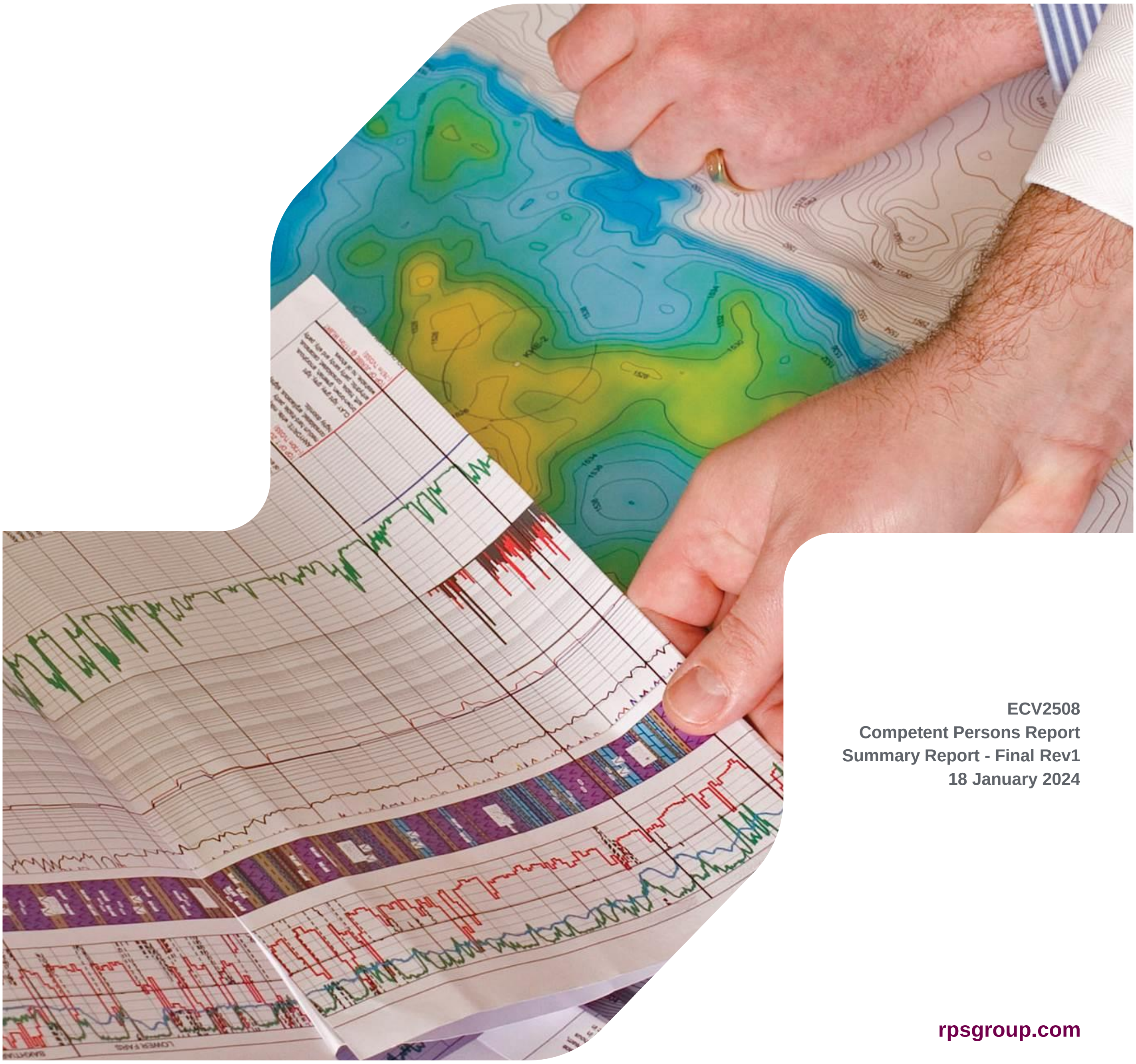
SUMMARY COMPETENT PERSONS REPORT

Pensacola Discovery, Licence P2252 (Blocks 41/5a, 41/10a and 42/1a), UK North Sea



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Approval for issue

Gordon Taylor

This is an abbreviated version of the RPS report that was prepared in response to a request by Deltic Energy under and subject to the Letter of Engagement dated 07 March 2023 with Deltic Energy Plc (the "Agreement"), RPS Energy Ltd ("RPS") to detail the independent evaluation of the Pensacola Discovery in Licence P2252 UKCS. This report should be read in conjunction with the full report provided to Deltic on the same date that this version was issued. The use of this abbreviated report is at the clients own risk

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Prepared by:

RPS Energy Consultants Ltd

Clare Wilson, CGeol
Principal Advisor Geoscience

Goldvale House
27-41 Church Street West
Woking, Surrey GU21 6DH

T +44 1483 746 500
E clare.wilson@rpsgroup.com

Prepared for:

Deltic Energy Plc

Andrew Nunn

1st Floor,
150 Waterloo Road,
London,
SE1 8SB

T +44 207 887 2630
E a.nunn@delticenergy.com

Our ref: ECV2508

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

Date: 18 January 2024

Deltic Energy
1st Floor,
150 Waterloo Road,
London,
SE1 8SB

Andrew Nunn

SUMMARY COMPETENT PERSONS REPORT: PENSACOLA DISCOVERY

In response to a request by Deltic Energy ("Deltic Energy Plc"), and the Letter of Engagement dated 07 March 2023 with Deltic Energy Plc (the "Agreement"), RPS Energy Ltd ("RPS") has completed an independent evaluation of the Pensacola Discovery in Licence P2252 UKCS.

This report is issued by RPS under the appointment by Deltic Energy Plc and is produced as part of the Services detailed therein and subject to the terms and conditions of the Agreement.

RPS has estimated Contingent Resources as of 01 January 2024. All resources definitions and estimates shown in this report are based on the 2018 Petroleum Resource Management System of SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE ("PRMS"). The work was undertaken by a team of petroleum engineers, geoscientists and economists and is based on data supplied by Deltic Energy Plc. Our approach has been to audit the Deltic estimates of Resources, based on the 2019 SPE Reserves Auditing Standards.

In estimating resources, we have used standard geoscience and petroleum engineering techniques. We have estimated the degree of uncertainty inherent in the measurements and interpretation of the data and have calculated a range of recoverable volumes, based on a notional predicted field performance.

We have taken the working interest that Deltic Energy Plc has in the discovery as presented by Deltic Energy Plc. We have not investigated, nor do we make any warranty as to Deltic Energy Plc interest in the Assets.

No site visit was conducted as part of this study.

The Net Entitlement Resources as of 1st January 2024 are summarised in Section 6. RPS has classified the Pensacola Discovery as Contingent Resources - Development Pending. Development is contingent on the successful appraisal of the crestal area of the discovery, understanding of the discovered hydrocarbons, an agreed and more detailed development plan and necessary approvals.

QUALIFICATIONS

RPS is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. The provision of professional services has been solely on a fee basis. Gordon Taylor, Director has supervised this evaluation. Mr Taylor is a Chartered Geologist and Chartered Engineer with over 40 years' experience in upstream oil and gas. The project has been managed by Clare Wilson, who has 25 years' experience in upstream oil and gas. Other RPS employees involved in this work hold at least a degree in geology, geophysics, petroleum engineering or a related subject or have at least five years of relevant experience in the practice of geology, geophysics or petroleum engineering.

BASIS OF OPINION

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

The report represents RPS's best professional judgment and should not be considered a guarantee or prediction of results. It should be understood that any evaluation, particularly one involving future performance and development activities may be subject to significant variations over short periods of time as new information becomes available. This report relates specifically and solely to the subject assets and is conditional upon various assumptions that are described herein. This report must, therefore, be read in its entirety. This is an abbreviated version of the RPS report and should be read in conjunction with the full report[1] provided to Deltic on the same date that this version was issued.

This report was provided for the sole use of Deltic Energy Plc and their corporate advisors, as agreed in the Letter of Engagement, on a fee basis.

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Yours sincerely,
for RPS Energy Ltd

Gordon Taylor, CGeol
Technical Director

Name	Role	Signature
Clare Wilson	Geology and Geophysics Lead and Project Manager	
Ben Lowden	Petrophysics Lead	
Adolfo Perez	Reservoir Engineering Lead	
David Walker	Costs & Facilities Engineering Lead	
Joseph Tan	Economist Lead	

[1] ECV2508_Deltic Energy Competent Persons Report – Pensacola Discovery Final rev0.pdf

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1 EXECUTIVE SUMMARY

In response to a request by Deltic Energy Plc ("Deltic"), and the Letter of Engagement dated 07 March 2023 with Deltic (the "Agreement"), RPS Energy Ltd ("RPS") has completed an Independent Audit of the contingent resources in the Pensacola Discovery in Licence P2252 of the UK North Sea.

This report is issued by RPS under the appointment by Deltic and is produced as part of the Services detailed therein and subject to the terms and conditions of the Agreement.

RPS has audited the interpretations generated by Deltic and has then estimated low (P90), base (P50) and high (P10) recoverable hydrocarbon volumes, based on statistical ranges of hydrocarbon-initially-in-place (HIIP) estimates. Significant uncertainty exists in the range of hydrocarbons since the discovery well location was sub-optimal. No development plan has been approved and Deltic has provided RPS with two possible development plans for consideration. The commerciality of the notional developments presented by Deltic have been assessed and the project is classified as Contingent Resources – Development Pending.

All definitions and estimates shown in this report are based on the 2018 Petroleum Resource Management System of SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE ("PRMS"). The work was undertaken by a team of petroleum engineers and geoscientists and is based on data supplied by Deltic. Our approach has been to audit Deltic's own estimates of resources, based on the 2019 SPE Reserves Auditing Standards.

No site visit was conducted as part of this study.

The effective date of this report is 01 January 2024. The effective date of the report is 1st January 2024. RPS work was based on data and an audit of Deltic interpretations provided to end October 2023. Deltic advises that, other than the North Sea Transition Authority releasing data from the Crosgan Zechstein appraisal well, drilled in early 2023 by ONE-Dyas, there is no additional data and there are no changes to the interpretations or development plans audited in the CPR. The release of the Crosgan well data occurred after completion of RPS work and results of that well have not been incorporated in this report.

1.1 Overview of Assets

This report only covers the Pensacola Discovery in Licence P2252. The P2252 licence was awarded in December 2014, the second Term has been extended to 30th September 2028 and the licence expiry is 30th November 2040. The licence covers blocks 41/5a, 41/10a and 42/1a. The discovery is northwest of the Breagh Field in water depths of approximately 70 metres. The discovery well, 41/5a-2, was completed in January 2022. Gas was discovered and tested in the Zechstein carbonates of the Hauptdolomit Formation. A small amount of oil was also produced.

1.2 Subsurface and Resource Evaluation

RPS has audited the seismic interpretation and depth mapping and the petrophysical parameters for the Pensacola discovery. RPS used the geological and geophysical data provided to estimate statistical ranges of low, mid and high case hydrocarbon-initially-in-place that are presented in Table 1-1.

Case	In Place Volumes			
	Low (P90)	Best (P50)	High (P10)	Mean
Free Gas in place[1] (Bscf)				
Total[2]	194	384	663	411
STOIIP (MMstb)				
Total[2]	87	239	482	266
Associated Gas in place (Bscf)				
(from oil leg)[2]	49	135	276	152

1. Raw gas - includes inerts

2. Aggregated total for crest and flank areas with dependency on GOC/OWC/area uncertainty/FVF/GOR

Table 1-1: Gross HCIIP

At this stage of the Pensacola project, there is no clarity on how the field will be developed. In this study, RPS audited recoverable volumes for the Pensacola discovery based on two notional development plans provided by Deltic. The cases are a gas only case and a combined gas and oil case. Both cases assume three horizontal wells with 1,000m effective section in the gas zone, however, the combined gas and oil case considers three additional horizontal wells with the same effective section in the oil zone. RPS has reviewed the costs of the two development options provided by Deltic and screened them for commerciality.

RPS recognises that eventual commercial development may be possible but further appraisal and detailed development planning is required. RPS understands, that the Joint Venture are working towards an appraisal well potentially at end 2024.

The recoverable volume estimates have been made in this report based on preliminary modelling provided by Deltic and material balance models built by RPS. The Economic Limit Test (ELT) performed for the determination of Resources is based on RPS's estimates of recoverable volumes, a review of Deltic's estimates of Capex and Opex and assumed gas and oil sales prices.

A summary of Contingent Resources for Pensacola is presented for the Gas Only Case in Table 1-2 and for the Oil and Gas Case in Table 1-3. RPS classifies the resources as Contingent Resources – Development Pending, in accordance with PRMS terms, as appraisal activities are planned. However, the choice of development concept requires further clarification after successful appraisal.

Based on the uncertainty in the oil potential and in the reservoir characteristics on the crest of the structure, that are likely to be different to those encountered in the flank well and potentially variable across the platform further appraisal is required. A development concept has then to be agreed and the detailed development plan prepared. At this early stage in the project, given the understanding of the range of volumes, of oil in particular, and the development options still being considered, RPS consider assigning a chance of development is premature.

SUMMARY OF CONTINGENT RESOURCES: GAS ONLY CASE As of 1st January 2024 BASE CASE PRICES AND COSTS							
	Full Field Gross Resources[1]			Deltic Net Working Interest[2]			Pd[3]
	1C	2C	3C	1C	2C	3C	
Gas (Bscf)	112.4	296.8	631.7	33.7	89.0	189.5	*
Condensate (MMstb)	0.2	0.6	1.5	0.1	0.2	0.4	
Oil Equivalent (Mmboe) [4]	18.9	50.0	106.7	5.7	15.0	32.0	

Notes:
[1]Gross field Resources (100% basis) ***after*** *economic limit test.*
[2]Deltic holds a 30% working interest in P2252.
[3]Chance of Development ("Pd") is the estimated probability that a known accumulation, once discovered, will be commercially developed. At this early stage in the project, given the understanding of the range of volumes, of oil in particular, and the development options still being considered, RPS consider assigning a chance of development is premature
[4]Conversion rate of 6,000 scf per boe

Table 1-2: Contingent Resources (Gas Only Case) as of 01 January 2024

SUMMARY OF CONTINGENT RESOURCES: COMBINED GAS AND OIL CASE As of 1st January 2024 BASE CASE PRICES AND COSTS							
	Full Field Gross Resources[1]			Deltic Net Working Interest[2]			Pd[3]
	1C	2C	3C	1C	2C	3C	
Gas (Bscf)	113.6	313.0	616.7	34.1	93.9	185.0	*
Oil (MMstb)	4.7	19.8	50.9	1.4	5.9	15.3	
Condensate (MMstb)	0.2	0.6	1.4	0.1	0.2	0.4	
Oil Equivalent (Mmboe) [4]	23.9	72.6	155.1	7.2	21.8	46.5	

Notes:
[1]Gross field Resources (100% basis) ***after*** *economic limit test.*
[2]Deltic holds a 30% working interest in P2252.
[3]Chance of Development ("Pd") is the estimated probability that a known accumulation, once discovered, will be commercially developed. At this early stage in the project, given the understanding of the range of volumes, of oil in particular, and the development options still being considered, RPS consider assigning a chance of development is premature
[4]Conversion rate of 6,000 scf per boe

Table 1-3: Contingent Resources – Combined Gas and Oil Case as of 01 January 2024

A summary of the economic evaluation of Contingent Resources for gas only and combined gas and oil case is presented in Table 1-4.

