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Competent Person Report – Buffalo Development

For Advance Energy plc and Strand Hanson Ltd

March 2021

At the request of Advance Energy plc and Strand Hanson Limited, RISC has prepared this Competent Persons Report (CPR) relating to the Buffalo oil field re-development operated by Carnarvon Petroleum. The CPR has been prepared for inclusion in an Admission Document to be sent to shareholders of Advance Energy plc and to be available on the company's website. It has been prepared in accordance with the AIM Note for Mining, Oil and Gas Companies, which forms part of the AIM Rules for Companies, as published by the London Stock Exchange. The resource volume assessments are reported in compliance with the definition and guidelines set out in the 2018 Petroleum Resource Management System (PRMS).

There are no material changes to resources or values evaluated at 31 December 2020 or to the analysis and opinions expressed in this CPR.

Peter Stephenson

RISC Partner

23 March 2021

1. Executive Summary

The Buffalo oil field was discovered in 1996 by BHP and produced 20.5 MMstb of light oil between 1999 and 2004. It was developed using four production wells with gas lift, drilled from a wellhead platform (WHP) in 25 m water depth with fluid processing and storage on an FPSO. The original development has been fully abandoned and decommissioned.

Carnarvon Petroleum acquired 100% of the WA-523-P Exploration Permit including the Buffalo field in May 2016, reprocessed the 3D seismic and remapped the field. Improved seismic imaging shows that the crest of the field is further east than previously mapped and drilled in the original development. Re-mapping has identified the opportunity to re-develop the field.

The original WA-523-P Exploration Permit was located in Australian federal waters. However, a Maritime Boundary Agreement signed between Australia and East Timor moved a portion of the original WA-523-P Exploration Permit to Timor-Leste waters and exclusive jurisdiction was ratified on 30 August 2019. The Timor Leste portion, including the Buffalo field, is held 100% by Carnarvon Petroleum Timor, Unipessoal Lda ("Carnarvon Petroleum Timor") as a new Production Sharing contract (TL-SO-T19-14, the "Buffalo PSC")). Advance Energy TL Limited ("AETL") has signed the Buffalo Subscription Agreement to subscribe for up to 50% of the equity in Carnarvon Petroleum Timor resulting in an indirect interest in the Buffalo PSC and Buffalo re-development project.

The exploration phase of the Buffalo PSC expires 26 May 2023 (following a one year extension granted to Carnarvon Petroleum Timor) and may be followed by an exploration extension or 25 year development and production period.

RISC has independently reviewed the subsurface evaluation, development plans, costs, schedule and economics as detailed in this Competent Person Report. Resources in Table 1-1 are classified as Contingent Resources, sub-class "development pending".

Table 1-1: Summary of contingent resources for Buffalo Field in PSC TL-SO-T19-14 as at 31 December 2020

Oil contingent resources and development NPV	Contingent Resources (MMstb)			NPV_{10} (US$million at 31/12/2020)		
	1C	2C	3C	1C	2C	3C
Gross (100% Field)	16.0	34.3	62.8	-	-	-
PSC contractor net Entitlement (100%)	12.2	25.0	44.4	140	339	611
Net indirectly attributable to AETL (50% contractor)	6.1	12.5	22.2	69	169	305

Notes:

1. "Gross" are 100% of the field resources some of which may fall outside the Buffalo PSC.
2. "Contractor Net" are attributable to contractor under terms of the PSC.
3. "Net indirectly attributable to ATEL" is the proportion attributable to AETL's equity in Carnarvon Petroleum Timor. ATEL interest in Carnarvon Petroleum Timor post subscription farm-in is to be confirmed.
4. Associated gas will be consumed in operations with limited surplus volumes flared.
5. Contingent resources are economic and an economic cut-off has been applied. RISC estimate the probability of development to be 86%.

In PSC's the contractors net entitlement is derived from cost and profit oil as dictated by the terms of the PSC. The remaining oil is the property of the Government. Carnarvon Petroleum Timor is currently the 100%

contractor. ATEL's equity in Carnarvon Petroleum Timor will depend on the subscription funds raised. Table 1-1 indicates the position assuming ATEL subscribes for 50% of the equity in Carnarvon Petroleum Timor, which would be achieved if they contribute US$20 million which is expected to fully fund the appraisal well.

The project economics shown in this report are the unrisked project NPVs for the contractor of the PSC. They should not be taken as fair market value which needs to consider other factors such as project maturity, uncertainty and probability of development.

Gross resource volumes are slightly altered from previous estimates by the economic cut-off applied (see section 5.3).

A Buffalo-10 appraisal well is planned to be drilled in 2H 2021. The intention is that this well will confirm the depth of the remapped crest of the field and will be suspended and subsequently completed as an oil producer.

A number of development options are being considered using existing available Floating Production Storage and Offtake units (FPSO) or Mobile Oil Production Units (MOPU). This analysis has assumed development using the appraisal and two additional development wells drilled using a jack-up rig with wellheads on a leased MOPU and oil storage and transfer via a leased Floating Storage and Offtake vessel (FSO). RISC estimate project FID in early 2022 after the appraisal well results are known, with first oil by January 2024, although an earlier date may be possible. Development costs for this option are estimated to be US$145 million including US$69 million for appraisal and development wells. This equates to a development Capex of less than 4 $/stb. Annual average operating costs are estimated to be US$60 million per year with some reduction for reduced maintenance in the last two years of field life.

If appraisal demonstrates a low case or 1C outcome the number of development wells and facility capacity will be adjusted to optimise a smaller development. Contingent resources can be reclassified as reserves post project sanction. However, the contingent resources in Table 1-1 are likely to be updated post appraisal and the uncertainty range reduced. Post appraisal key issues to be resolved prior to project approval are joint venture support to progress the development, project funding and acceptable commercial arrangements to secure the MOPU, FPSO and/or FSO facilities.

Table of contents

1. Executive Summary 2
2. Introduction 8
   2.1. Asset description 8
   2.2. Terms of reference 11
   2.3. Basis of assessment 11
3. Buffalo Field Evaluation 13
   3.1. Regional information 13
      3.1.1. Regional Geology 13
      3.1.2. Field history 15
   3.2. Subsurface interpretation 16
      3.2.1. Seismic data and processing 16
      3.2.2. Seismic interpretation 19
      3.2.3. Reservoir description 22
      3.2.4. Petrophysical interpretation 22
      3.2.5. Fluid contacts 24
      3.2.6. Geological modelling 24
      3.2.7. Fluid properties 28
      3.2.8. Production History 28
      3.2.9. Dynamic modelling 28
4. Field Development Plan 32
   4.1. Drilling and completions 32
   4.2. Production Facilities 32
   4.3. Capital and Operating Costs 34
      4.3.1. Capital costs 35
      4.3.2. Operating costs 36
   4.4. Abandonment costs 37
   4.5. Development Schedule 37
   4.6. Production and cost forecasts 37
5. Resources 39
   5.1. In-place resource volumes 39
   5.2. Production Forecasts 39
   5.3. Resource summary 39
   5.4. Project Risks 40
6. Commercial 41
   6.1. Methodology 41
   6.2. Fiscal regime/PSC terms 41
      6.2.1. Assumptions 41
   6.3. Economic results 43

7. Declarations 45
7.1. Terms of Engagement 45
7.2. Qualifications 45
7.3. Standard 45
7.4. Limitations 45
7.5. Use of advice or opinion and reliance 46
7.6. Independence 46
7.7. Copyright 46
7.8. Authorisation for release 47
8. List of terms 48

List of figures

Figure 2-1: Location map 8
Figure 2-2: Map showing the original WA-523-P permit area, the Maritime Boundary change and the new PSC TL-SO-T19-14. 11
Figure 3-1: Structural elements of the Bonaparte Basin 14
Figure 3-2: Northern Bonaparte Stratigraphy 15
Figure 3-3: Bathymetric Topography Overlying the Buffalo Field Reservoir 17
Figure 3-4: TWT Seismic Section through the Shoal Overlying the Buffalo Field 18
Figure 3-5: BHP's Top Elang Depth Structure Map (Source: Buffalo 5 WCR, BHP) 19
Figure 3-6: Nexen's Top Elang Depth Structure Map (Source: Buffalo 9 WCR, BHP) 20
Figure 3-7: Interpreted Seismic Depth Section through Buffalo-3 Showing Updip Potential in the South (Carnarvon) 21
Figure 3-8: Carnarvon's Post FWI Final (June 2017) Top Elang Depth Structure Map (modified after Carnarvon) 21
Figure 3-9: Buffalo field Elang Formation reservoir correlation (Carnarvon) 22
Figure 3-10: Buffalo field formation pressure data (Carnarvon) 24
Figure 3-11: 3D view of input data used in structural modelling of Buffalo (Carnarvon) 25
Figure 3-12: Upscaled vs Well Data (Carnarvon) 26
Figure 3-13: OOIP Histogram from 500 simulation runs (after Carnarvon) 27
Figure 3-14: Buffalo measured and simulated well production history (Carnarvon) 29
Figure 3-15: Simulated water saturations after 2½ years production (Carnarvon) 30
Figure 3-16: Buffalo-3 history match in low, mid and high case realisations (Carnarvon) 31
Figure 3-17: Simulated production with 3 well re-development (Carnarvon) 31
Figure 4-1: Schematic representation of development concept (Carnarvon) 33
Figure 4-2: Development cost schedule 36
Figure 4-3: 1C, 2C, 3C Oil Production Forecasts 38
Figure 6-1: Brent Oil Price Index Performance History 42
Figure 6-2: OPEC market share of global production 42
Figure 6-3: Contractor NPV tornado diagram 44
Figure 6-4: NPV sensitivity to key parameters 44

List of tables

Table 1-1: Summary of contingent resources for Buffalo Field in PSC TL-SO-T19-14 as at 31 December 2020. 2
Table 2-1: Summary Table of Assets 9
Table 2-2: Asset work program commitment summary 10
Table 3-1: Elecrofacies Classification..... 23
Table 3-2: Gross Hydrocarbons In-place for the Buffalo Field 27
Table 4-1: Buffalo capital costs..... 35
Table 4-2: Buffalo facility Operating costs 36
Table 4-3: Estimated facility capacity..... 38
Table 5-1: Contingent resources as at 31/12/2020..... 39
Table 6-1: Summary of economic evaluation of discovered assets 43

2. Introduction

2.1. Asset description

The Buffalo oil field is located in the northern Bonaparte Basin in the Timor Sea, between the Australian mainland and the island of Timor Leste. Oil fields located nearby include the Laminaria, Corallina, Jahal, Kuda Tasi and Kitan oil fields (Figure 2-1).

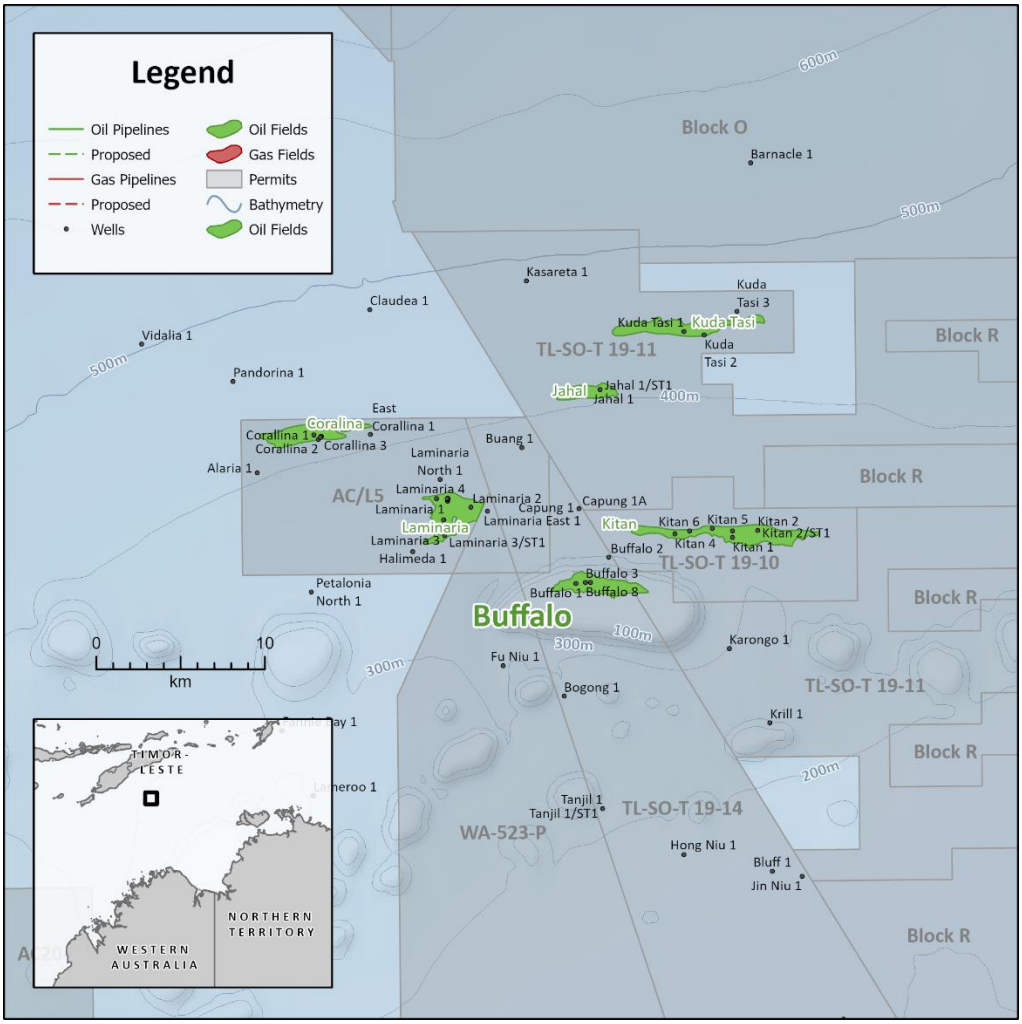


Figure 2-1: Location map

The Buffalo oil field was discovered in 1996 by BHP and produced 20.6 MMstb of light oil between 1999 and 2004. It was developed using four production wells with gas lift, a Well Head Platform ('WHP') in 25 m water depth and a Floating Production Storage and Offtake ('FPSO') vessel. The original development has been fully abandoned and decommissioned.

Carnarvon Petroleum acquired the 4,220 km^2 WA-523-P Exploration Permit 100% in May 2016, including the Buffalo field, following a successful work program bid on the W15-2 Release Area as part of the Australian 2015 Federal Offshore Release Round. The work program consisted of 3D reprocessing and geological studies plus one exploration well to be drilled by May 2023, having been deferred 1 year following an extension granted to Carnarvon Petroleum Timor.

Carnarvon Petroleum reprocessed the 3D seismic utilising Full Waveform Inversion ('FWI') and remapped the field. Improved seismic imaging as a result of the FWI shows that the crest of the field is located further east than previously mapped and identified the opportunity to re-develop the field.

Following the mapping of the field on the newly reprocessed seismic data, Carnarvon Petroleum undertook geological static modelling and simulation studies to determine if redevelopment of the field was possible. This work showed that if the interpretation of an un-drilled attic was correct, a redevelopment of the field was possible. RISC undertook an audit of this re-evaluation and certified Contingent Resources in August 2017, with a 2C contingent resource within permit of 31.1 MMstb.

The original WA-523-P Exploration Permit was located entirely in Australian Federal waters. However, a Maritime Boundary Agreement signed between Australia and Timor Leste on 6 March 2018 resulted in a portion of the original WA-523-P Exploration Permit becoming Timor-Leste waters (Figure 2-2). Exclusive jurisdiction was ratified on 30 August 2019. The Timor Leste portion, including the Buffalo field, is held as a new Production Sharing Contract ('PSC') TL-SO-T19-14 (the 'Buffalo PSC').

As part of the maritime boundary change treaty, parties that were affected by the boundary change were to be guaranteed security of title and the preservation of rights and conditions afforded under Australian jurisdiction. Following the agreement of the maritime boundary change Carnarvon Petroleum negotiated the new PSC with both the Australian and Timor Leste regulators. In addition to the Buffalo PSC, a 'Buffalo Decree Law' and the Timor Leste petroleum law govern the title.

The assets covered by this CPR are shown in Table 2-1. The Buffalo PSC has the following periods:

- An exploration period of 6 years commencing 27 May 2016 and expiring 26 May 2023 following a one year extension granted to Carnarvon Petroleum Timor
- An option to extend the PSC for up to two five periods of five years subject to an agreed minimum work programme
- A development and production period of 25 years, subject to submission and approval of a Development Plan.

Table 2-1: Summary Table of Assets

Asset	Operator	Interest	Status	Licence Expiry date	Licence Area (km2)	Comments
Buffalo PSC, TL-SO-T19-14, Timor Leste	Carnarvon Petroleum Timor Unipessoal Lda	100%	Exploration PSC	26/05/2023	1347.5	25 year development and production period upon dev plan application/approval

The Buffalo PSC is deemed to have commenced on 27 May 2016 in conjunction with the WA-523-P Exploration Permit. The work program commitments for Years 1 to 3 of both WA-523-P and the Buffalo PSC are deemed to have been satisfied, and the remaining work program commitments for both titles is shown in Table 2-2. The prior WA-523-P well commitment and associated planning has been transferred to the Buffalo PSC. The seismic acquisition for Year 6 remains with WA-523-P.

A Buffalo-10 well is planned to be drilled on the field to confirm the attic structural interpretation and to determine the current oil-water contact in the field.

Carnarvon Petroleum was granted approval of a drilling environmental plan by the Australian National Offshore Petroleum Safety and Environmental Management Authority ('NOPSEMA') on 14 May 2019 for a period of three (3) years. This has been duly acknowledged and accepted by the Timor Leste regulator.

