and is an asset that does not involve Heritage. In contrast to many Trinidadian mature onshore partially depleted oil fields, Cory Moruga can be developed using modern drilling technology and practices and sand jet perforating technology using the wealth of geological and production data from offset fields to increase development and production efficiency.
- T-Rex has substantial tax losses to offset against Petroleum Profit Taxes (PPT)
- Unique opportunity onshore Trinidad to create a potentially high-value asset from primary production but with the added advantage of potential future upside through enhanced secondary recovery and deeper drilling.
- Accelerated 3-year work programme to de-risk Prospective Resources identified in existing wells on the licence including well re-entries, workovers and new drilling to initiate production and cashflow
- An appraisal well "Snowcap-3" is planned in the near-term by PRD intended to prove up the P90 resources case with an NPV @10% discount of £67 Million or 12 pence per share based on £159 million undiscounted post-tax profits for the Base Case of approximately 8.33MMbbl recoverable using a 15 year production profile peaking at 3,500bopd which equates to c. 58.2% of available 2C + P50 (Unrisked) Prospective Resources.
- Cory Moruga asset sets PRD apart from other listed onshore operators in terms of near term growth potential.

Table 1 Summary of unrisked Prospective and Contingent Resources for the Snowcap structure

		Unrisked Prospective Resources							Contingent Resources
		Herrera #1	Herrera #2	Herrera #3	Herrera #4	Herrera #5	Herrera #6	Herrera #7	Herrera #8
Total Petroleum in place (PIIP) MMSTB	P90	9.01	4.59	2.35	1.83	4.73	5.65	6.87	4.57
	P50	15.97	7.54	3.62	2.97	6.75	8.08	9.97	5.94
	P10	26.83	11.23	5.09	4.40	9.20	11.21	13.75	7.54
Recoverable Oil Resources MMSTB	P90	**2.08 1U**	**1.07 1U**	**0.54 1U**	**0.42 1U**	**1.09 1U**	**1.31 1U**	**1.58 1U**	**1.04 1C**
	P50	**3.77 2U**	**1.77 2U**	**0.85 2U**	**0.69 2U**	**1.58 2U**	**1.91 2U**	**2.34 2U**	**1.40 2C**
	P10	**6.37 3U**	**2.68 3U**	**1.24 3U**	**1.04 3U**	**2.22 3U**	**2.70 3U**	**3.32 3U**	**1.84 3C**

Cory Moruga represents a rare opportunity to explore and produce hydrocarbons from an existing discovered but undeveloped accumulation in a low-cost onshore operating environment in the Southern Basin of Trinidad. The undeveloped Snowcap discovery is located immediately north of the mature Moruga West field, developed and produced by BP over many years, in a separate thrust structure at the proven Miocene aged Herrera sands reservoir level. Oil has been produced on short-term test from several different sand levels in three wells associated with the Snowcap structure: Snowap-1 (2011), Snowcap-2ST1 (2019) and Rochard-1 (1955) which is now thought to be drilled on the western periphery of the Snowcap structure based on new 3D seismic mapping. The Herrera #8 sand "H#8" tested in Snowcap-1 is judged on a fair and reasonable basis to represent a *known accumulation* with other stacked sands (H#1-H#7) requiring additional appraisal and testing to confirm the extent of producible hydrocarbons. Scorpion Geoscience note potential for stacked low resistivity missed pay intervals in existing wells on the block e.g. RD-6, RD-7 and Green Hermit-1 which through the use of sand jet perforation technology provide an opportunity to add significant future project value with substantial efficiency savings compared with conventional perforation and testing methods.

Preliminary independent resource estimations undertaken by Scorpion Geoscience indicate existing PRMS equivalent Best Estimate 2C recoverable oil resources in the single uppermost tested Herrera #8 sand to be in the region of 1.42 MMSTB of light sweet crude with c. 0.99 BCF associated solution gas from a best estimate petroleum initially in place (PIIP) of 5.94 MMSTB. Best Estimate (PRMS 2U) of 12.9 MMSTB and 9.04 BCF associated gas at a measured GOR of 700 scf/STB are classified as Unrisked Prospective Resources from an Unrisked Best Estimate PIIP of 54.9 MMSTB assigned to the remaining stacked Herrera sequence in the remapped Snowcap structure. A risked addition has been applied to the H#1-H#7 stack resulting in combined risked PMEAN PIIP of 21.8 MMSTB yielding a risked PMEAN recoverable prospective resource volume of 5.16 MMSTB with 3.6 BCF associated gas. Wells drilled in the neighbouring Moruga West field have produced up to 455,000 bbls per well using mostly non-optimised pumping demonstrating excellent producibility which can be further enhanced using gas injection and modern completion technologies.

PRD is in the process of outlining a three year accelerated work programme, assessing appraisal and development options for the Snowcap discovery including opportunities to survey and re-enter existing boreholes to re-establish near term production. Plans are also progressing towards drilling of a Snowcap-3 well to further explore and appraise Miocene oil production potential in preferential zones and underexplored levels within the Miocene Herrera turbiditic reservoir sands on the Cory Moruga licence.

1. Introduction

This Independent Technical Report (ITR) seeks to provide a broad summary of the Cory Moruga asset and geological setting in which the Snowcap discovery is located (e.g. Figure 1). The report is designed for technical and non-technical readers wishing to gain knowledge of the Cory Moruga asset including potential strategies being applied by PRD to quantify discovered Contingent Resources and Prospective Resources. Reviews of the seismic and well database pertinent to this ITR are provided. Key aspects of the petroleum system are summarised and geological, geophysical and petrophysical inputs are outlined with explanations of the methods used to determine preliminary resource estimations and determine potential exploration and development activities necessary to convert Contingent and Prospective Resources into formally recognised reserves.

Summaries of informal volumetric estimation outputs and geological risk analysis are provided based on industry standard probabilistic methods. Explanations and methodologies used to define volumetric input parameters are discussed in context of data sources and consideration is given to the accuracy and precision of the available database. All preliminary resource estimation quoted in this document are assigned using PRMS 2018 guidelines based on a fair and reasonable assessment of the available database provided by PRD and supplemented from published literature and online sources. All resource estimations are made in context of uncertainties and risks regarding the subsurface and prevailing market conditions which are duly acknowledged.

Trinidad and Tobago has been involved in the petroleum sector for over 150 years undertaking considerable hydrocarbon exploration activity on land and in shallow water with cumulative production totalling over four billion barrels of oil to 2020 (SLR 2020). Trinidad is the largest hydrocarbon producer in the Caribbean and has a long history of commercial exploration and production onshore dating back to the Aripero discovery well of 1866. With 11 ammonia plants and seven methanol plants, Trinidad and Tobago is one of the world's largest exporters of ammonia and methanol. The market for oil in Trinidad remains strong and stable based on robust local refining capacity and export infrastructure. According to the MEEI, the energy sector continues to be integral to the long-term economic growth and development of the country contributing significantly to Government revenue, export earnings and GDP

The 30km² (7,422 acre) Cory Moruga licence block and Snowcap discovery are situated in the Southern Basin of the southern coastal region of Trinidad close to the main oil pipeline shown in Figure 1 facilitating efficient c.1km tie-in to the Moruga west spur. Road access is generally excellent, and a strong precedent is set for exploration and development activities including seismic acquisition and drilling. The nearest producing accumulations are Heritage's Moruga West ("MW") and Inniss Trinity. For context of the potential scale and commercial potential of the Snowcap accumulation, Moruga West (1957) produced 12.2 MMSTB from an estimated PIIP of 68 MMSTB giving an overall c.18% recovery up to the latest published data point which can reasonably be expected to continue increasing as a result of ongoing production. Inniss-Trinity (1956) has an estimated PIIP ranging 68 MMSTB-150 MMSTB of 32.5°API oil based on assessments published by Texaco 1973 and Gaffney Cline 2011. The mapped closure area of 3.27km² (810 acres) has yielded in the region of 22.9 MMSTB attributed to the Miocene Herrera Turbiditic Sands to 2016 (SLR CPR Jan 2020). Through the use of modern production techniques, recovery factors are capable of being extended >30% and up to 38% in the case of individual compartments in Moruga West. However, for the purposes of this assessment a cautious and conservative approach is taken until such time more data is gathered on the Snowcap reservoirs.

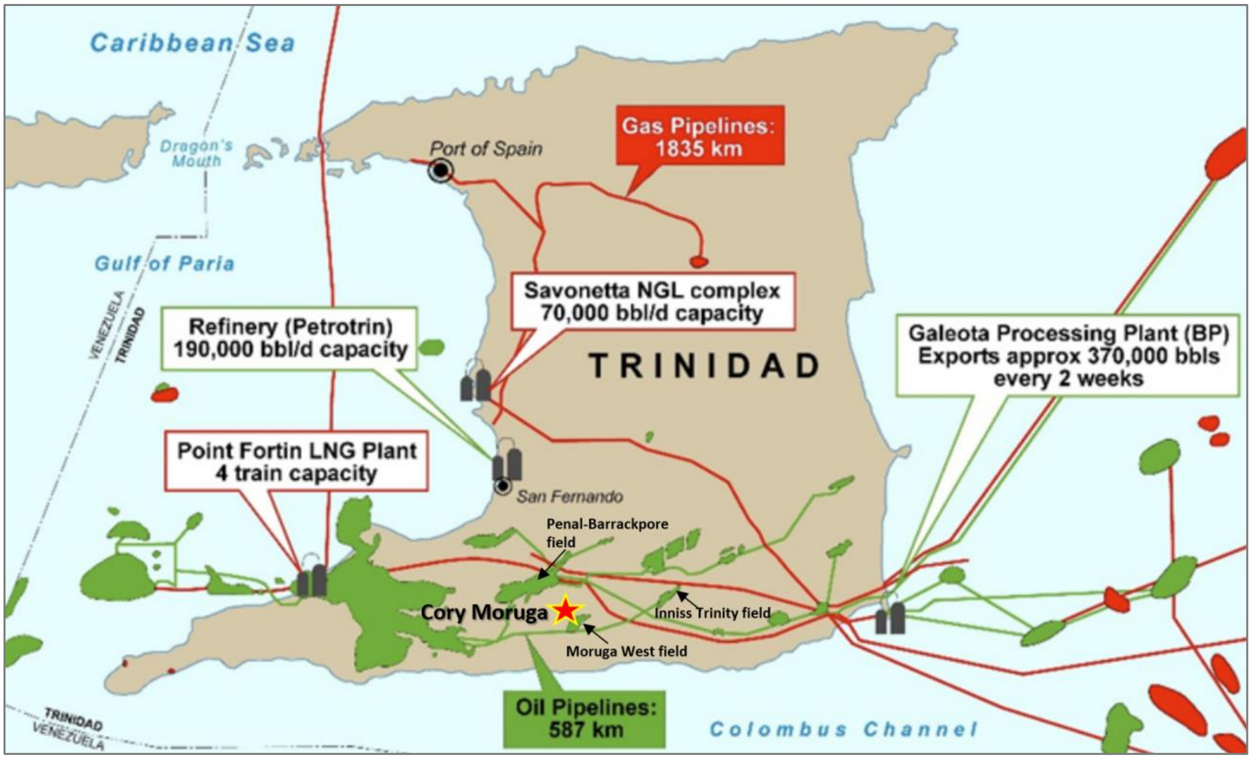


Figure 1 Map showing the study area of interest in relation to Trinidad and existing hydrocarbon discoveries (MEEI).

2. Cory Moruga Technical Database

PRD have made available an extensive database comprising well reports, seismic data and technical reports relevant to the Cory Moruga licence (See Appendix B Tables 1-3). Additional data have been sourced as part of the ITR compilation process including block outlines, infrastructure maps and other geographical shape files pertinent to the assessment. A review of published literature has been undertaken to establish the fundamentals of the geological setting and petroleum system. Whilst no new laboratory or field work has been undertaken, a thorough review of relevant documentation concerning well test and engineering data together with new geophysical interpretation has been undertaken to establish and validate the technical conclusions presented. All conclusions, forward statements and opinions presented have been developed based on the available database and should be viewed as forward-looking statements for the purposes of investment decisions in line with the Disclaimer at the front of this document and those disclaimers made available on **www.predator-oil and-gas.com**.