	ELT Date	Post-Tax Net Present Value (Net to Deltic) (US$ Million, MOD) at different Discount Rates			
		0%	10%	12%	15%
Gas Only Case					
1C	2034	124	20	8	(6)
2C	2044	599	199	158	111
3C	2058	1,664	412	323	226
Combined Gas and Oil Case					
1C	2036	(29)	(114)	(121)	(127)
2C	2048	792	205	148	84
3C	2058	2,236	566	437	296

Table 1-4: Post-Tax Valuation at RPS Base Case Price Scenario as of 01 January 2024

1.3 Summary Report

This is an abbreviated version of the RPS report. This report should be read in conjunction with the full report provide to Deltic on the same date that this version was issued[2].

[2] ECV2508_Deltic Energy Competent Persons Report – Pensacola Discovery Final rev1.pdf

2 INTRODUCTION

In response to a request by Deltic Energy ("Deltic Energy Plc"), and the Letter of Engagement dated 07 March 2023 with Deltic Energy Plc (the "Agreement"), RPS Energy Ltd ("RPS") has completed an independent evaluation of the Pensacola Discovery in Licence P2252 UKCS.

This report is issued by RPS under the appointment by Deltic. It is produced as part of the Services detailed therein and subject to the terms and conditions of the Agreement. This report was provided for the sole use of Deltic and their corporate advisors on a fee basis. The effective date of the report is 1st January 2024. RPS work was based on data and an audit of Deltic interpretations provided to end October 2023. Deltic advises that, other than the North Sea Transition Authority releasing data from the Crosgan Zechstein appraisal well, drilled in early 2023 by ONE-Dyas, there is no additional data and there are no changes to the interpretations or development plans audited in the CPR. The release of the Crosgan well data occurred after completion of RPS work and results of that well have not been incorporated in this report.

As per Phase 1 of the Agreement, we have generated Low, Mid and High ranges of both Hydrocarbons-Initially-In-Place (HIIP) and recoverable hydrocarbon volumes based on the 2018 Petroleum Resource Management System of SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE ("PRMS"). The work was undertaken by a team of petroleum engineers and geoscientists and is based on data supplied by Deltic Energy Plc.

The P2252 licence was awarded in December 2014 the second Term has been extended to 30th September 2028 and the licence expiry is 30th November 2040. The licence covers blocks 41/5a, 41/10a and 42/1a.

Asset/ Country	Deltic Working Interest	Development Status	Licence Expiry Date	Licence Area (sq. km)	Type of deposit	Partners
Pensacola, UKCS	30%	Second Term	Second term end date 30/09/28. Anticipated Licence end date 30th November 2040	214.4	Gas and Oil	Shell UK Ltd. (65%) Operator, ONE Dyas (5%)

Note
1. Licence P2252 coverers UKCS Blocks 41/5a, 41/10a and 42/1a

Table 2-1: Summary of Deltic Energy Plc Assets

2.1 Pensacola Discovery

The Pensacola discovery is northwest of the Breagh Field in water depths of approximately 70 metres (Figure 2-1). The discovery was made by well 41/5a-2 in January 2022. Gas was discovered and tested in the Zechstein carbonates of the Hauptdolomit Formation. A small amount of oil was also recovered.

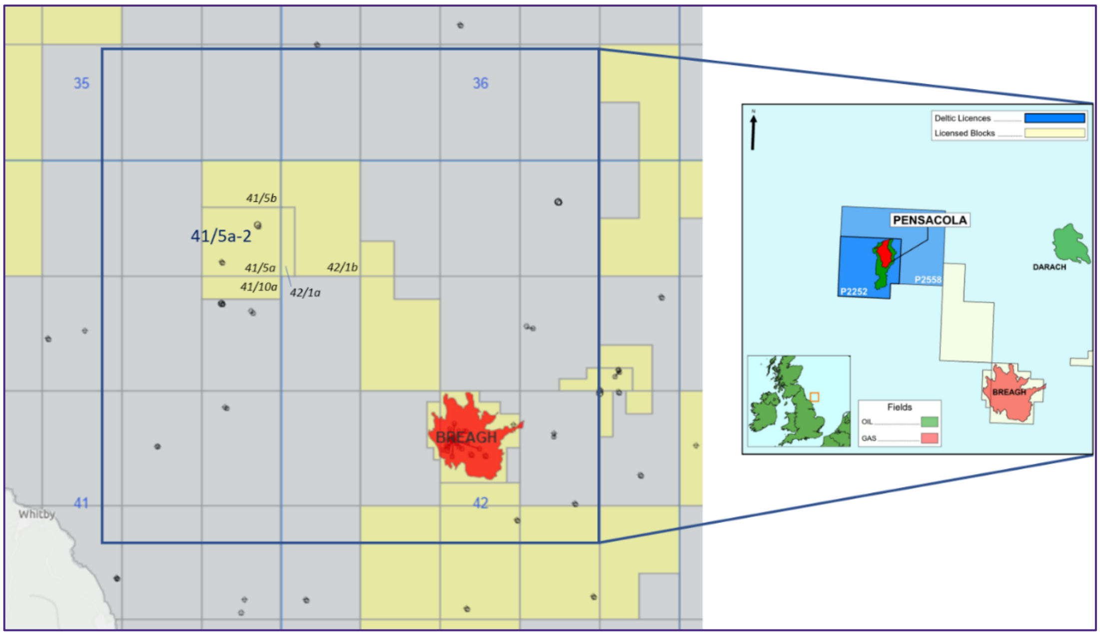

Figure 2-1: Pensacola Discovery Location Map

The well was drilled on the flank of a Zechstein Carbonate platform confirming an aggregational geological model for the platform carbonates. The flank facies are sourced from erosion of the updip crestal carbonates however their properties are affected by a different depositional development. The properties and facies of the crestal part of the field are one of the main uncertainties in the estimate of hydrocarbons in place.

The well encountered an 18m thickness of Hauptdolomit in a slope facies, with good porosity (17%). The well was tested and flowed at a maximum of 4.5 MMscf/day gas. The gas had a high methane content (80%) but also approximately 10% CO_2, 2% Nitrogen and <3 ppm H_2S. The well also produced a small amount of 34-36 API black oil at a rate equivalent to approximately 25 stb/d.

The Pensacola structure forms an elongate high some 12 km long and up to 5 km at its widest point. The Permian age Hauptdolomit reservoir is sealed by the overlying Stassfurt halite. The dolomite was deposited on a Werraanhydrit sulphate mound near the northern edge of the Southern Permian Basin . The Zechstein lies unconformably over Carboniferous age rocks. The gas is likely to be sourced from the Carboniferous however the source of the oil is less clear. Geochemistry indicates it is likely to be a mixture of Zechstein and Carboniferous sources.

2.2 Basis of Opinion

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

The report represents RPS' best professional judgment and should not be considered a guarantee or prediction of results. It should be understood that any evaluation, particularly one involving future performance and development activities may be subject to significant variations over short periods of time as new information becomes available. This report relates specifically and solely to the Pensacola Discovery and is conditional upon various assumptions that are described herein. This report must, therefore, be read in its entirety. However, this is an abbreviated report and should be read in conjunction with the full report[2] provide to Deltic on the same date.

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2.2.1 Audit Methodology

As noted above, our approach has been to audit Deltic's estimates of recoverable volumes, based on the 2019 SPE Reserves Auditing Standards, which describe an audit as follows:

A Reserves Audit is the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves and/or Reserves Information prepared by others and the rendering of an opinion about:

(1) the appropriateness of the methodologies employed,

(2) the adequacy and quality of the data relied upon,

(3) the depth and thoroughness of the reserves estimation process,

(4) the classification of reserves appropriate to the relevant definitions used, and

(5) the reasonableness of the estimated reserves quantities and/or the Reserves Information.

The term "reasonableness" cannot be defined with precision but should reflect a quantity and/or value difference of not more than plus or minus 10%, or the subject Reserves Information does not meet minimum recommended audit standards.

3 SUBSURFACE EVALUATION

3.1 Geology

The Pensacola structure is controlled by the geometry of the Werraanhydrit (Figure 3-1). The platform dips southwards forming a trap that is dip closed to the south, west and east and fault closed or possibly stratigraphically closed to the north. Shallow-water carbonate platform facies of the Hauptdolomit were deposited on highs generated by the sulphate platform of the Werraanhydrit, which themselves were created on pre-existing topography on the Base Permian Unconformity. Following the deposition of the Werraanhydrit, transgression led to conditions favourable for carbonate deposition. The general stratigraphy of the area is shown in Figure 3-2 (from Garland, Tiltman and Inglis, Journal of Pet. Geol. Vol 46(3), 2023).

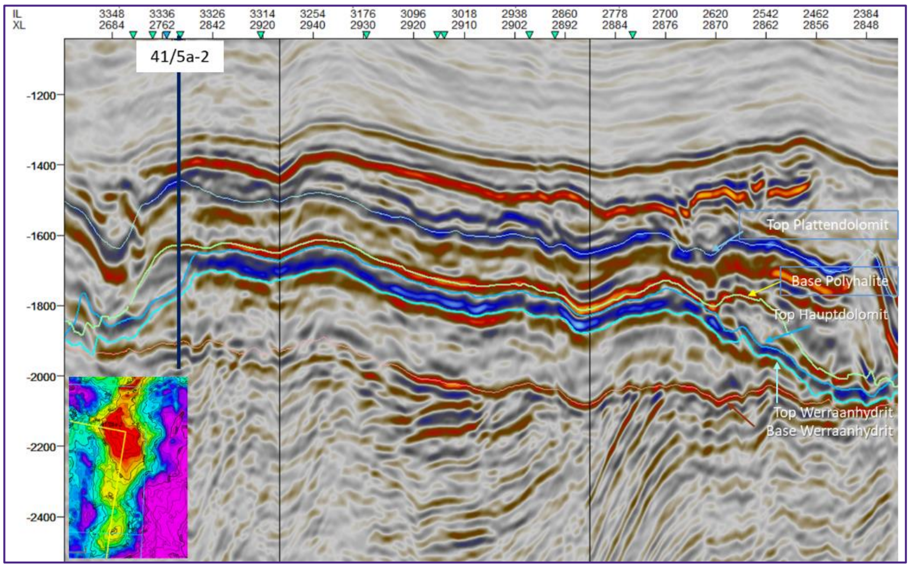


Figure 3-1: Seismic line through the Pensacola discovery well (41/5a-2) showing the Western Flank and southwards along the platform.

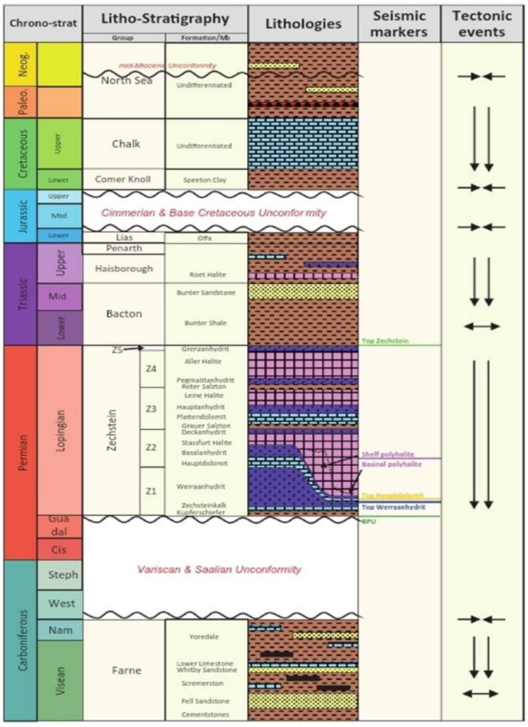


Figure 3-2: Stratigraphic column showing the Zechstein carbonates

The Pensacola well was planned to target the flank of the structure to test the geological depositional model which pre-drill was considered by Deltic to be either a progradational model with thick Hauptdolomit 'wings', or an aggregational model with thinner flank dolomites. The well proved the latter model. The thicker 'wings' are correlated to halites within the Stassfurt Formation in 41/5a-2 and the well encountered Zechstein age Hauptdolomit reservoir which has good porosity (17%). The Hauptdolomit is overlain and sealed by the anhydrites and halite of the Stassfurt Halite.

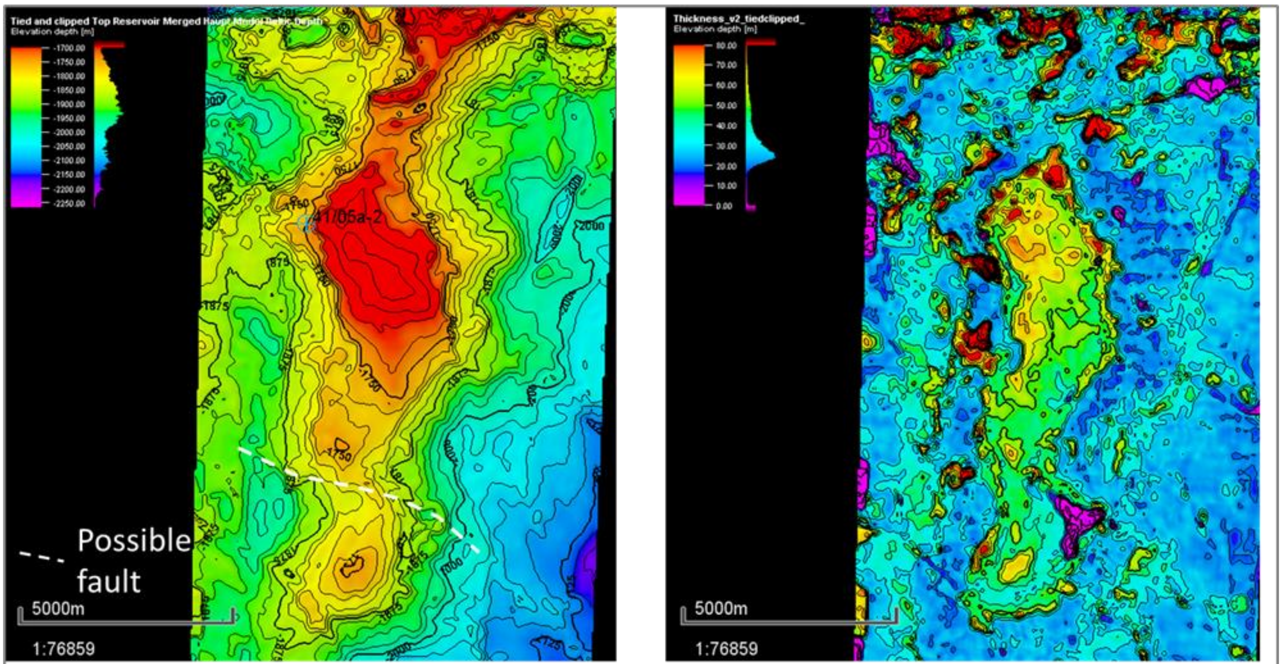
3.2 Seismic interpretation

RPS has reviewed the seismic interpretation on the depth converted PSDM seismic volume. The reservoir section is only 18m thick in the discovery well and the overlying Basalanhydrit is only 7m thick. Both are below seismic resolution. The seismic to well tie is ambiguous. Different interpretations of the seismic to well tie by the Operator, Deltic and RPS clearly highlights uncertainty which is exacerbated on the crest of the structure where both the Basalanhydrit and Hauptdolomit are expected to thicken. Modelling of the impact on seismic response as the thicknesses increase is ambiguous.