Table 2-2: Asset work program commitment summary

Period	WA-523-P Exploration Permit	TL-SO-T19-14 PSC
Year 4: 27 May 2019 – 26 May 2020	Nil	G&G studies
Year 5: 27 May 2020 – 26 May 2021	Nil	Well planning and Long Lead studies. Environmental plan.
Year 6: 27 May 2021 – 26 May 2022	210 km^2 broadband seismic acquisition. PSDM and FWI processing.	1 well[#1]
#1: extension to 26 May 2023 granted to Carnarvon Petroleum Timor		

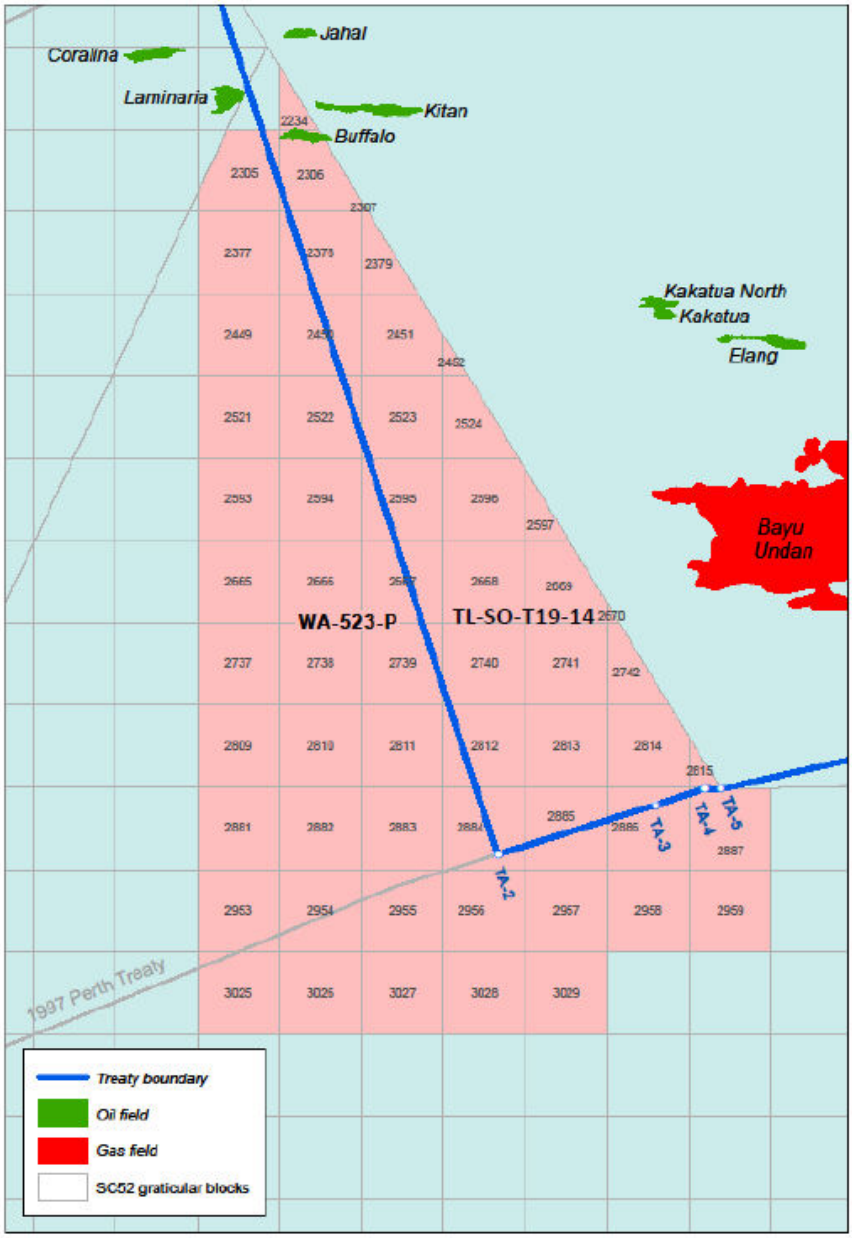


Figure 2-2: Map showing the original WA-523-P permit area, the Maritime Boundary change and the new PSC TL-SO-T19-14.

2.2. Terms of reference

RISC was commissioned by Advance Energy plc ("Advance") to provide a Competent Persons Report on the Buffalo re-development to support an AIM admission. This included an independent subsurface, development and project economics evaluation. The work has been completed in consultation with Strand Hanson who are acting as nominated advisor in connection with the AIM admission.

2.3. Basis of assessment

The data and information used in the preparation of this report were provided by the Operator, Carnarvon Petroleum Timor supplemented by public domain information and RISC's database. RISC has relied upon the

information provided and has undertaken the evaluation on the basis of a review and audit of existing interpretations and assessments as supplied making adjustments that in our judgment were necessary.

RISC has reviewed the reserves/resources in accordance with the Society of Petroleum Engineers internationally recognised Petroleum Resources Management System (PRMS).

RISC's methodology was to review deterministic and probabilistic resource evaluation carried out by Carnarvon Petroleum Timor, modify some of the inputs to conform to our views and update the resource estimation. Details of the findings of our review and the resource estimation process are presented in this report.

RISC has also reviewed and adjusted the production forecasts and costs prepared and provided by Carnarvon Petroleum Timor. The resources presented in this report are based on long term oil price projections of US$35 to US$65/bbl real terms. We have used the mid-point value of US$50/bbl real terms for the economic cut off for production and associated resource volumes.

Unless otherwise stated, all resources presented in this report are gross (100%) quantities within the Buffalo field with an effective date of 31 December 2020. All costs are in US$ real terms with a reference date of 2020 (RT2020).

We have not conducted a site visit and do not consider it appropriate or necessary as the development has not taken place.

3. Buffalo Field Evaluation

3.1. Regional information

The Democratic Republic of Timor Leste, which forms the eastern half of the Island of Timor, gained independence from Indonesia in 2002. As a result, Timor Leste's oil and gas industry is small with limited technical experience but does have two projects of note, Bayu Undan and Greater Sunrise.

The largest project has been the offshore Bayu Undan field which was discovered in 1995 and was subsequently developed and started production in 2004, with ConocoPhillips as operator. The gas produced from the field comes ashore to an LNG plant in Darwin, Australia. Timor Leste has regulated the project and supplied some offshore personnel and support facilities. ConocoPhillips' interest in the field was acquired by Australia's Santos in March 2020.

Revenues from Bayu Undan have provided the bulk of the country's oil and gas revenues, which make up approximately 95 percent of Timor Leste's income, and fed the country's sovereign wealth fund.

The Greater Sunrise project, which straddles Timor Leste and Australian waters (following the settlement of the maritime boundary by the two countries in 2018) is operated by Woodside, with Timor Leste holding a majority position as a result of acquiring stakes from ConocoPhilips and Shell, its former partners in the project, in 2018. It is a gas and condensate field discovered in 1974 and now estimated to contain estimated 2C resources of 5.13 tcf dry gas and 225.9 million barrels of condensate.

3.1.1. Regional Geology

The Cambrian to recent Bonaparte Basin is a fan-shaped hydrocarbon-bearing basin extending over 270,000 km^2 in the north-western offshore and onshore Australia (Figure 3-1). The basin contains up to 15 km of sediments and has a multi-phase history, comprising the southern Palaeozoic and northern Mesozoic depocentres. The latter forms part of the Westralian Super-basin. The Bonaparte Basin adjoins the Browse Basin to the west and the Money Shoals Basin to the northeast. The Timor Trough defines its northern boundary. The basin developed as a v-shaped, north-opening rift during the Devonian to Early Carboniferous.

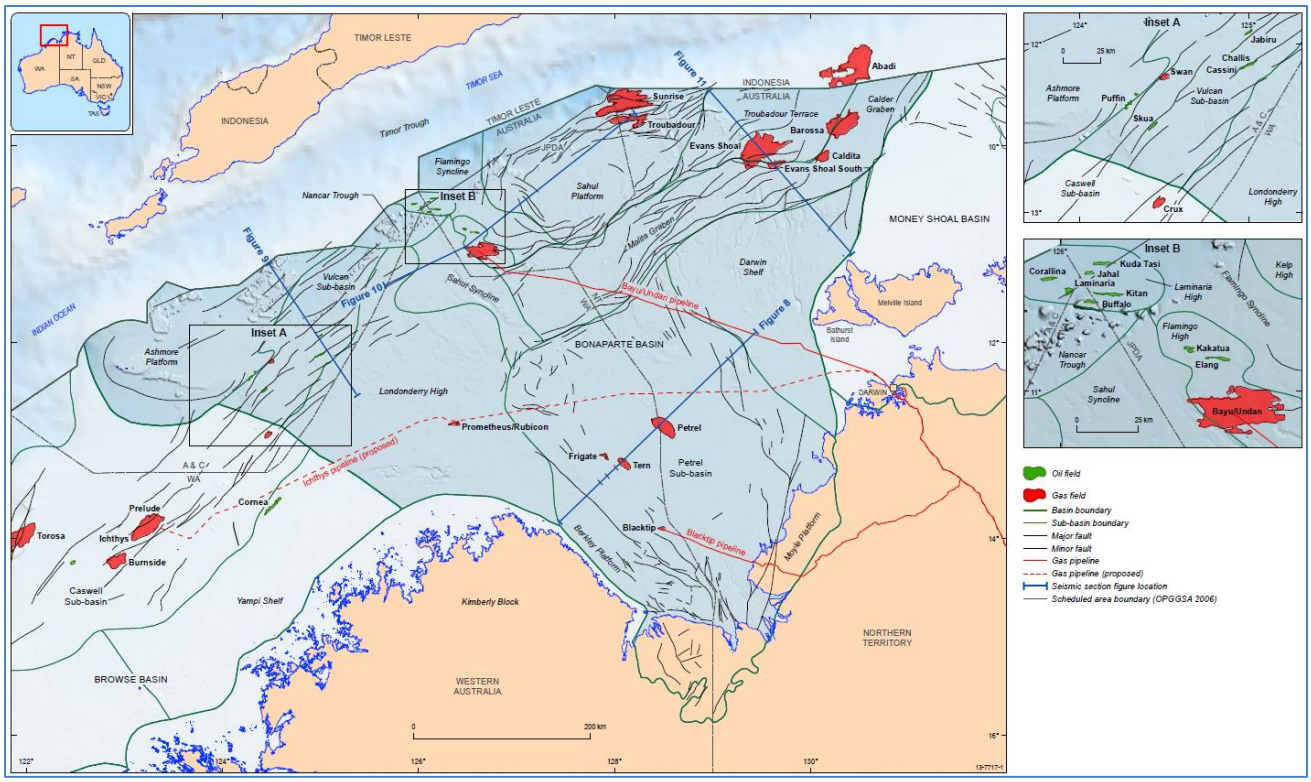


Figure 3-1: Structural elements of the Bonaparte Basin

The basin developed during two phases of Palaeozoic extension and Late Triassic compression prior to the onset of Mesozoic extension. Initial rifting occurred in the Late Devonian (NW-trending Petrel Sub-basin) and was orthogonally overprinted in the Late Carboniferous to Early Permian by north-east trending rift basins (proto-Malita and proto-Vulcan depocentres). Regional north-south compression in the Late Triassic resulted in widespread uplift and erosion, and, together with salt tectonics, produced inversion structures and anticlines in the Petrel Sub-basin. Erosion and collapse of these uplifted areas led to the widespread deposition of Lower to Middle Jurassic 'redbeds' and fluvio-deltaic clastics. Late Jurassic extension resulted in a series of linked, north-east trending (Vulcan Sub-basin, Malita and Calder Grabens) and south-east trending (Sahul Syncline) intracontinental grabens.

The Jurassic depocentres contain thick marine mudstones flanked by fan delta sandstone deposits. A thick post-rift Cretaceous to Tertiary succession is dominated by fine-grained clastic and carbonate facies. Late Miocene to Pliocene convergence of the Australian and Eurasian plates resulted in flexural down-warp of the Timor Trough and widespread reactivation of the previous extensional fault systems.

The most prospective part of the Bonaparte Basin includes the Vulcan Sub-basin, Laminaria-Flamingo High and northern Sahul Platform. The Late Jurassic marine section is the major source interval in the outboard grabens, together with Middle-Lower Jurassic marine shales and coastal plain coals. In the Petrel Sub-basin the main sources are postulated Lower Carboniferous marine shales and Permian coastal plain coals and pro-delta shales.

Reservoirs range in age from Carboniferous to Permian in the Petrel Sub-basin and Londonderry High, Triassic to Cretaceous in the Vulcan Sub-basin and Jurassic in the northern parts of the basin. Fault seal breach is one of the main risks in the western part of the basin.[1]

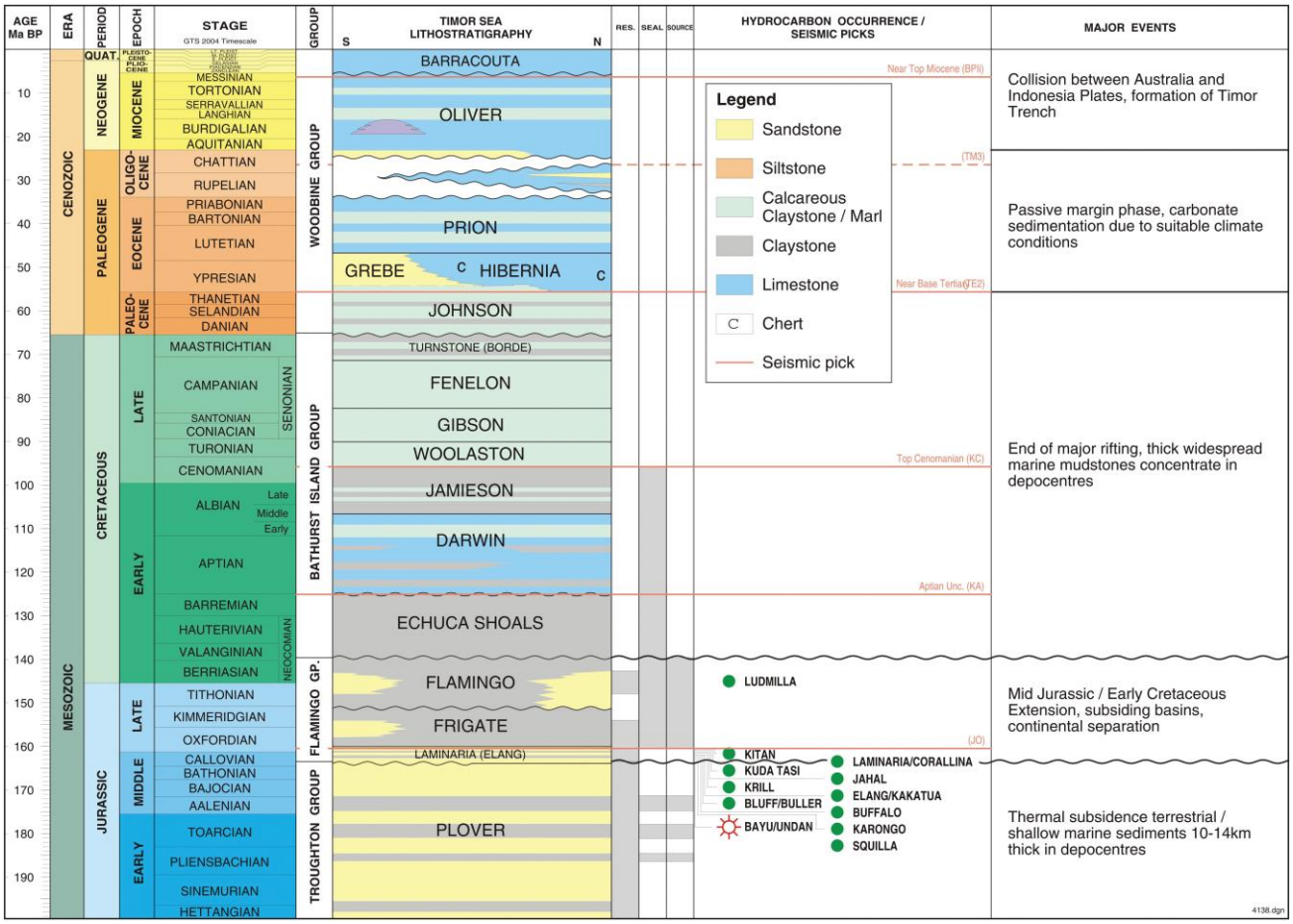


Figure 3-2: Northern Bonaparte Stratigraphy[2]

3.1.2. Field history

Buffalo-1 was drilled in 27.2 m water depth during September 1996 by BHP and encountered a 45 m oil column in good quality sandstone reservoirs of the Callovian aged Elang Formation. A 27 m interval within the Elang Formation was production tested, yielding 52.7 degree API oil at a stabilized rate of 11,790 stb/d. The well test analysis determined that the well had an Ideal Productivity Index of 120 stb/d/psi with a reservoir permeability of 1,130 millidarcies. The well was subsequently plugged and abandoned.[3]

Buffalo-2 was drilled in May 1997 as a deviated well located off "Big Bank" in 295 m of water and deviated to the target location 1.5 km to the southeast. The Elang Formation was intersected 40 m low to prognosis. Wireline log evaluation and RFT pressure defined a 21 m oil column in the well, but the well was not tested. A 44 m core was cut in the upper part of the Elang reservoir. Analysis of the core confirmed continuity of

[1] Geoscience Australia
[2] Discovery to Development: A Subsurface Case History of the Kitan Oil Field, Timor Sea, West Australian Basins Symposium 2013, Wheller et al.
[3] Buffalo Redevelopment "The Wee Field That Grew", SPE 77918, 2002, Begg et al.

quality reservoirs in the Elang Formation with porosities averaging 13% and permeabilities ranging from 30 to 2,500 millidarcies. The well was plugged and abandoned.

The development of the field started in mid-1999 with the installation of the WHP on the "Big Bank" and the refurbishment of the FPSO by Modec. Buffalo-3 was drilled in July 1999, and the objective Elang Formation was intersected 0.6 m high to prognosis. Wireline log evaluation and an MDT pressure survey defined a 49.9 m oil column. The reservoir section was as expected. Buffalo-4 was drilled in August 1999 as a deviated well into the north-west fault compartment of the field. The Elang Formation was intersected 94.5 m low to prognosis and was below the Oil-Water Contact ('OWC') at this location. However, the base Aptian marker, which was the deepest reliable seismic event, was encountered on prognosis. Buffalo-5 was drilled in June 1999. It was a re-drill of Buffalo-1 (400 m west).

The Buffalo field was brought on stream on 29 December 1999. Initial clean oil rates of 50,000 bopd were achieved in January 2000. Water production began in mid-February 2000, earlier than expected. In December 2000, Nexen assumed Operatorship and 100% equity in the field. Buffalo 6, which was planned by BHP to target the currently mapped crest of the field, was not drilled.