A number of key wells shown in Figure 2 and listed in Appendix B Table 2 have been analysed. Logging suites are noted to be incomplete, missing resistivity or modern log suite data due to tool availability (e.g. RD-1) and operational issues including hole integrity at SC-2ST1, therefore analysis has been completed using available logs and results from RD-1 and SC-2ST1 with oil volumes in H#1-H#7 sands discounted from contributing to discovered contingent resource classification until such time additional downhole data can be obtained. RD-6 and RD-7 are on the Cory Moruga Block and are reported as testing and producing oil from what are re-interpreted to be H#2 sands. Green Hermit-1 is also identified as having potential pay in H#1 sands. Additional wells which are in the Cory Moruga block or off block considered relevant for the ITR include Firecrown-1 & 2, Jacobin-1 (old well), Marac-1 & 2, CoryBros-1, -2 & -3 and a suite of eight

Rochard Douglas wells RD-2 to RD-10X for which a mixture of unverified surface locations, electric logs, TD and deviation surveys have been taken into account.

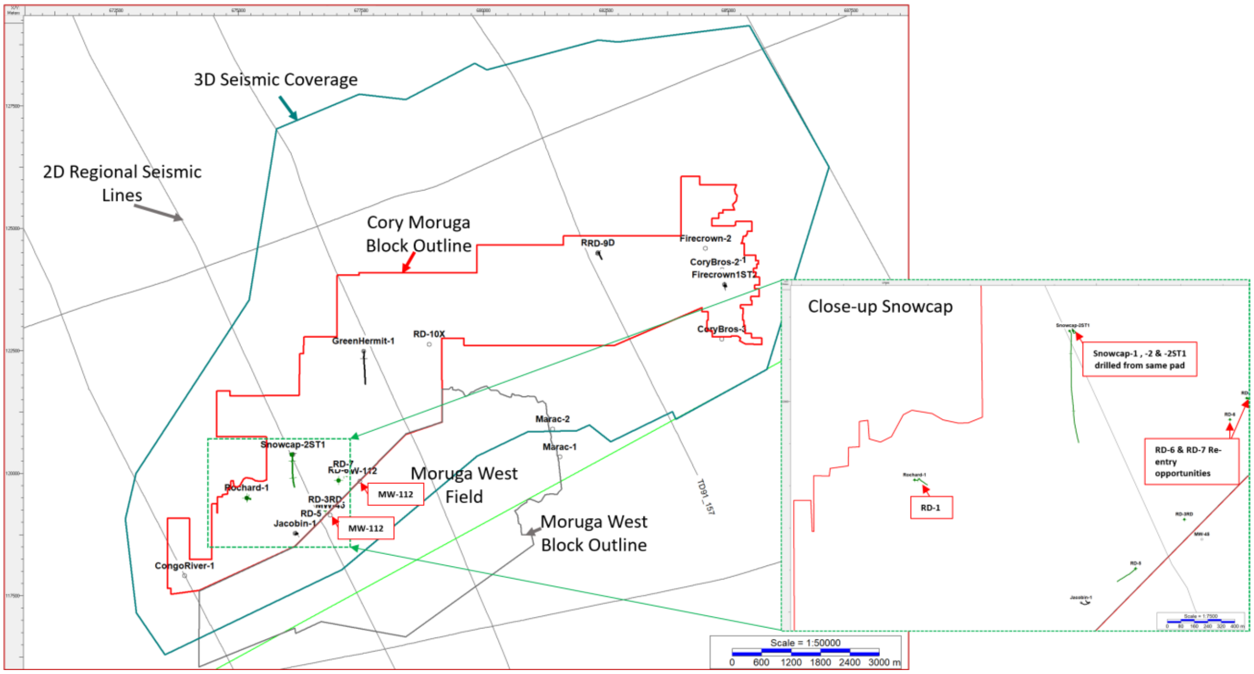


Figure 2 Map produced from S&P Global Kingdom® seismic and well interpretation suite based on key database items interpreted by Scorpion Geoscience as part of this ITR showing the Cory Moruga block and key wells, seismic database and nearby field at Moruga West. Inset shows the relative positions of SC-1, SC-2ST1 and Rochard-1 (RD-1).

3. Tectono-stratigraphic Framework and Petroleum System

The Cory Moruga Block and Snowcap discovery are situated in the Southern Basin of Trinidad (Figure 3). The Trinidadian petroleum system comprises multiple often stacked accumulations in multi-layered clastic reservoirs which formed in response to rapid uplift and marine turbidite sedimentation during the Oligo-Miocene. More recently, movements in the Caribbean plate which began in the Middle Miocene and peaked during the late Pleistocene-Holocene formed a series of imbricated thrust sheets which provides the principal trapping mechanism in the Southern Basin fields and are responsible for hosting the Snowcap discovery and nearby Moruga West, Inniss-Trinity and Barrackpore-Penal accumulations e.g. Bitterli 1958.

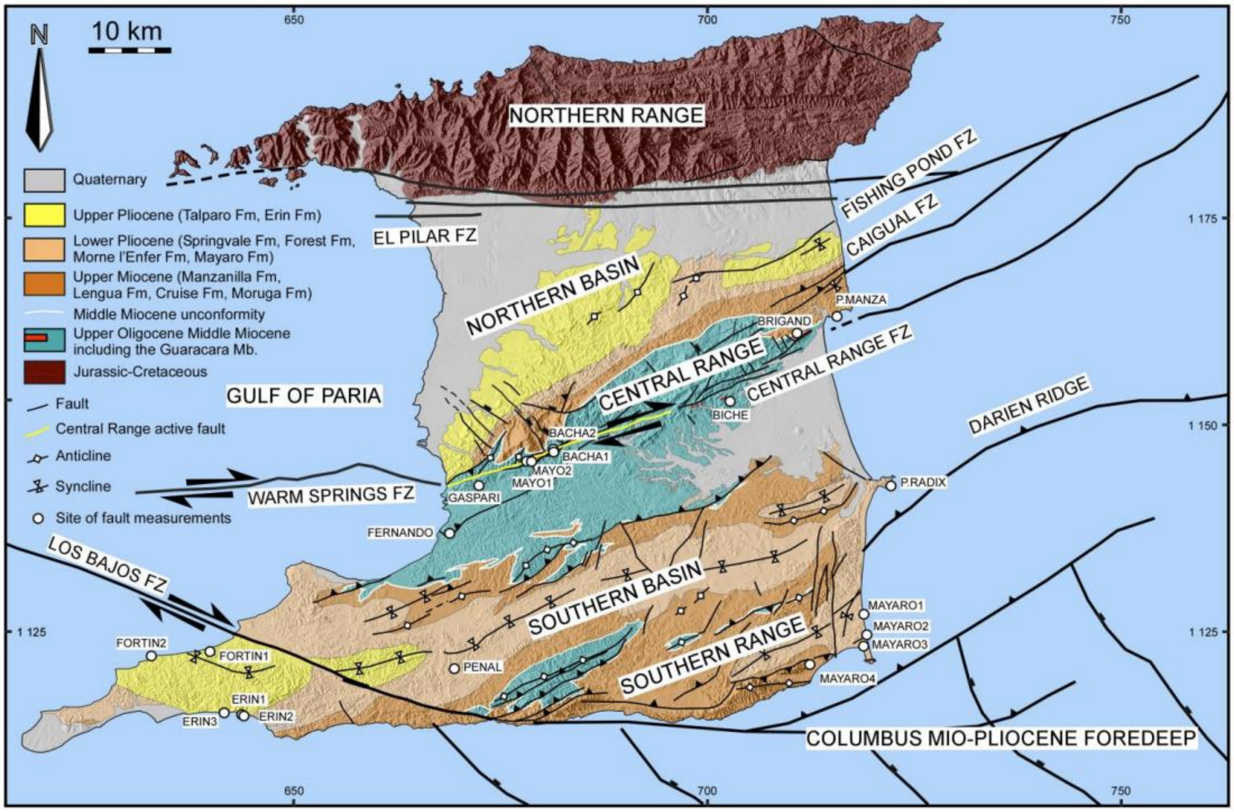


Figure 3 Geological map of Trinidad modified from earlier geologic maps of Trinidad compiled by Kugler (1959), De Verteuil et al. (2006) and Hippolyte & Mann 2022.

Developments around Cory Moruga have typically been focused on Oligo-Miocene targets in the Herrera sands e.g. Moruga West, Inniss Trinity and Barrackpore-Penal; however, significant production is also noted locally in shallower reservoirs of the Moruga Group shown in Figure 4, e.g. the Forest Field. Whilst this ITR is primarily focused on the potential of the Herrera Sands, Scorpion Geoscience note potentially significant future oil exploration potential on the Cory Moruga licence in deeper reservoirs of the Eocene equivalent to the Late Eocene Point-A-Pierre Formation in the central range. Scorpion Geoscience also observes significant opportunities to target low resistivity "missed pay" in existing wells within the Herrera sequence e.g. RD-6 and RD-7 wells, an opportunity which requires detailed petrophysical analysis and perforation of potential reservoirs with relatively weak pay indications. Advanced testing methods including sand jet perforation technologies enable the targeting of many potential pay intervals in a single run facilitating efficient exploration of stacked potential pay levels such as those found in and around Cory Moruga and neighbouring fields.

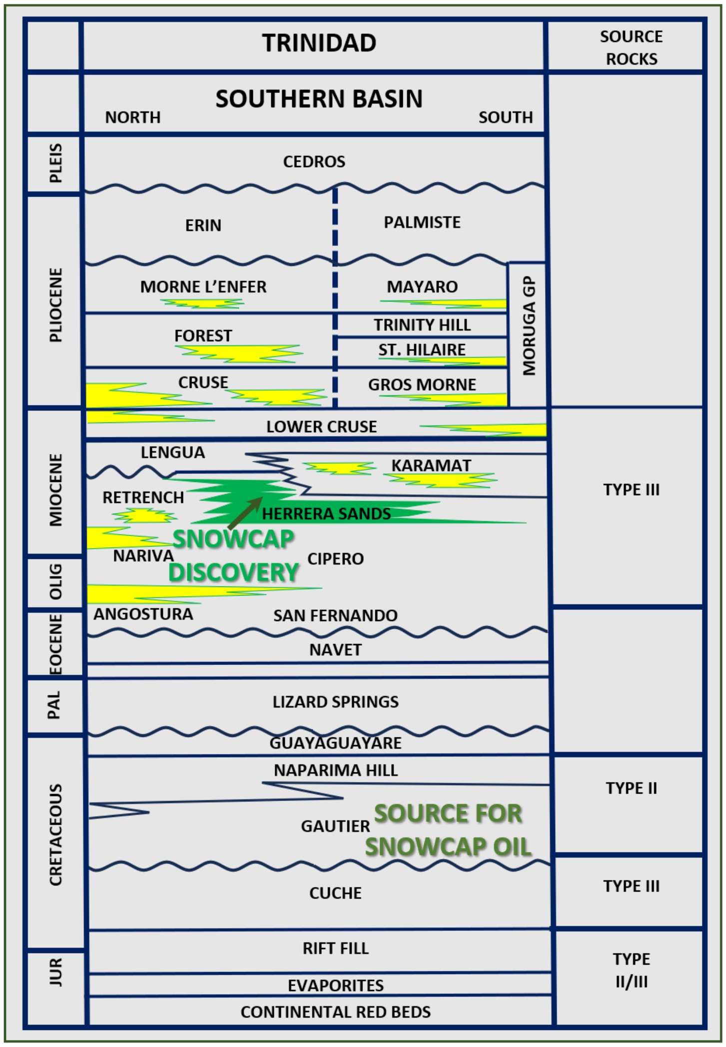


Figure 4 Stratigraphy of the Southern Basin Trinidad showing the key elements of the petroleum system responsible for forming the Snowcap accumulation with yellow and green zones indicating known reservoirs and oil presence in the southern basin, modified from Kugler 1953, Saunders 1972 and Carr-Brown & Frampton 1979.