As the interpreted horizon on the flanks could be tied to any of the three possible well tops (the Basalanhydrit, the Top Hauptdolomit or the Top Werraanhydrit), for volumetrics Deltic's Top Hauptdolomit horizon was used after a bulk shift to tie to the well top. This surface is used as the basis for in-place volume estimates on the flanks and is discussed in Section 3.4 below. For the crest there is more uncertainty given there is no crestal well to tie the top reservoir or Top Werraanhydrit horizons. This impacts the accuracy of reservoir thickness estimates. The reservoir thickness is based on analogue data so it is the height of the reservoir on the crest than needs to be defined from seismic data. For the crest, RPS has used the Top Werraanhydrit horizon and stacked up to the Top reservoir. RPS has accounted for the uncertainty in its approach to volumetric ranges discussed in Section 3.4 below.

A fault is evident from the Top Hauptdolomit depth map (Figure 3-3a) in the southern part of the closure. Within the dolomite this does not appear to offset the reservoir. Faulting may enhance reservoir properties so with the current limited understanding of the facies, it is not assumed to further compartmentalise the field.

The thickness map between the Top Hauptdolomit and Top Werraanhydrit (Figure 3-3b) shows clearly the crestal area of the field and the likely stratigraphic or fault closure to the north of the field.



a) Deltic Top Hauptdolomit Depth Map

b) Thickness Top Hauptdolomit to Top Werraanhydrit

Figure 3-3: Pensacola – Deltic Top Hauptdolomit Depth map and Hauptdolomit thickness map

3.3 Petrophysics

RPS' petrophysical review was focussed on the Hauptdolomit interval in well 41/5a-2 (1744-1761mTVDSS). The logs and PVT analysis of fluid samples show gas down to 1755 mTVDSS, underlain by a mix of gas, oil and water to the base Hauptdolomit. However, it is unclear whether oil or water dominates the basal part of the Hauptdolomit and if the oil is moveable. Deltic interprets gas over moveable oil, with GOC at 1755 mTVDSS and ODT 1761 mTVDSS based on oil having been produced to surface on test at a rate of 25 stb/d. RPS notes that the Operator interprets a GDT at 1755 mTVDSS with mostly water below this and assumes any oil, if present, is largely immoveable.

RPS conclusions are:

- Resistivity Sw shows hydrocarbon throughout the Hauptdolomit interval
- DMRP analysis shows a clear gas signal down to 1755m TVDSS indicating gas down to this depth
- DMRP analysis shows negligible gas below 1755m TVDSS, indicating oil in this lower interval
- Resistivity Sw matches NMR Swirr with no evidence of moveable water.
- Permeability of this lower zone ranges between 1 to 10mD, which is above the standard limit for oil production (1mD).

3.4 Estimates of In-place Volumes

RPS has estimated volumes of the free gas and oil initially-in-place in the Pensacola Discovery. The oil has dissolved gas associated with it that may come out of solution either in the reservoir contributing to the gas cap, or on production. RPS has estimated the associated gas in place and it is included in the estimates of recoverable gas.

RPS has estimated a range of in-place volumes for both the crestal area and flank areas of the structure. The flank and crestal areas are recognised to have different geological development and are likely to have different properties. The limit of the crest area has been defined by the thinning of the isopach between the Deltic Top Hauptdolomit to Top Werraanhydrit depth maps. There is uncertainty in the seismic tie to the top and base reservoir horizons at the well and on the crest, as discussed in Section 3.2. RPS has used the Top Hauptdolomit horizon tied to the well for the flank area and stacked down, and for the crestal area has used the Top Werraanhydrit horizon and stacked up to top reservoir.

There is no well data for the discovery on the crest and seismic character is ambiguous so reservoir thickness on the crest is based on analogue data and the range used by the Operator, Deltic and RPS are all similar.

RPS estimates of the NTG, porosity and saturation from well 41/5a-2 were used on the flank. For the crest, the reservoir parameters are based on analogue well data from the Crosgan discovery and other Hauptdolomit discoveries in the same basin in the UKCS, Germany and the Netherlands. RPS has used the logged gas oil contact (GOC) of 1755 mTVDSS and chosen a wide range of OWC inputs, to reflect uncertainty in this parameter.

In place volumes are estimated for total gas including inerts. The input parameter ranges for the estimation of the HCIIP are summarised in Table 3-1.

Name		Unit	Crest Shape	Crest P90	Crest P50	Crest P10	Flank Shape	Flank P90	Flank P50	Flank P10
Thickness		m	Normal	35	45	55	Normal	12	18	24
Shift top res[1]		m	Normal	-35	-45	-55	Normal	6	8	10
Area Uncertainty		%	Normal	75	100	125	Normal	75	100	125
GOC		m	Single	1755	1755	1755	Single	1755	1755	1755
OWC		m	Lognor	1761[2]	1825	1860	Lognor	1761[2]	1825	1860
Net-to-gross		%	Single	100	100	100	Single	100	100	100
Porosity		%	Normal	10	17	24	Normal	13	17	21
Sw	gas	%	Normal	20	25	30	Normal	20	25	30
	oil	%	Normal	35	45	55	Normal	35	45	55
FVF (Bo)		rb/stb	Beta	1.21	1.26	1.35	Beta	1.21	1.26	1.35
Gas FVF (1/Bg)		scf/cf	Normal	195	205	215	Normal	195	205	215
Solution GOR		scf/bbl	Beta	460	560	700	Beta	460	560	700

1. *Shift up from Top Werraanhydrit depth surface to top Hauptdolomit, upwards is negative*
2. *P99 input*

Table 3-1: Pensacola Discovery Volumetric inputs

RPS used the area-depth pairs for the depth maps for the flank and crest and the range of average parameters for the crest and flank areas in Table 3-1 as inputs for the probabilistic estimation of the range of hydrocarbons in-place for the Pensacola field. The gross free GIIP, STOIIP and associated GIIP for Pensacola is presented in Table 3-2. The volumes are all within the P2252 licence.

RPS notes that volumes on the crest are based on analogue data and future appraisal will be required to better define the reservoir properties and structural mapping.

Case	Pensacola Discovery In Place Volumes			
	Low (P90)	Best (P50)	High (P10)	Mean
Free GIIP (Bscf)				
Crest	178	364	643	393
Flank	10	17	27	18
Total[2]	**194**	**384**	**663**	**411**
STOIIP (MMstb)				
Crest	64	190	404	216
Flank	14	41	100	51
Total[2]	**87**	**239**	**482**	**266**
Associated GIIP (Bscf)				
(from oil leg)[2]	**49**	**135**	**280**	**153**

1. Raw gas - includes inerts
2. Aggregated total: dependency on GOC/OWC/area uncertainty/FVF/GOR

Table 3-2: Gross HIIP for the Pensacola Discovery

3.5 Reservoir Engineering

3.5.1 Sampling and Testing

In-situ samples were taken from three different depths, 1799 mMD, 1806 mMD and 1812 mMD. The sample from the shallowest depth contained gas and the ones from the two other intervals contained gas and oil/condensate. Due to the tightness of the formation and the small quantity of fluids recovered, it was not clear what is the dominant phase of these two deeper samples.

A well test was also performed with some subsequent separator liquid and gas sampling. The gas has 10% CO_2 and 2% N_2 content and a CGR of 1.6 to 2.1 stb/MMscf with a gas gravity to air of 0.696-0.699.

During Flow Period 2 of the well test, after the first acid job, stable hydrocarbon liquid rates were recorded. The fluid densities average around 35° API and are in line with in-situ oil samples and not condensate. The hydrocarbon liquid to gas ratio was 6.2 stb/MMscf which is higher than the CGR from gas in situ samples (1.6-2.1 stb/MMscf). These data suggests that the fluid produced during Flow Period 2, correspond to oil and not condensate.

Analysis of the pressure build up after cleaning showed moderate skin (3-4) and poor permeability with kH=3.5-4 mDm. An injectivity test for an acid job was performed given the low permeability. The injectivity test showed limited injectivity however, two acid treatments were performed.

The permeability calculated from the test interpretation is lower than the Kh obtained from the mini DST test performed during the in situ sampling gathering where Kh was approximately 21mDm. In addition, the core permeability indicated average permeabilities of 7mD which appear to be higher than the permeabilities obtained from the first build up interpretation.

Two acid jobs were performed. After clean-up following the second acid job, initial gas rates were 5 MMscf/d decreasing to approximately 2 MMscf/d (115 psi FWHP) after 12 hours of flow. Some liquids were recovered, mainly water injected during acidisation but with a stable oil flow of approximately 25 stb/d oil (API of 34-35°).

Both the laboratory analysis and the test results indicate the oil produced during test does not correspond to condensate dropping out from the gas but indicates an oil bearing reservoir. The well test also confirmed that the oil is movable, however given the low permeability environment a large pressure draw down is required for the liquids to flow.

3.5.2 Production Forecasts

Deltic modelled various developments using the Kappa Rubis simulation software. Deltic built a single realisation model using a top reservoir map and a thickness map in Rubis. The GOC was specified at 1755mTVDSS and the FWL positioned at 1800m TVDSS.

Deltic then investigated various gas only and oil only scenarios plus a combined oil and gas development with all wells being assumed to be horizontal in the reservoir section. Deltic used Kappa Rubis simulation software for the analysis with a single realisation model with a top reservoir map and thickness map. The GOC was specified at 1755mTVDSS and the FWL positioned at 1800m TVDSS. Deltic did not include any uncertainty range on the in place values. The recovery factors for the gas cases were between 60 and 70% whereas the oil only cases had oil recovery between 10 and 13% with gas recovery between 15 and 30%. The combined oil and gas case showed a recovery of 9% for the oil and close to 70% for the gas.

To validate results and establish a range of recovery factors to apply to the range of in-place volumes, RPS built a multi-tank material balance model using MBAL® (part of the Petex IPM software suit) and horizontal well models using Prosper® (part of the same software suit) to model the deliverability of the wells. Two scenarios were considered in line with Deltic's preferred development concepts: -

- A development including 3 horizontal gas wells with approximately 1000m of horizontal section (the Operator's current notional plan).

- A development including 3 horizontal gas wells and 3 horizontal oil wells with approximately 1000m of horizontal section.

Inflow performance curves for these wells used the "Horizontal well with dP friction loss in wellbore" model defined by Petex. Permeabilities of around 3mD were used for the low and base cases whereas higher permeabilities of 40mD were included for the high case. The low and base case assume permeabilities in line with the mini DST and the core permeabilities from the flank, given the wells will be placed in the crest with expected larger permeabilities slightly higher permeabilities (40mD) were included in the high case in line with Deltic's assumptions.

The MBAL model was set up using the black oil model approach with a gas cap and 'monitor contact' option. RPS included two tanks with one tank having a volume with good connection to the existing wells and a second tank with poor connection to the wells.

The PVT uncertainty was included by using a range of GOR values of 460, 560 and 750 scf/bbl matching the bubble point pressure to the reservoir pressure (2840psi). An oil API of 34° was used and a CGR of 1.5 - 1.7 - 2.0 was considered for the low, base and high cases, respectively. In addition, 10% of CO_2 and 2% of N_2 impurities were incorporated. No aquifer influx was considered since the rock below is a salt interval and the only connection to the aquifer through the flanks. Given the flanks are very low permeability, no aquifer mobility is expected there.

3.5.3 Pre-ELT Recoverable Volumes and Recovery Factors

The RPS pre-ELT forecasts for hydrocarbon gas and for condensate for the gas case and combined oil and gas case are presented in Appendix C and D:

Pre ELT recoveries and recovery factors for the mentioned cases are shown in Table 3-3.

	Low	Base	High
Gas Only Development			
Raw Gas recovery (Bscf)	146.5	345.6	727.8
Condensate recovery (MMstb)	0.2	0.6	1.5
RF (%)	62.5	66.7	72.9
Combined Gas and Oil Development			
Raw Gas recovery (Bscf)	144.7	360.6	710.5
Oil recovery (MMstb)	4.7	19.8	50.9
Condensate recovery (MMstb)	0.2	0.6	1.4
Gas RF (%)	61.7	69.6	71.1
Oil RF (%)	5.4	8.2	10.6

Table 3-3: Pre ELT recovery volumes for the gas only and combined gas and oil developments

4 DEVELOPMENT CONCEPT AND COSTS

Deltic provided RPS with a conceptual development report prepared by S&P. The S&P report covers both the gas only development and the combined gas and oil development. The report includes cost estimates for the two developments made using S&P's commercially available Que$tor costing software package. RPS is familiar with the Que$tor program and its functionality which generally produces reasonable cost estimates.

4.1 Gas Only Case

The profiles provided to S&P for their study were based on a flowing wellhead pressure (FWHP) of 300 psia, necessitating offshore compression based on a normally unmanned platform. RPS understands that the compression was assumed to be electrically driven. Gas would be dehydrated offshore and compressed then exported to shore via a new pipeline to a new onshore facility to remove the CO_2 and then exported to the nearby gas terminals at Teesside. It is planned for the recovered CO_2 to be exported to the planned BP operated Net Zero Teesside (NZT) for injection offshore. RPS currently understands the owners of the NZT development are planning to take FID in 2024 with first injection in 2027. A Pensacola development is unlikely to be ready for start-up before 2028 if the appraisal well is drilled in 2024.

For the export gas profiles RPS has assumed an export gas CO_2 content of 2% by volume. This is comfortably within the 2.9% specification for export to allow for process upsets, and shutdown margins.

4.2 Combined Gas and Oil Case

The concept detailed in the S&P report is based on the oil development being an add-on to the gas development rather than a fully integrated development. It has a gas platform with power generation, compression and dehydration similar to the gas only concept. Located approximately 16km away S&P have assumed a manned oil drilling, processing and accommodation platform. Associated gas from the oil platform is exported to the gas platform. Oil is exported to shore via a new oil line and gas is exported to a new onshore facility for CO_2 removal and final export. RPS understands that a single tophole location for the oil and gas wells is unlikely to be feasible due the distances between the gas and oil well bottom hole targets in the reservoir.

RPS understands the Operator is not considering a combined oil and gas development.

4.3 Cost Forecasts

RPS has reviewed and accepted the S&P Capex estimates for the two development scenarios albeit RPS considers both development concepts could be improved. RPS has reviewed and adjusted the S&P Opex to take into account the variable proportion to enable correct evaluation of the economics. RPS has taken the S&P Opex and stripped out the S&P Gas Tariff and CO_2 disposal costs to yield the fixed costs. RPS has then used these fixed costs for the RPS profiles and calculated the variable Opex using the S&P assumptions for gas tariff ($0.14/Mscf) and CO_2 disposal ($30/tonne). The CO_2 disposal cost of $30/tonne will be subject to negotiation with the Net Zero Teesside operators. As this project has not passed FID the charges applicable are unlikely to be determined yet so should be considered as likely to change.

The RPS gas export profile is based on allowing 2% CO_2 in the export gas. A fuel and flare allowance of 3% is also deducted. The gas export profile therefore represents the raw gas with sufficient CO_2 removed to achieve the required CO_2 specification and fuel allowance deducted. The RPS cost profiles based on these volumes are shown in Appendix C and D.

5 ECONOMIC EVALUATION

5.1 Fiscal Overview

UK petroleum activities are taxed within a concessionary tax system. Company profits from upstream oil and gas operations in the UK are subject to Corporation Tax (CT) at a rate of 30%, and a revised Supplementary Charge (SC) at a rate of 10% from 1 January 2016. Both taxes are ring-fenced to upstream activities. Capex and Opex incurred are allowed against tax once the company is in a tax paying position. Abandonment and decommissioning costs are allowed at 100% against CT and SC subject to there being sufficient taxable revenues in prior years. An Investment Allowance is available from 1 April 2015 against SC. The allowance removes an amount equal to 62.5% of investment expenditure incurred by a company in relation to a field from its ring fence profits which are subject to the supplementary charge.