Buffalo-7, was drilled in March 2002 targeting a northern fault compartment. Nexen believed that the well proved the existence of a northern attic from reprocessing of the seismic and remapping, and the well came on production in April 2002 at a rate of 25,000 bopd. Buffalo-8 targeting a western fault compartment, was spudded in April 2002 and encountered the Elang Formation 8 m below the OWC. The adjacent Buffalo-9 well was spudded May 2002 and encountered shallower reservoir in the western area. The well came on production in June 2002 at 10,000 bopd.

No further wells were drilled and the Buffalo field was shut-in at 89% water-cut in November 2004 after production had declined to 4,000 bopd. The field was fully decommissioned and all facilities removed in 2005.

3.2. Subsurface interpretation

RISC has reviewed and supports the Operator's static modelling and STOIIP estimates. We have reviewed the simulation, history match and production forecasts and accept the simulated recovery factors as being at the higher end of the range, analogous to Laminaria Corrallina field 10 km to the west. A range of recovery factors, based on analogue fields has been used with the STOIIP estimates to generate the range of resource volumes and corresponding production forecasts.

3.2.1. Seismic data and processing

The Top Elang Formation surface has been difficult to interpret on seismic data which is typical in this area. Forward modelling has shown this boundary to have a Class II Amplitude vs Offset ('AVO') response, i.e. a polarity reversal of the seismic event occurs across the shot gathers resulting in attenuation of the event during stacking. This has been used to aid interpretation.

The Buffalo field underlies a seafloor carbonate bank, which rises from the seafloor (300 m below sea level) up to a depth of 27 m below sea level (Figure 3-3). Interpretation of the underlying geology on conventionally processed seismic data is difficult due to ray-path distortion from the steep sides of this bank and the large velocity contrast with the surrounding water. At the top reservoir level, the poor seismic data quality is a consequence of poor signal penetration, poor reflectivity contrast, faulting and multiples, which also give the reservoir section the appearance of being highly faulted.

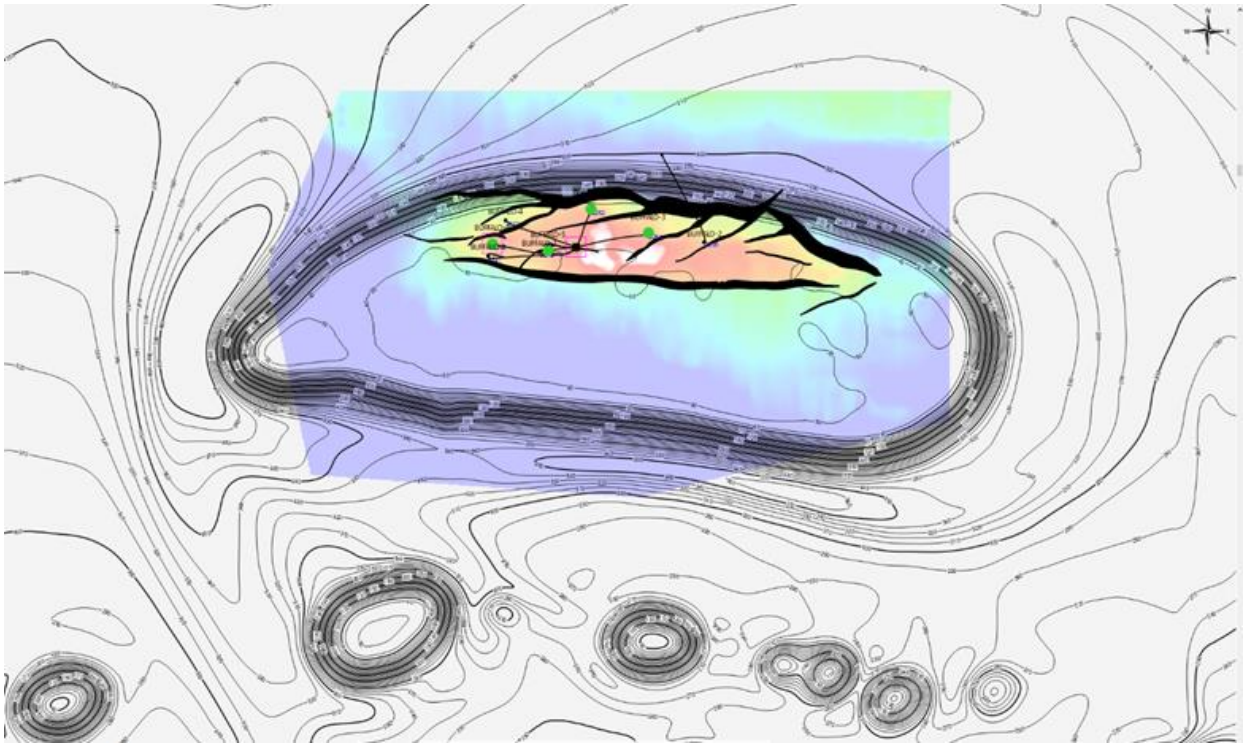


Figure 3-3: Bathymetric Topography Overlying the Buffalo Field Reservoir

The bathymetric topography and associated interval-velocity complexity causes seismic ray-path distortion, leading to poor imaging, and mis-location; especially under the reef margins. Note the significant "pull-up" in TWT domain under the carbonate bank in Figure 3-4.

The earth modelling process named Full Waveform Inversion ('FWI') is widely used as an additional tool for improving velocity models in seismic imaging workflows[4]. The approach by Carnarvon Petroleum Timor was to apply FWI to better resolve the velocity field, and to use that high-quality velocity field as input to 3D pre-stack depth migration ('PSDM') in order to better image the subsurface and correct ray path distortion under the Big Bank.

DownUnder GeoSolutions ('DUG') has reprocessed the 3D marine seismic data from the Buffalo 3D (1996), Buller 3D (1997), and Tiger 3D (2008) surveys within the WA-523-P permit in the Bonaparte Basin, offshore Australia. The datasets were processed from field tapes by DUG in their Perth office from June 2016 to May 2017[5].

The main objective of the project was to accurately image the seismic data in depth by applying a high-end processing workflow. Velocity model building for this project used a number of iterations. To begin with, a simplified initial model was built from the vintage velocities, with modifications around the reefs. This was used as input to refraction tomography, which was then in turn used as input to FWI, and then followed by several iterations of velocity model building. The final migration was VTI anisotropic. The velocity modelling was supported by the interpretation of 11 horizons in total, and logs from 21 wells.

[4] SEG wiki

[5] 3D Marine Reprocessing over WA-523-P, Bonaparte Basin, Australia – Processing Report, July 2017, DownUnder GeoSolutions

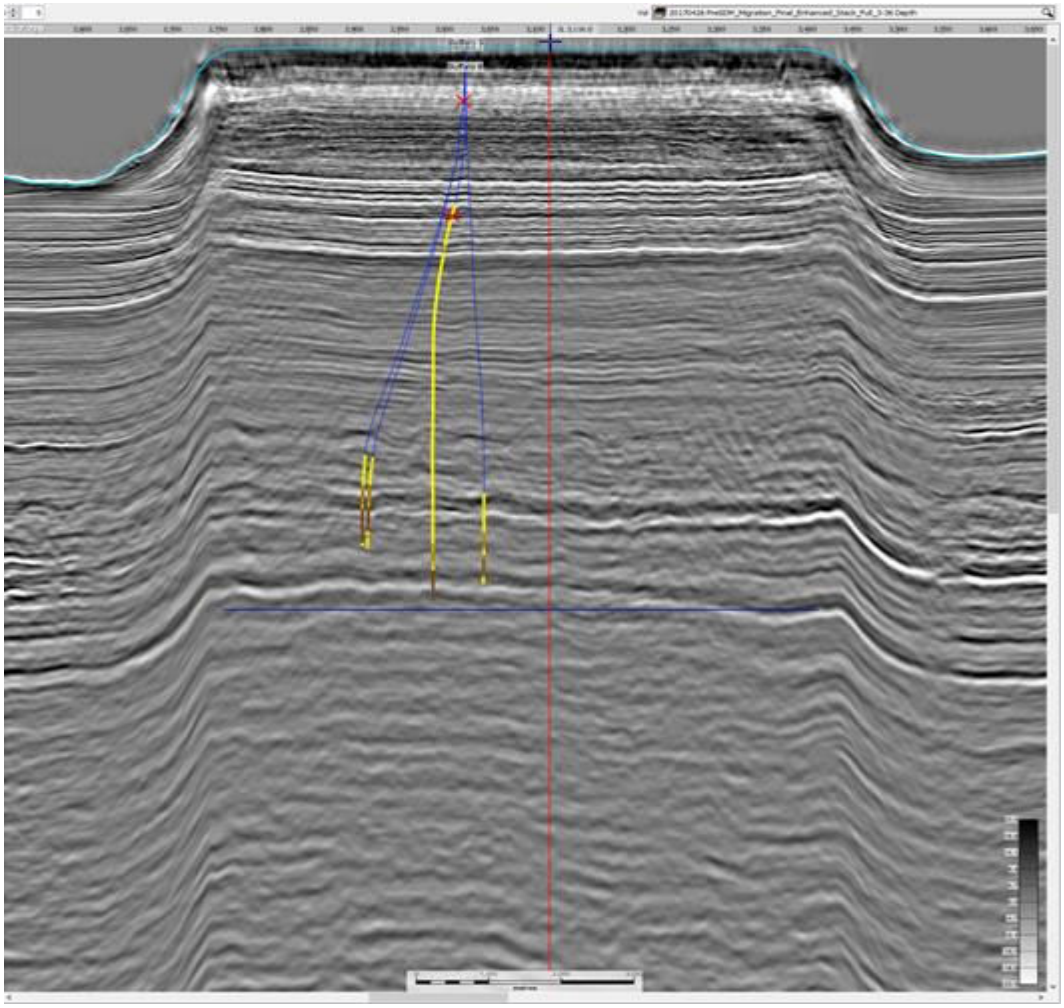


Figure 3-4: TWT Seismic Section through the Shoal Overlying the Buffalo Field

The final 3D seismic data in depth domain was adjusted using a simple velocity field to tie the well markers, a process which created a tilt of the structure across Buffalo in an east-west direction. The well tie adjustments are of long wavelength supported by well observations regionally. Depth errors before well tie correction are in the order of several of 10's of meters.

This dataset ('DUG1') was utilised for interpretation and formed the basis of the geological modelling discussed in section 3.2.6. This dataset showed that that the crest of the field is further east than previously mapped and identified the opportunity to re-develop the field.

Over a period of 12-months from mid-2017 further processing of the seismic data was undertaken[6]. In order to verify the FWI processing results, an independent processing study was undertaken with CGG to verify the DUG processing results. For this study a portion of the dataset over the field was processed without the DUG velocity model to initialise. This dataset and its interpretation confirm that an undrilled structural attic is present in the east.

[6] R. McGee, H. Debenham, P. Hoiles, A. O'Neill, J. Miller & A. Padman (2019) 'Reviving an old Buffalo – Breathing new life into an old dataset with modern technology.', in KEEP, M. & MOSS, S.J. (Eds), The Sedimentary Basins of Western Australia V: Proceedings of the Petroleum Exploration Society of Australia Symposium, Perth, WA, 2019, 13 pp.

A further two iterations of the processing were conducted with DUG with further refinement of the processing flow and parameterisation. The final version ('DUG4') benefitted from Kirchhoff PSDM that allowed for refinement of the pre-stack, post-migration demultiple.

3.2.2. Seismic interpretation

During the early field development, BHP found that the Buffalo structure at reservoir level appeared to be composed of two en-echelon horsts (Figure 3-5). The mapped structure dipped down to the south and north from a central high running east-west along strike[7].

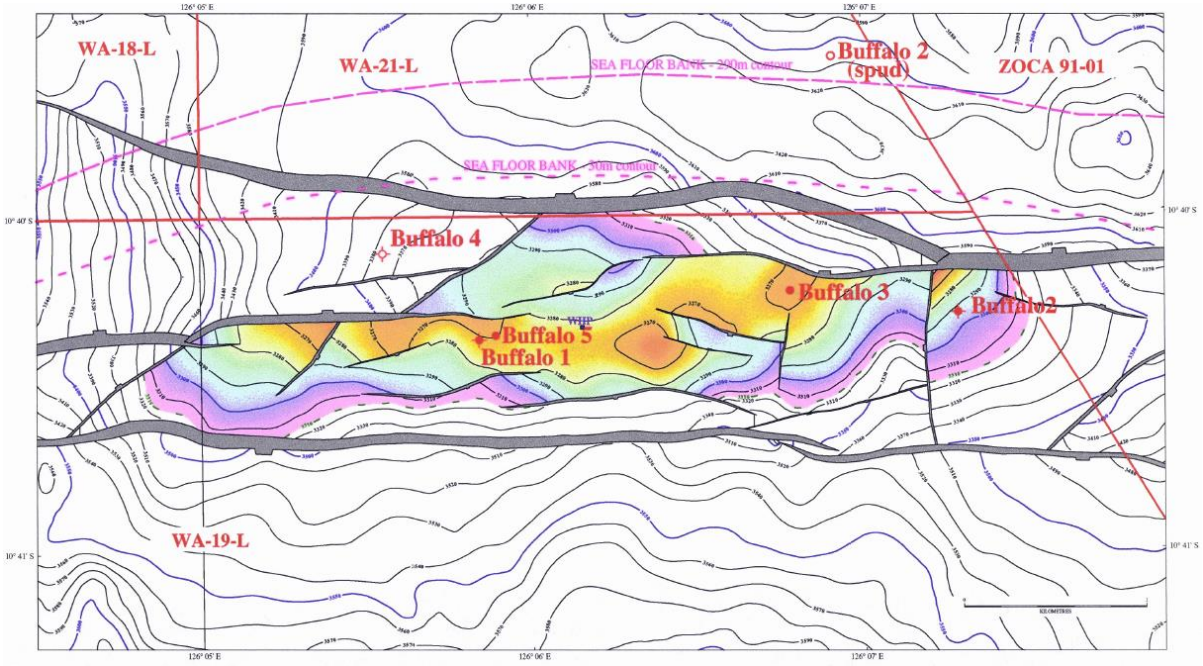


Figure 3-5: BHP's Top Elang Depth Structure Map (Source: Buffalo 5 WCR, BHP)

After assuming operatorship of the field, Nexen in 2001 re-mapped the Buffalo structure as an east/west-trending horst, created during the Tithonian extension in the Northern Bonaparte Basin (Figure 3-6). The southern bounding fault appeared to be relatively continuous, while the north-bounding fault system consisted of several en-echelon faults.

The Nexen PSDM-based interpretation showed a significantly different structural style for the Buffalo horst. Previous interpretations have shown a gently dipping anticlinal crest on the horst; whereas the revised interpretation recognized a steep southerly dip across the crestal area. The north and west flanks of the structure were mapped with up to approximately 100 m structural relief above the previous interpretation, thereby defining 'attics' with significant additional potential reserves[8].

[7] Buffalo-5 Basic and Interpretative WCR, 1999, BHP

[8] Buffalo-9 Well Completion Report – Interpretive Volume, 2002, BHP

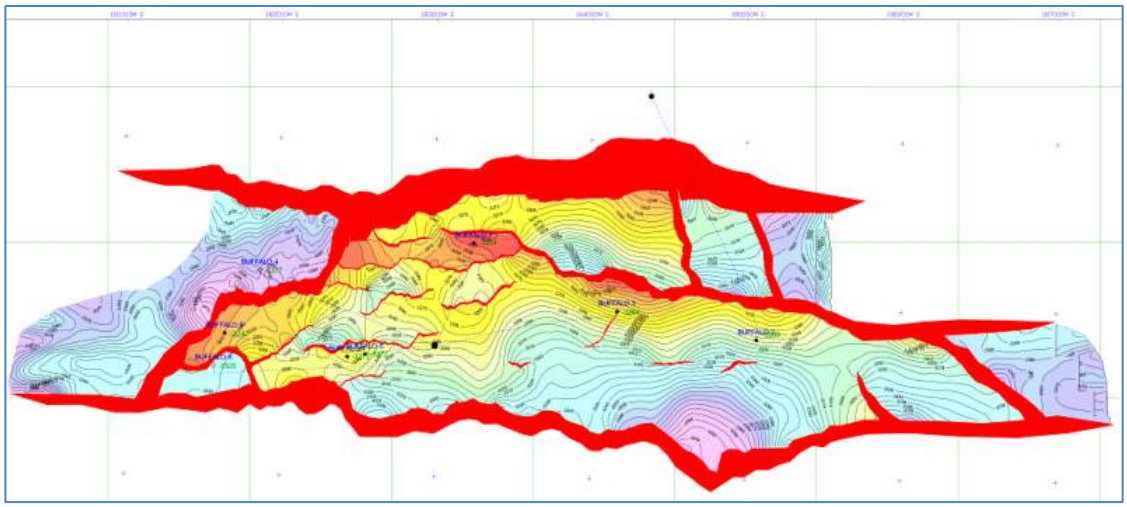


Figure 3-6: Nexen's Top Elang Depth Structure Map (Source: Buffalo 9 WCR, BHP)

The Carnarvon Petroleum reprocessing by utilising modern processing workflows and the incorporation of FWI has significantly improved the subsurface imaging of the Buffalo structure, allowing for increased confidence in the interpretation of the reservoir and structure.

Carnarvon Petroleum has utilised the PSDM depth data for interpretation, which is quite common in the industry. In RISC's opinion it would be preferable to interpret the data in two-way-time ('TWT') rather than depth domain. Interpreting in TWT allows for the interpreter to utilise synthetic seismograms to accurately tie the well formation tops to the seismic and is independent of any residual corrections applied to the velocity model or the depth domain data to tie the wells. However, BHP did note some issues tying synthetics.

However, RISC supports Carnarvon Petroleum's interpretation of bounding faults and the Top Elang Formation depth horizon, given the latest seismic dataset (depth domain, tied to wells, structurally oriented filter) (Figure 3-7). The data still suffers from various dipping noise and remnant multiple reflections despite a heavy processing effort. The depth map ties the well markers in their given positions. RISC is confident of the re-mapped crest to the east, and that the planned appraisal well will find updip oil.