3.1 Source Rock Presence, Maturity and Charging

Oils in the Snowcap discovery and nearby Penal-Barrackpore, Moruga West and Inniss-Trinity producing fields are interpreted from available geochemical reporting to be sourced from the prolific Type II shale facies of the Upper Cretaceous known locally as the *Naparima Hill* and *Gautier* Formations in the Southern Basin of Trinidad (Figure 4 and Higgins 1990). These Cenomanian to Campanian aged argillaceous shales coincide with major global anoxic events (OAE 2) and are characterised by preserved total organic content (TOC) of up to 5.3% which is mostly Type II oil-prone amorphous Kerogen according to Persad (2009). The RD-1 Cretaceous penetration and new 3D seismic interpretation work undertaken by Scorpion Geoscience confirms the Naparima Hill source rocks are widespread and up to 400m thick throughout the Cory Moruga block. The Trinidadian Cretaceous source rocks are time equivalents of the world class *Gauyuta* and *Sucre* Groups in neighbouring Venezuela's extensive petroleum system. Source rocks of the Cretaceous are expected to be mature for oil in and around the Cory Moruga Block and produce light oils which have migrated updip and along faults through relatively simple migration pathways into the overlying Miocene Herrera reservoirs. The standard Trinidadian Galeota blend is a 37.8°API sweet crude with sulphur content of 0.19%. Locally to Cory Moruga crudes vary between 24.9 to 37°API as a result of fluctuations in source rock geochemistry, maturation histories and reservoir depth. Associated solution gas is expected to be c. 700scf/STB based on the SC-1 flow tests and is expected to be separated during production and used for reinjection and enhanced oil recovery. Source rock presence, maturity and charging are classified as low risk petroleum system elements for the purposes of geological risk analysis presented in this ITR.

3.2 Reservoir Presence and Producibility

The main reservoir targets for the Snowcap project are the Miocene-aged Herera turbiditic sands. The reservoirs are part of a marine fan complex within the mudstone dominated deep water facies of the Cipero and Karamat Formations (e.g. Hosein 1990). Within the Hererra sequence, there are at least eight and occasionally nine separate sand units noted in the Southern Basin with numbers ascending upward from the basal Hererra #1 sand "H#1" (See Figure 5). The collective Hererra sand units generate a set of narrow but relatively strong seismic marker events which can be tied from the Moruga West field and between local wells such as RD-1 and SC-1 confirming there is a strong likelihood (> 50%) that at least some of the stacked sands are preserved across the Cory Moruga Block beneath the Middle Miocene Unconformity. Greatest confidence is given to those sands which are visible on electric log signatures in SC-1, SC-2 and RD-1. The H#8 sand flowed on test in Snowcap-1 confirming discovery status and the presence of a known accumulation albeit with relatively poorly defined extent based largely on inference from continuous events mapped in 3D seismic although it should be noted there are currently no direct hydrocarbon indications visible on the current iteration of 3D seismic data. Scorpion Geoscience understands seismic reprocessing to investigate potential AVO signatures is being considered by PRD as part of the forward work programme contingent on improved log data being obtained from well re-entries and a new Snowcap-3 appraisal well.

The H#1, H#6 & H#7 sands are identified as potential pay zones in the Rochard-1 wells based on historic production tests which flowed oil on test over the course of several years (see Table 2); however at the time of writing, it is anticipated more work such as well re-entry or appraisal drilling is required to determine whether wax suppression is required to improve and sustain long term commercial flow rates. The H#2 to H#5 sands are variously thrusted out or poorly developed in existing penetrations of the Snowcap structure e.g. SC-1. Based on net sand maps obtained from Moruga West and on the balance of probability, the H#2 to H#5 sands are potentially present as narrow sand units within the mapped closure and offer excellent upside potential when encountered and are thus classified as having the potential to host Prospective Resources with appropriate indicative geological risk factors taken into account in Section 4.2 of this ITR.

For the purpose of this ITR, reservoir presence is classified as a proven hydrocarbon play element at the Snowcap closure at the H#8 level, although the presence of individual Herrera sands at any given location is subject to some uncertainty based on newly developed net sand maps presented in Figure 6 which is given due consideration when calculating risked resources presented in Section 5.2. Sands show characteristic deflections on GR logs with Neutron crossover in pay zones where such logs are available which can be tied across wells with a reasonable degree of confidence in the area of interest with a substantial offset well database noted in the likes of Moruga West e.g. Figure 5.

Reservoir quality and effectiveness is determined by porosity and permeability which are related to sedimentary depositional facies and burial characteristics e.g. cementation and compaction. The main environment of deposition of the Herrera Sands is marine turbidite with fine to coarse bedded sands. Net sand maps presented in Figure 6 based on many offset wells in Moruga West field show preservation of kilometre-scale fan lobes and channels consistent with the turbiditic fan setting. Based on the mapping presented in Figure 6, individual Herrera sand units show a degree of mounding in the higher energy central channels and at the toes of palaeoslopes resulting in maximum net sand thickness in excess of 12.5m in most of the Herrera sands and locally >30m in H#1 based on penetrations in Moruga West. The presence of fan and channel facies affords a degree of control and predictability when extrapolating fairways into the more sparsely drilled intervals in and around the mapped Snowcap closure. For the Snowcap evaluation presented in this ITR, a simple paleogeographic reconstruction is employed and is it assumed fairway trends will extend westwards across the Cory Moruga block towards the source of the sands which would have been the rapidly denuded central range uplift area shown in Figure 3. Individual sands are anticipated to narrow and thin towards the sediment source with higher Net:Gross in the core of the semi-confined channels and zones with only shale or very thin sands between the channels which is consistent with the results from existing well penetrations. Where present, sands tend to have good to excellent preserved porosity based on >100 local well penetrations.

A low case net sand porosity cutoff is defined as 18% representing the lower practicable limit at which oil is expected to flow freely. A skewed mid case porosity of 27% is based on petrophysical analysis of the Herrera #8 reservoir in Snowcap-1 where pay is categorised by Vcl < 50% and Sw of <60%. The petrophysical analysis is supported with sidewall cores which have measured values of 28.4% and 27.3% noted in Herrera sand #8 at 1400m and 1403m in Snowcap-1 relating to air permeabilities of 76.59 md and 69.93 md respectively at 800psi overburden pressure (Source Report "*Reservoir Extent GR7A KH Sand #8 Snowcap 1 Final*"). An upside porosity value of 32% is used as part of a simple triangular distribution reflecting a paucity of raw data with which to attempt more sophisticated analysis e.g. application of a clipped log-normal probability density function. A lack of resistivity logging in key reservoir levels is common at Cory Moruga and presents an opportunity to identify missed pay by relogging potential pay sections. Low resistivity pay is also noted in some wells in Moruga West, therefore a related opportunity exists to perforate any sand interval showing a weak resistivity signature with modern sand jet perforation technology to determine if additional pay has been missed.

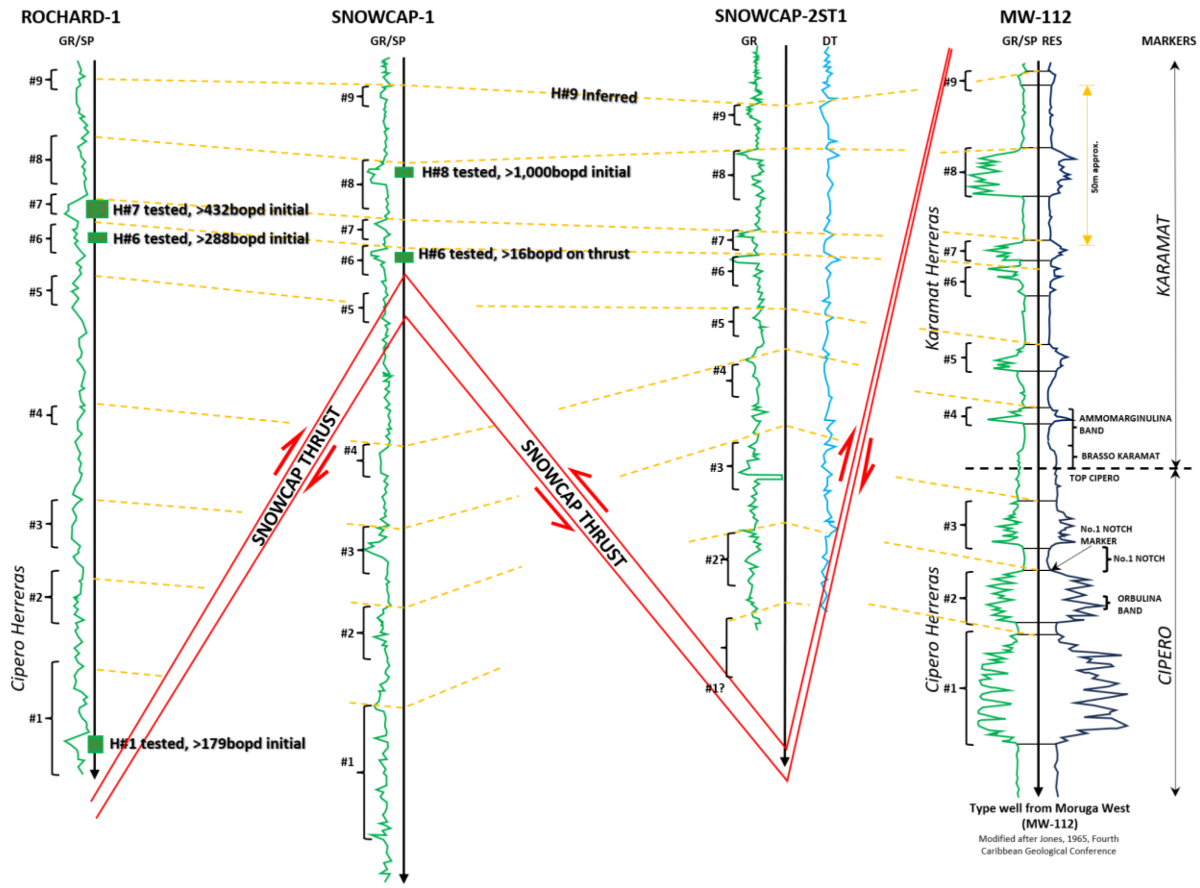


Figure 5 Stratigraphic correlation of the main Herrera sands across the Snowcap discovery tied to the MW-112 Moruga West type well transposed from Jones 1968.

For the development of volumetric estimations, a "net sand thickness" methodology is employed to generate *Net Sand Volumes* or NSVs which are equivalent to conventional Gross Rock Volumes subjected to a Net:Gross adjustment using the minimum 18% net cutoff previously mentioned. This method is well suited to the availability of well data in the adjacent Moruga West Field which is used to define sand fairways and extrapolate net sand trends into these sand fairways. The results of NSV mapping are presented in Figure 6 along with superimposed outlines of the low, mid and high case Snowcap prospect/discovery outlines which are divided into an upper (H#5-H#8) and lower (H#1-H#4) set based on top and base Herrera structural maps described later in Section 3.3. It is noted there is an overall reduction in total sand supply heading up through the Herrera section ("fining up") and a greater degree of channelisation and fan development which matches with an overall increase in relative sea level and trend from proximal deltaic to distal turbidite deposition also supported by assessment of faunal assemblages in available reports from Snowcap-1. In order to account for Geological Uncertainty in the thickness and quality of sands in the Herrera within the Snowcap closure area, a discount of 50% is made to expected NSVs in the low case input and 25% discount to mid case NSV inputs. The high case uses the full modelled NSV. This approach is judged to be fair and reasonable given available well penetrations provide a degree of confidence at SC-1 and RD-1 and take into account the natural variance in sand thickness noted between individual wells across the area.

