Competent Person's Report of the Petroleum and Natural Gas (P&NG) Reserves and Resources of Orcadian Energy PLC

(As of April 1, 2021)

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Prepared for:	**Orcadian Energy PLC**
	W. H. Ireland Limited (as Nominated Advisor to Orcadian Energy PLC)
Project No.:	25703.110745
Distribution:	Orcadian Energy PLC
	Summary Volume (Digital copy)
	Sproule (Full digital copy retained)
Editor:	KMH
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Executive Summary

This Competent Person's Report ("CPR") was prepared by Sproule B.V. ("Sproule") at the request of Mr. Stephen A. Brown, CEO, Orcadian Energy PLC and of the Directors of W. H. Ireland Limited. Orcadian Energy PLC is hereinafter referred to as "the Company". W. H. Ireland Limited is the Nominated Advisor ("NOMAD") to the Company on their proposed public disclosure. The effective date of this report is April 1, 2021 and was prepared for the Company between February and May 2021 for the purpose of public disclosure and equity fundraising through admission of its shares to trading on the AIM market of the London Stock Exchange.

For clarity, Orcadian Energy PLC is the proposed holding company of 100 percent of the shares of Orcadian Energy (CNS) Ltd. Orcadian Energy (CNS) Ltd. has been created by a change in name of Pharis Energy Ltd. Some, or all, of the permits and licences discussed in this report may still be in the name of Pharis Energy Ltd. and are subject to the notification and documentation process, currently underway, that is necessary to effect such change in name.

The preparation date of this report is July 8, 2021. This date is subsequent to the effective date and refers to the last date on which information, relating to the period ending on the effective date, was received and considered in the preparation of this report. As of the preparation date of this report, Sproule confirms that there has been no material change in the assets, of which we have been informed, since the Effective Date.

In preparation of this report, Sproule has received customary fees associated with the preparation of the CPR. Neither Sproule, nor any of its directors, staff or sub-consultants who contributed to the report has any interest in the Company, its parent or subsidiaries, or any of its assets or securities (including the common shares of the Company). Our fees are not linked to the admission of the shares to trading on the AIM market of the London Stock Exchange or the value of the Company.

Sproule is independent of the Company, its directors, senior management and advisors.

Tables S-1 and S-1A summarize our evaluation, before and after income taxes, of the P&NG reserves and unrisked contingent resources, respectively of Orcadian Energy PLC, as of April 1, 2021.

Table S-1B summarizes technically recoverable resources of the unrisked P&NG prospective resources of Orcadian Energy PLC, as of April 1, 2021.

Tables S-2A and S-2B summarize the P&NG contingent resources and the P&NG prospective resources of Orcadian Energy PLC, as of April 1, 2021 on a risked basis.

The reserves and resources definitions and ownership classification used in this evaluation are in accordance with the PRMS reserve definitions and used by Sproule. The oil reserves and resources are presented in thousands of barrels, at stock tank conditions.

No gas reserves or resources have been assigned, as gas is proposed to only be used for fuel and flare and no expense has been included in the cash flows for the use of the solution gas as fuel gas.

The estimates of reserves are those reserves which remain in the ground. Volumes of P&NG reserves produced but not sold which reside in inventory, including overlift and underlift situations, are not accounted for in the reserve volumes presented.

The Company plans to develop the Pilot Main, Pilot South, Pilot Channels, Blakeney, Elke, Narwhal and Bowhead fields under a full field polymer flood development scenario. Tiberius and Bottlenose fields are expected to be a lighter oil, and would be planned for development under a conventional water flood scheme. Reserves were assigned to the Pilot Main and Pilot South fields.

Contingent resources were assigned to the Blakeney, Elke, Narwhal and Pilot Peripheral Area fields.

Prospective Resources were assigned to Pilot Channels, Elke field undiscovered areas, Bowhead, Tiberius and Bottlenose fields.

An economic evaluation was completed for the reserves and contingent resources having Development Pending and Development On Hold project maturity sub-classes. Forecasts of production and net revenue for the contingent resources of Development Unclarified maturity sub-class and prospective resources were not prepared at the request of the Company.

The net present values of the reserves are presented (on a before and after income tax basis) in United States dollars and are based on annual projections of net revenue, which were discounted at various rates using the mid-period discounting method. These rates are 5, 8, 10, 15 and 20 percent and undiscounted.

The price forecasts that formed the basis for the revenue projections in the evaluation were based on Sproule’s March 31, 2021 pricing model. The price offset applicable to sales of crude oil was based on publicly available information from operators of producing properties in the same general region and with comparable quality crude as that proposed to be produced by the Company. Table S-3 presents a summary of selected forecasts.