The mapped structure is a horst bounded to the north and south by east-west trending fault systems formed post-deposition during Jurassic rifting. The field is also partly bisected by NE-SW trending faults related to younger faulting and Timor subduction. The south and east areas are not controlled by well penetrations and this is where Carnarvon identify opportunity for volume upside to that previously identified (Figure 3-8).

The Top Echuca Shoals seismic event (strong peak) can be picked throughout the data with high confidence, and shows a culmination over the eastern area of Buffalo. An alternative to direct interpretation of the Top Elang Formation horizon is to isochore down from the Top Echuca Shoals horizon and tie to wells with the Top Elang Formation marker.

The resultant Top Elang Formation depth map had a similar form to the one directly interpreted on the seismic data and tied to well tops.

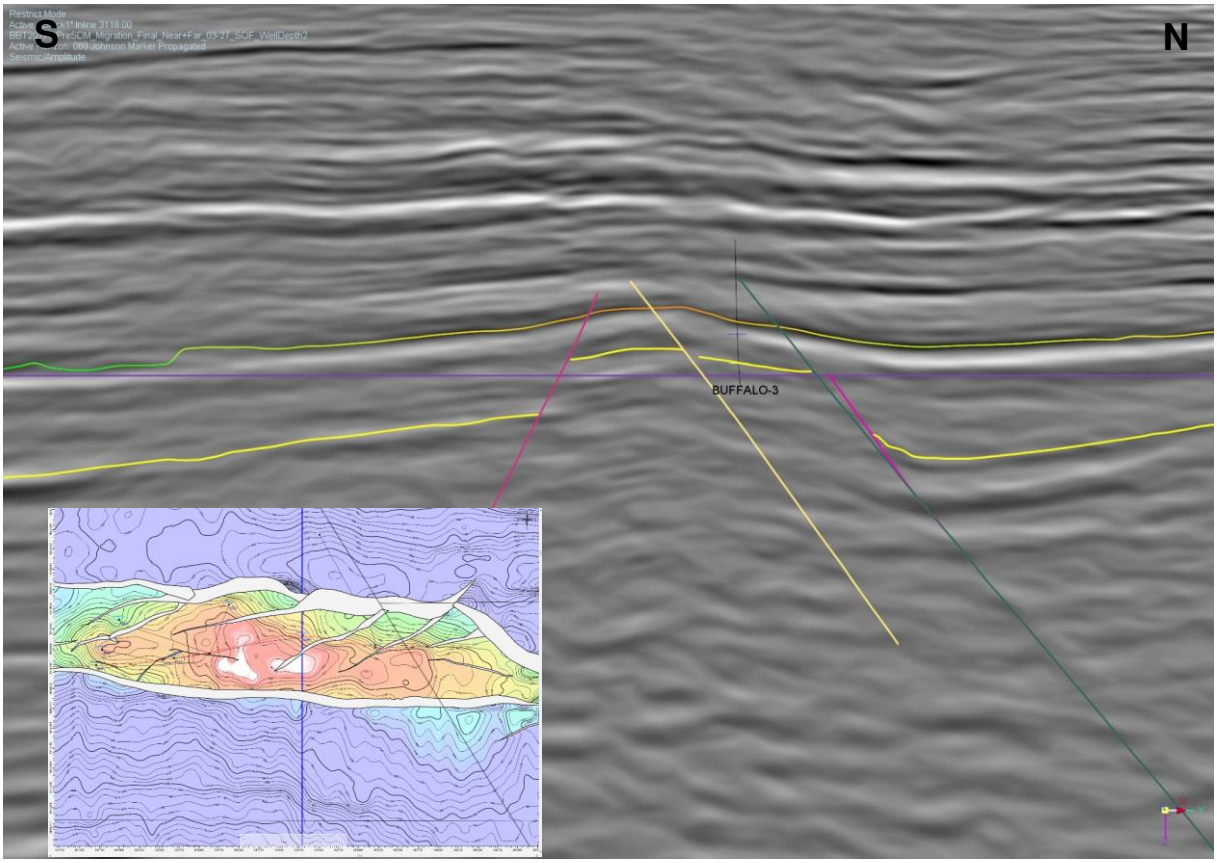


Figure 3-7: Interpreted Seismic Depth Section through Buffalo-3 Showing Updip Potential in the South (Carnarvon)

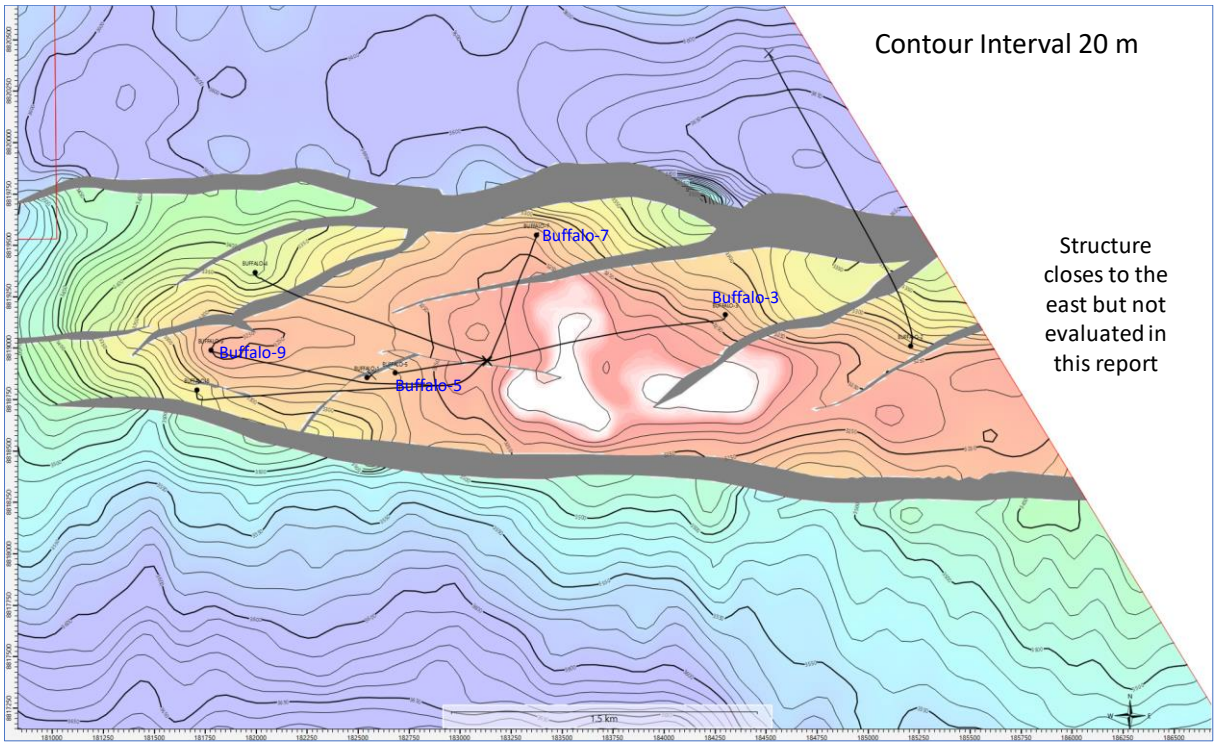


Figure 3-8: Carnarvon's Post FWI Final (June 2017) Top Elang Depth Structure Map (modified after Carnarvon)

Carnarvon Petroleum has noted thinning of the Top Johnson to Top Echuca Formation isochore over the Buffalo field. It is assumed that this relates to a combination of onlap and differential compaction over the underlying Elang Formation structure.

3.2.3. Reservoir description

The reservoir in the Buffalo field is the Callovian to Oxfordian Elang Formation (refer Figure 3-2). Sandstones were deposited in an overall transgression in the late Jurassic during a time of minor extension and subsidence. It is regionally recognised as an excellent reservoir. Regional lateral equivalents include the Laminaria and Montara Formations.

The Elang Formation conformably overlies the early to middle Jurassic Plover Formation which itself is a regionally thick unit of fluvio-deltaic sediments and also an excellent reservoir.

The Elang Formation reservoir exhibits excellent correlation across the field (Figure 3-9). Reservoir nomenclature is based upon the biostratigraphic zones of the Elang Formation, namely the *W. digitata* (WD zone) and *R. aemula* (RAB zone).

The Buffalo oil column is reservoired predominantly in the Elang Formation, with the Plover Formation rising above the original OWC in the central core of the field, as mapped. The Plover Formation aquifer is volumetrically significant and provides the strong water drive for the field, which is key to delivering high recovery factors.

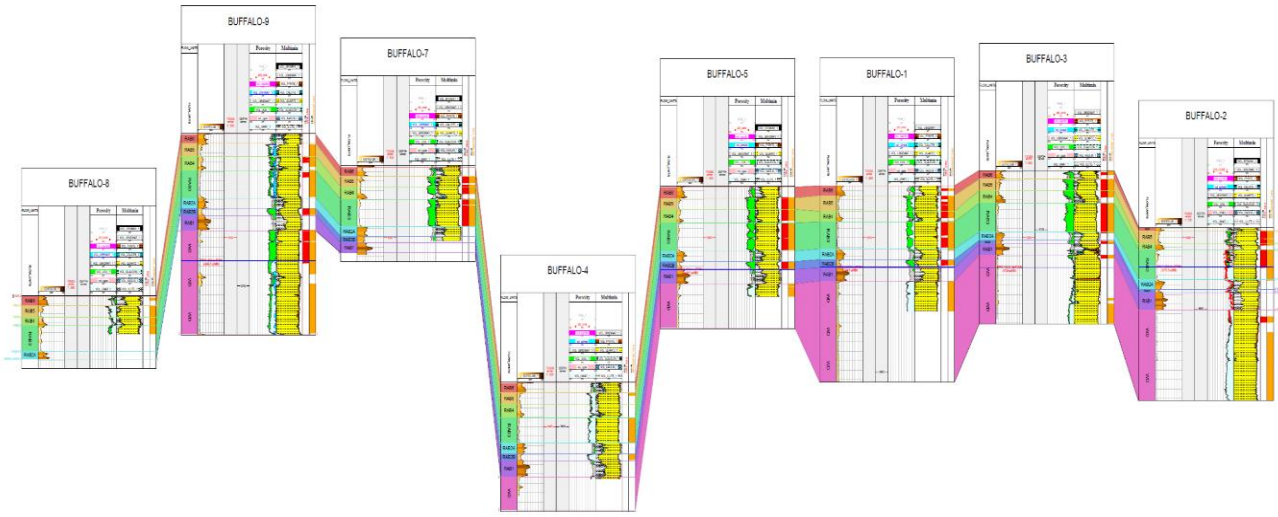


Figure 3-9: Buffalo field Elang Formation reservoir correlation (Carnarvon)

3.2.4. Petrophysical interpretation

Available well data for the Buffalo Field included:

- Drilling Mud:
  - Buffalo-1, 2, 3, 4 & 5 were drilled with SBM by BHP (Buffalo-1 WBM through Elang Formation to TD.).
  - Buffalo-7, 8 & 9 were drilled with WBM by Nexen.
- Core & SWC:
  - Buffalo-2: Complete core (3,759 – 3,808 mMD).

- Buffalo-1: SWC (44 samples).

- Pressure Data:
  - Buffalo-1, 2, 3, 5 & 9.

Petrophysical interpretation of the Buffalo field was undertaken by Carnarvon Petroleum through integrating log data from eight wells (Buffalo 1, 2, 3, 4, 5, 7, 8 & 9), MDT pressure and sample data from Buffalo-1, 3, 5 & 9 plus core data from Buffalo-2.

Buffalo-2 was considered as a key well as this well has a complete set of data (petrography, SEM, core description, core analysis, SCAL, pressure data and capillary pressure curves) to incorporate into log analysis.

The Multimin petrophysical module was used to evaluate the Lower Vulcan, Elang and Plover Formations. The Multimin model was set up using response equations for predicting volumes of minerals (quartz, pyrite, glauconite, calcite, illite and kaolinite in the Buffalo wells) and fluids that actually influenced each logging tool sensor. The approach of optimizing to gain the best match between data, model, and results is the keystone of optimizing the petrophysical interpretation in the Buffalo wells.

The permeability log was predicted through neural network modelling methodologies i.e. MRGC (Multi-Resolution Graph-Based Clustering) log prediction approach. The model was established between available core permeability and a model consists of log derived porosity, clay volume and pyrite content and then populated across the wells.

Additionally, a MRGC model was established from the porosity, permeability and clay volume to define four rock types: SS (Sandstone), SS-1 (sandstone), SS-ST (Sandstone, slightly argillaceous) and Siltstone/ very fine sand.

Electrofacies were modelling with estimated V_{SH}, permeability and porosity in a petrophysical analysis of Buffalo-2. Four electrofacies were defined in order of decreasing porosity and permeability, and increasing V_{sh}: SS, SS-1, SS-ST, and Siltstone (Table 3-1). To define Net to Gross (NTG) the following cut-off criteria were utilised:

- Porosity >8%;
- Water saturation <60%;
- Clay volume <30%.

Table 3-1: Elecrofacies Classification

RockType	Facies	Grain Size	Sorting	PHIE_AV (%)	PERM_AV (md)	VSH_AV (%)
SS	Sandstone	Medium to Coarse	Well	14.3	1297	1
SS-1	Sandstone	Medium to Coarse	Moderate to Well	9	210	1
SS_ST	Sandstone slightly argillaceous	V.Fine to Fine	Poor to Moderate	12	30	10
Siltstone	Siltstone to Shale	V.Fine to Fine	Poor	3	0.2	27

RISC considers the petrophysical evaluation as appropriate for use in reservoir parametrisation and geological modelling.

3.2.5. Fluid contacts

Buffalo-2 pressure data showed a slight offset to Buffalo-1, 3, and 5. Buffalo-9 was drilled post-production and showed 42 psi depletion after 24.3 MMstb of oil production. A field-wide OWC was interpreted at 3,316 mTVDSS with the oil gradient interpreted between 0.97 – 0.99 psi/m and water gradient 1.34 – 1.38 psi/m (Figure 3-10).

3.2.6. Geological modelling

Geological modelling was conducted on the original DUG1 version of the Buffalo 3D reprocessing. This modelling was the basis of the RISC audited Contingent Resources in August 2017. This modelling scope included uncertainty analysis of depth structure, facies, porosity, net-to-gross and Sw.

Carnarvon Petroleum used SKUA-GOCAD™ to construct the static models for the Buffalo field. The process involved construction of the structural model using seismic depth horizons and fault sticks. This was followed by defining the 3D grid, upscaling well logs, and creation of facies and petrophysical properties.

The input data for the structural model (Figure 3-11) consisted of:

- Two horizons for top and base reservoir:
  - Top RAB6 (Elang Formation) interpreted and adjusted for well tie by Carnarvon Petroleum;
  - Top Plover horizon: depth shifted down from modelled Top RAB6 (<10 m mistie to Top Plover Marker).
- Well markers for all stratigraphic units;
- 14 faults.

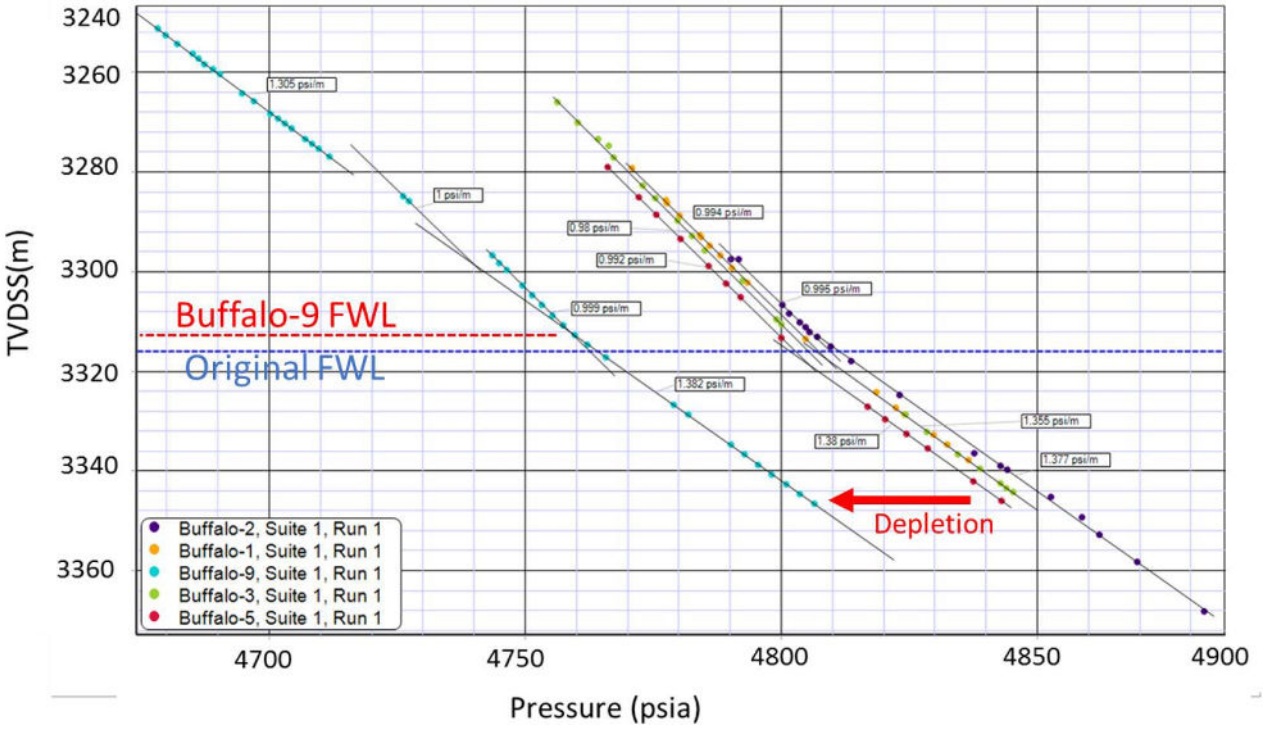


Figure 3-10: Buffalo field formation pressure data (Carnarvon)

A geological grid cell size of 25 m x 25 m laterally and 1 m vertically was used to generate the geological grid model. This was deemed to be sufficient to capture the heterogeneity in the vertical layering and control the lateral variation in facies geometry. The 1 m vertical cell size was set independently for each stratigraphic unit as the mean cell thickness. As all units were defined as conformable, the cell thickness varied proportionally as unit thickness increases and decreases. A flow simulation grid was defined with I and J lateral grid resolution was set to 50 m, and vertical grid resolution controlled by setting the average cell thickness to 2 m.