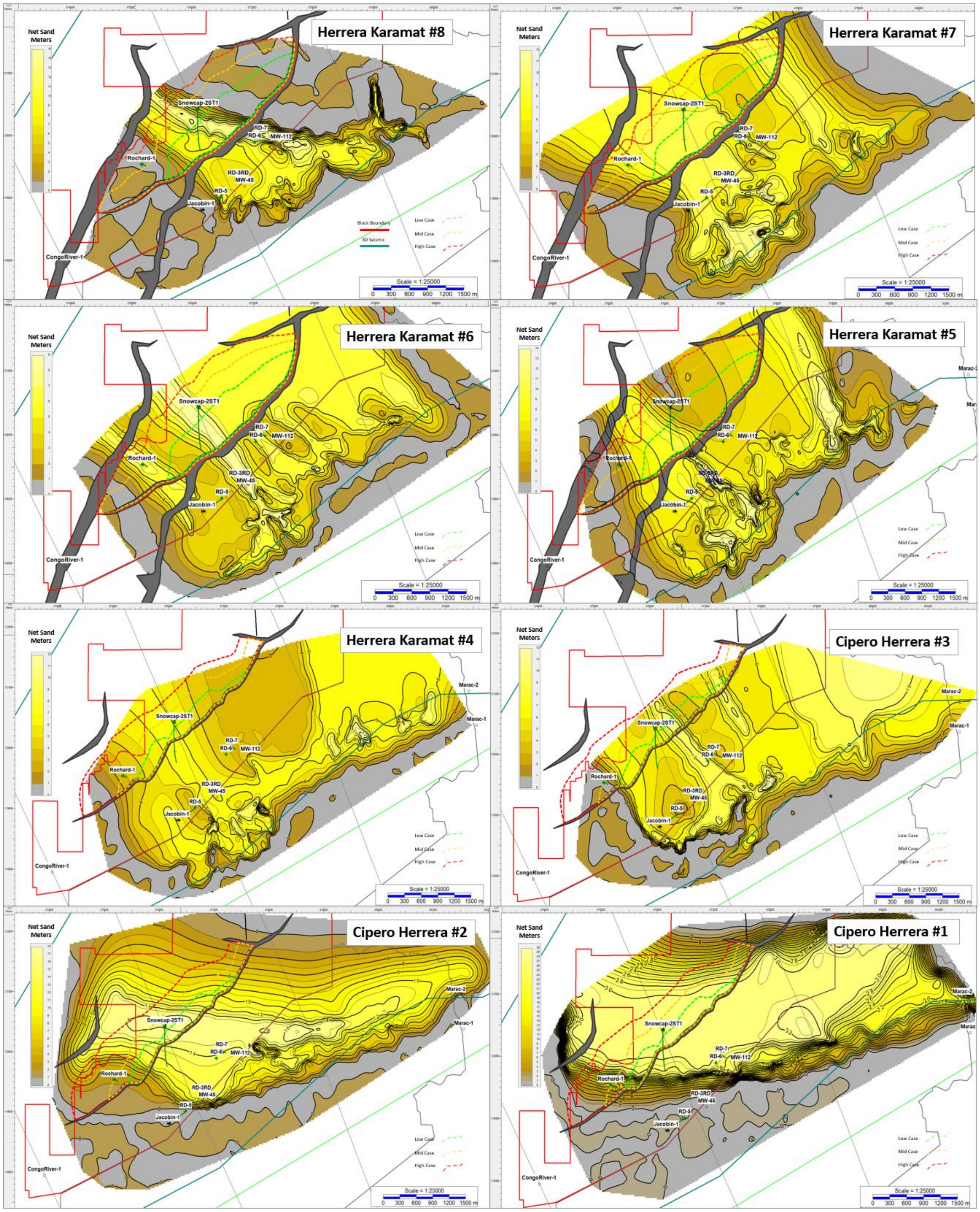


Figure 6 Net sand thickness isopach maps for the Herrera Karamat and Cipero Herrera stacked units #1 to #8 constructed from available well data and published materials e.g. Pindell & Lorcan 2005.

To date, the Cory Moruga block has three key well penetrations, Rochard-1 ("RD-1", 1955) flowing a combined initial rate of up to 899 bopd, Snowcap-1 flowing a combined initial stabilised rate of 566 bopd and Snowcap-2ST1 which could not be tested due to hole conditions. These results are deemed to demonstrate good to excellent flow potential substantially derisking the reservoir effectiveness aspect of the petroleum system.

PRD is targeting re-entry of several wells in Cory Moruga to provide IP and cashflow. Based on the values presented in Table 2, average flow where a single Herrera reservoir sand flowed on test is 264 bopd per flowing unit. Peak sustained flows of 432 bopd have been measured from single sands in Rochard-1 yielding a combined flow of 1,321 bopd from the five intervals that flowed on test in the three wells located in the main Snowcap structure. No effective testing was conducted on Snowcap-2ST1 due to operational issues. RD-6 and RD-7 located adjacent to the Moruga West field on the southern boundary of the Cory Moruga block in preferential sand fairways identified in Moruga West both produced oil from what is interpreted to be H#2 sands, however elevated resistivity in H#1 sands indicates there may be missed pay which can be accessed by PRD. Based on local benchmarking, PRD can expect to target sustained flows in the region of 100-200 bopd per sand per well as a Mid Case for IP planning purposes.

In terms of product characterisation and engineering considerations, the uppermost H#8 sand in SC-1 tested c.550 bopd with 4.5 MMcf/day of gas during flow test four from a 2m perforated interval at 1401m-1403m MD with no formation water. Overpressure of up to 0.62 psi/ft was noted with short term open choke flow rates were noted ranging 1,100-1,450 bopd and gas at a rate of 2.2 MMscf. Static initial surface tubing pressure was recorded at 2516 psia, initial static bottom hole pressure was 2761 psia. Live oil recovered from the initial testing was found to have a sulphur content of 0.47 % and a viscosity of 0.59 cp. Live dry oil gravity measured at 60°F was 34.5°API with wet oil measured at 34.3°API based on 0.784% measured water content. Stock tank oil minus solution gas had an oil gravity reading of 29.5°API at 60°F and pour point of c.55°F (12.7°C) consistent with loss of gases making it a light sweet crude suitable for export by existing pipelines which experience typical annual nighttime temperature minimums of 22°C.

Table 2 Production summary from existing wells

	SC-1	SC-2ST1	RD-1	RD-6	RD-7
Reservoir Level	Test Result	Test Result	Test Result	Production	Production
Herrera 8	406 bopd	2-4 bopd	-	-	-
Herrera 7			432 bopd	-	-
Herrera 6	16 bopd	Oil, Not tested	288 bopd	-	-
Herrera 2	-	-	-	IP 29 bopd, total 11,645 bbls	IP 30 bopd, total 43,360 bbls
Herrera 1	-	-	179 bopd	Oil, Not Tested Based on Res Log	Oil, Not Tested Based on Res Log

Despite the good quality reservoir encountered in SC-1, the flowing tubing head pressure (THP) did not stabilize during seven days of drawdown and showed up to 22% depletion after the test. Test interpretation undertaken by the operator Parex at the time suggested reservoir barriers at 1500m, or more, from well location which is supported by the presence of the thrusts noted by PRD and mapped by Scorpion Geoscience using the available 2D and full coverage 3D seismic datasets e.g. Figure 7 and Figure 8 in Section 3.3.

Further extended testing of the SC-1 H#8 sand undertaken in Q3 2012 resulted in sustained flows of 150-200 bopd on 7-12/32" choke. Operational issues associated with wax deposition in the tubing led to early termination of the testing. Appropriate interventions are planned for well re-entries and new wells drilled by PRD to restrict wax deposition through maintenance of PVT and geochemical conditions to prevent wax drop out. Measured initial flow rates in excess of 1,000 bopd stabilising to 100's bopd are expected for any new completed penetrations in the virgin Snowcap accumulation e.g. planned SC-3 well based on the initial stages of production at Moruga West, Penal-Barrackpore and Inniss Trinity fields (e.g. Dyer & Cosgrove 1992, and Higgins 1990) .

The SC-1 well was tested again in May 2015 with initial oil rates of c.80 bopd and water cut of 30% on natural flow producing an emulsion mix. During the test, a sudden water cut increase from 30% to 70% was observed which was interpreted by the operator to have resulted from a possible breakdown of casing cement which allowed water to flow into the wellbore from deeper formations. This interpretation was potentially corroborated with the results of a final test undertaken in Q4 2018 where c. 7,000 bbls of water was produced over a period of two months with no oil recovered suggesting the main oil reservoir was not linked to the wellbore and water from an unknown source became the single flowing phase. The main H#8 sand is therefore anticipated to effectively be a virgin reservoir based on the insignificant volume of oil produced to date. Taking into account the relatively high GOR of c700scf/STB of the oils encountered in Snowcap-1, detailed PVT analysis is recommended following any workovers and for future appraisal wells to determine the *in situ* bubble point of the oil at each interval to inform optimal production strategies.

The SC-2 (lost hole due to borehole instability and swelling clays) and subsequent SC-2ST1 sidetrack wells were drilled in 2015. There is no open hole data available for SC-2ST1 with only GR, neutron, density, sonic and CBL obtained through casing. CERP completed the well in Dec 2018 with a total perforated interval of 16 ft (2 x 8 ft) targeting the H#8 sands tested in SC-1 but without the benefit of resistivity logging to calibrate perforation depths in the SC-2ST1 deviated hole. The test intervals were evaluated via swabbing with no success possibly due to missing the main H#8 sands, so the well was converted to pump (rod pump) to evaluate its productivity. SC-2ST1 produced intermittent low rates (2-4 bopd) of oil 27°API and no formation water indicating an oil saturated reservoir but the testing is not considered to be representative of true flow potential. In contrast to SC-1, no wax was seen during the test which is inconsistent with the results of SC-1 H#8 results and later assays on the SC2-ST1 oils recovered which had a calculated viscosity of 43.62 cp and pour point of c.78.8°F (26°C). The results support the conclusion that perforations were not correctly located across the main pay interval and poor record keeping prevented errors being compounded in subsequent efforts to re-test the well. Downhole gauges showed depleted reservoir (0.23 psi/ft) which was initially assigned to a very small compartment or depletion by Moruga West, invoking long distance production across the Snowcap boundary fault which does not match with observations in Moruga West which indicate seismically resolvable faults form production barriers. The differences between the SC-1 and SC-2ST1 wells are interpreted by PRD and Scorpion Geoscience to have resulted from poor drilling, logging and completion practices rather than a fundamental change in geology over a distance of only 200m in the same mapped compartment. Furthermore, injectivity tests performed at a later date by the operator provided additional evidence of damaged reservoir. A subsequent acid stimulation program was prepared for the Herrera intervals with the aim of removing the reservoir damage. The acid job was suspended due to operational difficulties with the tubing remaining in the well further restricting the quantity of reliable data obtained from the well. PRD will resurvey the well and attempt to run a resistivity log to enable improved understanding of SC-2ST1. Re-entry of the SC-2ST1 and multi-level testing using sand jet perforation is considered by PRD to be an option to 1) help locate potential pay intervals, 2) determine true reservoir conditions and 3) determine if the well can be cleaned up convert SC-2ST1 to production.

Whilst primary data on reservoir conditions from the Snowcap discovery are sparse and potentially unreliable, a range of calibrated oil saturations (So) are used to estimate oil in place based on more detailed records obtained from the mature Moruga West field. A low case So cutoff of 50% is used to define pay. An upper case So of 70% has been determined from the Parex's detailed Snowcap-1 well report and data available for in the Cory Moruga Field. A mid case So input of 60% is deemed to be fair and reasonable based on calculated values from the H#8 reservoir in SC-1.

A range of formation shrinkage factors (Bo) associated with conversion of reservoir oil to standard barrels (STB) are applied ranging from 1.15 to 1.25 with a best estimate of 1.20 based on data acquired from production tests at, *inter alia*, SC-1 and RD-1.

Initial estimations of recovery rates are based on established production and depletion trends for nearby fields e.g. Moruga West. Optional enhanced oil recovery techniques (EOR) are also considered for the Snowcap development with injection of associated gas successful at Moruga West and CO2 EOR already employed elsewhere in Trinidad by PRD. At the Inniss Trinity AT-5X EOR test, production was sustained at an average rate 88% higher than the average rate for a CO2 EOR monitoring well in the month prior to the start of CO2 injection. Taking into account the opportunity for EOR, the expected ultimate recoverable oil volumes at Snowcap are based on a low case of 18% tied to the overall recovery factor for the entire Moruga West field to date. A best estimate mid case of 25% assumes some uplift through the benefits of modern completions and a high case of 30% is anticipated if reservoir quality and connectivity is towards the higher end of modelled expectations. The highest recorded recovery rates from Moruga West are up to 38% in certain compartments according to Jones 1968 where injection of solution gas was used to pressurise the reservoir and ensure efficient oil sweep increasing recovery from 10.18% to 31.68% over the course of 3 years up to 1964. Full field recovery values above 30% require calibrated measurements of OIP which are not currently available therefore High Case estimate (P10) recovery rate is currently capped at 30% until additional evaluations can be made of recovery factors in nearby fields and details of potential gas injection options are considered by PRD as part of the initial forecast work programme and full field development plan once re-entries and Snowcap-3 have been completed to obtain appropriate information on reservoir and fluid characteristics.

3.3 Snowcap Structure, Trap and Sealing

Mapping has been undertaken using S&P Global Kingdom® platform using the available 2D database of seven regional lines and full coverage 3D seismic denoted by the dark green line in Figure 6. The average elevation of the area is c. 35m above mean sea level. Legacy 2D seismic totals some 10 line km on the block. Additional data has been obtained by Predator to allow ties to key wells in the surrounding area. The main prospective area containing the Snowcap discovery is also covered by 3D seismic data acquired by British Gas as part of a regional 3D survey in 2015 and processed in the time domain by *Down Under Geosolutions* "DUG" to produce a full stack and enhanced stack 3D volumes.