5.2 Petroleum Pricing Basis

The valuation has been based on the RPS (Q4 2023) long term forecasts for Brent Crude (for oil and condensate sales), and UK National Balancing Point (NBP) for sales gas. These forecasts are presented in Table 5-1.

Year	RPS Brent Oil Price (US$/stb) MOD	RPS NBP Price (US$/MMBtu) MOD
2024	84.00	15.50
2025	83.00	14.68
2026	83.00	14.30
2027	83.00	14.09
2028	84.00	14.38
2029	85.00	14.67
2030	85.00	14.96
2031	87.00	15.26
2032	86.97	15.56
2033	88.71	15.87
2034	90.48	16.19
2035	92.29	16.51
2036	94.14	16.84
2037	96.02	17.18
2038	97.94	17.52
2039	99.90	17.87
2040+	+2% p.a.	+2% p.a.

Table 5-1: Oil and Gas Price Assumptions for Pensacola Field

5.3 Cashflow Analysis

RPS has reviewed all pertinent fiscal terms related to the licence and confirmed they are correctly interpreted within the economic model presented by Deltic. The model has then been used to perform the economic analysis of the field. An annual inflation rate of 2 per cent has been built into the cash flow analysis. This inflation rate has also been applied to all cost estimates to adjust them from 2023 dollars to MOD. The effective date of this report is 1st January 2024 and this has been used as the discount date for the valuation.

An Economic Limit Test (ELT) was performed for the determination of Resources. The economic limit is defined as the production rate at the time when the maximum cumulative net cash flow occurs for a project[3].

A summary of the economic evaluation of Contingent Resources for gas only and combined gas and oil case is presented in Table 5-2 and cash flow forecasts are in Appendix D.

	ELT Date	Post-Tax Net Present Value (Net to Deltic) (US$ Million, MOD) at different Discount Rates			
		0%	10%	12%	15%
Gas Only Case					
1C	2034	124	20	8	(6)
2C	2044	599	199	158	111
3C	2058	1,664	412	323	226
Combined Gas and Oil Case					
1C	2036	(29)	(114)	(121)	(127)
2C	2048	792	205	148	84
3C	2058	2,236	566	437	296

Table 5-2: Post-Tax Valuation at RPS Base Case Price Scenario as of 01 January 2024

[3] *PRMS 2018: 3.1.3 Economic Limit*

6 RESOURCES

A summary of Contingent Resources for Pensacola is presented in Table 6-1 and Table 6-2. RPS classifies the resources as Contingent Resources – Development Pending.

SUMMARY OF CONTINGENT RESOURCES: GAS ONLY CASE
As of 1st January 2024
BASE CASE PRICES AND COSTS

	Full Field Gross Resources[1]			Deltic Net Working Interest[2]			Pd[3]
	1C	2C	3C	1C	2C	3C	
Gas (Bscf)	112.4	296.8	631.7	33.7	89.0	189.5	-
Condensate (MMstb)	0.2	0.6	1.5	0.1	0.2	0.4	
Oil Equivalent (Mmboe) [4]	18.9	50.0	106.7	5.7	15.0	32.0	

Notes:
*[1]Gross field Resources (100% basis) **after** economic limit test.*
[2]Deltic holds a 30% working interest in P2252.
[3]Chance of Development ("Pd") is the estimated probability that a known accumulation, once discovered, will be commercially developed. At this early stage in the project, given the understanding of the range of volumes, of oil in particular, and the development options still being considered, RPS consider assigning a chance of development is premature
[4]Conversion rate of 6,000 scf per boe

Table 6-1: Contingent Resources (Gas Only Case) as of 01 January 2024

SUMMARY OF CONTINGENT RESOURCES: COMBINED GAS AND OIL CASE As of 1st January 2024 BASE CASE PRICES AND COSTS							
	Full Field Gross Resources[1]			Deltic Net Working Interest[2]			Pd[3]
	1C	2C	3C	1C	2C	3C	
Gas (Bscf)	113.6	313.0	616.7	34.1	93.9	185.0	-
Oil (MMstb)	4.7	19.8	50.9	1.4	5.9	15.3	
Condensate (MMstb)	0.2	0.6	1.4	0.1	0.2	0.4	
Oil Equivalent (MMboe) [4]	23.9	72.6	155.1	7.2	21.8	46.5	

Notes:
*[1]Gross field Resources (100% basis) **after** economic limit test.*
[2]Deltic holds a 30% working interest in P2252.
[3]Chance of Development ("Pd") is the estimated probability that a known accumulation, once discovered, will be commercially developed. At this early stage in the project, given the understanding of the range of volumes, of oil in particular, and the development options still being considered, RPS consider assigning a chance of development is premature
[4]Conversion rate of 6,000 scf per boe

Table 6-2: Contingent Resources – Combined Gas and Oil Case as of 01 January 2024

7 CONSULTANT'S INFORMATION

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

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

To the best of our knowledge, no conflict of interest has existed in the work conducted as part of this report. Furthermore, RPS nor any of the management and employees involved in the work have any interest in the assets evaluated or related to the analysis carried out as part of this report.

Mr Gordon Taylor, Director, Consulting, has supervised this evaluation. Mr Taylor is a Chartered Geologist and Chartered Engineer with over 40 years' experience in upstream oil and gas. Other RPS employees involved in this work hold at least a Masters degree in geology, geophysics, petroleum engineering or a related subject or have at least five years of relevant experience in the practice of geology, geophysics or petroleum engineering. Table 5.1 provides a summary of staff involved in this evaluation, their level of experience and professional qualifications.

.Name	Role	Years of Experience	Qualifications	Professional Memberships
Gordon Taylor	Supervisor	>40	BSc. Geological Sciences, Birmingham University MSc. Foundation Engineering, Birmingham University	Fellow, Geological Society (Chartered Geologist -1991) Member, Institute of Materials, Minerals and Mining (Chartered Engineer-1983) Member, AAPG Division of Professional Affairs (Certified Geologist-2005) Member, Society of Petroleum Engineers
Clare Wilson	Geoscience Lead	25	BSc Geophysics (Geological) MBA (dist.) Hull University	Fellow, Geological Society (Chartered Geologist - 2014) Member, PESGB
Ben Lowden	Petrophysics Lead	25	BSc Geology & Oceanography, University of the South West MSc Sedimentology, Reading University PhD, Imperial College, London	Member SPWLA
Adolfo Perez	Reservoir Engineering Lead	>20	BSc, Hons Geology, University of Barcelona MSc Geotechnical Engineering, University of Barcelona MSc Petroleum Engineering, Heriot-Watt University	Member – Society of Petroleum Engineers (SPE) AMEI
David Walker	Facilities & Cost Engineering Lead	>20	MEng (Hons) Chemical Process Engineering with Fuel Technology, University of Sheffield	
Joseph Tan	Economics Lead	22	B.Eng. (Hons.) Petroleum Engineering, Universiti Teknologi Malaysia, 2001	Member – Society of Petroleum Engineers (SPE) Member – Southeast Asia Petroleum Exploration Society (SEAPEX) Member and Malaysia Section Lead – Association of International Energy Negotiators (AIEN)

Table 7-1: Summary of Consultant Personnel

Appendix A
Glossary

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

IPR	Inflow performance relationship
HIIP	Hydrocarbon Initially in Place
KB	Kelly Bushing
k_a	Absolute permeability
k_h	Horizontal permeability
km	Kilometres
m	Metres
m^3	Cubic metres
m^3/d	Cubic metres per day
ma	Million years
M	Thousand
M$	Thousand US dollars
MBAL	Material balance software
Mstb	Thousand barrels
mD	Permeability in millidarcies
MD	Measured depth
MDT	Modular formation dynamics tester tool
MM	Million
MMcm	Million cubic metres
MMscf/d	Millions of standard cubic feet per day
MMstb	Million stock tank barrels (at 14.7 psi and 60° F)
MM$	Million US dollars
m/s	Metres per second
msec	Milliseconds
Mt	Thousands of tonnes
NTG or N:G	Net to gross ratio
NGL	Natural Gas Liquids
NPV	Net Present Value
OWC	Oil water contact
P90	There is estimated to be at least a 90% probability (P90) that this quantity will equal or exceed this low estimate
P50	There is estimated to be at least a 50% probability (P50) that this quantity will equal or exceed this best estimate
P10	There is estimated to be at least a 10% probability (P10) that this quantity will equal or exceed this high estimate
petroleum	Naturally occurring mixtures of hydrocarbons which are found beneath the Earth's surface in liquid, solid or gaseous form
phi	Porosity
p_i	Initial reservoir pressure
psi	Pounds per square inch
psia	Pounds per square inch (absolute)
psig	Pounds per square inch (gauge)
p_{wf}	Flowing bottom hole pressure
PSDM	Pre-stack depth migrated seismic data
PSTM	Pre-stack time migrated seismic data
PVT	Pressure volume temperature
REP™	A Monte Carlo simulation software package
RF	Recovery factor

RFT	Repeat formation tester
RKB	Relative to kelly bushing
rm^3	Reservoir cubic metres
SCAL	Special Core Analysis
scf	Standard cubic feet measured at 14.7 pounds per square inch and 60° F
scf/d	Standard cubic feet per day
scf/stb	Standard cubic feet per stock tank barrel
sm^3	Standard cubic metres
S_o	Oil saturation
S_{oi}	Initial oil saturation
S_{or}	Residual oil saturation
S_{orw}	Residual oil saturation relative to water
sq. km	Square kilometers
stb	Stock tank barrels measured at 14.7 pounds per square inch and 60° F
stb/d	Stock tank barrels per day
STOIIP	Stock tank oil initially in place
S_w	Water saturation
S_{wc}	Vonnate water saturation
$	United States Dollars
t	Tonnes
Tscf	Trillion standard cubic feet
TVDSS	True vertical depth (sub-sea)
TVT	True vertical thickness
TWT	Two-way time
US$	United States Dollar
VLP	Vertical lift performance
V_{sh}	Shale volume
WUT	Water Up To
ϕ	Porosity

Appendix B
Summary of Reporting Guidelines

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

B.1 Basic Principles and Definitions

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

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

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

B.1.1 Petroleum Resources Classification Framework

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

The term resources as used herein is intended to encompass all quantities of petroleum naturally occurring within the Earth's crust, both discovered and undiscovered (whether recoverable or unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered as conventional or unconventional resources.

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

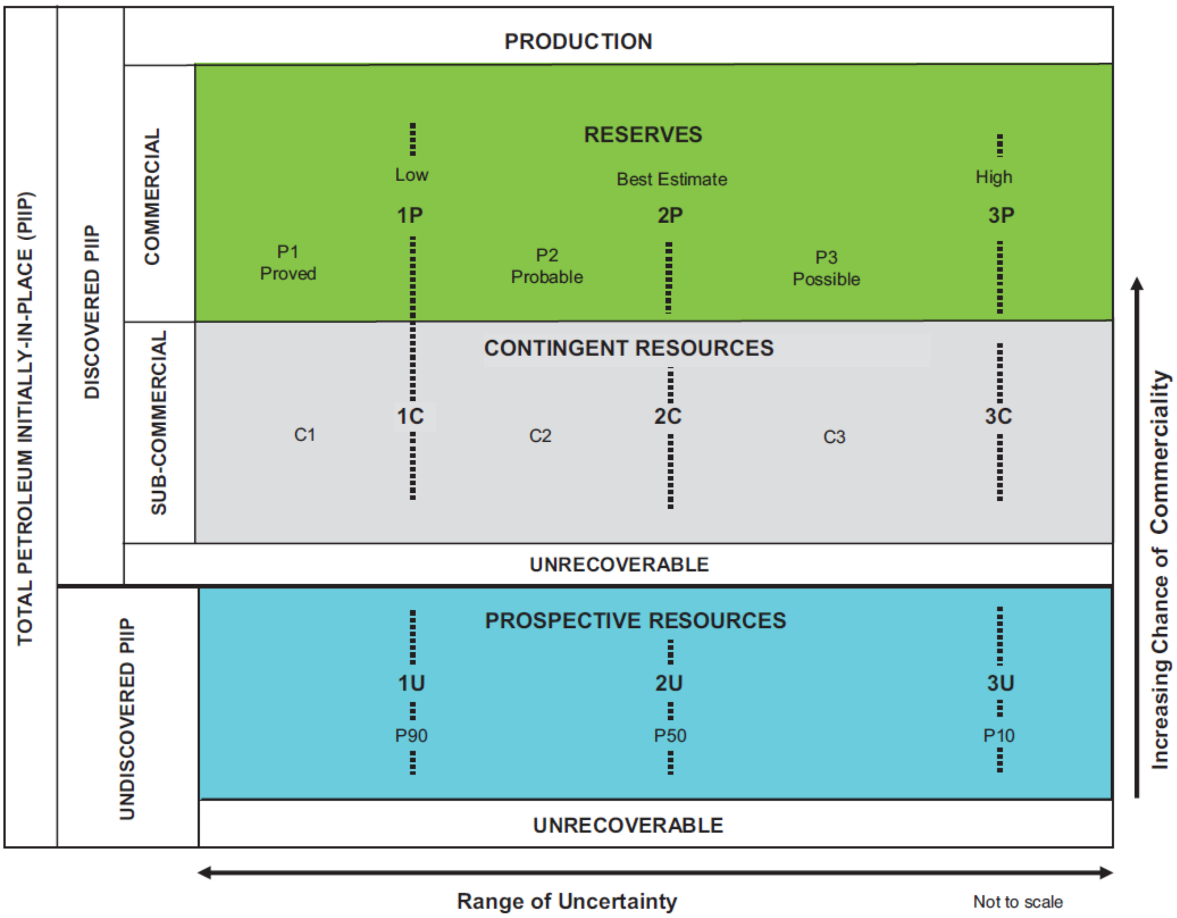


Figure B-1: Resources classification framework

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

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

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

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

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

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

- **Reserves** are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.

Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) (see PRMS 2018 Section 3.2.2), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

Reserves are further categorized in accordance with the range of uncertainty and should be sub-classified based on project maturity and/or characterized by development and production status.

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

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

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

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

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

Other terms used in resource assessments include the following:

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

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

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

B.1.2 Project Based Resource Evaluations

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

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

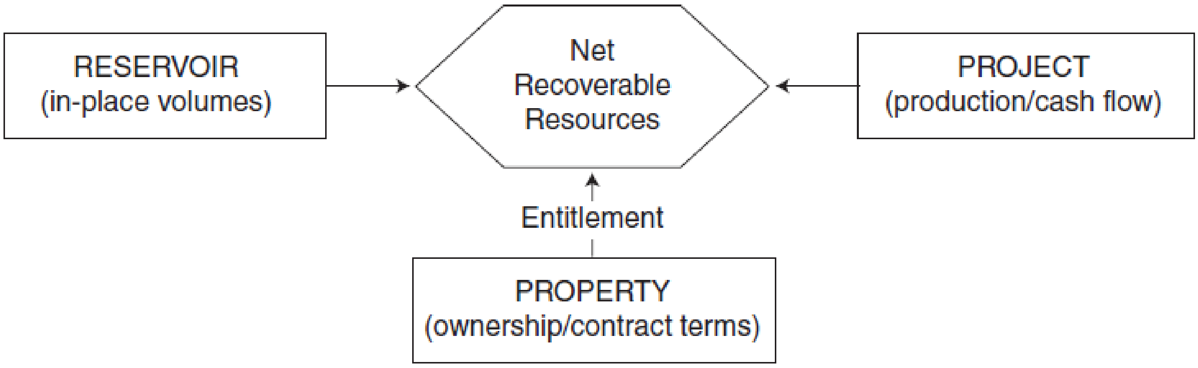


Figure B-2: Resources Evaluation

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

The project: A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty. The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

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

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

In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See Section B.2.1.3.1 (PRMS 2018 Section 2.1.3.5), Project Maturity Sub-Classes) at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project (See Section B1.1 (PRMS 2018 Section 2.2.1), Range of Uncertainty). For completeness, a developed field is also considered to be a project.