Summary of the Evaluation of the P&NG Reserves
Orcadian Energy PLC
Escalated Prices and Costs
(As of April 1, 2021)

	Remaining Reserves			Net Present Values Before and After Income Taxes (M$ US) At Various Discount Rates					
	Project	Company							
	Gross	Gross	Net	At 0%	At 5%	At 8%	At 10%	At 15%	At 20%
Oil (Mbbl) - Before Tax (M$ US)									
Proved Undeveloped	58,436	58,436	58,436	666,224	359,460	229,427	159,525	29,278	-55,020
Total Proved	**58,436**	**58,436**	**58,436**	**666,224**	**359,460**	**229,427**	**159,525**	**29,278**	**-55,020**
Probable Undeveloped	20,383	20,383	20,383	971,825	685,606	562,036	494,380	363,856	272,901
Total Probable	20,383	20,383	20,383	971,825	685,606	562,036	494,380	363,856	272,901
Total Proved + Probable	**78,819**	**78,819**	**78,819**	**1,638,049**	**1,045,066**	**791,463**	**653,905**	**393,134**	**217,881**
Possible Undeveloped	31,712	31,712	31,712	1,581,070	1,105,248	903,458	793,988	584,852	440,624
Total Possible	31,712	31,712	31,712	1,581,070	1,105,248	903,458	793,988	584,852	440,624
Total Proved + Probable + Possible	**110,531**	**110,531**	**110,531**	**3,219,119**	**2,150,314**	**1,694,921**	**1,447,893**	**977,986**	**658,505**
Income Tax (M$ US)									
Proved Undeveloped				158,544	103,750	81,309	69,403	47,360	32,908
Total Proved				**158,544**	**103,750**	**81,309**	**69,403**	**47,360**	**32,908**
Probable Undeveloped				358,952	236,316	186,196	159,601	110,266	77,744
Total Probable				358,952	236,316	186,196	159,601	110,266	77,744
Total Proved + Probable				**517,496**	**340,066**	**267,505**	**229,004**	**157,626**	**110,652**
Possible Undeveloped				652,441	432,219	342,650	295,145	206,856	148,283
Total Possible				652,441	432,219	342,650	295,145	206,856	148,283
Total Proved + Probable + Possible				**1,169,937**	**772,285**	**610,155**	**524,149**	**364,482**	**258,935**
Grand Total (MBoe) - After Tax (M$ US)									
Proved Undeveloped	58,436	58,436	58,436	507,680	255,710	148,118	90,122	-18,082	-87,928
Total Proved	**58,436**	**58,436**	**58,436**	**507,680**	**255,710**	**148,118**	**90,122**	**-18,082**	**-87,928**
Probable Undeveloped	20,383	20,383	20,383	612,873	449,290	375,840	334,779	253,590	195,157
Total Probable	20,383	20,383	20,383	612,873	449,290	375,840	334,779	253,590	195,157
Total Proved + Probable	**78,819**	**78,819**	**78,819**	**1,120,553**	**705,000**	**523,958**	**424,901**	**235,508**	**107,229**
Possible Undeveloped	31,712	31,712	31,712	928,629	673,029	560,808	498,843	377,996	292,341
Total Possible	31,712	31,712	31,712	928,629	673,029	560,808	498,843	377,996	292,341
Total Proved + Probable + Possible	**110,531**	**110,531**	**110,531**	**2,049,182**	**1,378,029**	**1,084,766**	**923,744**	**613,504**	**399,570**

Values may not add due to rounding

Summary of the Evaluation of the P&NG Contingent Resources (Unrisked)[1,2]
Orcadian Energy PLC
Escalated Prices and Costs
(As of April 1, 2021)

	Remaining Resources			Net Present Values					
	Project	Company		Before and After Income Taxes (M$ US) At Various Discount Rates					
	Gross	Gross	Net	At 0%	At 5%	At 8%	At 10%	At 15%	At 20%
Oil (Mbbl) - Before Tax (M$ US)									
1C	28,621	28,621	28,621	339,364	149,655	89,252	62,052	21,944	4,121
2C	77,854	77,854	77,854	2,168,063	1,041,361	681,416	516,628	263,305	137,122
3C	183,852	183,852	183,852	8,059,337	3,959,158	2,638,336	2,028,858	1,079,303	593,474
Income Tax (M$ US)									
1C				86,812	43,275	28,977	22,323	11,879	6,502
2C				744,021	349,909	227,471	172,162	88,211	46,875
3C				3,118,902	1,496,275	985,796	753,087	395,310	215,348
Grand Total (MBoe) - After Tax (M$ US)									
1C	28,621	28,621	28,621	252,552	106,380	60,275	39,729	10,065	-2,381
2C	77,854	77,854	77,854	1,424,042	691,452	453,945	344,466	175,094	90,247
3C	183,852	183,852	183,852	4,940,435	2,462,883	1,652,540	1,275,771	683,993	378,126

Values may not add due to rounding
1- The oil volumes and corresponding NPV values are for Economic, Contingent Resources
2- Project maturity sub-class Development On Hold. Contingent resources with project maturity sub-class Development Not Viable and Development Unclarified are excluded.