The middle Miocene angular unconformity separates lower tightly folded and thrusted rocks of the Karamat and Cipero Herrera sands from less deformed overlying upper Miocene to Quaternary rocks. The Snowcap structure visible in Figure 7 is part of a south-verging truncated thrust anticline with a maximum displacement of c. 250m on the basal detachment fault. As with other thrust faults in the area, the position of the thrust is inferred by the presence of discontinuities in otherwise continuous seismic marker horizons and therefore interpretations carry a degree of uncertainty which is acknowledged using a range of prospect outlines spanning a range from high to low confidence with the most likely outcome used as the Mid Case volumetric input. The uppermost tip of the Snowcap thrust is accompanied by a weakly developed thrusted anticlinal fold which is a key component of the up-dip trapping configuration (Figure 7 LHS). The thrust itself is expected to be sealing due to the presence of shale gouge based on large proportion of shale in the Karamat and Cipero Formations.

New 3D mapping undertaken as part of this ITR has resulted in production of a new top and base reservoir map (H#8 and H#1 respectively) shown in Figure 8. Mapping work indicates the main thrust plane intersects RD-1 below the H#1 tested sand penetration, therefore flowing oil discovered in RD-1 from H#1, H#6 and H#7 sands detailed in section 3 could potentially be part of a larger hangingwall accumulation which was missed by SC-1. SC-1 intersects the basal thrust at c.H#5 level (Figure 5) and therefore does not penetrate H#1 to H#4 on the hangingwall side of the thrust inside the closure shown in the RHS of Figure 8. Although in a potentially useful location in the hangingwall, SC-2ST1 does not contain sufficient log or test data to determine whether stacked Herrera sand and associated oil accumulations have been penetrated and requires, where practicable, re-entry to obtain appropriate logging plus testing . SC-2 and SC-2ST1 did not reach the Herrera #1 and #2 Sands

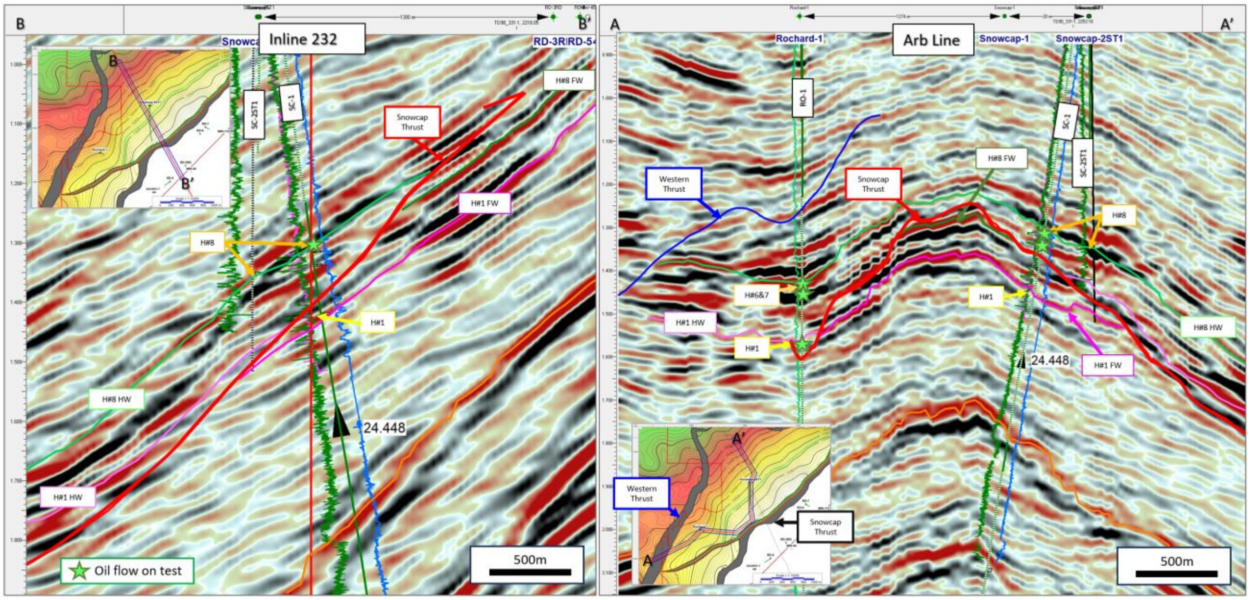


Figure 7 3D LHS Seismic dip line and RHS arbitrary strike line showing the seismic characteristics of the Snowcap Discovery Structure and key well penetrations through the Herrera sands and main bounding thrust plane.

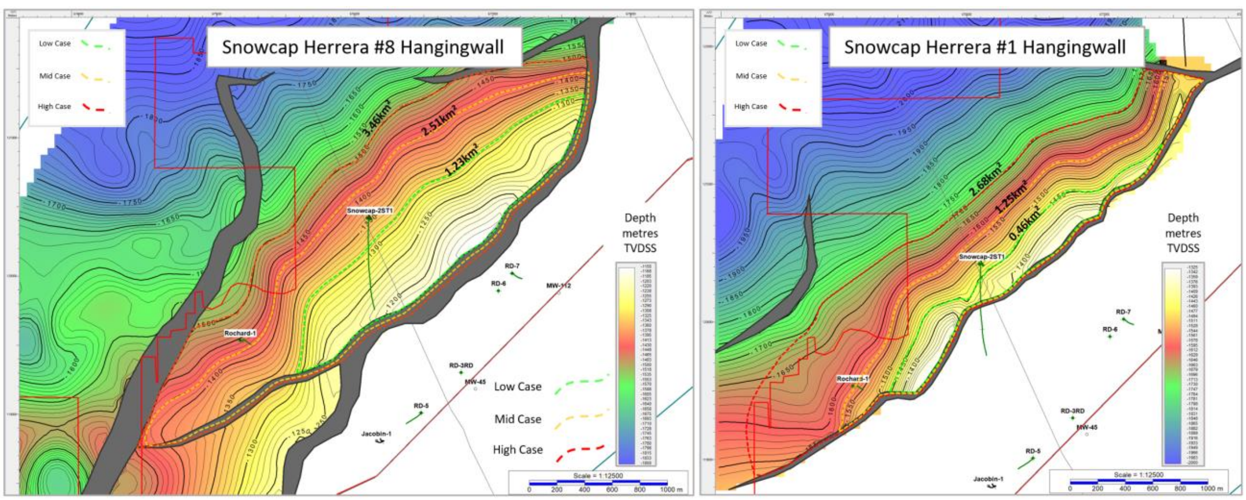


Figure 8 Seismic time maps of the Snowcap structure at LHS top Herrera#8 and RHS Herrera #1 sands mapped using 3D seismic data

Resolution constraints of the 2D and 3D seismic database prevent mapping of individual Herrera sand horizons, therefore the main prospect outlines for the Snowcap Discovery Structure at the Herrera #8 sand shown in the left hand side of Figure 8 are made using a seismic horizon pick on the top of the bright amplitude package tied to H#8 sands in RD-1, SC-1, SC-2ST1, RD-6, RD-7 and MW-112. The H#8 sand is also used as the closure map for H#7, H#6 and H#5 sands. A second map shown on the RHS of Figure 8 has been generated on the bright marker at the base of the Herrera succession equivalent to H#1 sand in RD-1 and MW-112 and is used to define the closure outlines for H#1, H#2 H#3 and H#4 sands. Both maps show only the hangingwall since the component of lateral displacement means the hangingwall projects over the underlying footwall making plan view maps difficult to translate to a flat page. Both hangingwall and footwall markers are shown in the section Figure 7.

It is Scorpion Geoscience's interpretation that the thrust fault provides up-dip sealing and separation between the accumulations at Moruga West and oil discovered in RD-6 and RD-7. Mapping indicates the likelihood that a branch of the main thrust provides sealing potential to the south of RD-1 which may also be enhanced by components of stratigraphic trapping associated with the southerly pinchout of sands expected from net sand and fairway mapping. It is noted previous and existing operators e.g. Parex, CEG and PRD have slightly different interpretations of the intersection points and patterns of the main thrusts, however all available reports agree the Snowcap closure is c.3km² at the upper end of estimations e.g. "best case". From a risking perspective, sealing as an integral component of the Petroleum system is deemed to be excellent and effective in the Snowcap structure as evidenced by the presence of flowing oil accumulations in SC-1, RD-1 and the neighbouring fields such as Moruga West which is reliant on a similar trapping configuration based on assessment of the seismic database and published materials e.g. Jones 1965. A degree of stratigraphic trapping may also be expected and invoked to the south of the mapped Mid and High case Snowcap closure based on the potentially discontinuous nature of the Herrara sand units as modelled and shown in Figure 6.

Table 3 Closure areas used in volumetric calculations with Herrera sands split into two main groups related to top and base Herrera sand mapping

Closure Level / Area	Minimum Case (km²)	Mid Case "Most Likely" (km²)	High Case (km²)	Comments
H#8-H#5 (Using H#8 Depth Map tied to wells)	**1.23**	**2.51**	**3.46**	Minimum based on oil encountered in H#8 & H#6 in SC-1. Most Likely Based on oil encountered in H#7 & H#6 in RD-1, Upside based on potential mapped closure using fault sealing
H#1 to H#4 (Using H#1 Depth Map tied to wells)	**0.46**	**1.25**	**2.68**	Minimum requires only main fault sealing, Most Likely based on oil encountered in H#1 in RD-1, Upside based on potential mapped closure using multiple fault sealing

4. Snowcap Discovery Resource Estimations

Preliminary Resource Estimations are provided for the remapped Snowcap structure with H#8 classified as Contingent Resources (PRMS "C" classification) and the remaining seven levels H#1-H#7 classified as Prospective Resources (PRMS "U" classification).

4.1 Unrisked Estimates of Prospective Resources

A probabilistic Monte Carlo methodology has been applied in all cases recognizing there are inherent geological uncertainties associated with several input parameters e.g. NSV, reservoir quality, oil saturation and recovery factors. The estimations presented in Table 4 are designed to encompass a range of possible outcomes consistent with published PRMS 2018 guidelines on resource classification.

Table 4 Volumetric estimations for Prospective Resources in the stacked Herrera sand units at the Snowcap Structure.

		Unrisked Volumetric Estimations						
		Prospective Resources						
		Herrera #1	Herrera #2	Herrera #3	Herrera #4	Herrera #5	Herrera #6	Herrera #7
Total Petroleum in place (PIIP) MMSTB	P90	9.01	4.59	2.35	1.83	4.73	5.65	6.87
	P50	15.97	7.54	3.62	2.97	6.75	8.08	9.97
	PMEAN	17.10	7.76	3.69	3.05	6.88	8.30	10.16
	ML	14.03	6.54	3.33	2.96	6.79	7.86	9.69
	P10	26.83	11.23	5.09	4.40	9.20	11.21	13.75
Recoverable Oil Resources MMSTB	P90	**2.08 (1U)**	**1.07 (1U)**	**0.54 (1U)**	**0.42 (1U)**	**1.09 (1U)**	**1.31 (1U)**	**1.58 (1U)**
	P50	**3.77 (2U)**	**1.77 (2U)**	**0.85 (2U)**	**0.69 (2U)**	**1.58 (2U)**	**1.91 (2U)**	**2.34 (2U)**
	PMEAN	4.05	1.83	0.87	0.72	1.63	1.97	2.41
	ML	3.40	1.64	0.75	0.63	1.45	1.70	2.14
	P10	**6.37 (3U)**	**2.68 (3U)**	**1.24 (3U)**	**1.04 (3U)**	**2.22 (3U)**	**2.70 (3U)**	**3.32 (3U)**
Associated Gas BCF	P90	1.46	0.75	0.38	0.29	0.76	0.92	1.11
	P50	2.64	1.24	0.60	0.48	1.11	1.34	1.64
	PMEAN	2.84	1.28	0.61	0.50	1.14	1.38	1.69
	ML	2.38	1.15	0.53	0.44	1.02	1.19	1.50
	P10	4.46	1.88	0.87	0.73	1.55	1.89	2.32

For comparison, previous operators Parex and TRex/CEG carried estimations of 9.11 MMSTB PIIP and 1.82 MMSTB Best Estimate 2C equivalent recoverable oil using 20% RF for the H#8 sand. Build up tests and later modelling undertaken by CEG indicated revised estimates of c.5.7 MMSTB PIIP and 1.14 MMSTB 2C which can be compared directly with the latest estimates of 2C resources presented in this ITR Table 4. The latter modelled values are more consistent with the revised Scorpion Geoscience estimates using the equivalent P50 (Best Estimate) figure for Herrera #8 sand indicating a degree of convergence on a most likely outcome using completely independent methods, one a static volumetric calculation the other a dynamic pressure derived output.