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

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

Not all technically feasible development projects will be commercial. The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see PRMS 2018 Section 3.1, Assessment of Commerciality). Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions (e.g., inflation, market factors, and contingencies), exchange rates, transportation and processing infrastructure, fiscal terms, and taxes.

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

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

B.2 Classification and Categorization Guidelines

To consistently characterize petroleum projects, evaluations of all resources should be conducted in the context of the full classification system shown in Figure B-1. These guidelines reference this classification system and support an evaluation in which projects are "classified" based on their chance of commerciality, P_c (the vertical axis labelled Chance of Commerciality), and estimates of recoverable and marketable quantities associated with each project are "categorized" to reflect uncertainty (the horizontal axis). The actual workflow of classification versus categorization varies with individual projects and is often an iterative analysis leading to a final report. Report here refers to the presentation of evaluation results within the entity conducting the assessment and should not be construed as replacing requirements for public disclosures under guidelines established by regulatory and/or other government agencies.

B.2.1 Resources Classification

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

B.2.1.1 Determination of Discovery Status

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

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

B.2.1.2 Determination of Commerciality

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

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

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

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

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

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

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

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

The commerciality test for Reserves determination is applied to the best estimate (P50) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the *2P* Reserves. Stricter cases [e.g., low estimate (P90)] may be used for decision purposes or to investigate the range of commerciality (see PRMS 2018 Section 3.1.2, Economic Criteria). Typically, the low- and high-case project scenarios may be evaluated for sensitivities when considering project risk and upside opportunity.

To be included in the Reserves class, a project must be sufficiently defined to establish both its technical and commercial viability as noted in Section B.2.1.2 (PRMS 2018 Section 2.1.2.1). There must be a reasonable expectation that all required internal and external approvals will be forthcoming and evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where justifiable; for example, development of economic projects that take longer than five years to be developed or are deferred to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

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

B.2.1.3 Project Status and Chance of Commerciality

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

As a project moves to a higher level of commercial maturity in the classification (see Figure B-1 vertical axis), there will be an increasing chance that the accumulation will be commercially developed and the project quantities move to Reserves. For Contingent and Prospective Resources, this is further expressed as a chance of commerciality, P_c, which incorporates the following underlying chance component(s):

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

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

There must be a high degree of certainty in the chance of commerciality, P_c, for Reserves to be assigned; for Contingent Resources, $P_c = P_d$; and for Prospective Resources, P_c is the product of P_g and P_d.

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

B.2.1.3.1 Project Maturity Sub-classes

As Figure B-3 illustrates, development projects and associated recoverable quantities may be sub- classified according to project maturity levels and the associated actions (i.e., business decisions) required to move a project toward commercial production.

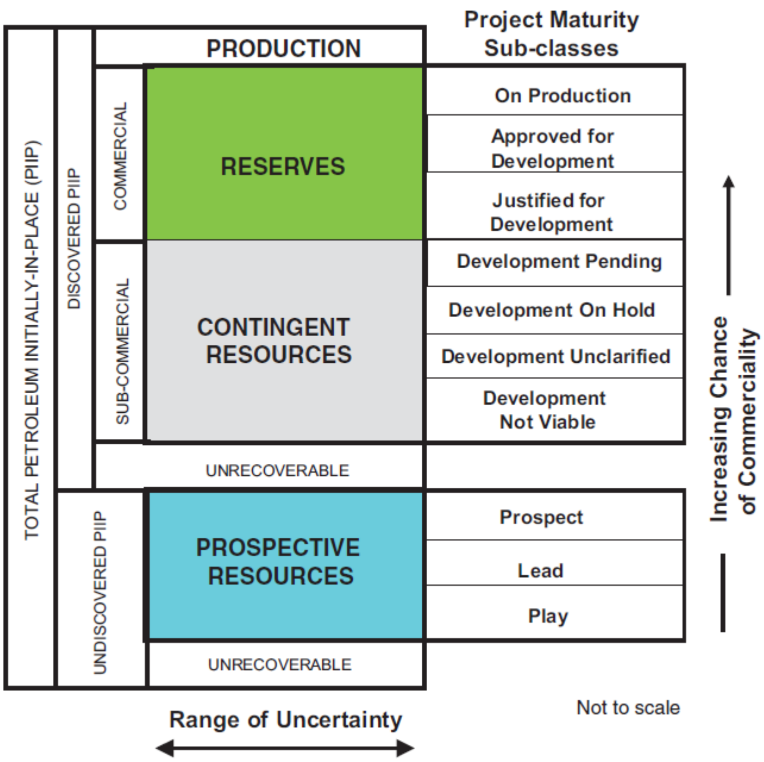


Figure B-3: Sub-classes based on project maturity

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

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

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

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

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

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

For Contingent Resources, evaluators should focus on gathering data and performing analyses to clarify and then mitigate those key conditions or contingencies that prevent commercial development. Note that the Contingent Resources sub-classes described above and shown in Figure B-3 are recommended; however, entities are at liberty to introduce additional sub-classes that align with project management goals.

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

Appendix C Cost Profiles

ECONOMIC INPUT SHEETS

Client	Deltic
Country	UK
Field	Pensacola
Brief Description	Offshore Gas Compression, Onshore CO2 Removal
Estimated Reserves	146.44 bcf
Case	RPS Low Profile, S&P Costs
Working Interest	100% Gross
Basis	
Currency	million USD

DESCRIPTION	UNITS	Rate	TOTAL	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
				365	366	365	365	365	366	365	365	365	366	365	365	365	366
CAPEX																	
Facilities																	
						5%	30%	40%	25%								
Gas Platform Topsides	$mm		333.0			16.7	99.9	133.2	83.3								
Gas Platform Jacket	$mm		55.0			2.8	16.5	22.0	13.8								
Gas Pipeline to Shore	$mm		107.0			5.4	32.1	42.8	26.8								
Gas Pipeline onshore	$mm		8.0			0.4	2.4	3.2	2.0								
CO2 Removal Plant	$mm		107.0			5.4	32.1	42.8	26.8								
Faciities Direct Total	$mm		610.0			30.5	183.0	244.0	152.5								
Owner's Costs	$mm	15%	91.5			4.6	27.5	36.6	22.9								
Contingency	$mm	0%	0.0														
Faciities Total	$mm		701.5			35.1	210.5	280.6	175.4								
Drilling & Completion																	
Appraisal Wells	$mm		33.0		33.0												
Gas Development Wells	$mm		108.0						108.0								
Oil Development Wells	$mm		0.0														
Drilling Total	$mm		141.0	-	33.00	-	-	-	108.00	-	-	-	-	-	-	-	-
Total CAPEX	$mm		842.5	0.0	33.0	35.1	210.5	280.6	283.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fixed Opex	$mm		570.7							29.4	29.8	30.0	37.2	31.5	52.3	30.1	36.9
Tariff ($0.14/Mscf)	$mm	0.14	20.5							6.8	4.4	2.8	1.9	1.3	1.0	0.3	0.2
CO2 ($30/tonne)	$mm	30	23.6							7.8	5.0	3.3	2.2	1.5	1.1	0.4	0.2
OPEX	$mm		614.8		0.0	0.0	0.0	0.0	0.0	44.0	39.2	36.1	41.3	34.3	54.3	30.8	37.3
ABEX	$mm		84.3														
Production																	
Oil	bopd		0.00														
Condensate	bopd		0.22							200	128	83	55	38	28	10	6
Gas	MMscf/d									133.01	85.47	55.24	36.77	25.47	18.59	6.70	3.80
Gas	bcf		146.44							48.5	31.2	20.2	13.5	9.3	6.8	2.4	1.4
Fuel & Flare	Mmscfd	3%	4.39							4.0	2.6	1.7	1.1	0.8	0.6	0.2	0.1
CO2 Removed to Injection	MMscfd		14.94							13.6	8.7	5.6	3.8	2.6	1.9	0.7	0.4
Export Gas	MMscfd		127.11							115.4	74.2	47.9	31.9	22.1	16.1	5.8	3.3
Total	bcf		127.1		0.0	0.0	0.0	0.0	0.0	42.1	27.1	17.5	11.7	8.1	5.9	2.1	1.2

DESCRIPTION	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
	365	365	365	366	365	365	365	366	365	365	365	366	365	365
Drilling Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total CAPEX	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fixed Opex	27.3	26.7	26.2	25.7	25.2	24.7	24.2	23.7	23.2	22.7	22.3	21.8		
Tariff ($0.14/Mscf)	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1		
CO2 ($30/tonne)	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.2	0.1	0.1	0.1		
OPEX	27.7	27.1	26.6	26.0	25.5	25.0	24.5	23.9	23.5	23.0	22.5	22.1	0.0	0.0
ABEX													42.1	42.1
Condensate	6	6	5	5	5	5	4	4	4	4	4	4	0	0
Gas (MMscf/d)	3.83	3.79	3.32	3.32	3.32	3.32	2.84	2.36	2.84	2.36	2.37	2.36	0.00	0.00
Gas (bcf)	1.4	1.4	1.2	1.2	1.2	1.2	1.0	0.9	1.0	0.9	0.9	0.9	0.0	0.0
Fuel & Flare	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0
CO2 Removed to Injection	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.2	0.3	0.2	0.2	0.2	0.0	0.0
Export Gas	3.3	3.3	2.9	2.9	2.9	2.9	2.5	2.0	2.5	2.0	2.1	2.0	0.0	0.0
Total	1.2	1.2	1.1	1.1	1.1	1.1	0.9	0.7	0.9	0.7	0.7	0.7	0.0	0.0

RPS Gas Development Low Case Cost Profile

ECONOMIC INPUT SHEETS

Client	Deltic
Country	UK
Field	Pensacola
Brief Description	Offshore Gas Compression, Onshore CO2 Removal
Estimated Reserves	345.59 bcf
Case	RPS Mid Profile, S&P Costs
Working Interest	100% Gross
Basis	
Currency	million USD

DESCRIPTION	UNITS	Rate	TOTAL	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
				365	366	365	365	365	366	365	365	365	366	365	365	365	366
CAPEX																	
Facilities																	
						5%	30%	40%	25%								
Gas Platform Topsides	$mm		**333.0**			16.7	99.9	133.2	83.3								
Gas Platform Jacket	$mm		**55.0**			2.8	16.5	22.0	13.8								
Gas Pipeline to Shore	$mm		**107.0**			5.4	32.1	42.8	26.8								
Gas Pipeline onshore	$mm		**8.0**			0.4	2.4	3.2	2.0								
CO2 Removal Plant	$mm		**107.0**			5.4	32.1	42.8	26.8								
Faciities Direct Total	$mm		**610.0**			30.5	183.0	244.0	152.5								
Owner's Costs	$mm	15%	**91.5**			4.6	27.5	36.6	22.9								
Contingency	$mm	0%	**0.0**														
Faciities Total	$mm		**701.5**			35.1	210.5	280.6	175.4								
Drilling & Completion																	
Appraisal Wells	$mm		**33.0**		33.0												
Gas Development Wells	$mm		**108.0**						108.0								
Oil Development Wells	$mm		**0.0**														
Drilling Total	$mm		**141.0**	-	33.00	-	-	-	108.00	-	-	-	-	-	-	-	-
Total CAPEX	**$mm**		**842.5**	**0.0**	**33.0**	**35.1**	**210.5**	**280.6**	**283.4**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Fixed Opex	$mm		**570.7**							29.4	29.8	30.0	37.2	31.5	52.3	30.1	36.9
Tariff ($0.14/Mscf)	$mm	0.14	**48.4**							7.6	6.6	5.6	4.7	4.0	3.4	2.9	2.5
CO2 ($30/tonne)	$mm	30	**55.7**							8.8	7.6	6.4	5.4	4.6	3.9	3.3	2.8
OPEX	**$mm**		**674.8**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**45.7**	**44.0**	**42.0**	**47.3**	**40.0**	**59.5**	**36.3**	**42.2**
ABEX	**$mm**		**84.3**														
Production																	
Oil	bopd		**0.00**														
Condensate	bopd		**0.59**							253	220	185	156	132	112	95	81
Gas	MMscf/d									148.77	129.66	108.80	91.75	77.58	65.85	56.05	47.86
Gas	bcf		**####**							54.3	47.3	39.7	33.6	28.3	24.0	20.5	17.5
Fuel & Flare	Mmscfd	3%	**10.37**							4.5	3.9	3.3	2.8	2.3	2.0	1.7	1.4
CO2 Removed to Injection	MMscfd		**35.26**							15.2	13.2	11.1	9.4	7.9	6.7	5.7	4.9
Export Gas	**MMscfd**		**####**							**129.1**	**112.5**	**94.4**	**79.6**	**67.3**	**57.2**	**48.6**	**41.5**
Total	**bcf**		**300.0**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**47.1**	**41.1**	**34.5**	**29.1**	**24.6**	**20.9**	**17.8**	**15.2**

DESCRIPTION	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
	365	365	365	366	365	365	365	366	365	365	365	366	365	365
Drilling Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total CAPEX	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Fixed Opex	27.3	26.7	26.2	25.7	25.2	24.7	24.2	23.7	23.2	22.7	22.3	21.8		
Tariff ($0.14/Mscf)	2.1	1.8	1.6	1.4	1.2	1.0	0.9	0.8	0.2	0.1	0.1	0.1		
CO2 ($30/tonne)	2.4	2.1	1.8	1.6	1.4	1.2	1.1	0.9	0.2	0.1	0.1	0.1		
OPEX	**31.8**	**30.6**	**29.5**	**28.6**	**27.7**	**26.9**	**26.1**	**25.3**	**23.6**	**23.0**	**22.5**	**22.1**	**0.0**	**0.0**
ABEX													**42.1**	**42.1**
Condensate	70	60	52	45	39	35	31	26	6	4	3	4	0	0
Gas (MMscf/d)	41.03	35.29	30.51	26.50	23.13	20.42	18.09	15.11	3.35	2.35	1.88	2.35	0.00	0.00
Gas (bcf)	15.0	12.9	11.1	9.7	8.4	7.5	6.6	5.5	1.2	0.9	0.7	0.9	0.0	0.0
Fuel & Flare	1.2	1.1	0.9	0.8	0.7	0.6	0.5	0.5	0.1	0.1	0.1	0.1	0.0	0.0
CO2 Removed to Injection	4.2	3.6	3.1	2.7	2.4	2.1	1.8	1.5	0.3	0.2	0.2	0.2	0.0	0.0
Export Gas	**35.6**	**30.6**	**26.5**	**23.0**	**20.1**	**17.7**	**15.7**	**13.1**	**2.9**	**2.0**	**1.6**	**2.0**	**0.0**	**0.0**
Total	**13.0**	**11.2**	**9.7**	**8.4**	**7.3**	**6.5**	**5.7**	**4.8**	**1.1**	**0.7**	**0.6**	**0.7**	**0.0**	**0.0**