Eight Buffalo wells had their facies (EFAC), porosity (PHIE), and permeability (log10Perm) logs up-scaled to the grid model 1 m resolution (Buffalo-1 SW was excluded due to anomalous resistivity readings). A 1D vertical trend curve average of well facies proportions from all wells was used to constrain facies modelling. Likewise, trend maps for each facies type (four) and per zone was also used to guide the indicator kriging. Variogram analysis of the well data within the domain of the geological grid was performed to control the indicator and sequential Gaussian simulation of facies, porosity and permeability. This was analysed per facies type, but due to the limited number of wells the lateral variogram range (r1 and r2) was quite uncertain, and could vary between 500-2,500 m. The variogram for the shale was clearer and was set at the larger range of 2,000 m.

A field-wide original OWC of 3,316 mTVDSS was assumed as interpreted prior to initial production. A water saturation above the contact was defined by a distribution per facies type. No transition zone was applied in the static model as Carnarvon Petroleum deemed this negligible due to the high permeability sands.

RISC verified that the mean value of the 3D properties were in good agreement with the well log sums and average values, indicating that the upscaling result was appropriate (Figure 3-12).

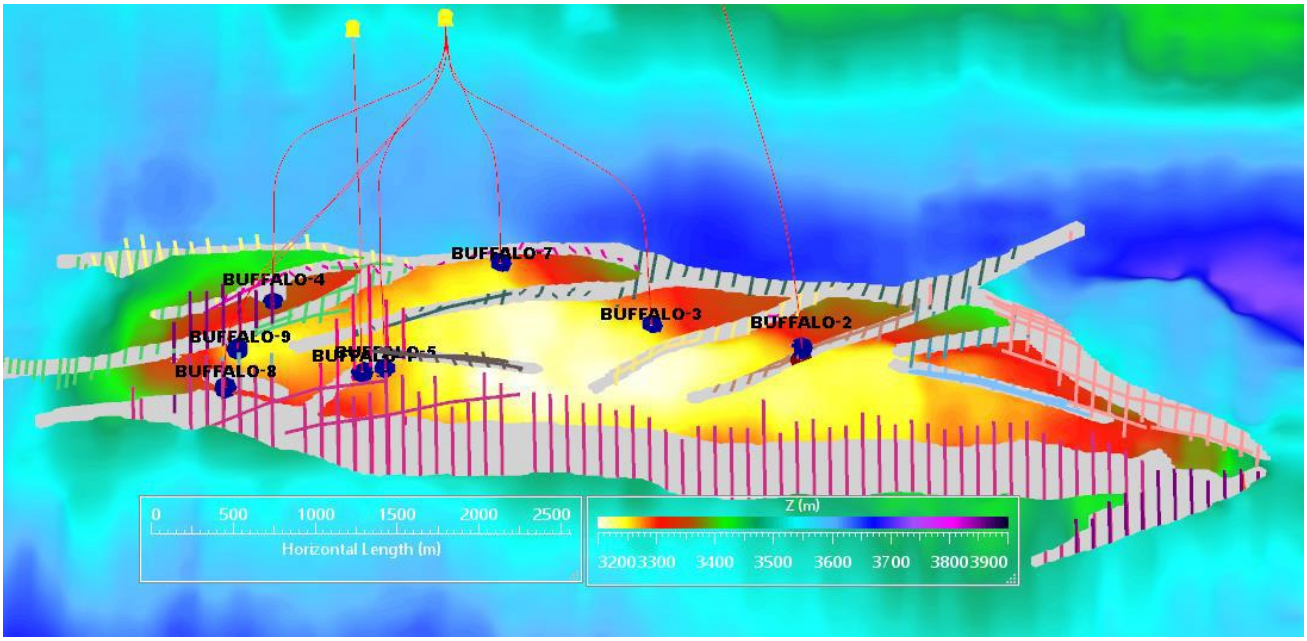


Figure 3-11: 3D view of input data used in structural modelling of Buffalo (Carnarvon)

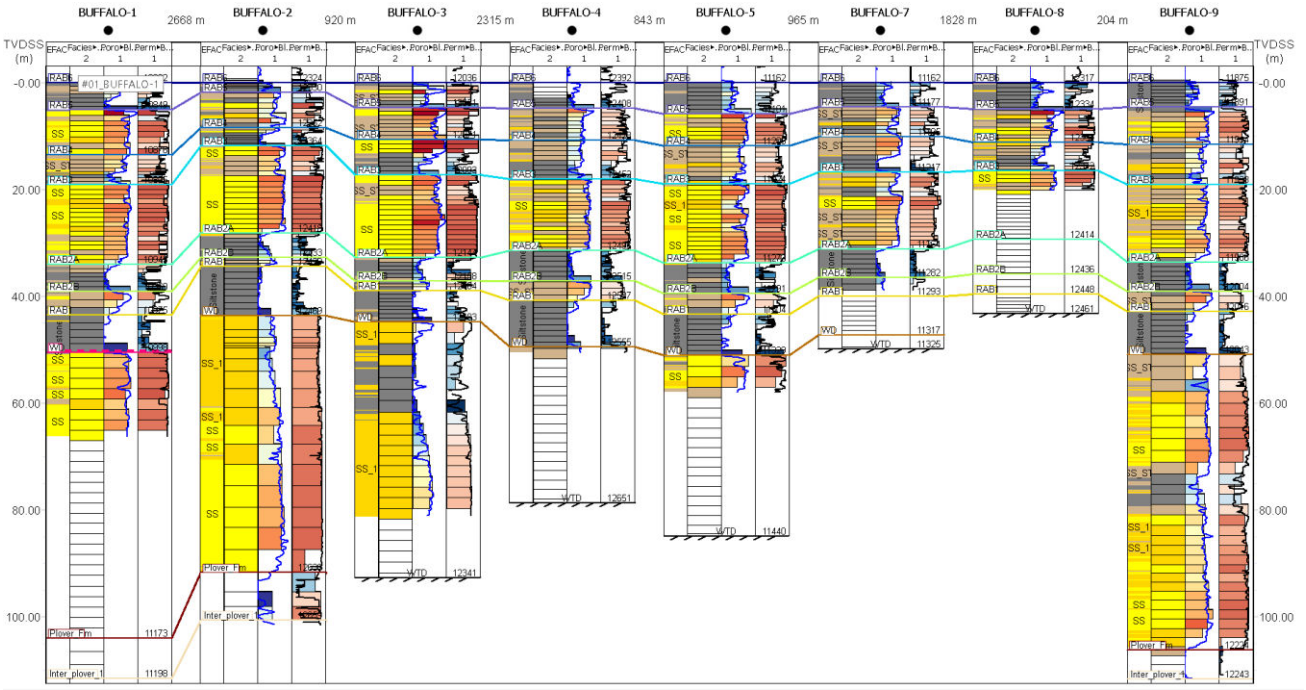


Figure 3-12: Upscaled vs Well Data (Carnarvon)

The migration (lateral positioning) of the seismic reflectors are still subject to the velocity field modelled, and the algorithms chosen for this process.

In order to capture velocity uncertainty and potential mis-picking of the resultant seismic data, an 80 m depth uncertainty was applied to the structural simulation within a variogram 1.8 km x 0.9 km orientated east-west. The simulation process allows the flexing of the top structure surface within the degrees of freedom (variogram range, model type and variance) and the result of each realisation is recorded. Given the historical drilling results, RISC's opinion is that this level of depth uncertainty is reasonable.

RISC endorses the stochastic simulation approach rather than a deterministic one due to the simultaneous factors of weak reflector difficult to distinguish from noise, and imaging difficulties leading to seismic event position and inclination depth uncertainty.

500 stochastic model realisations were created within SKUA-GOCAD™ and run in a Monte Carlo process to explore the STOIIP uncertainty range. In addition to structure, facies uncertainty (up to 27% variability), porosity uncertainty (+1/-3 p.u. mean value shift per facies), Sw uncertainty distribution sampled per facies. Contact, NTG, and permeability were not varied in this analysis (Figure 3-13).

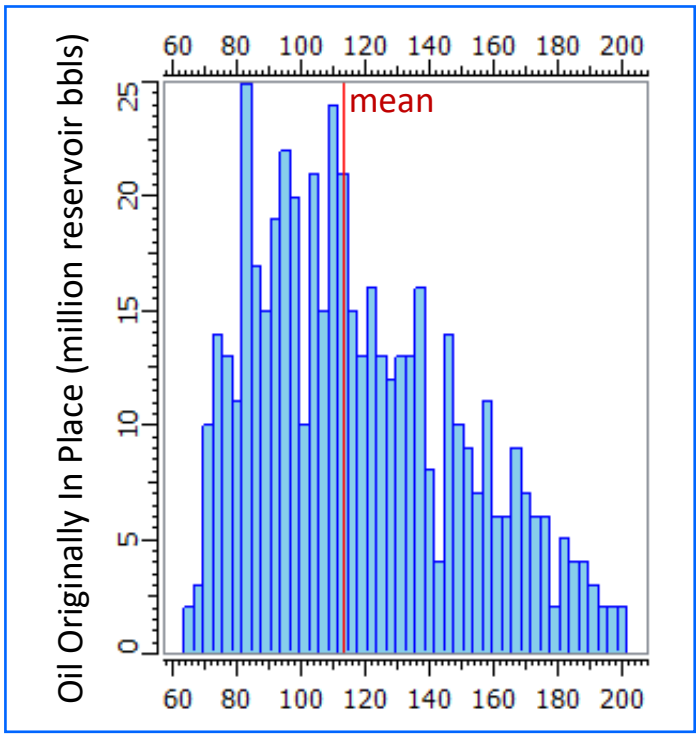


Figure 3-13: OOIP Histogram from 500 simulation runs (after Carnarvon)

Three deterministic cases were selected from the Skua uncertainty workflow to approximate the P90/P50/P10 STOIIP and used in the history matching and simulation of recoverable volumes. The history matching was found to not be sensitive to the STOIIP due to strong aquifer drive, and thus did not reduce the static volume uncertainty range. The field was abandoned at high water cut and updip areas of the field without wells remains undeveloped.

Table 3-2: Gross Hydrocarbons In-place for the Buffalo Field

Buffalo Field Elang Fm	Low Case STOIIP (MMstb)	Best Case STOIIP (MMstb)	High Case STOIIP (MMstb)
Full-field	75.2	106	156
Truncated within Buffalo PSC	73.7	94.8	114

The initial Buffalo development produced 20.6 MMstb giving a best estimate remaining STOIP of 85.4 MMstb.

Following the ongoing seismic processing effort, Carnarvon Petroleum subsequently updated the geological modelling with the Elang Formation structural interpretation of the final iteration DUG4 processing to create a single deterministic model for simulation studies. No uncertainty realisations were incorporated into this model. RISC opinion is that the DUG1 vintage models are more appropriate for simulations studies given the probabilistic approach and the uncertainty analysis incorporated.

In addition, Carnarvon Petroleum made a change in the model with respect to way facies were propagated in the model, resulting in a slight increase in the net pore volume, which is offset by a lower gross rock volume resulting from the DUG4 seismic data interpretation.

Given that the DUG4 processing derived structure interpretation is Carnarvon Petroleum's preferred representation of the Elang Formation reservoir structure, it would be appropriate to update the probabilistic modelling suite with the revised depth structure, although the effect is expected to be small.

RISC reviewed the static model output of both the P50 case of the (DUG1) probabilistic modelling and the (DUG4) deterministic model and the resultant oil-in-place calculation is similar (113 MMbbls vs 114 MMbbls) indicating in a static sense that the revised model is not a significant departure from the probabilistic modelling. We also understand that simulation results are similar.

3.2.7. Fluid properties

The oil in Buffalo field is a low viscosity oil/condensate with a low GOR (120 scf/stb) and low bubble point (500 psia). It is similar to oil developed in the adjacent Laminaria-Corallina field. The key fluid properties are:

- Reservoir Pressure: 4,777 psia;
- Reservoir Temperature: 277 deg F (136 deg C);
- Oil formation volume factor (Bo): 1.06447 rb/stb;
- Oil Viscosity at reservoir conditions: 0.167 cp
- Oil API (degrees): 53

The low oil viscosity and low bubble point gives a favourable water flood mobility ratio that is likely to result in good sweep and high oil recovery factors. Recovery factor in the Laminaria-Corallina fields are over 60%.

No H_2S has been detected and the associated gas contains 12-18% carbon dioxide.

3.2.8. Production History

The original development of the Buffalo field started production in Dec-1999 from Buffalo-3 and 5. Two additional development wells, Buffalo-7 and 9 were added in July-2003 (Figure 3-14).

The vertical/deviated production wells had high productivity with peak initial oil rates of 19,000 to 22,000 bpd in Buffalo-3, 5 and 7, and 7,000 bopd in Buffalo-9 with 50% watercut.

Water production started after 2 months in Buffalo-3 and 5 and rose to over 80% water cut during the life of the original development. Wells had gas lift to enable production at high water cut.

Buffalo-9 logs showed limited (42 psi) pressure depletion in all reservoir units (Figure 3-10) and the Upper RAB units were largely swept by aquifer influx. Water production started immediately in Buffalo-7 and 9 and also increased to over 90% during the well life. Buffalo-9 watered out in late 2003 and the other wells were shut at the end of economic life in late 2004, partially curtailed by limited gas available for gas lift. Cumulative oil production from the field was 20.6 MMstb.

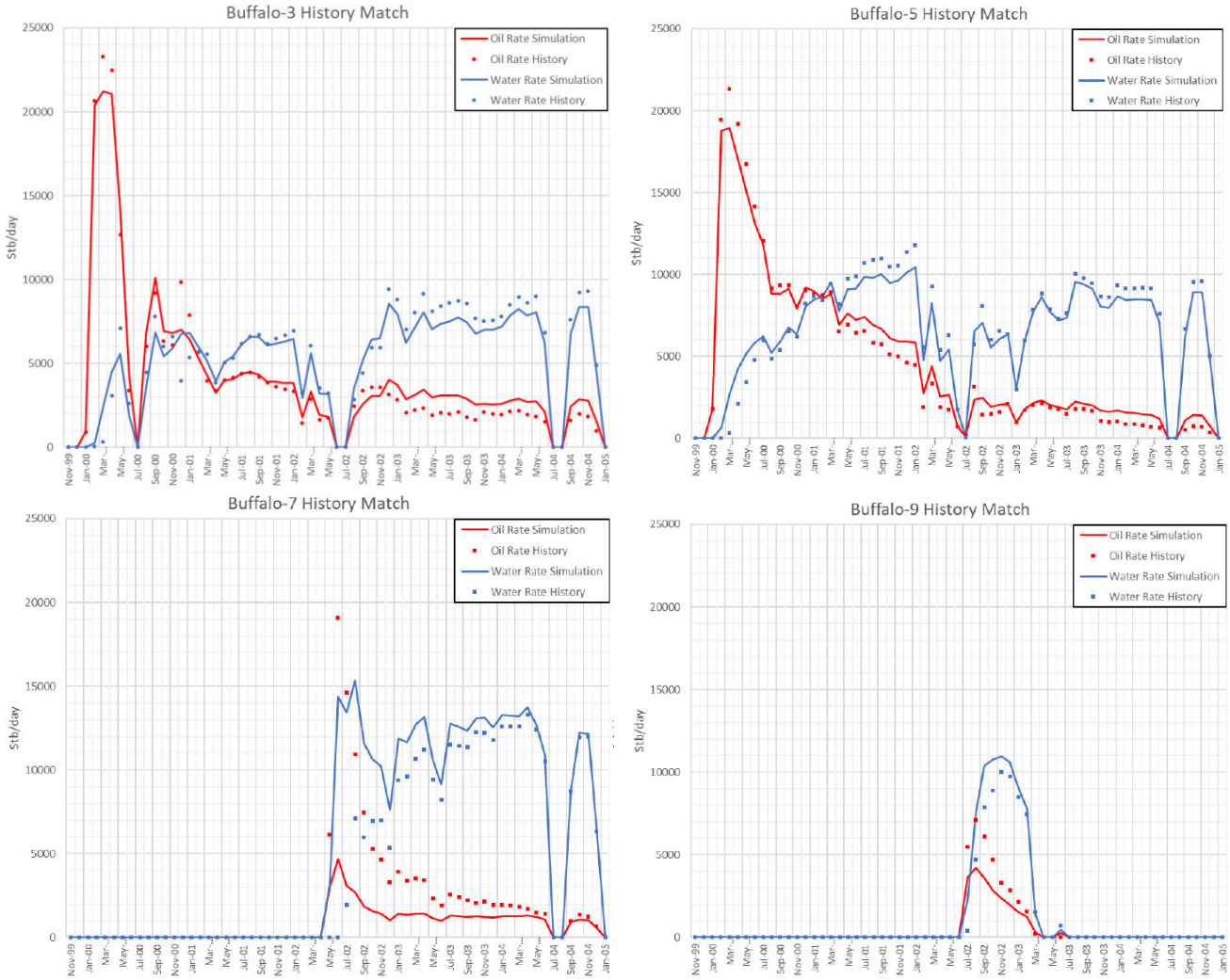
3.2.9. Dynamic modelling

Carnarvon Petroleum have undertaken history matching for both the probabilistic and deterministic reference case models. History matching key data include:

- Pressure depletion (42 psi) observed in Buffalo-9 when drilled;
- Sweep of Upper RAB reservoir seen in Buffalo-9 when drilled;

- The water breakthrough of all wells with an emphasis on the most crestal well Buffalo-3. This crestal well is estimated to be the best analogue for re-development which uses more crestal wells.

The initial water saturations are low in all wells and match the logged saturations in Buffallo-3 and 5. The history matched model shows increased saturation in all wells after 2½ years production when Buffallo-7 and 9 were drilled. Figure 3-15 shows the simulated saturations.