A series of plots are shown in Figure 9 to illustrate the contributions to Unrisked Prospective Resources from each of the Herrera sands (H#1-H#7). Estimations for associated solution gas are based on 700scf/STB across all cases.

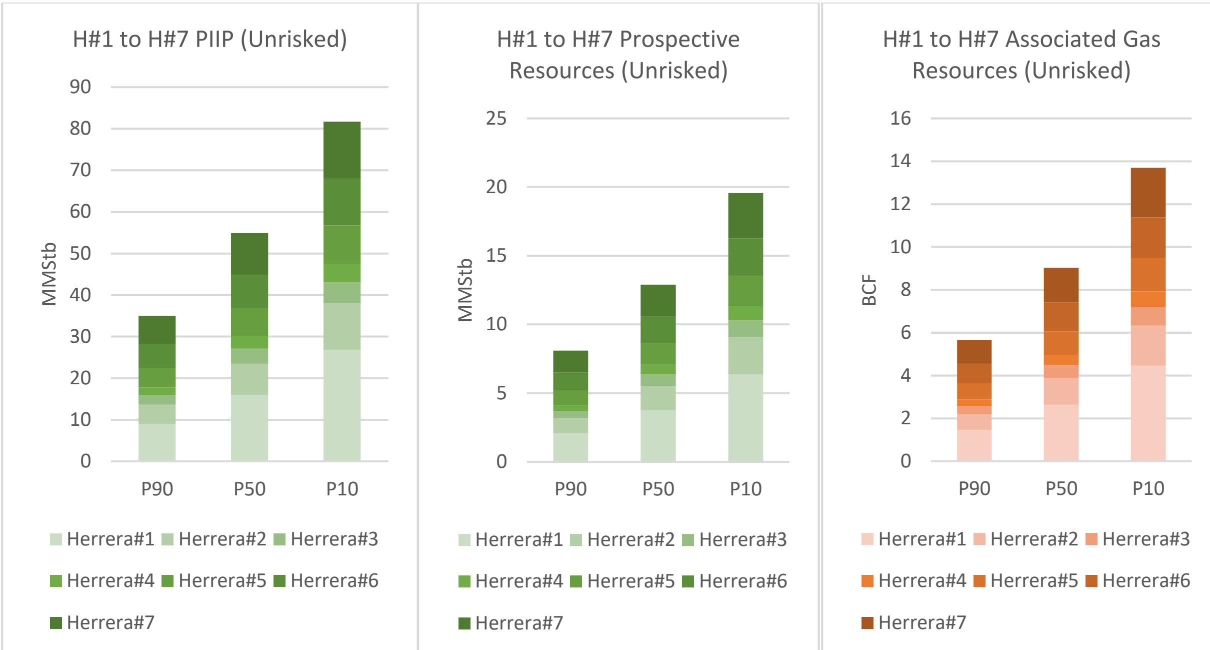


Figure 9 Stacked column charts showing estimates of Unrisked PIIP and Prospective Resources for the stacked Herrera sands H#1 to H#7.

4.2 Risked Estimation for Prospective Resources

The Snowcap discovery is interpreted to be a known accumulation at the H#8 sand level therefore aspects of geological petroleum system risking are focused primarily on exploration of H#1-H#7 sands.

Geological risk in the Snowcap project can be summarised as the chance of:

1) not encountering reservoir,

2) encountering reservoir that is not saturated with oil and

3) encountering reservoir from which oil will not flow to surface and is thus not producible

Values in this ITR are quoted as chance of success (COS) e.g. 1 in 2 or 50% with individual risk elements considered as fractions e.g. 0.8 = 80% or 4 in 5 likelihood of being present and effective. Table 5 lists the specific risk values attributed to each petroleum system element for each of the Herrera sand units expected to be present in the Cory Moruga block and mapped Snowcap Discovery.

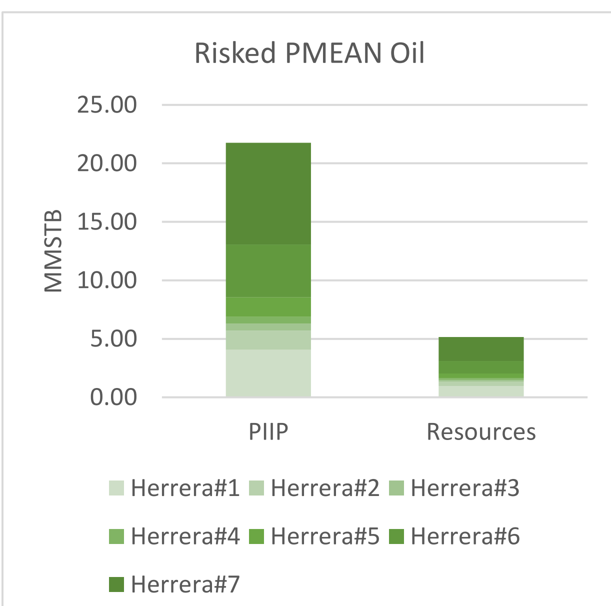
Table 5 Summary of four-point geological risking applied to each of the separate Herrera sand levels based on assessment of the key petroleum system elements of Reservoir (combined presence and effectiveness), Source (presence and effectiveness), Combined Migration and Charge, and Trap Presence

	Herrera #1	Herrera #2	Herrera #3	Herrera #4	Herrera #5	Herrera #6	Herrera #7
Reservoir	0.95	0.85	0.65	0.50	0.65	0.85	0.95
Source	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Charge	0.50	0.50	0.50	0.50	0.50	0.75	0.95
Trap	0.50	0.50	0.50	0.75	0.75	0.85	0.95
Total	**0.24**	**0.21**	**0.16**	**0.19**	**0.24**	**0.54**	**0.86**

The risk estimations from *Table 5* are used to generate a series of risked resource estimations presented in *Table 6*.

Table 6 Summary of risked PIIP and Recoverable Prospective Resource volumetric estimations for H#1-H#7

	Herrera#1	Herrera#2	Herrera#3	Herrera#4	Herrera#5	Herrera#6	Herrera#7	Arithmetic Sum
Risked PMEAN PIIP MMSTB	4.06	1.65	0.60	0.57	1.68	4.50	8.71	**21.77**
PMEAN Risked Prospective Resources MMSTB	0.96	0.39	0.14	0.14	0.40	1.07	2.07	**5.16**
Ass. Gas bcf	0.67	0.27	0.10	0.09	0.28	0.75	1.45	**3.61**



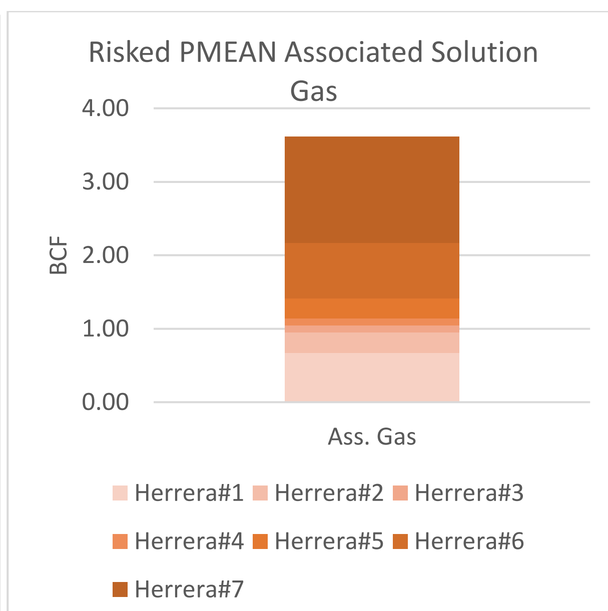


Figure 10 Risked PMEAN volumetric estimations for Herrera sand units H#1 to H#7

Readers should take into account that the PRD expected work programme could materially derisk the Estimated Prospective Resources with final outcomes being anywhere within the *unrisked* Prospective Resource distributions. As a result, the PRD Base Case economic assessment summarised in Section 5 of this report takes into account conversion of P90 (1C) contingent Resources and the PMEAN Risked Addition of Prospective Resource estimations to arrive at what is considered to be a fair and reasonably conservative potential recoverable resource for economic modelling purposes.

4.3 Estimation of Contingent Resources for H#8

No attempt is made to establish current commerciality. Readers should take into account there remains some uncertainty associated with flow assurance and well deliverability therefore there remains a low but tangible risk that the Contingent Resources quoted will not achieve commercial production at Snowcap and thus cannot currently be classed as Proven, Probable and Possible (3P) Reserves using current PRMS guidelines.

The 1C P90 values quoted in Table 7 and Figure 11 are based on Low case parameter estimates designed to indicate at least a 90% probability that, assuming the accumulation is developed, the quantities actually recovered will equal or exceed the Low Estimate and following demonstrable commerciality will transfer from being Contingent Resources to be deemed 1P "*Proven reserves"* using PRMS nomenclature. The P50 output value is intended to represent Best Estimate of Contingent Resources and is a thus a fair and reasonable indication of the potential 2P or "*Proven plus Probable*" size of the Snowcap accumulation should commerciality be established. The upper P10 estimations reported are designed to be indicative of the 3C High Estimate Contingent Resource case.

Table 7 Volumetric estimations for Contingent Resources in the Herrera H#8 sand unit at the Snowcap Structure.

		Unrisked Volumetric Estimation
		Contingent Resources
		Herrera #8 Sand
Total Petroleum in place (PIIP) MMSTB	P90	4.57
	P50	5.94
	PMEAN	6.01
	ML	5.66
	P10	7.54
Recoverable Oil Resources MMSTB	P90	**1.04 (1C)**
	P50	**1.40 (2C)**
	PMEAN	1.42
	ML	1.26
	P10	**1.84 (3C)**
ASG BCF	P90	0.73
	P50	0.98
	PMEAN	0.99
	ML	0.88
	P10	1.29

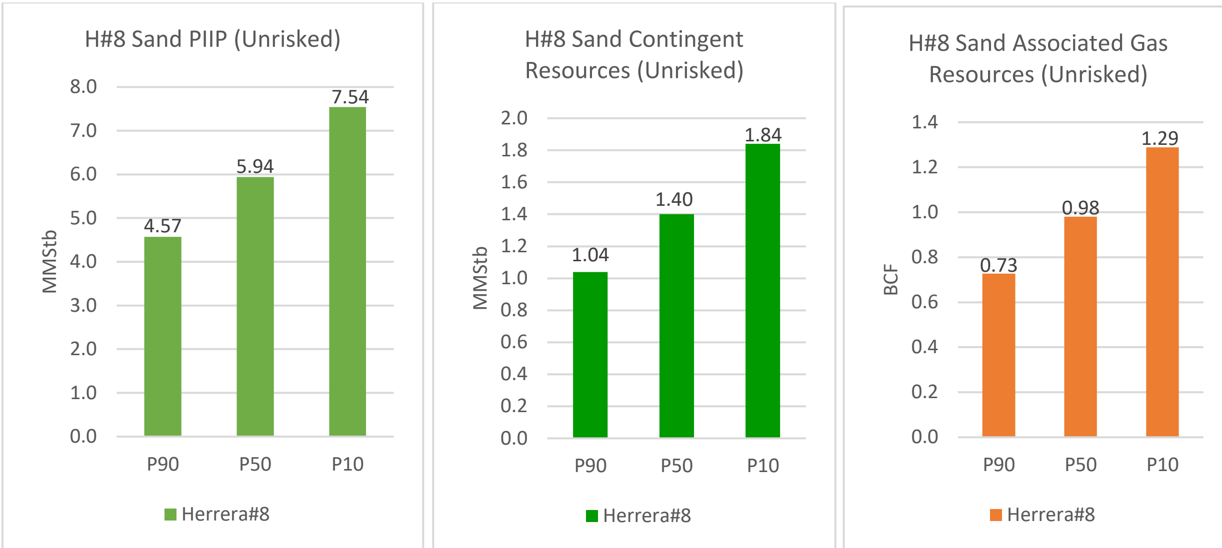


Figure 11 Stacked column charts showing Unrisked PIIP and Contingent Resource estimates for the H#8 sand at Snowcap

4.4 Risks associated with H#8 Contingent Resources at Snowcap-1

Whilst it is judged there is sufficient evidence to suggest that the Snowcap structure is an accumulation capable of achieving commercial production in the near future, and thus resource estimates for the H#8 sand can be reasonably be expected to be justified as Contingent Resources with a prescribed range reflecting inherent geological uncertainties, it should be borne in mind by the reader that there are subsurface risks associated with the continuity and producibility of oil which can only be mitigated with further testing and drilling. The difficulties encountered in the drilling of SC-2ST1 related to tight hole conditions and as a consequence incomplete logging and very limited testing are judged to have resulted from poor planning and operational delivery given the apparent ease with which >100 wells have been drilled in the neighbouring Moruga West field. As such, the forecast work programme being developed by PRD as an experienced operator, seeks to tackle historical well delivery issues directly by using improved drilling practices to obtain valuable data regarding oil presence, oil character and oil producibility from existing well re-entries and at least one new well, Snowcap-3 with the key aim being to establish sustained commercial flow rates. Experiments will be undertaken to determine whether aspects of flow assurance such as wax suppression and gravel pack completions are required which if unmitigated could decrease or prevent sustained oil production through the clogging effect of wax or sand build ups. In addition to subsurface and production risks, this report also acknowledges aspects of commercial uncertainty regarding future oil price and markets which potentially translate to project risks if potential commerciality cannot be established during the accelerated initial operational phase.