RPS Gas Development Mid Case Cost Profile

ECONOMIC INPUT SHEETS

Client	Deltic
Country	UK
Field	Pensacola
Brief Description	Offshore Gas Compression, Onshore CO2 Removal
Estimated Reserves	727.76 bcf
Case	RPS High Profile, S&P Costs
Working Interest	100% Gross
Basis	
Currency	million USD

DESCRIPTION	UNITS	Rate	TOTAL	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
				365	366	365	365	365	366	365	365	365	366	365	365	365	366	365	365	365
CAPEX																				
Facilities																				
						5%	30%	40%	25%											
Gas Platform Topsides	$mm		333.0			16.7	99.9	133.2	83.3											
Gas Platform Jacket	$mm		55.0			2.8	16.5	22.0	13.8											
Gas Pipeline to Shore	$mm		107.0			5.4	32.1	42.8	26.8											
Gas Pipeline onshore	$mm		8.0			0.4	2.4	3.2	2.0											
CO2 Removal Plant	$mm		107.0			5.4	32.1	42.8	26.8											
Faciities Direct Total	$mm		610.0			30.5	183.0	244.0	152.5											
Owner's Costs	$mm	15%	91.5			4.6	27.5	36.6	22.9											
Contingency	$mm	0%	0.0																	
Faciities Total	$mm		701.5			35.1	210.5	280.6	175.4											
Drilling & Completion																				
Appraisal Wells	$mm		33.0		33.0															
Gas Development Wells	$mm		108.0						108.0											
Oil Development Wells	$mm		0.0																	
Drilling Total	$mm		141.0	-	33.00	-	-	-	108.00	-	-	-	-	-	-	-	-	-	-	-
Total CAPEX	$mm		842.5	0.0	33.0	35.1	210.5	280.6	283.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fixed Opex	$mm		592.1							29.4	29.8	30.0	37.2	31.5	52.3	30.1	36.9	27.3	26.7	26.2
Tariff ($0.14/Mscf)	$mm	0.14	89.6							7.7	7.7	7.3	6.7	6.1	5.6	5.2	4.8	4.4	4.1	3.8
CO2 ($30/tonne)	$mm	30	103.2							8.8	8.8	8.4	7.7	7.1	6.5	6.0	5.5	5.1	4.7	4.4
OPEX	$mm		785.0		0.0	0.0	0.0	0.0	0.0	45.9	46.3	45.6	51.6	44.6	64.4	41.3	47.3	36.9	35.6	34.4
ABEX	$mm		84.3																	
Production																				
Oil	bopd		0.00																	
Condensate	bopd		1.42							300	300	285	261	240	221	204	188	174	161	149
Gas	MMscf/d									150.00	149.95	142.26	130.36	119.82	110.36	101.82	94.05	86.98	80.51	74.57
Gas	bcf		####							54.8	54.7	51.9	47.7	43.7	40.3	37.2	34.4	31.7	29.4	27.2
Fuel & Flare	Mmscfd	3%	21.83							4.5	4.5	4.3	3.9	3.6	3.3	3.1	2.8	2.6	2.4	2.2
CO2 Removed to Injection	MMscfd		74.26							15.3	15.3	14.5	13.3	12.2	11.3	10.4	9.6	8.9	8.2	7.6
Export Gas	MMscfd		631.66							130.2	130.1	123.5	113.1	104.0	95.8	88.4	81.6	75.5	69.9	64.7
Total	bcf		631.7		0.0	0.0	0.0	0.0	0.0	47.5	47.5	45.1	41.4	38.0	35.0	32.3	29.9	27.6	25.5	23.6

DESCRIPTION	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060
	366	365	365	365	366	365	365	365	366	365	365	365	366	365	365	365	366	365	365	365	366
CAPEX																					
Drilling Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total CAPEX	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fixed Opex	25.7	25.2	24.7	24.2	23.7	23.2	22.7	22.3	21.8	21.4	21.0	20.6	20.1	19.7	19.3	19.0	18.6	18.2	17.8		
Tariff ($0.14/Mscf)	3.5	3.3	3.1	2.8	2.7	2.5	2.3	2.1	2.0	1.9	1.7	1.6	1.5	1.4	1.3	1.3	1.2	1.1	1.0		
CO2 ($30/tonne)	4.1	3.8	3.5	3.3	3.1	2.8	2.7	2.5	2.3	2.2	2.0	1.9	1.8	1.7	1.5	1.5	1.4	1.3	1.2		
OPEX	33.3	32.2	31.2	30.3	29.4	28.5	27.7	26.9	26.2	25.4	24.7	24.1	23.4	22.8	22.2	21.7	21.1	20.6	20.1		
ABEX																				42.1	42.1
Production																					
Oil																					
Condensate	138	129	120	111	104	97	90	84	78	73	68	64	60	56	53	49	46	43	41	0	0
Gas (MMscf/d)	69.14	64.29	59.82	55.69	51.86	48.31	45.03	41.99	39.17	36.56	34.14	31.93	29.90	28.02	26.27	24.63	23.12	21.71	20.40	0.00	0.00
Gas (bcf)	25.3	23.5	21.8	20.3	19.0	17.6	16.4	15.3	14.3	13.3	12.5	11.7	10.9	10.2	9.6	9.0	8.5	7.9	7.4	0.0	0.0
Fuel & Flare	2.1	1.9	1.8	1.7	1.6	1.4	1.4	1.3	1.2	1.1	1.0	1.0	0.9	0.8	0.8	0.7	0.7	0.7	0.6	0.0	0.0
CO2 Removed to Injection	7.1	6.6	6.1	5.7	5.3	4.9	4.6	4.3	4.0	3.7	3.5	3.3	3.1	2.9	2.7	2.5	2.4	2.2	2.1	0.0	0.0
Export Gas	60.0	55.8	51.9	48.3	45.0	41.9	39.1	36.4	34.0	31.7	29.6	27.7	26.0	24.3	22.8	21.4	20.1	18.8	17.7	0.0	0.0
Total	22.0	20.4	19.0	17.6	16.5	15.3	14.3	13.3	12.4	11.6	10.8	10.1	9.5	8.9	8.3	7.8	7.3	6.9	6.5	0.0	0.0

RPS Gas Development High Case Cost Profile

ECONOMIC INPUT SHEETS

Client **Deltic**
Country **UK**
Field **Pensacola**
Brief Description **Oil & Gas Development**
Estimated Reserves **144.69** bcf
Case **RPS Low Profile, S&P Costs**

Working Interest **100% Gross**
Basis
Currency **million USD**

DESCRIPTION	UNITS	Rate	TOTAL	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049
				365	366	365	365	365	366	365	365	365	366	365	365	365	366	365	365	365	366	365	365	365	366	365	365	365	366	365
CAPEX																														
Facilities																														
						5%	30%	40%	25%																					
Oil Platform Topsides	$mm		**256.0**			12.8	76.8	102.4	64.0																					
Oil Platform Jacket	$mm		**53.0**			2.7	15.9	21.2	13.3																					
Oil Line to Shore	$mm		**79.0**			4.0	23.7	31.6	19.8																					
Gas Line to Oil	$mm		**50.0**			2.5	15.0	20.0	12.5																					
Gas Platform Topsides	$mm		**388.0**			19.4	116.4	155.2	97.0																					
Gas Platform Jacket	$mm		**63.0**			3.2	18.9	25.2	15.8																					
Gas Pipeline to Shore	$mm		**116.0**			5.8	34.8	46.4	29.0																					
Gas Pipeline onshore	$mm		**8.0**			0.4	2.4	3.2	2.0																					
CO2 Removal Plant	$mm		**125.0**			6.3	37.5	50.0	31.3																					
Faciities Direct Total	$mm		**1,138.0**			56.9	341.4	455.2	284.5																					
Owner's Costs	$mm	15%	**170.7**			8.5	51.2	68.3	42.7																					
Contingency	$mm	0%	**0.0**																											
Faciities Total	$mm		**1,308.7**			65.4	392.6	523.5	327.2																					
Drilling & Completion																														
Appraisal Wells	$mm		**33.0**		33.0																									
Gas Development Wells	$mm		**107.0**						107.0																					
Oil Development Wells	$mm		**111.0**						111.0																					
Drilling Total	$mm		**251.0**	-	33.00	-	-	-	218.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total CAPEX	**$mm**		**1,559.7**	**0.0**	**33.0**	**65.4**	**392.6**	**523.5**	**545.2**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Fixed Opex	$mm		**685.6**							73.2	73.1	30.0	37.2	31.5	52.3	30.1	36.9	27.3	26.7	26.7	26.7	26.7	26.7	26.7	26.7	26.7	26.7	26.7	26.7	
Tariff ($0.14/Mscf)	$mm	0.14	**20.3**							3.3	3.1	3.1	3.4	2.2	1.5	1.1	0.7	0.2	0.2	0.2	0.2	0.2	0.1	0.2	0.1	0.1	0.1	0.1	0.1	
CO2 ($30/tonne)	$mm	30	**23.3**							3.8	3.5	3.5	3.9	2.6	1.8	1.3	0.8	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.2	0.1	
OPEX	**$mm**		**729.2**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**80.4**	**79.7**	**36.6**	**44.4**	**36.2**	**55.5**	**32.4**	**38.3**	**27.8**	**27.1**	**27.1**	**27.1**	**27.1**	**27.0**	**27.1**	**27.0**	**27.0**	**27.0**	**27.0**	**27.0**	**0.0**
ABEX	**$mm**		**156.0**																											**78.0**
Production																														
Oil	bopd		**4.74**							12,839	154	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Condensate	bopd		**0.22**							98	90	90	98	65	45	32	19	6	6	5	6	5	4	5	4	4	4	4	4	0
Gas	MMscf/d									65.31	60.06	60.00	65.55	43.49	29.79	21.32	12.74	4.27	3.80	3.32	3.80	3.32	2.84	3.32	2.85	2.84	2.37	2.84	2.36	0.00
Gas	bcf		**144.69**							23.8	21.9	21.9	24.0	15.9	10.9	7.8	4.7	1.6	1.4	1.2	1.4	1.2	1.0	1.2	1.0	1.0	0.9	1.0	0.9	0.0
Fuel & Flare	Mmscfd	3%	**4.34**							2.0	1.8	1.8	2.0	1.3	0.9	0.6	0.4	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
CO2 Removed to Injection	MMscfd		**14.76**							6.7	6.1	6.1	6.7	4.4	3.0	2.2	1.3	0.4	0.4	0.3	0.4	0.3	0.3	0.3	0.3	0.3	0.2	0.3	0.2	0.0
Export Gas	**MMscfd**		**125.59**							**56.7**	**52.1**	**52.1**	**56.9**	**37.7**	**25.9**	**18.5**	**11.1**	**3.7**	**3.3**	**2.9**	**3.3**	**2.9**	**2.5**	**2.9**	**2.5**	**2.5**	**2.1**	**2.5**	**2.0**	**0.0**
Total	**bcf**		**125.6**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**20.7**	**19.0**	**19.0**	**20.8**	**13.8**	**9.4**	**6.8**	**4.0**	**1.4**	**1.2**	**1.1**	**1.2**	**1.1**	**0.9**	**1.1**	**0.9**	**0.9**	**0.7**	**0.9**	**0.7**	**0.0**

RPS Oil & Gas Development Low Case Cost Profile

ECONOMIC INPUT SHEETS

Client	**Deltic**
Country	**UK**
Field	**Pensacola**
Brief Description	**Oil & Gas Development**
Estimated Reserves	**360.63** bcf
Case	**RPS Mid Profile, S&P Costs**
Working Interest	**100% Gross**
Basis	
Currency	**million USD**

DESCRIPTION	UNITS	Rate	TOTAL	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
				365	366	365	365	365	366	365	365	365	366	365	365	365
CAPEX																
Facilities																
						5%	30%	40%	25%							
Oil Platform Topsides	$mm		**256.0**			12.8	76.8	102.4	64.0							
Oil Platform Jacket	$mm		**53.0**			2.7	15.9	21.2	13.3							
Oil Line to Shore	$mm		**79.0**			4.0	23.7	31.6	19.8							
Gas Line to Oil	$mm		**50.0**			2.5	15.0	20.0	12.5							
Gas Platform Topsides	$mm		**388.0**			19.4	116.4	155.2	97.0							
Gas Platform Jacket	$mm		**63.0**			3.2	18.9	25.2	15.8							
Gas Pipeline to Shore	$mm		**116.0**			5.8	34.8	46.4	29.0							
Gas Pipeline onshore	$mm		**8.0**			0.4	2.4	3.2	2.0							
CO2 Removal Plant	$mm		**125.0**			6.3	37.5	50.0	31.3							
Faciities Direct Total	$mm		**1,138.0**			56.9	341.4	455.2	284.5							
Owner's Costs	$mm	15%	**170.7**			8.5	51.2	68.3	42.7							
Contingency	$mm	0%	**0.0**													
Faciities Total	$mm		**1,308.7**			65.4	392.6	523.5	327.2							
Drilling & Completion																
Appraisal Wells	$mm		**33.0**		33.0											
Gas Development Wells	$mm		**107.0**						107.0							
Oil Development Wells	$mm		**111.0**						111.0							
Drilling Total	$mm		**251.0**	-	33.00	-	-	-	218.00	-	-	-	-	-	-	-
Total CAPEX	**$mm**		**1,559.7**	**0.0**	**33.0**	**65.4**	**392.6**	**523.5**	**545.2**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Fixed Opex	$mm		**804.6**							73.2	73.1	72.2	91.3	81.9	52.3	30.1
Tariff ($0.14/Mscf)	$mm	0.14	**50.5**							3.5	3.4	3.3	6.3	5.2	4.4	3.8
CO2 ($30/tonne)	$mm	30	**58.2**							4.0	3.9	3.9	7.3	6.0	5.1	4.3
OPEX	**$mm**		**913.3**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**80.7**	**80.4**	**79.4**	**104.9**	**93.1**	**61.7**	**38.2**
ABEX	**$mm**		**156.0**													
Production																
Oil	bopd		**19.80**							15,315	13,560	11,915	9,489	3,932	0	0
Condensate	bopd		**0.61**							116	113	111	210	173	146	125
Gas	MMscf/d									68.22	66.66	65.37	123.30	102.03	85.74	73.41
Gas	bcf		**360.63**							24.9	24.3	23.9	45.1	37.2	31.3	26.8
Fuel & Flare	Mmscfd	3%	**10.82**							2.0	2.0	2.0	3.7	3.1	2.6	2.2
CO2 Removed to Injection	MMscfd		**36.80**							7.0	6.8	6.7	12.6	10.4	8.7	7.5
Export Gas	**MMscfd**		**313.01**							**59.2**	**57.9**	**56.7**	**107.0**	**88.6**	**74.4**	**63.7**
Total	**bcf**		**313.0**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**21.6**	**21.1**	**20.7**	**39.2**	**32.3**	**27.2**	**23.3**