Total liquid is specified in simulation and oil and water rates matched

Figure 3-14: Buffalo measured and simulated well production history (Carnarvon)

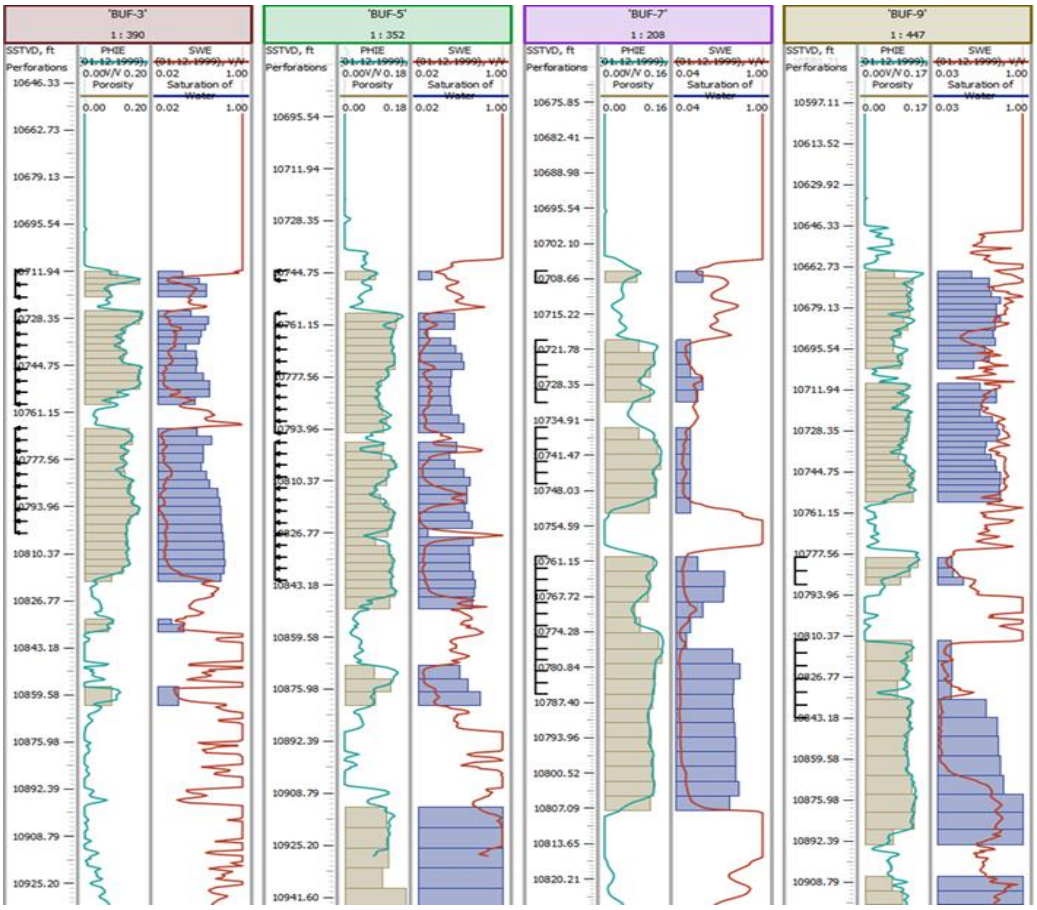


Figure 3-15: Simulated water saturations after 2½ years production (Carnarvon)

From Figure 3-15:

- Water saturations (blue bars) have increased in Buffalo-3 and 5 in compared to the original logs and saturations (red lines).
- Simulated water saturations in Buffalo-9 are consistent with the log saturations (red line) obtained after 2½ years production.
- Simulated water saturations in Buffalo-7 show increased water saturation in the lower reservoir after 2½ years production which is not seen in the logs.

A reasonable history match (Figure 3-14) of individual well water production was achieved by adjusting edge and bottom water aquifer dimensions and permeability and the water relative permeability. The most crestal wells Buffalo-3 is the best analogue for the crestal redevelopment and has been well matched in models with low, mid and high STOIIP (Figure 3-16). This good match improved confidence in Carnarvon's dynamic modelling.

The history matched simulation model has been used to generate production forecasts for the re-development and select well numbers and locations.

Wells in the original development recovered between 1 and 8.3 MMstb oil per well. Two wells had an average oil recovery of 8 MMstb each from a 43 and 51 m oil column; the other two wells are in small fault blocks that limited oil recovery.

The proposed re-development wells are simulated to recover between 3 and 29 MMstb per well with a low, mid and high case average of 6, 13 and 20 MMstb per well (Figure 3-17).

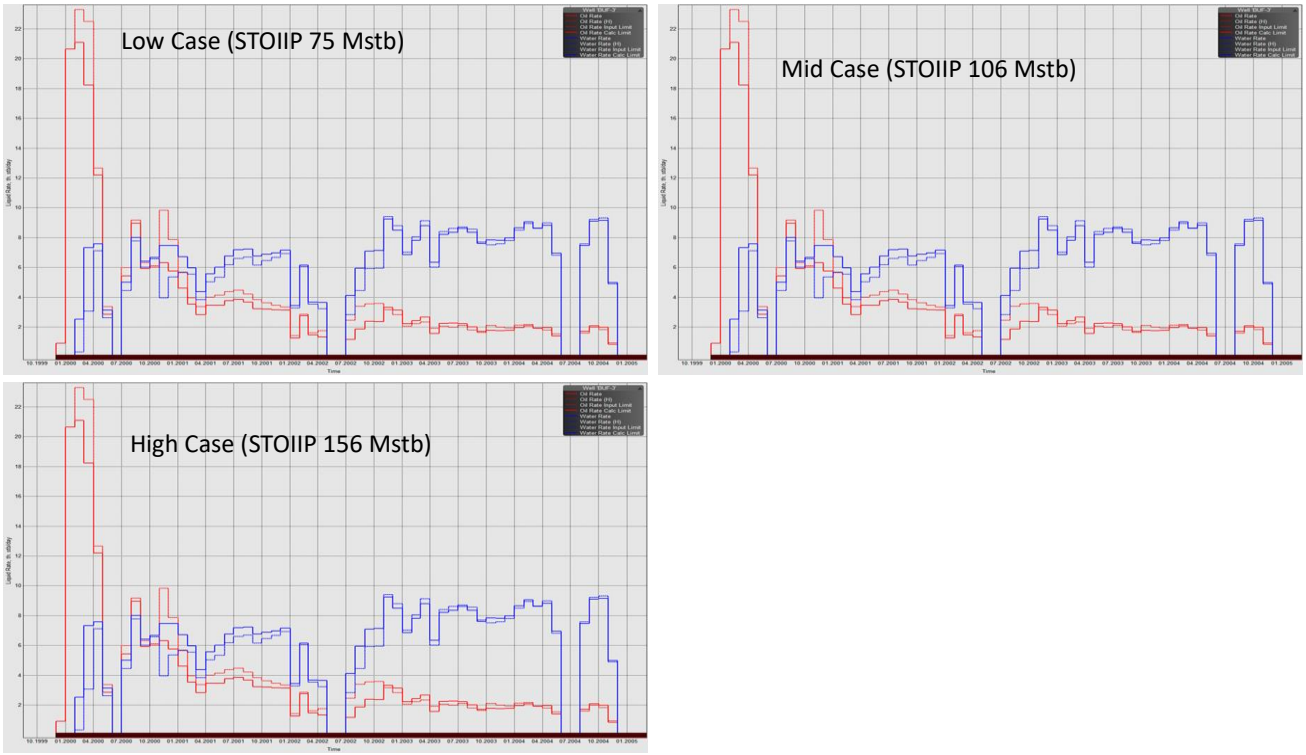


Figure 3-16: Buffalo-3 history match in low, mid and high case realisations (Carnarvon)

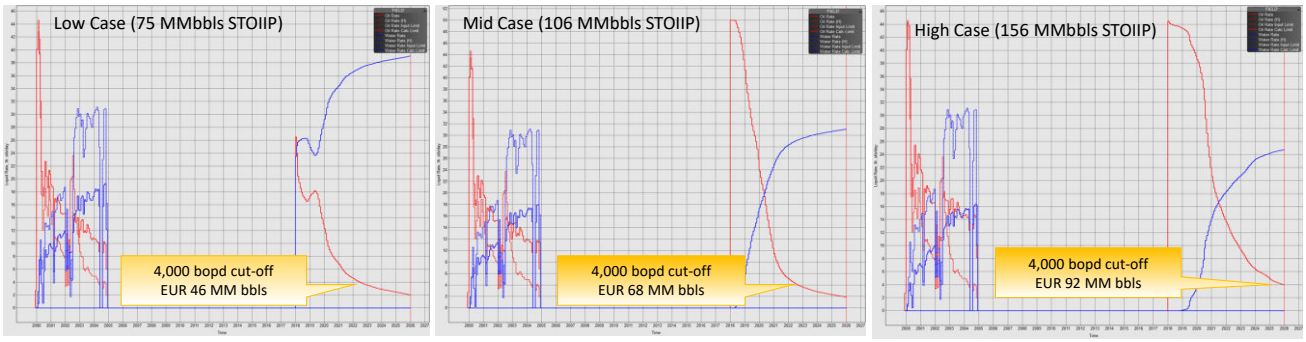


Figure 3-17: Simulated production with 3 well re-development (Carnarvon)

Following the initial development, the OWC is simulated to have risen and stabilised at 3290 mtvdss, 26m above the original OWC. Re-development wells are estimated to find 90 to 113 m oil column (low case 61 to 89 m, high case 106 to 127 m), twice the 47m oil column of the best two original well. This accounts for the higher oil recovery per well.

The reservoir has strong water drive which results in water-drive or waterflood recovery factors. Oil recovery factors simulated by Carnarvon Petroleum are high at between 60 and 66%. This is consistent with recovery factors achieved in Laminaria-Corallina but is estimated to represent a high case, as Laminaria-Corallina has a larger oil column, higher permeability, and less reservoir heterogeneity. The Kitan field is estimated to be a low case analogue as it has a smaller oil column, lower permeability, and more reservoir heterogeneity. Kitan has an estimated recovery factor of 40%. Accordingly, RISC estimate the recovery factor range for the Buffalo field to be 40% to 65% and used this range to estimate resources. We applied a 40% to 60% range in oil recovery factor to the STOIIP range determined by Carnarvon and supported by RISC to estimate the contingent resources.

4. Field Development Plan

The proposed re-development plan is for three vertical/deviated wells with ESPs producing to a processing facility with total liquid handling capacity of about 75,000 bpd.

Produced water will be treated and discharged overboard. Associated gas production will be limited and most gas used to provide fuel for power generation, therefore flaring will be limited and diesel or oil will be needed to supplement the fuel to the power generators.

4.1. Drilling and completions

Vertical/deviated oil production wells with 5½ inch tubing are planned and considered to be optimum given the good well productivity. High angle and horizontal wells are options also being considered to defer water production and optimise the development. Solids production is not expected so no sand exclusion is planned.

Artificial lift is required as the wells are expected to cut water and have an increasing water cut over field life. Gas lift has the advantage of lower operating cost but field restarts can be difficult, especially as gas production declines, and gas lift compressors will be required. ESPs are modelled to give slightly higher oil recovery but run-life and the cost and means of replacing failed ESPs must be considered. The planned development assumes ESPs with replacement using a mobile hydraulic workover unit. Dual bypass ESP completions have life cycle cost benefits and are being considered. Given the limited expected gas production RISC supports the choice of ESPs.

Simulation has determined that the base field interpretation can be developed using 2 or 3 oil production wells. The third well provides operation flexibility and redundancy to optimize recovery. If appraisal demonstrates a low case or 1C outcome the third well can be dropped and facility capacity potentially reduced without significantly affecting oil recovery.

The appraisal well, which will be retained as a production well, will be vertical. Subsequent wells will be deviated wells drilled from the same location and tied back with dry trees to the WHP or MOPU. Wells will be perforated underbalance from top Elang formation to a selected water stand-off depth using through tubing wireline guns. Isolation of basal water production using mechanical bridge-plugs will be an option.

4.2. Production Facilities

The assumed production and processing facilities are based on a MOPU or converted jack up in 25 m water capable of supporting topsides with 75,000 bbl liquids handling capacity including:

- Production Xmas trees;
- Supporting infrastructure and space for a mobile hydraulic workover rig or similar;
- Inlet manifold arrangement for production and well testing;
- Oil and gas separation and stabilization;
- Produced water clean-up and facilities for discharge overboard;
- Utilities and safety systems required to support the above-mentioned facilities, including flare, power generation.

In addition, there will be an export line and a FSO for crude storage and offloading with associated mooring systems.

- Five potentially available MOPU's have been identified. Two would require processing equipment to be installed, two already have sufficient capacity installed, one would require modification.
- Twelve potentially available FPSOs have also been identified with liquid handling capacities of between 10,000 and 90,000 bpd. Five are considered to have suitable capacity.
- Four suitable FSOs have been identified.

We note a MOPU with 30,000 bopd, 75,000 bfpd and 3 MMscfd gas handling capacity and an FSO with 1.1 MMbbl storage capacity has been identified. Production and cost forecasts are based on this development.

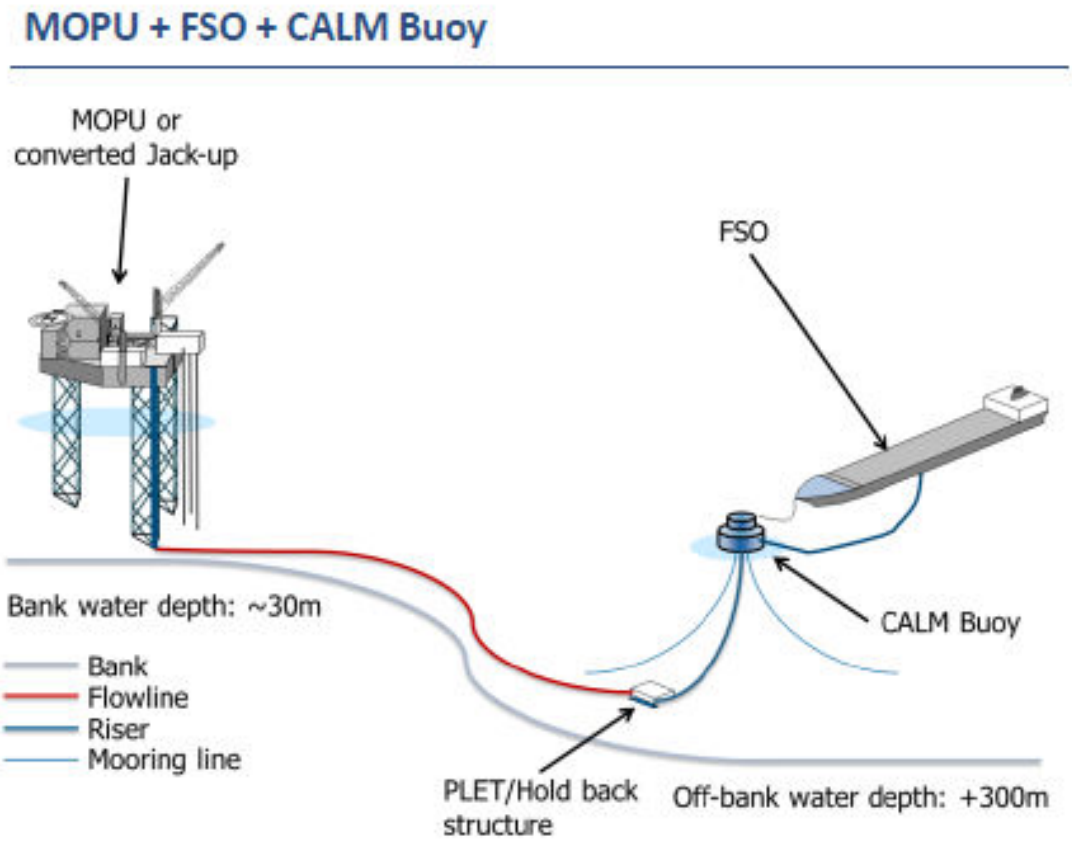


Figure 4-1: Schematic representation of development concept (Carnarvon)

Oil will be periodically sold and exported from this facility to trading tankers, contracted by the Operator, which will transport the crude for refinery processing.

Fuel for power generation and heating will be produced gas sourced from separator flash gas and this will include power for the downhole electric submersible pumps (ESP). The relatively small quantity of excess gas, surplus to fuel gas requirements for the in-field facilities, will be flared to atmosphere. Fuel gas will have to be supplemented with liquid fuel as the oil and associated gas production reduces.

A number of suitable alternative facilities have been identified should commercial arrangement for this concept not progress.

4.3. Capital and Operating Costs

Carnarvon are considering 2 development concepts - a WHP and FPSO option and a MOPU (with processing on the platform) and FSO option. They have screened a number of existing facilities that are potentially available, selecting different fit-for-purpose facilities for a low case and base case appraisal outcomes.

There are options to purchase or lease the WHP, MOPU, FPSO and FSO. Clearly leasing will reduce capital costs while increasing operating costs – there are fiscal advantages to this in a PSC environment where operating costs are generally recoverable in the year incurred. It is not straightforward to compare the lifecycle costs of purchased v lease options as lease rates will vary significantly with lease period therefore total opex will depend on field life and economic cut-off will occur earlier when facilities are leased.

RISC has reviewed the different options and concluded that:

- The five year life cycle cost of a purchased WHP and leased FPSO is very similar to a leased MOPU and leased FSO in both the 1C and 2C cases. Either option is viable, available and would give similar project economics.
- A leased WHP and leased FPSO is estimated to have a 30% higher life cycle cost so appears less attractive. However, the actual facility lease rates will be clearer post appraisal when final commercial negotiations with suppliers are conducted. Therefore, all three options are viable and any of them may prove the most attractive option once final quotes are received post appraisal.

The most attractive option and ultimate selection will be subject to a more rigorous analysis including facility status (availability, condition and reliability) better cost estimates after a tender process, more accurate lifecycle cost estimates and economic evaluation taking into account economic field life for a reasonable range of oil price forecasts.

For the purposes of this report RISC has used the costs of a leased MOPU and FSO (lowest 2C lifecycle cost).