5. Snowcap Development Options and Economics

Taking into account local infrastructure and the location of existing production hubs and export routes the optimal exit route for oil produced from Cory Moruga is via the Moruga West pipeline.

Based on the available data, the Snowcap structure is a proven oil discovery with an as yet undefined resource. Existing production in the Moruga West field and other comparable Miocene Herrera sandstone reservoirs indicates an optimal drainage area of c. 10 hectares (25 acres) per historical well using rudimentary completions and natural flow. Wells drilled in the neighbouring Moruga West field at Herrera levels have produced up to 455,000 bbls per well and an overall 12.2 MMbls with the top 50 producers in the field producing an average cumulative total of 141,000 bbls and c.0.4bcf associated gas per well available for reinjection. Initial production is reported at >1000bopd from individual wells in the Penal field (e.g. Bitterli 1958).

Key aims of the initial development work programme being progressed by PRD are as follows:

SC-1

- Workover H#8 Sand only
- 200 bopd Initial Production (IP) declining to 130 bopd after 12 months
- Wax treatment and gas management critical to reduce decline rate

SC-2ST1

- Workover H#6, H#7 and H#8 Sand – subject to borehole condition
- 200 bopd IP declining to 130 bopd after 12 months (upside 300 to 400 bopd IP)
- Wax treatment and gas management critical to reduce decline rate

SC-3 (Proposed)

- Target H#1 - H#3 and H#6 - H#8 stacked sands in single well "Snowcap-3"
- Co-mingle Herrera H#1, H#2 and H#3 Sands for 1,000 bopd IP declining by 35% over 12 months
- Once H#1, H#2 and H#3 Sands are at equal pressure add H#6, H#7 and H#8 sands to production for an additional 400 bopd Initial Production (IP) declining by an estimated 35% over the first 12 months

An initial indicative cash profile has been developed from forecast near-term development operations (not taking into account long term full field development plans). A summary of the model outcomes is provided in Table 8. Details of the model were provided by PRD and have been independently verified as being fair and reasonable based on prevailing market conditions as part of this ITR process, notwithstanding acknowledged uncertainties and risks associated with such operation activities.

Table 8 Initial indicative cash profile forecast for near-term production activities on the Cory Moruga Licence planned to occur within the next 18 months based on current market conditions.

Exchange rate 1.24$/£ WTI spot price 76.52 US$/STB	30th Jun 24	31st Jul 24	31st Aug 24	30th Sep 24	31st Oct 24	30th Nov 24	31st Dec 24	31st Jan 25	28th Feb 25	31st Mar 25	30th Apr 25	31st May 25
Snowcap-1 bopd Workover well re-entry, one sand	200	194	188	182	176	170	164	158	151	144	137	130
Net profit £ (100%)	162,437	157,993	153,549	149,105	144,661	140,217	135,733	130,311	124,889	119,467	114,045	109,103
Snowcap-2ST1 bopd from workover well re-entry of two sands	200	194	188	182	176	170	164	158	151	144	137	130
Net profit £ (100%)	145,902	141,586	137,270	132,954	128,638	124,322	120,006	115,690	111,374	107,058	102,742	98,421
Snowcap-3 new bopd from Appraisal well Up to eight sands	1000	970	940	910	880	850	820	790	755	720	685	650
Net profit £ (100%)					729,510	707,930	686,350	664,770	643,190	621,610	600,030	578,450

In terms of longer term full field development potential, additional data from workovers and new wells are required to refine key inputs; however, based on the historical BP and Shell production profiles from Moruga West shown in Figure 12, it is estimated a peak flow rate of c.3,500 bopd is a realistic target for Snowcap. By comparison, Inniss-Trinity produced at a peak rate of 4,200 bopd on natural flow in 1958 from 100 closely spaced production wells (2.5 hectares or less). Individual wells typically produced at rates of c.420bopd and in the case of AT7 produced a cumulative total of some 344,417 STB.

Whilst resource estimates in this ITR are benchmarked and weighted towards historical recovery factors, it is expected that improved modern production techniques will require fewer wells in the development and in the region of 14 new production wells are expected to be required to develop a Base Case Production scenario at Snowcap targeting H#8 2C P90 STOIIP OF 6.01MMSTB and PMEAN Risked Prospective Resource STOIIP of 21.77MMSTB yielding 8.33MMSTB recoverable oil. Wax suppression and pressure maintenance are seen as key aspects of ensuring long term productivity and improved Expected Ultimate Recovery (EUR). Gas injection undertaken by BP in a single compartment of the Moruga West Field boosted EUR recovery by an additional 10% in 1963 but was abandoned due to a lack of gas. The Base Case Production and Economic models produced by PRD, reviewed by Scorpion Geoscience and summarised below utilise a 30% recovery factor.

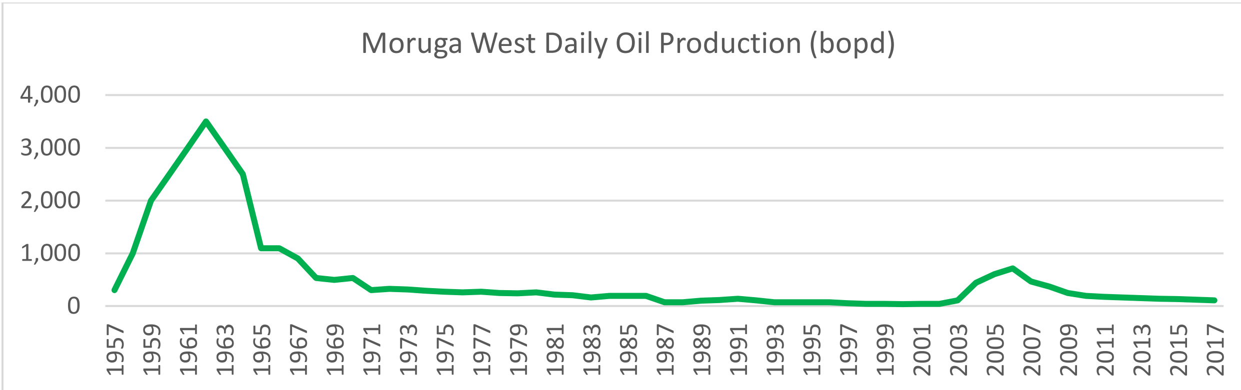


Figure 12 Example historical production profile from BP and Shell's Moruga West development showing a sustained early flow phase and later invigoration using EOR methods

A preliminary Base Case production profile scenario is illustrated in Figure 13 taking into account phased drilling of 14 new production wells and 30% EUR over a 15 year period. The production profile model takes into account pad drilling is used in the established onshore field developments in the area e.g. Moruga West and Inniss Trinity to minimise surface footprints, drilling costs and allow efficient collection and initial processing e.g. gas separation for re-injection and maintenance of reservoir pressures.

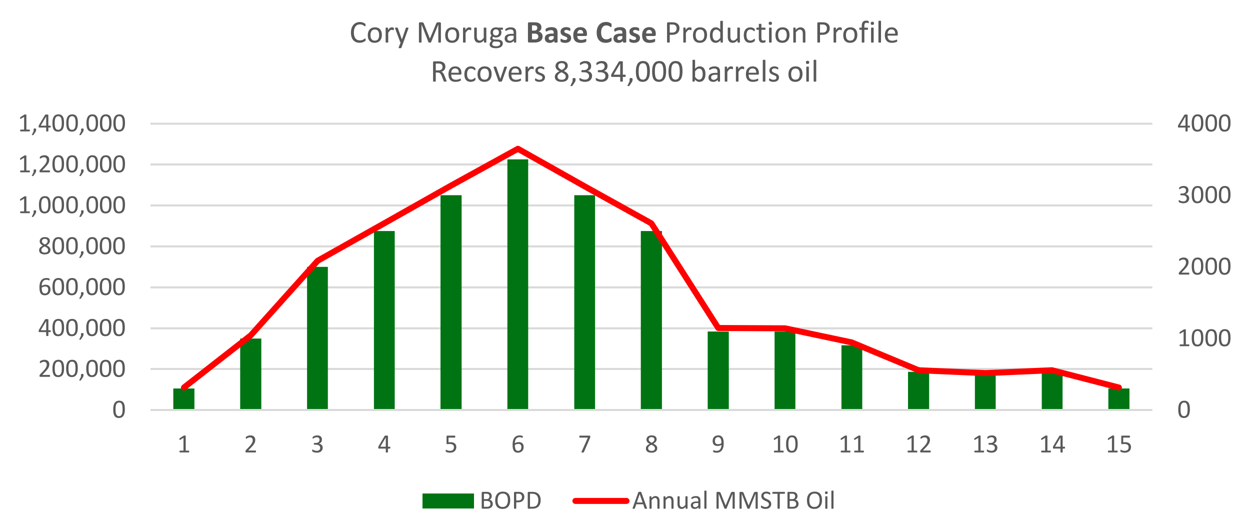


Figure 13 Example Base Case 15-year production profile being considered for Snowcap development

The modelled production profile model from Figure 13 is combined with a range of estimations for CAPEX, OPEX, Taxes and Government Royalties with a long term average WTI spot price of US$76 to yield a preliminary Base Case Economic Model (BCEM). Allowances are made for abandonment liabilities, green fund levies and asset acquisition costs and liabilities.

The BCEM predicts 15-year Gross Revenues for Snowcap Base Case development of c. US$632m with Total Variable OPEX of US$83.1m, Variable OPEX US$11.3m. Total capital allowances are estimated at US$79.9m based on the conservative 14 well and workover scenario. Government Royalties levied at 12.5% total US$79.0m yielding a PreTax Operating profit of US$453m and Undiscounted Operating Profit of US$202.12m. Undiscounted netbacks of US$19.61/bbl after CAPEX yield an undiscounted Upside (P10) Case preliminary estimated operator value of US$420m.

The NPV at 10% Discount is estimated at $US85.14m based on a flat WTI spot price of 76US$/STB with US$71.3m net to PRD yielding an IRR of 240.9% confirming Snowcap as a valuable asset in PRD's portfolio.

6. Indicative Work Programme

The Snowcap discovery requires additional appraisal and development drilling to better define the PIIP and potential recoverable resources and determine sustained production rates. Key aims of the expected re-entry, workover and drilling operations are:

- To confirm continuity of the oil accumulation penetrated by Snowcap-1 and Snowcap-2ST
- Determine whether oil discovered in the Herrera #1, #6 and #7 sands in Rochard-1 extends into the mapped Snowcap closure and can be produced as part of the Snowcap development
- To obtain detailed information regarding pay thickness in the Herrera sands across the mapped closure
- To obtain detailed information regarding reservoir quality and long term producibility e.g. special core analysis
- To obtain formation pressures and determine natural flow rates and the potential for enhanced oil recovery options including reinjection of associated gas and possible longer-term miscible CO_2 EOR scheme which could be implemented at the appropriate time in the FDP after a period of primary oil recovery
- For flow assurance considerations determine whether any chemical treatments are required to maintain optimal well bore conditions e.g. supress wax and any sand inflows
- To determine the optimal development strategy including number or wells and well spacing based on long term drawdown testing and identification of baffles or barriers indicating compartmentalisation.