DESCRIPTION	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049
	366	365	365	365	366	365	365	365	366	365	365	365	366	365
CAPEX														
Facilities														
Oil Platform Topsides														
Oil Platform Jacket														
Oil Line to Shore														
Gas Line to Oil														
Gas Platform Topsides														
Gas Platform Jacket														
Gas Pipeline to Shore														
Gas Pipeline onshore														
CO2 Removal Plant														
Faciities Direct Total														
Owner's Costs														
Contingency														
Faciities Total														
Drilling & Completion														
Appraisal Wells														
Gas Development Wells														
Oil Development Wells														
Drilling Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total CAPEX	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Fixed Opex	36.9	27.3	26.7	26.2	25.7	25.2	24.7	24.2	23.7	23.2	22.7	22.3	21.8	
Tariff ($0.14/Mscf)	3.2	2.8	2.4	2.1	1.8	1.6	1.4	1.2	1.1	1.0	0.9	0.7	0.5	
CO2 ($30/tonne)	3.7	3.2	2.8	2.4	2.1	1.8	1.6	1.4	1.2	1.1	1.0	0.9	0.6	
OPEX	**43.9**	**33.3**	**31.9**	**30.7**	**29.6**	**28.5**	**27.6**	**26.7**	**26.0**	**25.3**	**24.6**	**23.9**	**22.9**	**0.0**
ABEX														**78.0**
Production														
Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Condensate	107	92	80	69	60	52	46	40	36	32	29	25	17	0
Gas (MMscf/d)	63.06	54.34	46.94	40.66	35.31	30.74	26.84	23.55	21.04	18.90	17.01	14.48	9.75	0.00
Gas (bcf)	23.1	19.8	17.1	14.8	12.9	11.2	9.8	8.6	7.7	6.9	6.2	5.3	3.6	0.0
Fuel & Flare	1.9	1.6	1.4	1.2	1.1	0.9	0.8	0.7	0.6	0.6	0.5	0.4	0.3	0.0
CO2 Removed to Injection	6.4	5.5	4.8	4.1	3.6	3.1	2.7	2.4	2.1	1.9	1.7	1.5	1.0	0.0
Export Gas	**54.7**	**47.2**	**40.7**	**35.3**	**30.6**	**26.7**	**23.3**	**20.4**	**18.3**	**16.4**	**14.8**	**12.6**	**8.5**	**0.0**
Total	**20.0**	**17.2**	**14.9**	**12.9**	**11.2**	**9.7**	**8.5**	**7.5**	**6.7**	**6.0**	**5.4**	**4.6**	**3.1**	**0.0**

RPS Oil Gas Development Mid Case Cost Profile

ECONOMIC INPUT SHEETS

Client	**Deltic**
Country	**UK**
Field	**Pensacola**
Brief Description	**Oil & Gas Development**
Estimated Reserves	**710.57** bcf
Case	**RPS High Profile, S&P Costs**
Working Interest	**100% Gross**
Basis	
Currency	**million USD**

DESCRIPTION	UNITS	Rate	TOTAL	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
				365	366	365	365	365	366	365	365	365	366	365	365	365	366	365	365	365
CAPEX																				
Facilities																				
						5%	30%	40%	25%											
Oil Platform Topsides	$mm		**256.0**			12.8	76.8	102.4	64.0											
Oil Platform Jacket	$mm		**53.0**			2.7	15.9	21.2	13.3											
Oil Line to Shore	$mm		**79.0**			4.0	23.7	31.6	19.8											
Gas Line to Oil	$mm		**50.0**			2.5	15.0	20.0	12.5											
Gas Platform Topsides	$mm		**388.0**			19.4	116.4	155.2	97.0											
Gas Platform Jacket	$mm		**63.0**			3.2	18.9	25.2	15.8											
Gas Pipeline to Shore	$mm		**116.0**			5.8	34.8	46.4	29.0											
Gas Pipeline onshore	$mm		**8.0**			0.4	2.4	3.2	2.0											
CO2 Removal Plant	$mm		**125.0**			6.3	37.5	50.0	31.3											
Faciities Direct Total	$mm		**1,138.0**			56.9	341.4	455.2	284.5											
Owner's Costs	$mm	15%	**170.7**			8.5	51.2	68.3	42.7											
Contingency	$mm	0%	**0.0**																	
Faciities Total	$mm		**1,308.7**			65.4	392.6	523.5	327.2											
Drilling & Completion																				
Appraisal Wells	$mm		**33.0**		33.0															
Gas Development Wells	$mm		**107.0**						107.0											
Oil Development Wells	$mm		**111.0**						111.0											
Drilling Total	$mm		**251.0**	-	33.00	-	-	-	218.00	-	-	-	-	-	-	-	-	-	-	-
Total CAPEX	**$mm**		**1,559.7**	**0.0**	**33.0**	**65.4**	**392.6**	**523.5**	**545.2**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Fixed Opex	$mm		**1,095.7**							73.2	73.1	72.2	91.3	81.9	104.2	75.8	82.2	68.9	64.9	63.6
Tariff ($0.14/Mscf)	$mm	0.14	**86.0**							3.7	3.7	3.6	8.0	7.2	6.5	5.9	5.4	5.0	4.5	4.1
CO2 ($30/tonne)	$mm	30	**99.1**							4.3	4.2	4.2	9.2	8.3	7.5	6.8	6.2	5.7	5.2	4.7
OPEX	**$mm**		**1,280.8**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**81.2**	**81.0**	**80.1**	**108.5**	**97.4**	**118.2**	**88.6**	**93.9**	**79.5**	**74.7**	**72.4**
ABEX	**$mm**		**156.0**																	
Production																				
Oil	bopd		**50.89**							18,000	18,000	18,000	17,612	15,552	13,598	11,930	10,330	8,709	6,901	725
Condensate	bopd		**1.42**							145	143	142	312	281	255	232	212	194	178	161
Gas	MMscf/d									72.30	71.71	71.16	156.12	140.59	127.37	115.97	105.93	97.00	88.95	80.31
Gas	bcf		**710.57**							26.4	26.2	26.0	57.1	51.3	46.5	42.3	38.8	35.4	32.5	29.3
Fuel & Flare	Mmscfd	3%	**21.32**							2.2	2.2	2.1	4.7	4.2	3.8	3.5	3.2	2.9	2.7	2.4
CO2 Removed to Injection	MMscfd		**72.51**							7.4	7.3	7.3	15.9	14.3	13.0	11.8	10.8	9.9	9.1	8.2
Export Gas	**MMscfd**		**616.74**							**62.8**	**62.2**	**61.8**	**135.5**	**122.0**	**110.6**	**100.7**	**91.9**	**84.2**	**77.2**	**69.7**
Total	**bcf**		**616.7**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**22.9**	**22.7**	**22.5**	**49.6**	**44.5**	**40.4**	**36.7**	**33.7**	**30.7**	**28.2**	**25.4**

DESCRIPTION	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059
	366	365	365	365	366	365	365	365	366	365	365	365	366	365	365	365	366	365	365	365
CAPEX																				
Facilities																				
Oil Platform Topsides																				
Oil Platform Jacket																				
Oil Line to Shore																				
Gas Line to Oil																				
Gas Platform Topsides																				
Gas Platform Jacket																				
Gas Pipeline to Shore																				
Gas Pipeline onshore																				
CO2 Removal Plant																				
Faciities Direct Total																				
Owner's Costs																				
Contingency																				
Faciities Total																				
Drilling & Completion																				
Appraisal Wells																				
Gas Development Wells																				
Oil Development Wells																				
Drilling Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total CAPEX	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Fixed Opex	26.7	26.2	25.7	25.2	24.7	24.2	23.7	23.2	22.7	22.3	21.8	21.4	21.0	20.6	20.1	19.7	19.3	19.0	18.6	
Tariff ($0.14/Mscf)	3.8	3.5	3.3	3.1	2.9	2.7	2.5	2.3	2.2	2.0	1.9	1.8	1.7	1.6	1.5	1.4	1.3	1.2	1.2	
CO2 ($30/tonne)	4.4	4.1	3.8	3.5	3.3	3.1	2.9	2.7	2.5	2.4	2.2	2.1	1.9	1.8	1.7	1.6	1.5	1.4	1.3	
OPEX	**34.9**	**33.8**	**32.8**	**31.8**	**30.8**	**29.9**	**29.1**	**28.2**	**27.4**	**26.7**	**26.0**	**25.2**	**24.6**	**23.9**	**23.3**	**22.7**	**22.1**	**21.6**	**21.1**	
ABEX																				**78.0**
Production																				
Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Condensate	149	138	129	120	112	105	98	91	86	80	75	70	66	61	58	54	51	48	45	0
Gas	74.38	69.18	64.50	60.17	56.16	52.43	48.97	45.75	42.75	39.97	37.39	34.98	32.77	30.74	28.86	27.10	25.46	23.93	22.51	0.00
Gas	27.2	25.2	23.5	22.0	20.6	19.1	17.9	16.7	15.6	14.6	13.6	12.8	12.0	11.2	10.5	9.9	9.3	8.7	8.2	0.0
Fuel & Flare	2.2	2.1	1.9	1.8	1.7	1.6	1.5	1.4	1.3	1.2	1.1	1.0	1.0	0.9	0.9	0.8	0.8	0.7	0.7	0.0
CO2 Removed to Injection	7.6	7.1	6.6	6.1	5.7	5.3	5.0	4.7	4.4	4.1	3.8	3.6	3.3	3.1	2.9	2.8	2.6	2.4	2.3	0.0
Export Gas	**64.6**	**60.0**	**56.0**	**52.2**	**48.7**	**45.5**	**42.5**	**39.7**	**37.1**	**34.7**	**32.5**	**30.4**	**28.4**	**26.7**	**25.0**	**23.5**	**22.1**	**20.8**	**19.5**	**0.0**
Total	**23.6**	**21.9**	**20.4**	**19.1**	**17.8**	**16.6**	**15.5**	**14.5**	**13.6**	**12.7**	**11.8**	**11.1**	**10.4**	**9.7**	**9.1**	**8.6**	**8.1**	**7.6**	**7.1**	**0.0**

RPS Oil & Gas Development High Case Cost Profile

Appendix D
Cash Flow Tables

Gas Only Case – P90

Year	Net to DELT											NET PRESENT VALUE			
	Oil Production	Gas Production	NGL Production	Total Production	Total Revenue	Capex	Total Opex	Decomm. Cost	Pre-Tax NCF	Corporation Tax	Post-Tax NCF	Annual Discounted Cash Flow @ 0%	Annual Discounted Cash Flow @ 10%	Annual Discounted Cash Flow @ 12%	Annual Discounted Cash Flow @ 15%
	MMstb	Bscf	MMstb	MMBOE	US$mm	US$mm	US$mm	US$mm	US$mm	US$mm	US$mm	MMUS$	MMUS$	MMUS$	MMUS$
2024	-	-	-	-	-	10	-	-	(10)	-	(10)	(10)	(9)	(9)	(9)
2025	-	-	-	-	-	11	-	-	(11)	-	(11)	(11)	(9)	(9)	(9)
2026	-	-	-	-	-	66	-	-	(66)	-	(66)	(66)	(52)	(49)	(46)
2027	-	-	-	-	-	89	-	-	(89)	-	(89)	(89)	(64)	(60)	(55)
2028	-	-	-	-	-	92	-	-	(92)	-	(92)	(92)	(60)	(55)	(49)
2029	-	12.6	0.0	2.1	187	-	15	-	173	-	173	173	102	93	80
2030	-	8.1	0.0	1.4	123	-	13	-	109	-	109	109	59	52	44
2031	-	5.3	0.0	0.9	81	-	12	-	68	-	68	68	34	29	24
2032	-	3.5	0.0	0.6	55	-	15	-	41	-	41	41	18	15	12
2033	-	2.4	0.0	0.4	39	-	12	-	27	6	20	20	8	7	5
2034	-	1.8	0.0	0.3	29	-	20	-	9	6	3	3	1	1	1
2035	-	-	-	-	-	-	-	16	(16)	(2)	(14)	(14)	(5)	(4)	(3)
2036	-	-	-	-	-	-	-	16	(16)	(5)	(11)	(11)	(3)	(3)	(2)
2037	-	-	-	-	-	-	-	-	-	(2)	2	2	0	0	0
Total	**-**	**33.7**	**0.1**	**5.7**	**513.7**	**267.7**	**86.9**	**31.7**	**127.4**	**3.7**	**123.7**	**123.7**	**20.1**	**8.3**	**(5.9)**

Gas Case only – P50

Year	Oil Production	Gas Production	NGL Production	Total Production	Total Revenue	Capex	Total Opex	Decomm. Cost	Pre-Tax NCF	Corporation Tax	Post-Tax NCF	Annual Discounted Cash Flow @ 0%	Annual Discounted Cash Flow @ 10%	Annual Discounted Cash Flow @ 12%	Annual Discounted Cash Flow @ 15%
	Net to DELT											NET PRESENT VALUE			
	MMstb	Bscf	MMstb	MMBOE	US$mm	US$mm	US$mm	US$mm	US$mm	US$mm	US$mm	MMUS$	MMUS$	MMUS$	MMUS$
2024	-	-	-	-	-	10	-	-	(10)	-	(10)	(10)	(9)	(9)	(9)
2025	-	-	-	-	-	11	-	-	(11)	-	(11)	(11)	(9)	(9)	(9)
2026	-	-	-	-	-	66	-	-	(66)	-	(66)	(66)	(52)	(49)	(46)
2027	-	-	-	-	-	89	-	-	(89)	-	(89)	(89)	(64)	(60)	(55)
2028	-	-	-	-	-	92	-	-	(92)	-	(92)	(92)	(60)	(55)	(49)
2029	-	14.1	0.0	2.4	210	-	15	-	195	-	195	195	115	104	90
2030	-	12.3	0.0	2.1	186	-	15	-	172	-	172	172	92	82	69
2031	-	10.3	0.0	1.7	160	-	14	-	145	31	114	114	56	49	40
2032	-	8.7	0.0	1.5	138	-	17	-	121	48	73	73	32	28	22
2033	-	7.4	0.0	1.2	118	-	14	-	104	44	60	60	24	20	16
2034	-	6.3	0.0	1.1	102	-	22	-	81	35	45	45	17	14	10
2035	-	5.3	0.0	0.9	89	-	14	-	75	31	45	45	15	12	9
2036	-	4.6	0.0	0.8	78	-	16	-	62	26	35	35	11	9	6
2037	-	3.9	0.0	0.7	68	-	12	-	55	23	32	32	9	7	5
2038	-	3.4	0.0	0.6	59	-	12	-	47	20	27	27	7	5	4
2039	-	2.9	0.0	0.5	52	-	12	-	40	17	23	23	5	4	3
2040	-	2.5	0.0	0.4	47	-	12	-	35	15	20	20	4	3	2
2041	-	2.2	0.0	0.4	41	-	12	-	30	13	17	17	3	2	1
2042	-	1.9	0.0	0.3	37	-	12	-	26	11	15	15	3	2	1
2043	-	1.7	0.0	0.3	34	-	11	-	22	9	13	13	2	1	1
2044	-	1.4	0.0	0.2	29	-	11	-	17	8	10	10	1	1	1
2045	-	-	-	-	-	-	-	19	(19)	(2)	(18)	(18)	(2)	(2)	(1)
2046	-	-	-	-	-	-	-	20	(20)	(6)	(14)	(14)	(2)	(1)	(1)
2047	-	-	-	-	-	-	-	-	-	(2)	2	2	0	0	0
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2057	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2058	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2059	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2060	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**-**	**89.0**	**0.2**	**15.0**	**1,447.6**	**267.7**	**220.9**	**38.7**	**920.3**	**321.6**	**598.8**	**598.8**	**198.6**	**158.1**	**110.7**