Carnarvon contracted consultants to survey the market for WHP, MOPUs, FPSOs and FSOs. This market survey is the basis for our capital and operating cost forecasts. We have added allowances for modifications, transportation and installation, contingency and project management where we consider appropriate.

4.3.1. Capital costs

Table 4-1 shows the estimated capital costs of the Buffalo re-development assuming 3 wells.

Table 4-1: Buffalo capital costs

Item	Capex (US$million)	Comment
Appraisal well (B-10)	20.0	Includes no mobilisation/demobilisation
Sub-total Appraisal	**20.0**	
Development wells + completion	49.1	Includes drilling of 2 new wells, completion of appraisal well and $1.7 MM mobilisation
MOPU	17.0	Modifications, transportation & installation, HUC
Pipeline	8.25	
FSO	20	Modifications, transportation & installation, HUC
Project Management	18	
Contingency	13	
Sub-total development	**125**	
Total Appraisal & Development	**145**	

If only 2 wells are required (one development and completion of appraisal well) we estimate total Capex of $119 million.

Carnarvon Petroleum estimated the vertical appraisal well to cost US$20 million to drill and suspend including 20% non-productive time excluding mobilisation/demobilisation. Carnarvon have advised mobilisation/demobilisation may not be payable if the same drilling contractor is used for the development wells. The well is estimated to take 27 days to drill, including standard logging, plus 5 days to suspend. No core or well testing is planned. These time estimates seem reasonable assuming lessons from drilling the original Buffalo wells are incorporated. The cost assumes a rig rate of US$100,000/day, this is reasonable in the current market where jack up rig utilisation is approximately 50% in SE Asia.

There is some uncertainty in rig mobilisation/demobilisation cost. A worst case estimate for a single well campaign is US$9.4 million, whereas Carnarvon estimate US$1.7 million for a working rig and potential zero mobilisation fee in the current market. In the absence of further information on well timing and hence rig availability we recommend adopting US$ 1.7 million.

Subsequent deviated (35 degrees) development wells with 724 and 1,590 m step out are estimated to cost US$20.4 and US$22 million respectively plus an additional US$1.7 million assumed mobilization/ demobilisation fee. Completion of the appraisal well adds an additional 6.7 days and US$5.0 million.

For the purposes of economics approximately 90% of well costs are intangible and therefore immediately cost recoverable in a PSC environment.

Carnarvon Petroleum have advised that due to benign meteorological ocean conditions oil offloading can be achieved with a floating hose from the FSO to export tankers therefore no offloading buoy is required.

Figure 4-2 shows the base case development cost schedule.

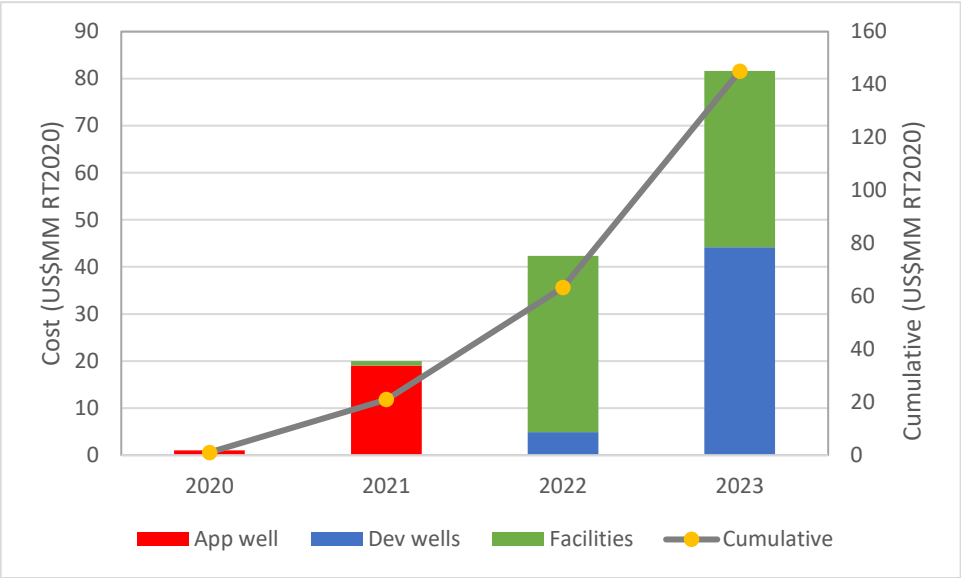


Figure 4-2: Development cost schedule

4.3.2. Operating costs

As mentioned above, operating costs are based on a preliminary survey of available vessels and MOPUs. In RISC's opinion the costs are very competitive and reflect 'bottom of the cycle' pricing.

RISC estimates operating costs of approximately US$60 million per year as summarised in Table 4-2.

Table 4-2: Buffalo facility Operating costs

	Opex (US$million/year)	Comment
MOPU lease	10.2	US$30,000/d from market survey
FSO Lease	9.1	US$25,000/d from market survey
MOPU O&M	11.0	US$30,000/d from market survey
FSO O&M	7.3	US$20,000/d RISC estimate
Consumables	5.0	
Logistics	4.0	Helicopter, boats, supply base
G&A	2.5	Management & Technical support
Insurance	1.0	
Contingency	10.3	
Total	**60.4**	

We consider the costs arising from the market survey to be immature. For example, one source quotes FSO BBC + O&M rates of US$20,000-25,000/day whereas another quotes lease rates of US$40,000-50,000/day depending on lease period.

In the low and high appraisal outcomes operating costs do not vary significantly due to lower lease rates as a result of the longer lease period associated with the high case offsetting higher variable and consumables costs due to the higher production. The reverse occurs in a low outcome where lease costs will be higher but production and consumables costs lower. We estimate that operating costs can be reduced by 20% in the last two years of production to extend economic field life. Leasing arrangements with a component of lease rates linked to production could also extend economic field life.

ESP refurbishment/replacement costs are based on a run life of 3 years replacing 1 ESP per year from the 3rd year of production. ESP's replacement is estimated to cost US$ 0.8 million per workover, plus some allowance for the maintenance and transportation of the hydraulic workover rig.

4.4. Abandonment costs

RISC estimates field abandonment and decommissioning costs of US$ 28.5 million (RT2021), based on abandoning 3 wells (US$3 million per well + mobilisaton/demobilisaton), removal and demobilisation of the MOPU and FSO (US$10 million), removal of moorings (US$5 million), planning and engineering (US$2.5 million). This reduces to US$25.5 million in the low case with two development wells.

4.5. Development Schedule

Carnarvon Petroleum have estimated an 18 month schedule from post appraisal to first oil, noting that for the original BHP development the actual time from FID to first oil was 15 months. This is based on leasing an existing MOPU and FSO with appropriate specifications. RISC consider this to be achievable but a relatively aggressive schedule. We note that the development concept will depend on the results of the appraisal well, and so may be altered. After the appraisal results are known, we have allowed 6 months to finalise development concept, complete financing and finalise contractual arrangements with the various suppliers. To ensure less than 2 years from FID to first oil will require sourcing a MOPU and FSO that require limited modifications.

Subject to securing funding and a joint venture partner, Carnarvon Petroleum forecast appraisal drilling in 2H 2021. Assuming appraisal drilling occurs in 2H 2021, RISC considers FID could occur in early 2022 and first oil potentially in 2023. However, the Joint Venture's intent to follow a fast-track approach to development could experience delays. Therefore, we estimate first oil 1 January 2024.

4.6. Production and cost forecasts

RISC has made an independent estimate of STOIIP and oil resources. We have modified Carnarvon Petroleum's simulation forecast for 3 wells with ESPs to match our resource volumes.

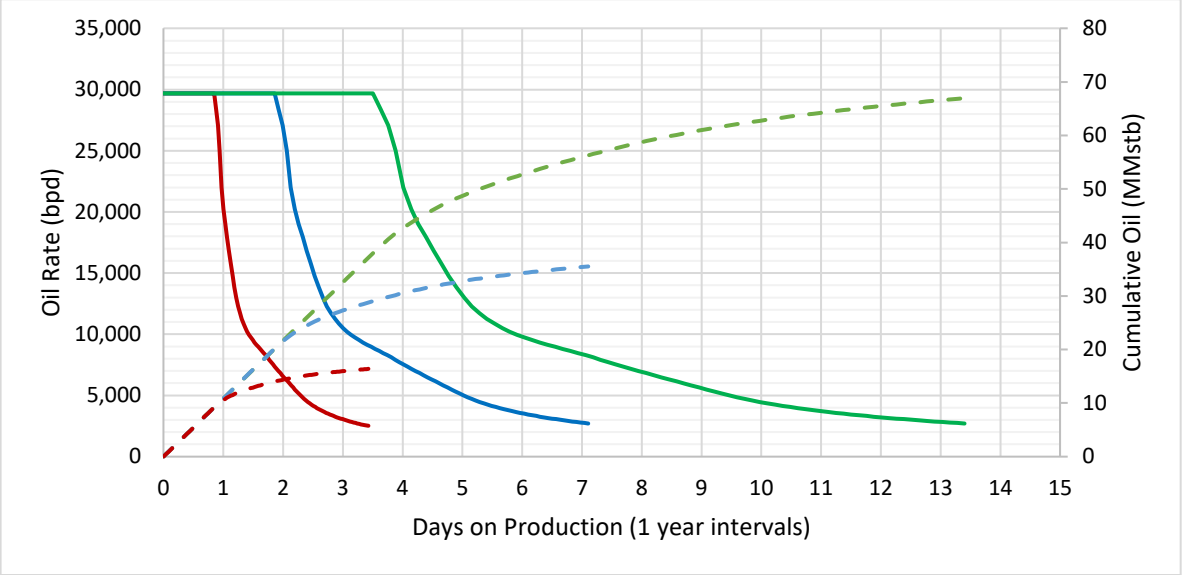


Figure 4-3: 1C, 2C, 3C Oil Production Forecasts

Table 4-3 shows the assumed facility capacity, based on an identified facility, that has been used to generate forecasts.

Table 4-3: Estimated facility capacity

Capacity (bpd)	Production day capacity	Incorporating 99% uptime
Oil	30,000	29,700
Water	75,000	74,250
Total Liquid	75,000	74,250

Production is initially constrained by the oil handling capacity with a plateau duration of 0.7, 1.3 and 2.2 years in the 1C, 2C and 3C realisations. Production comes off plateau due to the liquid handling capacity.

The high uptime, which was achieved by BHP and Nexen, is estimated based on facilities typically exceeding their nameplate capacities and with ESP failure the constrained liquid production can be made up by the other wells while an ESP is replaced.

The high water handling capacity is required to allow the facility to produce economically at high water cut. Reduced water handling capacity would reduce contingent resource estimates.

- Halving the liquid handling capacity reduces the 2C resource by 11% and the 2C project NPV_{10} by 23%.
- Doubling the oil capacity has a minor effect on resource volumes and an 7% increase in 2C project NPV_{10}.

5. Resources

5.1. In-place resource volumes

RISC has reviewed and support the Operator's static models and in-place volume estimates shown in Table 3-2. The Buffalo field potentially extends beyond the permit boundary, although potential volumes outside the permit are likely to be small but will contribute to production.

5.2. Production Forecasts

RISC has incorporated a wide range of recovery factors in the resource estimates and adjusted the Operator simulated production forecast to match the resource estimates and expected facility capacity constraints. Figure 4-3 shows the 1C, 2C and 3C oil production forecasts. Due to strong aquifer drive, the wells are simulated to cut-water and produce at increasing levels of water-cut in the course of the life of the field. The post plateau production rate is largely constrained by the facility water handling capacity.

5.3. Resource summary

Resources associated with the Buffalo re-development in Table 5-1 are classified as Contingent Resources, development pending. The contingent resources can be re-classified as reserves when the planned re-development is approved, which is expected to follow the appraisal well.

Table 5-1: Contingent resources as at 31/12/2020

Oil (MMstb)	Contingent Resources		
	1C	2C	3C
Gross (100%)	16.0	34.3	62.8
PSC contractors net entitlement (100%)	12.2	25.0	44.4
Net indirectly attributable to ATEL (50% contractor)	6.1	12.5	22.2

Notes:

1. "Gross" are 100% of the total field resources some of which may fall outside the Buffalo PSC.
2. "Net attributable to PSC contractors" are based on economic modelling and the terms of the PSC
3. "Net indirectly attributable to ATEL" is the proportion of contractor net attributable to AETL's equity in Carnarvon Petroleum Timor. ATEL interest in Carnarvon Petroleum Timor post subscription farm-in is to be confirmed.
4. Associated gas will be consumed in operations with limited surplus volumes flared.
5. Contingent resources are economic and an economic cut-off has been applied. RISC estimate the probability of development to be 86%.

In August 2017 RISC certified 1C - 2C - 3C gross contingent resource volumes as 15.3 - 31.1 - 47.8 MMstb. These remain valid and are carried by the Operator. Gross resources volumes in Table 5-1 differ from the Operator's previous volumes, due to production forecasts being adjusted to include potential off-block resources that will be produced, an update to the expected facility capacities and an update to economic

cut-off. Resource volumes will be updated following the appraisal well with an expected reduced 1C to 3C range.

5.4. Project Risks

This re-development project is based on re-mapping of the reservoir with the crest of the field and larger oil column east of the original development. RISC is confident of the re-mapped crest to the east, and that the planned appraisal well will find updip oil. The amount of recoverable oil has been quantified in the 1C to 3C range. However, there remain a 10% probability of an outcome worse than 1C.

Appraisal well results will provide an update to the most likely resource volume and is expected to narrow the 1C to 3C range.

Development is economic with current 1C, 2C and 3C resources. Development is expected to proceed after appraisal provided the appraisal outcome is not worse than 1C (~95%), acceptable commercial arrangements can be secured with facility (FPSO, MOPU, FSO) owners (95%) and the joint venture partners can secure development funding (95%). RISC estimate the probability of development to be 86% (95%x95%x95%).

6. Commercial

6.1. Methodology

Development economics have been run using the discounted cash flow method for the above cases based on estimates of future production of assessed reserves/resources and forecasts of future capital and operating costs. For some assets, we have applied adjustments for risk or used unit oil and gas values achieved in recent analogous transactions. We have evaluated the 1C, 2C and 3C contingent resource scenarios and tested cost and price sensitivities.

RISC has audited cash flow models based on the fiscal terms applying under the respective PSCs. The model and data input have been based on 100% project cash flows. PSC Contractor share of value and oil entitlement has then been determined by applying the terms of the PSC.

AETL is subscribing for equity in Carnarvon Petroleum Timor which is the 100% contractor of the Buffalo PSC. Whilst Carnarvon Petroleum Timor itself will hold 100% of the economic interest in the oil entitlement and project economics, for the purposes of these calculations, AETL's indirect economic interest will be treated as equal to their proportionate equity interest in Carnarvon Petroleum Timor. However, for the avoidance of doubt, actual entitlement to oil and the project remains in Carnarvon Petroleum Timor.

AETL's economic entitlement and project economics will generally be equal to their farm-in interest of the 100% contractor values. The proposed subscription carry on the appraisal well and subsequent cost recovery of this has a minor effect on their net economics or oil entitlement.

A summary description of the fiscal regime/PSC terms and assumptions used in the models follows.

6.2. Fiscal regime/PSC terms

A summary of the PSC terms applying to the asset are:

- 100% cost recovery;
  - Uplift; 11% plus 30-yr US treasury bond rate
- 65% contractor share of profit oil;
- 30% corporate tax rate;
- 5% royalty from revenue; and
- nil supplemental tax.

6.2.1. Assumptions

RISC has audited and used Carnarvon Petroleum's economic model which has previously been audited by PWC.

- The effective date is assumed to be 1 January 2021;
- A base oil price forecast of US$50/bbl flat in real terms, with sensitivities of US$35/bbl and US$65/bbl flat real;
- 2% pa inflation has been applied to costs and prices; and
- Net Present Values ("NPVs") are reported at a 10% nominal discount rate.

6.2.1.1. *Oil price forecast*

The first half of 2020 has seen the worst oil price downturn in recent years, both in terms of speed and depth (Figure 6-1). This latest price crash was as a result of demand destruction brought on by the COVID-19 pandemic as well as untimely disputes on production cuts from OPEC.

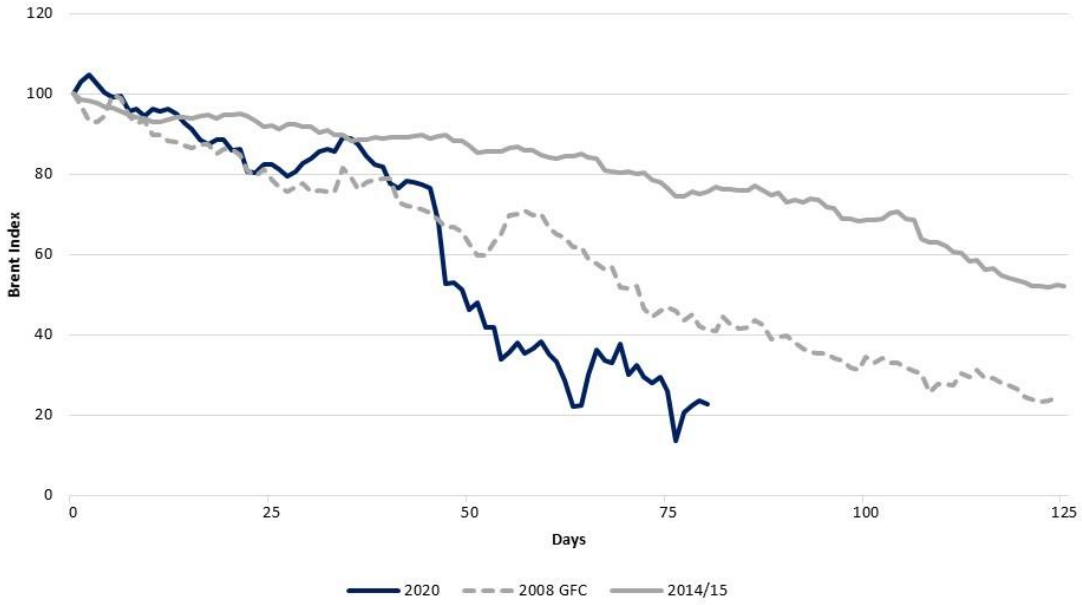


Figure 6-1: Brent Oil Price Index Performance History

Although demand recovery remains unclear, we consider that OPEC will continue to play an important role in influencing prices through supply. OPEC has been losing market share through production cuts since 2016 with the intention of supporting prices around US$50-60/bbl. This strategy of becoming the supply donor proved to be unsuccessful as any reduction from OPEC has been met by increased output from non-OPEC countries, particularly US shale producers.