The Initial Work Programme agreed by PRD with the MEEI will be conducted over the next three years effective from the Completion Date in November 2023 and will include:

- Re-entering Snowcap-1 to bring the Herrera #8 Sand onto production;
- Reprocessing, subject to the availability of seismic field tapes, the existing 3D seismic on Cory Moruga; and
- Drilling an appraisal/exploration well to test all eight Herrera reservoir intervals (Herrera #1 to #8 Sands) that produced in the adjoining ex-BP and Shell Moruga West field and several of which had tested oil in Rochard-1 drilled in 1955.

In addition, a re-entry and work-over with a wax treatment is planned and designed to restore production to a predicted rate of 100 to 200 bopd based on a successful wax treatment programme and re-completion of the SC-1 well. PRD plan to survey the Snowcap-2ST1 well for possible re-entry and if achievable will run a resistivity wireline log to select intervals for re-completion and testing, which if successful will allow this well also to come onto production. Ongoing studies have highlighted the potential for additional re-entries of wells such as RD-6, RD-7 and Green Hermit-1 which are on the Cory Moruga licence and may not have been produced despite showing indications of being on pay trends in the immediately adjacent Moruga West accumulation in the case of RD-6 and RD-7.

Scorpion Geoscience understands that PRD, at its discretion, can advance the timing of implementation and execution of any or all of the elements of its proposed amended FDP if warranted and subject to MEEI consent and regulatory approvals affording important flexibility during the appraisal and development process.

As part of the independent review of the Cory Moruga opportunity, Scorpion Geoscience has undertaken a reassessment of remaining prospectivity within the permit block using 2D and 3D seismic data and the results of wells drilled to date. In addition to the main proven Hererra play, there is also potential in the Forest, Cruse/Gros Morne, Lower Cruse above the Miocene UC and the Karamat formations which occur below the Miocene UC, it is recommended these units are considered as secondary targets during appraisal and development drilling.

7. Conclusions

The key findings of this ITR are as follows:

- The existing well database confirms the potential for the Cory Moruga block to contain a virgin oil accumulation referred to as the Snowcap discovery in the Miocene aged Herrera stacked turbiditic sands (H#1 to H#8).
- Snowcap is a faulted trap measuring up to c.3.5km² at the upper H#8 sand and 2.7km² in the lowermost H#1 sand.
- Flow tests confirm sustained flow rates of 400bopd plus 2MMscf associated gas are possible from the uppermost Herrera#8 sand in Snowcap-1 which is assigned discovery status and is referred to as a known accumulation for which contingent resource estimates have been assigned pending potential reclassification to reserves contingent on the results of well re-entry, long term testing and submittal of an appropriate FDP to MEEI, all of which are anticipated to occur as part of PRD's 3 year accelerated work programme.
- Preliminary independent resource estimations undertaken by Scorpion Geoscience indicate existing 2C best estimate Unrisked discovered recoverable resources in the H#8 sand to be in the region of 1.4 MMSTB of light sweet crude with c. 1.0 BCF ASG from a Best Estimate PIIP of 5.9 MMSTB. A combined unrisked Prospective PIIP of 54.9 MMSTB has been estimated for the Herrera #1 to #7 sand sequence in the remapped Snowcap structure yielding Unrisked Prospective Resources of 12.9 MMSTB and 9 BCF ASG. A risked addition of the mean outputs of each stochastic output provides an aggregated risked PMEAN Prospective PIIP of is 21.77 MMSTB yielding a risked PMEAN Prospective Resource volume of 5.16 MMSTB and 3.61BCF ASG. Calculations have been made assuming a range of geological play element parameters and recovery factors benchmarked against local fields e.g. Moruga West which is located immediately adjacent to the Snowcap structure.

- Re-entry options are being considered at Snowcap and potentially RD-6, RD-7 and Green Hermit-1 which may contain low resistivity stranded oil not produced by Moruga West. Decisions to re-enter wells will be based on the outcomes of downhole surveys of, amongst others, the existing Snowcap and Snowcap-2ST1 boreholes.
- A new appraisal well "Snowap-3" is also anticipated to be drilled downdip of the Snowcap 1 and Snowcap 2-ST1 penetrations in a position where the main proven Herrera#8 sands are encountered in the hangingwall of the mapped thrust to deliver near term production whilst also enabling exploration of the H#1 to H#7 sands in the hangingwall for which there is currently very limited modern log and test data in the existing wells in the mapped Snowcap closure.
- Longer term development and FDP will be determined by the outcomes of the above draft work programme items
- Project NPV 10% Base Case modelled value in the region of US$71.3m net to PRD based on 8.33MMSTB 15 Year Base Case production profile with up to US$420m undiscounted P10 Upside Case valuation based on production of c.58.2% of 2C and 2U Prospective Resources.

On behalf of Scorpion Geoscience Limited, I hope this report is to your satisfaction

Best regards, Dr Timothy Wright FGS, SEG & MIMMM

Signed: 11th January 2024

8. References

Bitterli, P., 1958, Herrera subsurface structure of Penal Field, Trinidad, B.W.I. AAPG Bulletin, v. 42, n.1, p. 145-158.

Carr-Brown, B. & Frampton, J. 1979.An outline of the stratigraphy of Trinidad. Field Guide, Fourth Latin American Geological Conference, Port-of-Spain, Trinidad, 7th-15th July, 12pp.

Dyer, B.L. & Cosgrove, P. 1992. Penal/Barrackpore field, West Indies: South Trinidad Basin, Trinidad. American Association of Petroleum Geologists, Treatise of Petroleum Geology Atlas of Oil and Gas

Fields, Structural Traps, v. VII, p.139–157.

Higgins, G.E., 1955, The Barrackpore-Wilson Oilfield of Trinidad, Journal. Inst. Petrol. v.41, p 125 - 147.

Hosein, F. 1990. Exploitation of the Middle Miocene oil bearing intermediate Herrera Sandstone reservoirs in Trinidad, West Indies: in Larue, D.K. & Draper, G. (eds), Transactions of the Twelth Caribbean Geological Conference, St. Croix, U.S. Virgin Islands, 7th-llth August, 1989, 430-443. Miami Geological Society, Florida

info.specommunications.org (Petroleum Resources Management System "PRMS") Petroleum Resources Management System jointly published by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation

Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysists and the European Association of Geoscientists and Engineers as amended June 2018 (PRMS 2018)

Jones, H.P. The Geology of the Herrera Sands in the Moruga West Oilfield of South Trinidad, Fourth Caribbean Geological Conference, Trinidad 1965

Kugler, H.G. 1953. Jurassic to Recent sedimentary environments of Trinidad.VereinigungSchweizerische Petroleum-Geologie und Ingenier Bulletin, 20 (59), 27-60.

Persad, Kh. 2009. The petroleum geology and prospects of Trinidad and Tobago. 100 years of petroleum in Trinidad and Tobago. Celebrating a Century of commercial oil production. P: 178-186

Pindell, J. & Lorcan, K., 2005, Paleogeographic Mapping and Documentation of Sandstones/Reservoir Systems, Palaeogene to mid-Miocene of Trinidad and Eastern Venezuela.

Ramlackhansingh, A., Ramsook, A., Boodoo, S., & Moonan, X., 2009, Exploration Evaluation of the Lower Cruse Formation within Petrotrin's Licence Areas A&C, Southern Sub-Basin, Trinidad: Exploration & Geophysics Group, Petrotrin Internal Report 10355.

Saunders, J. B. 1974. Trinidad Stratigraphic Chart. Ministry of Energy of Trinidad and Tobago.

SLR., Competent Persons Report, Predator Oil and Gas Trinidad ltd or predator oil and gas holdings plc onshore Trinidad, 30th Jan 2020 SLR Ref: 501.00269.00003

www.energy.gov.tt

www.predatoroilandgas.com

Appendix A Glossary of Selected Terms and Definitions*

Accumulation	An individual body of naturally occurring petroleum in a reservoir
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.
ASG	Associated Solution Gas
BCF	Billion Cubic Feet of Gas
bbl	Barrels
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.
1C	Denotes low estimate of Contingent Resources with >90% probability that recovered quantity will equal or exceed this estimate “P90”.
2C	Denotes Contingent Resources of same technical confidence as Probable, but not commercially matured to Reserves with >50% probability that recovered quantity will equal or exceed this estimate “P50”.
3C	Denotes Contingent Resources of same technical confidence as Possible, but not commercially matured to Reserves with >10% probability that recovered quantity will equal or exceed this estimate “P10”.
CEG	Challenger Energy Group
COS	Chance of Success
CPR	Competent Persons Review
Exploration	Prospecting for undiscovered petroleum using various techniques, such as seismic surveys, geological studies, and exploratory drilling.
FDP	Field Development Plan
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.
GOR or 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.
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.
IT	Inniss-Trinity Field
ITR	Independent Technical Report, informal equivalent to a formal Competent Person’s Report produced by a professionally qualified person reflecting
km	kilometres
km²	Square kilometres
Known Accumulation	An accumulation that has been discovered.
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.
MEEI	Ministry of Energy and Energy Industries
MMSTB	Million Stock Tank Barrels
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).
MW	Moruga West Field

PIIP	Petroleum Initially in Place
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.
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 licence or a registered or certified professional geologist's licence, 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")
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.
Risk	The probability of loss or failure. Risk is not synonymous with uncertainty. Risk is generally associated with the negative outcome e.g. failure to encounter reservoir, the term "chance" is preferred for general usage to describe the probability of a discrete event occurring.
SC	Snowcap Discovery / Well
STB	Stock Tank Barrels
TR	T-Rex Resources Trinidad
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.
Undiscovered Petroleum Initially in-Place	That quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.
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

***A full technical glossary pertaining to the reporting of hydrocarbon resource exploration, appraisal and development activities can be accessed at https://info.specommunications.org/**

Appendix B Database Reference Tables

Table B1 Seismic database made available to Predator Oil and Gas and used as the basis for this ITR.

SEISMIC DATATYPE	NUMBER OF ITEMS	Comments
137km 2D seismic Lines	**6**	Multiple vintages, 10km on Cory Moruga Block
102.6km² 3D seismic data	**2**	Cory Moruga 3D seismic survey as SEG-Y, "full-stack" and "enhanced stack" volumes. Full 30km² coverage of Cory Moruga Block
Migration Velocity Cube	**1**	V-int volume for depth conversion

Table B2 of key well penetrations relevant to the Snowcap structure and the content of this report for which data have been made available to PRD PLC

WELL	SPUD	TD Depth (MD Metres)	TD Formation
Rochard-1	**1955-04-05**	**3516 vertical**	**Cretaceous Naparima Hill shales**
RD-6 and RD-7 logs and production data	**1960**	**1253 & 1256 (deviated)**	**Gr. 7a Cipero Herrera Sands**
MW-45 & MW-112	**1957-02-01**	**2623 & NA (deviated)**	**Gr. 7a Cipero Herrera Sands**
Snowcap-1	**July 2010 (37 days)**	**2,621, deviated**	**Eocene, Navet Fm**
Snowcap-2 & 2ST	**2015**	**1,735 (lost) & 1,619 deviated**	**Gr. 7a Cipero Herrera Sands**

TABLE B3 Reports and associated database items made available to Predator Oil and Gas and used as the basis for this ITR.

Data type	Number of items	Comments
Well reports	**3**	Variable levels of detail in reporting but sufficient to locate wells, identify drilling parameters and well outcomes
Raster Image Log Suites	**12**	Typically older wells with limited range of wireline tools
LAS Digital log suites	**21**	Modern wells e.g. Snowcap
Deviation surveys	**24**	Available for most wells in the vicinity including Snowcap 1 & 2
VSPs & Checkshots	**2**	Limited number of modern wells including Snowcap-1
Reservoir Pressure Reports	**2**	Snowcap-1 & Snowcap-2
Production Test Reports	**5 (2)**	Snowcap-1 and Initial test reports for Snowcap-2ST1

Fluid Database	**2**	Snowcap-1 and from Initial testing of Snowcap-2ST1
Formation top data	**15+**	Formation tops and stratigraphic tables from previous operators Parex??
Technical reports and summaries	**5**	Range of technical presentations covering discoveries, production testing and aspects of remaining prospectivity
Permit boundaries and shapefiles	**3**	Obtained from online sources inc. Ministry