Gas Case only – P10

	Net to DELT											NET PRESENT VALUE			
Year	Oil Production	Gas Production	NGL Production	Total Production	Total Revenue	Capex	Total Opex	Decomm. Cost	Pre-Tax NCF	Corporation Tax	Post-Tax NCF	Annual Discounted Cash Flow @ 0%	Annual Discounted Cash Flow @ 10%	Annual Discounted Cash Flow @ 12%	Annual Discounted Cash Flow @ 15%
	MMstb	Bscf	MMstb	MMBOE	US$mm	US$mm	US$mm	US$mm	US$mm	US$mm	US$mm	MMUS$	MMUS$	MMUS$	MMUS$
2024	-	-	-	-	-	10	-	-	(10)	-	(10)	(10)	(9)	(9)	(9)
2025	-	-	-	-	-	11	-	-	(11)	-	(11)	(11)	(9)	(9)	(9)
2026	-	-	-	-	-	66	-	-	(66)	-	(66)	(66)	(52)	(49)	(46)
2027	-	-	-	-	-	89	-	-	(89)	-	(89)	(89)	(64)	(60)	(55)
2028	-	-	-	-	-	92	-	-	(92)	-	(92)	(92)	(60)	(55)	(49)
2029	-	14.3	0.0	2.4	212	-	15	-	197	-	197	197	116	105	91
2030	-	14.3	0.0	2.4	216	-	16	-	200	1	199	199	107	95	80
2031	-	13.5	0.0	2.3	209	-	16	-	193	52	141	141	69	60	50
2032	-	12.4	0.0	2.1	196	-	18	-	178	73	105	105	46	40	32
2033	-	11.4	0.0	1.9	183	-	16	-	167	68	99	99	40	34	26
2034	-	10.5	0.0	1.8	172	-	24	-	148	62	87	87	32	26	20
2035	-	9.7	0.0	1.6	162	-	15	-	146	59	88	88	29	24	18
2036	-	9.0	0.0	1.5	153	-	18	-	135	55	79	79	24	19	14
2037	-	8.3	0.0	1.4	144	-	14	-	130	53	77	77	21	17	12
2038	-	7.7	0.0	1.3	136	-	14	-	122	50	72	72	18	14	9
2039	-	7.1	0.0	1.2	128	-	14	-	114	47	68	68	15	12	8
2040	-	6.6	0.0	1.1	122	-	14	-	108	44	64	64	13	10	6
2041	-	6.1	0.0	1.0	115	-	14	-	102	41	60	60	11	8	5
2042	-	5.7	0.0	1.0	109	-	13	-	96	39	57	57	10	7	4
2043	-	5.3	0.0	0.9	104	-	13	-	90	37	54	54	8	6	4
2044	-	4.9	0.0	0.8	99	-	13	-	86	35	51	51	7	5	3
2045	-	4.6	0.0	0.8	94	-	13	-	81	33	48	48	6	4	2
2046	-	4.3	0.0	0.7	89	-	13	-	76	31	45	45	5	4	2
2047	-	4.0	0.0	0.7	85	-	13	-	72	29	43	43	5	3	2
2048	-	3.7	0.0	0.6	81	-	13	-	68	28	40	40	4	3	1
2049	-	3.5	0.0	0.6	77	-	13	-	64	26	38	38	3	2	1
2050	-	3.2	0.0	0.5	73	-	12	-	61	25	36	36	3	2	1
2051	-	3.0	0.0	0.5	70	-	12	-	57	23	34	34	2	2	1
2052	-	2.8	0.0	0.5	67	-	12	-	55	22	32	32	2	1	1
2053	-	2.7	0.0	0.4	64	-	12	-	51	21	30	30	2	1	0
2054	-	2.5	0.0	0.4	61	-	12	-	49	20	29	29	2	1	0
2055	-	2.3	0.0	0.4	58	-	12	-	46	19	27	27	1	1	0
2056	-	2.2	0.0	0.4	56	-	12	-	44	18	26	26	1	1	0
2057	-	2.1	0.0	0.3	53	-	12	-	41	17	25	25	1	1	0
2058	-	1.9	0.0	0.3	51	-	12	-	39	16	23	23	1	0	0
2059	-	-	-	-	-	-	-	25	(25)	0	(25)	(25)	(1)	(0)	(0)
2060	-	-	-	-	-	-	-	26	(26)	(8)	(18)	(18)	(1)	(0)	(0)
2061	-	-	-	-	-	-	-	-	-	(3)	3	3	0	0	0
Total	**-**	**189.5**	**0.4**	**32.0**	**3,436.2**	**267.7**	**419.4**	**51.1**	**2,698.0**	**1,033.9**	**1,664.1**	**1,664.1**	**412.0**	**322.9**	**225.8**

Combined Gas and Oil Case – P90

	Net to DELT											NET PRESENT VALUE			
Year	Oil Production	Gas Production	NGL Production	Total Production	Total Revenue	Capex	Total Opex	Decomm. Cost	Pre-Tax NCF	Corporation Tax	Post-Tax NCF	Annual Discounted Cash Flow @ 0%	Annual Discounted Cash Flow @ 10%	Annual Discounted Cash Flow @ 12%	Annual Discounted Cash Flow @ 15%
	MMstb	Bscf	MMstb	MMBOE	US$mm	US$mm	US$mm	US$mm	US$mm	US$mm	US$mm	MMUS$	MMUS$	MMUS$	MMUS$
2024	-	-	-	-	-	10	-	-	(10)	-	(10)	(10)	(9)	(9)	(9)
2025	-	-	-	-	-	20	-	-	(20)	-	(20)	(20)	(17)	(17)	(16)
2026	-	-	-	-	-	123	-	-	(123)	-	(123)	(123)	(97)	(92)	(86)
2027	-	-	-	-	-	167	-	-	(167)	-	(167)	(167)	(119)	(112)	(102)
2028	-	-	-	-	-	177	-	-	(177)	-	(177)	(177)	(115)	(106)	(94)
2029	1.4	6.2	0.0	2.5	211	-	27	-	185	-	185	185	109	99	86
2030	0.0	5.7	0.0	1.0	88	-	27	-	61	-	61	61	33	29	24
2031	-	5.7	0.0	1.0	88	-	13	-	75	-	75	75	37	32	26
2032	-	6.2	0.0	1.1	98	-	16	-	83	-	83	83	37	31	25
2033	-	4.1	0.0	0.7	66	-	13	-	53	-	53	53	22	18	14
2034	-	2.8	0.0	0.5	46	-	20	-	26	-	26	26	10	8	6
2035	-	2.0	0.0	0.3	34	-	12	-	22	-	22	22	7	6	4
2036	-	1.2	0.0	0.2	21	-	15	-	6	-	6	6	2	1	1
2037	-	-	-	-	-	-	-	30	(30)	(6)	(24)	(24)	(7)	(5)	(4)
2038	-	-	-	-	-	-	-	31	(31)	(9)	(22)	(22)	(5)	(4)	(3)
2039	-	-	-	-	-	-	-	-	-	(3)	3	3	1	1	0
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2057	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2058	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2059	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2060	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	1.4	34.1	0.1	7.2	652.1	496.2	141.8	61.1	(47.0)	(18.3)	(28.6)	(28.6)	(113.6)	(120.6)	(127.4)

Combined Gas and Oil Case – P50

	Net to DELT											NET PRESENT VALUE			
Year	Oil Production	Gas Production	NGL Production	Total Production	Total Revenue	Capex	Total Opex	Decomm. Cost	Pre-Tax NCF	Corporation Tax	Post-Tax NCF	Annual Discounted Cash Flow @ 0%	Annual Discounted Cash Flow @ 10%	Annual Discounted Cash Flow @ 12%	Annual Discounted Cash Flow @ 15%
	MMstb	Bscf	MMstb	MMBOE	US$mm	US$mm	US$mm	US$mm	US$mm	US$mm	US$mm	MMUS$	MMUS$	MMUS$	MMUS$
2024	-	-	-	-	-	10	-	-	(10)	-	(10)	(10)	(9)	(9)	(9)
2025	-	-	-	-	-	20	-	-	(20)	-	(20)	(20)	(17)	(17)	(16)
2026	-	-	-	-	-	123	-	-	(123)	-	(123)	(123)	(97)	(92)	(86)
2027	-	-	-	-	-	167	-	-	(167)	-	(167)	(167)	(119)	(112)	(102)
2028	-	-	-	-	-	177	-	-	(177)	-	(177)	(177)	(115)	(106)	(94)
2029	1.7	6.5	0.0	2.8	239	-	27	-	212	-	212	212	126	114	98
2030	1.5	6.3	0.0	2.6	222	-	27	-	195	-	195	195	105	93	79
2031	1.3	6.2	0.0	2.4	209	-	27	-	182	-	182	182	89	78	64
2032	1.0	11.8	0.0	3.0	275	-	37	-	239	26	212	212	94	81	65
2033	0.4	9.7	0.0	2.1	194	-	33	-	160	56	105	105	42	36	28
2034	-	8.1	0.0	1.4	133	-	23	-	111	51	60	60	22	18	14
2035	-	7.0	0.0	1.2	116	-	14	-	102	42	60	60	20	16	12
2036	-	6.0	0.0	1.0	102	-	17	-	86	36	49	49	15	12	9
2037	-	5.2	0.0	0.9	90	-	13	-	77	32	45	45	12	10	7
2038	-	4.5	0.0	0.8	79	-	13	-	66	28	38	38	10	7	5
2039	-	3.9	0.0	0.7	70	-	12	-	57	24	33	33	8	6	4
2040	-	3.4	0.0	0.6	62	-	12	-	50	21	29	29	6	4	3
2041	-	2.9	0.0	0.5	55	-	12	-	43	18	25	25	5	3	2
2042	-	2.6	0.0	0.4	49	-	12	-	37	16	21	21	4	3	2
2043	-	2.2	0.0	0.4	44	-	12	-	32	14	19	19	3	2	1
2044	-	2.0	0.0	0.3	40	-	12	-	28	12	17	17	2	2	1
2045	-	1.8	0.0	0.3	37	-	11	-	25	10	15	15	2	1	1
2046	-	1.6	0.0	0.3	34	-	11	-	22	9	13	13	2	1	1
2047	-	1.4	0.0	0.2	29	-	11	-	18	8	10	10	1	1	0
2048	-	0.9	0.0	0.2	20	-	11	-	9	5	4	4	0	0	0
2049	-	-	-	-	-	-	-	38	(38)	(6)	(32)	(32)	(3)	(2)	(1)
2050	-	-	-	-	-	-	-	39	(39)	(12)	(27)	(27)	(2)	(1)	(1)
2051	-	-	-	-	-	-	-	-	-	(4)	4	4	0	0	0
2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2057	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2058	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2059	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2060	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**5.9**	**93.9**	**0.2**	**21.8**	**2,099.0**	**496.2**	**347.5**	**77.5**	**1,177.9**	**385.6**	**792.2**	**792.2**	**204.6**	**148.3**	**83.9**

Combined Gas and Oil Case - P10

	Net to DELT											NET PRESENT VALUE			
Year	Oil Production	Gas Production	NGL Production	Total Production	Total Revenue	Capex	Total Opex	Decomm. Cost	Pre-Tax NCF	Corporation Tax	Post-Tax NCF	Annual Discounted Cash Flow @ 0%	Annual Discounted Cash Flow @ 10%	Annual Discounted Cash Flow @ 12%	Annual Discounted Cash Flow @ 15%
	MMstb	Bscf	MMstb	MMBOE	US$mm	US$mm	US$mm	US$mm	US$mm	US$mm	US$mm	MMUS$	MMUS$	MMUS$	MMUS$
2024	-	-	-	-	-	10	-	-	(10)	-	(10)	(10)	(9)	(9)	(9)
2025	-	-	-	-	-	20	-	-	(20)	-	(20)	(20)	(17)	(17)	(16)
2026	-	-	-	-	-	123	-	-	(123)	-	(123)	(123)	(97)	(92)	(86)
2027	-	-	-	-	-	167	-	-	(167)	-	(167)	(167)	(119)	(112)	(102)
2028	-	-	-	-	-	177	-	-	(177)	-	(177)	(177)	(115)	(106)	(94)
2029	2.0	6.9	0.0	3.1	270	-	27	-	243	-	243	243	144	130	113
2030	2.0	6.8	0.0	3.1	271	-	27	-	243	-	243	243	131	117	98
2031	2.0	6.8	0.0	3.1	276	-	28	-	248	1	247	247	121	106	87
2032	1.9	14.9	0.0	4.4	403	-	38	-	365	98	267	267	119	102	81
2033	1.7	13.4	0.0	4.0	366	-	35	-	331	137	194	194	78	66	51
2034	1.5	12.1	0.0	3.5	333	-	43	-	290	121	169	169	62	51	39
2035	1.3	11.0	0.0	3.2	305	-	33	-	272	111	161	161	54	44	32
2036	1.1	10.1	0.0	2.8	279	-	36	-	243	101	142	142	43	34	25
2037	1.0	9.2	0.0	2.5	252	-	31	-	221	91	130	130	36	28	20
2038	0.8	8.5	0.0	2.2	224	-	30	-	195	81	113	113	28	22	15
2039	0.1	7.6	0.0	1.4	146	-	29	-	117	57	60	60	14	10	7
2040	-	7.1	0.0	1.2	131	-	14	-	117	47	70	70	14	11	7
2041	-	6.6	0.0	1.1	124	-	14	-	110	45	65	65	12	9	6
2042	-	6.1	0.0	1.0	118	-	14	-	104	42	61	61	11	8	5
2043	-	5.7	0.0	1.0	112	-	14	-	98	40	58	58	9	6	4
2044	-	5.4	0.0	0.9	107	-	14	-	93	38	55	55	8	5	3
2045	-	5.0	0.0	0.8	102	-	14	-	88	36	52	52	7	5	3
2046	-	4.7	0.0	0.8	97	-	13	-	83	34	49	49	6	4	2
2047	-	4.3	0.0	0.7	92	-	13	-	79	32	47	47	5	3	2
2048	-	4.1	0.0	0.7	88	-	13	-	75	30	44	44	4	3	1
2049	-	3.8	0.0	0.6	84	-	13	-	71	29	42	42	4	2	1
2050	-	3.6	0.0	0.6	80	-	13	-	67	27	40	40	3	2	1
2051	-	3.3	0.0	0.6	76	-	13	-	63	26	38	38	3	2	1
2052	-	3.1	0.0	0.5	73	-	13	-	60	25	36	36	2	1	1
2053	-	2.9	0.0	0.5	70	-	13	-	57	23	34	34	2	1	1
2054	-	2.7	0.0	0.5	67	-	13	-	54	22	32	32	2	1	0
2055	-	2.6	0.0	0.4	64	-	13	-	51	21	30	30	2	1	0
2056	-	2.4	0.0	0.4	62	-	13	-	49	20	29	29	1	1	0
2057	-	2.3	0.0	0.4	59	-	12	-	46	19	27	27	1	1	0
2058	-	2.1	0.0	0.4	56	-	12	-	44	18	26	26	1	1	0
2059	-	-	-	-	-	-	-	47	(47)	(3)	(43)	(43)	(1)	(1)	(0)
2060	-	-	-	-	-	-	-	48	(48)	(14)	(34)	(34)	(1)	(1)	(0)
2061	-	-	-	-	-	-	-	-	-	(5)	5	5	0	0	0
Total	**15.3**	**185.0**	**0.4**	**46.5**	**4,785.4**	**496.2**	**607.8**	**94.5**	**3,586.9**	**1,355.7**	**2,231.2**	**2,236.0**	**565.6**	**437.5**	**296.2**

MAKING COMPLEX EASY

For more information contact:

Clare Wilson, CGeol
Principal Advisor Geoscience

T: +44 1483 746 500
M:
E: clare.wilson@rpsgroup.com