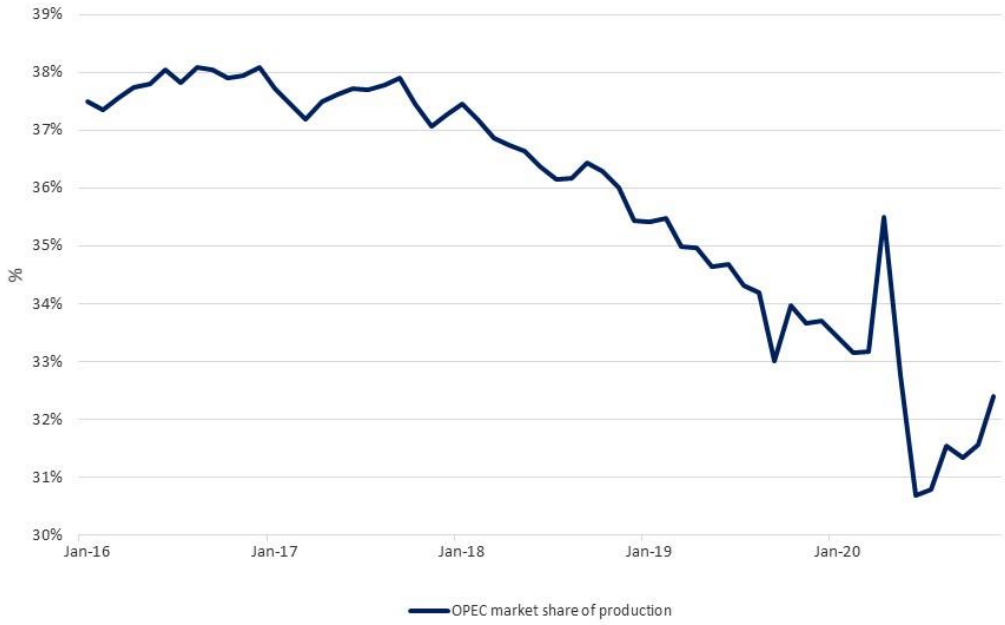


Figure 6-2: OPEC market share of global production

The May 2020 announcement by OPEC to cut production by 10 MMbbl/d provided little influence on prices as the global oil demand had already dropped by more than 20 MMbbl/d. Going forward, we consider that OPEC will defend its market share more aggressively and ensure that prices remain below US shale breakeven. Our analysis suggests that US shale breakeven price is around US$40/bbl WTI or US$45/bbl Brent.

We consider that the oil price will undergo a period of high volatility in the short term as global markets grapple with demand, inventories and storage capacity. Our mid case is representative of an OPEC controlled market of US$50/bbl flat real. We have provided a range around this figure of US$35 in the low case to account for further demand destruction from the COVID-19 pandemic and US$65 in the high case in a scenario that shows improved growth and lower output from capital-constrained US shale producers.

6.3. Economic results

Table 6-1 summaries the total contractor and AETD's indirect (50% contractor) resources entitlement and unrisked project NPV.

Table 6-1: Summary of economic evaluation of discovered assets

Resource Case	Contingent Resources after economic cut-off (MMstb)			NPV (US$ million, 10% nominal)	
	Total Field	100% Contractor	ADV (50%)[#2]	100% Contractor	ADV (50%)[#2]
1C	16.0	12.2	6.1	140	69
2C	34.3	25.0	12.5	339	169
3C	62.8	44.2	22.2	611	305

Notes:

1. NPV at 31 December 2020.
2. Based on AETL subscription to 50% equity in Carnarvon Petroleum Timor with a 100% carry of US$20 million appraisal with cost recovery. AETL indirect net NPV is slightly lower than 50% of the total contractor NPV due to the cost carry for appraisal.
3. The farm-in percentage is to be confirmed.

The project economics shown in this report represent the 100% contractor's interest and have not been adjusted for other factors (e.g. chance of development, strategic, political and security risks) that a buyer or seller may consider in any transaction concerning these assets and therefore should not be taken to be fair market values.

The development NPV has been tested against resource, cost and price uncertainties. Figure 6-3 is a tornado diagram of NPV sensitivities:

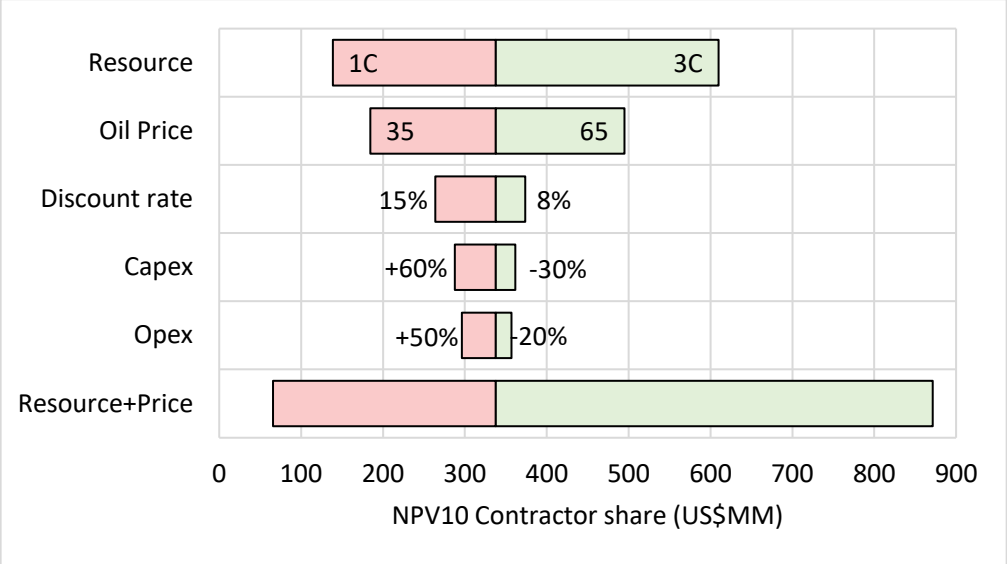


Figure 6-3: Contractor NPV tornado diagram

Figure 6-3 shows that the resource volume has the largest effect (other parameters as base case value) followed by oil price. Capex and Opex uncertainty have less effect. It also shows that the project is robust against the two highest sensitivities combined; resource volume and oil price.

Figure 6-4 shows the NPV sensitivity to individual sensitivities at different discount rates. The cost and price sensitivities have a small effect on contractor and AETL indirect oil entitlement.

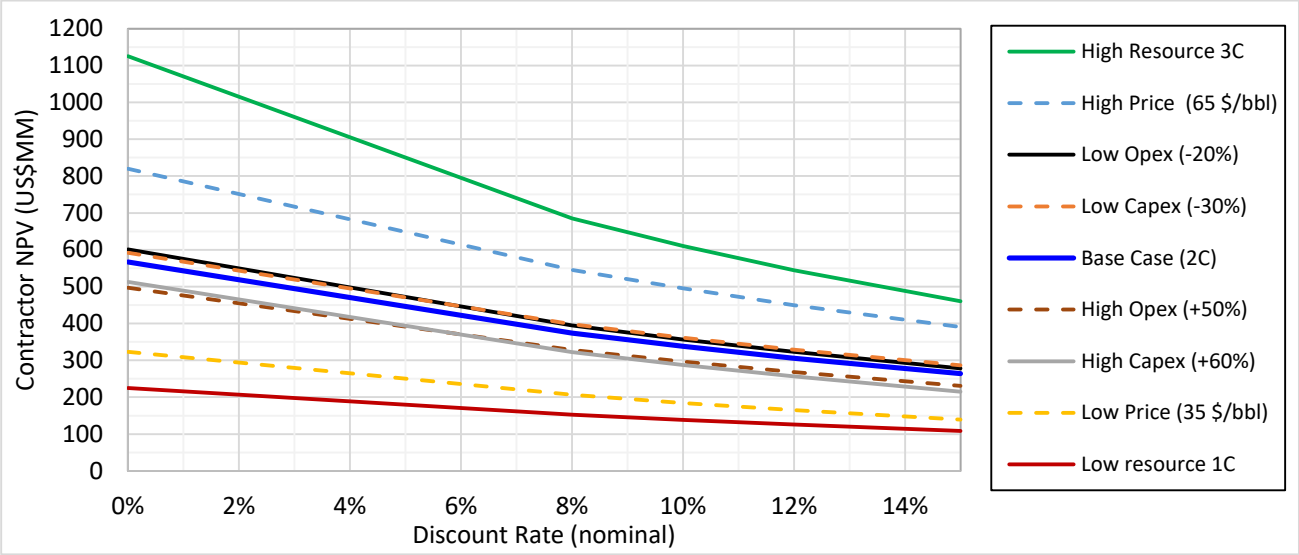


Figure 6-4: NPV sensitivity to key parameters

The economic production life is 3, 6 and 11 years in the 1C, 2C and 3C scenarios.

7. Declarations

7.1. Terms of Engagement

This CPR, any advice, opinions or other deliverables are provided pursuant to the Engagement Contract agreed to and executed by Advance Energy and RISC.

7.2. Qualifications

RISC is an independent oil and gas advisory firm. All of the RISC staff engaged in this assignment are professionally qualified engineers, geoscientists or analysts, each with many years of relevant experience and most have in excess of 20 years.

RISC was founded in 1994 to provide independent advice to companies associated with the oil and gas industry. Today the company has approximately 40 highly experienced professional staff at offices in Perth, Brisbane, Jakarta and London. We have completed over 2,000 assignments in 70+ countries for nearly 500 clients. Our services cover the entire range of the oil and gas business lifecycle and include:

- Oil and gas asset valuations, expert advice to banks for debt or equity finance;
- Exploration/portfolio management;
- Field development studies and operations planning;
- Reserves assessment and certification, peer reviews;
- Gas market advice;
- Independent Expert/Expert Witness;
- Strategy and corporate planning.

The preparation of this report has been managed by Mr Peter Stephenson who is an employee of RISC. Mr Stephenson is a member of the Society of Petroleum Engineers, Society of Petroleum Evaluation Engineers, Institute of Chemical Engineers and holds a BSc (Chemical Engineering), Nottingham University, 1982 and an MEng (Petroleum Engineering), Heriot Watt University, 1984. Mr Stephenson has over 35 years' experience in the sector and is a qualified petroleum reserves and resources evaluator (QPRRE) as defined by ASX listing rules, a Qualified Reserve Auditor (QRA) as defined by SPE and a member of the SPEE (Society of Petroleum Evaluation Engineers).

7.3. Standard

Reserves and resources are reported in accordance with the definitions of reserves, contingent resources and prospective resources and guidelines set out in the Petroleum Resources Management System (PRMS) prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the American Association of Petroleum Geologists (AAPG), World Petroleum Council (WPC), Society of Petroleum Evaluation Engineers (SPEE), Society of Exploration Geophysicists (SEG), Society of Petrophysicists and Well Log Analysts (SPWLA) and European Association of Geoscientists and Engineers (EAGE), revised June 2018.

7.4. Limitations

The assessment of petroleum assets is subject to uncertainty because it involves judgments on many variables that cannot be precisely assessed, including reserves/resources, future oil and gas production rates,

the costs associated with producing these volumes, access to product markets, product prices and the potential impact of fiscal/regulatory changes.

The statements and opinions attributable to RISC are given in good faith and in the belief that such statements are neither false nor misleading. While every effort has been made to verify data and resolve apparent inconsistencies, neither RISC nor its servants accept any liability, except any liability which cannot be excluded by law, for its accuracy, nor do we warrant that our enquiries have revealed all of the matters, which an extensive examination may disclose. In particular, we have not independently verified property title, encumbrances or regulations that apply to these assets.

Whilst every effort has been made to verify data and resolve apparent inconsistencies, neither RISC nor its servants accept any liability for its accuracy, nor do we warrant that our enquiries have revealed all of the matters, which an extensive examination may disclose. In particular, we have not independently verified property title, encumbrances, regulations that apply to this asset(s). RISC has also not audited the opening balances at the valuation date of past recovered and unrecovered development and exploration costs, undepreciated past development costs and tax losses.

We believe our review and conclusions are sound but no warranty of accuracy or reliability is given to our conclusions.

Our review was carried out only for the purpose referred to above and may not have relevance in other contexts.

7.5. Use of advice or opinion and reliance

a) The CPR is for the sole benefit of the directors of Advance Energy plc and Strand Hanson Limited. ***It may not be relied upon by any 3rd party.***

RISC grants permission for this CPR to be disclosed in the Company's Admission Document.

7.6. Independence

RISC makes the following disclosures:

- RISC is independent with respect to Advance Energy and confirms that there is no conflict of interest with any party involved in the assignment.
- Under the terms of engagement between RISC and Advance Energy, RISC will receive a time-based fee, with no part of the fee contingent on the conclusions reached, or the content or future use of this report. Except for these fees, RISC has not received and will not receive any pecuniary or other benefit whether direct or indirect for or in connection with the preparation of this report.
- Neither RISC Directors nor any staff involved in the preparation of this report have any material interest in Advance Energy or in any of the properties described herein.

7.7. Copyright

This document is protected by copyright laws. Any unauthorised reproduction or distribution of the document or any portion of it may entitle a claim for damages. Neither the whole nor any part of this report nor any reference to it may be included in or attached to any prospectus, document, circular, resolution, letter or statement without the prior consent of RISC.

7.8. Authorisation for release

This CPR is authorised for release by Mr. Peter Stephenson, RISC Partner dated 23 March 2021.

Peter Stephenson

RISC Partner

8. List of terms

The following lists, along with a brief definition, abbreviated terms that are commonly used in the oil and gas industry and which may be used in this report.

Term	Definition
1C	Low estimate contingent resource (P90 probability)
1P	Equivalent to Proved reserves or Proved in-place quantities, depending on the context.
2C	Best estimate contingent resources (P50 probability)
2P	The sum of Proved and Probable reserves or in-place quantities, depending on the context.
2D	Two Dimensional
3C	High estimate contingent resources (P10 probability)
3D	Three Dimensional
3P	The sum of Proved, Probable and Possible Reserves or in-place quantities, depending on the context.
AFE	Authority for Expenditure
Bbl	US Barrel
BBL/D	US Barrels per day
BCF	Billion (10^9) cubic feet
BFPD	Barrels of fluid per day
BOPD	Barrels of oil per day
BWPD	Barrels of water per day
°C	Degrees Celsius
Capex	Capital expenditure
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are a class of discovered recoverable resources as defined in the SPE-PRMS.
CO_2	Carbon dioxide
CP	Centipoise (measure of viscosity)
CPR	Competent Person Report
DEG	Degrees
DHI	Direct hydrocarbon indicator
Discount Rate	The interest rate used to discount future cash flows into a dollars of a reference date
DST	Drill stem test
ESP	Electric submersible pump
EUR	Economic ultimate recovery

Term	Definition
Expectation	The mean of a probability distribution
F	Degrees Fahrenheit
FDP	Field Development Plan
FEED	Front End Engineering and design
FID	Final investment decision
FM	Formation
FPSO	Floating Production Storage and offtake unit
FWL	Free Water Level
GRV	Gross rock volume
H_2S	Hydrogen sulphide
HHV	Higher heating value
JV(P)	Joint Venture (Partners)
km^2	Square kilometres
m	Metres
MDT	Modular dynamic (formation) tester
mD	Millidarcies (permeability)
MMbbl	Million US barrels
MMscf(d)	Million standard cubic feet (per day)
MMstb	Million US stock tank barrels
MOD	Money of the Day (nominal dollars) as opposed to money in real terms
MOPU	Mobile Offshore Production Unit
Mscf	Thousand standard cubic feet
Mstb	Thousand US stock tank barrels
MPa	Mega (10^6) pascal (measurement of pressure)
mss	Metres subsea
mTVDss	Metres true vertical depth subsea
NPV	Net Present Value (of a series of cash flows)
NTG	Net to Gross (ratio)
OOIP	Original Oil in Place
Opex	Operating expenditure
OWC	Oil-water contact
P90, P50, P10	90%, 50% & 10% probabilities respectively that the stated quantities will be equalled or exceeded. The P90, P50 and P10 quantities correspond to the Proved (1P), Proved + Probable (2P) and Proved + Probable + Possible (3P) confidence levels respectively.
PBU	Pressure build-up
POS	Probability of Success
Possible	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes

Term	Definition
Reserves	associated with a defined degree of uncertainty. Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.
Probable Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations as defined in the SPE-PRMS.
Proved Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. Often referred to as 1P, also as “Proven”.
PSC	Production Sharing Contract
PSDM	Pre-stack depth migration
PSTM	Pre-stack time migration
psia	Pounds per square inch pressure absolute
PVT	Pressure, volume & temperature
rb/stb	Reservoir barrels per stock tank barrel under standard conditions
RFT	Repeat Formation Test
Real Terms (RT)	Real Terms (in the reference date dollars) as opposed to Nominal Terms of Money of the Day
Reserves	RESERVES are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.
RT	Measured from Rotary Table or Real Terms, depending on context

Term	Definition
SPE	Society of Petroleum Engineers
SPE-PRMS	Petroleum Resources Management System, prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the American Association of Petroleum Geologists (AAPG), World Petroleum Council (WPC), Society of Petroleum Evaluation Engineers (SPEE), Society of Exploration Geophysicists (SEG), Society of Petrophysicists and Well Log Analysts (SPWLA) and European Association of Geoscientists and Engineers (EAGE), revised June 2018.
stb	Stock tank barrels
STOIIP	Stock Tank Oil Initially In Place
Sw	Water saturation
TVD	True vertical depth
TVDSS	True Vertical Depth Sub-Sea
TWT	Two Way Time
US$	United States dollar
WHFP	Well Head Flowing Pressure
WHP	WellHead Platform or WellHead Pressure
Working interest	A company's equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms.
WPC	World Petroleum Council
WTI	West Texas Intermediate Crude Oil