Summary of the P&NG Prospective Resources (Unrisked)[1]
Orcadian Energy PLC
(As of April 1, 2021)

	Remaining Resources		
	Project	Company Resources	
	Gross	Gross	Net
Oil (Mbbl)			
1U	**50,323**	**50,323**	**50,323**
2U	**191,400**	**191,400**	**191,400**
3U	**514,150**	**514,150**	**514,150**

Values may not add due to rounding

1- Technical Volumes are presented for Prospective Resources. No economic analysis was completed for Prospective Resources.

Summary of the Evaluation of the P&NG Contingent Resources (Risked)[1,2,3,4]
Orcadian Energy PLC
Escalated Prices and Costs
(As of April 1, 2021)

	Remaining Resources			Net Present Values Before and After Income Taxes (M$ US) At Various Discount Rates					
	Project	Company							
	Gross	Gross	Net	At 0%	At 5%	At 8%	At 10%	At 15%	At 20%
Oil (Mbbl) - Before Tax (M$ US)									
1C	22,611	22,611	22,611	268,098	118,227	70,509	49,021	17,336	3,256
2C	59,746	59,746	59,746	1,678,568	809,655	531,060	403,250	206,275	107,801
3C	142,338	142,338	142,338	6,256,408	3,080,867	2,055,756	1,582,166	843,272	464,464
Income Tax (M$ US)									
1C				68,581	34,187	22,892	17,635	9,384	5,137
2C				562,308	264,479	171,948	130,148	66,695	35,448
3C				2,360,522	1,132,923	746,611	570,472	299,598	163,291
Grand Total (MBoe) - After Tax (M$ US)									
1C	22,611	22,611	22,611	199,516	84,040	47,617	31,386	7,951	-1,881
2C	59,746	59,746	59,746	1,116,260	545,176	359,112	273,101	139,580	72,352
3C	142,338	142,338	142,338	3,895,886	1,947,944	1,309,145	1,011,694	543,674	301,174

Values may not add due to rounding

1- The oil volumes and corresponding NPV values are for Economic, Risked Contingent Resources

2- Project maturity sub-class Development On Hold. Contingent resources with project maturity sub-class Development Not Viable and Development Unclarified are excluded.

3- “Chance of Development” for Contingent Resources is the estimated chance, or probability, that a known accumulation will be commercially developed.

4- "Chance of Commerciality" is the estimated probability that the project will achieve commercial maturity to be developed. For Contingent Resources, this is equal to the Chance of Development.

Summary of the P&NG Prospective Resources (Risked)[1,2,3,4]
Orcadian Energy PLC
(As of April 1, 2021)

	Remaining Resources		
	Project	Company Resources	
	Gross	Gross	Net
Oil (Mbbl)			
1U	**12,316**	**12,316**	**12,316**
2U	**43,735**	**43,735**	**43,735**
3U	**109,621**	**109,621**	**109,621**

Values may not add due to rounding

1- Technical Volumes are presented for Risked Prospective Resources. No economic analysis was completed for Prospective Resources.

2- “Chance of Geologic Discovery” for Prospective Resources is the estimated chance, or probability, that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum.

3- “Chance of Development” for Prospective Resources is the estimated chance, or probability, that a known accumulation, once discovered, will be commercially developed.

4- "Chance of Commerciality" is the estimated probability that the project will achieve commercial maturity to be developed. For Prospective Resources, this is the product of the Chance of Geologic Discovery and the Chance of Development.

Table S-3
Summary of Selected Pricing and Inflation Rate Assumptions
(Effective March 31, 2021)

Year	UK Brent 38°API(1,3) ($US/bbl)	IPE Britain NBP(2.3) (£/MMBtu)	Operating Cost Inflation Rate4) (%/Yr)	Capital Cost Inflation Rate(4) (%/Yr)	Exchange Rate(5) ($US/£UK)
Historical					
2016	45.04	3.53	1.2%	-9.7%	1.36
2017	54.83	4.54	1.7%	2.4%	1.29
2018	71.53	5.92	2.4%	4.2%	1.34
2019	64.17	3.79	-0.7%	0.4%	1.28
2020	43.21	2.55	-5.0%	-5.0%	1.28
Forecast					
2021	60.00	4.60	0.0%	0.0%	1.35
2022	57.50	4.50	1.0%	1.0%	1.35
2023	55.00	4.50	2.0%	2.0%	1.35
2024	56.10	4.59	2.0%	2.0%	1.35
2025	57.22	4.68	2.0%	2.0%	1.35
2026	58.37	4.78	2.0%	2.0%	1.35
2027	59.53	4.87	2.0%	2.0%	1.35
2028	60.72	4.97	2.0%	2.0%	1.35
2029	61.94	5.07	2.0%	2.0%	1.35
2030	63.18	5.17	2.0%	2.0%	1.35
2031	64.44	5.27	2.0%	2.0%	1.35
Escalation rate of 2.0% percent per year thereafter					

Note:

(1) 38 degrees API, 1.0 percent sulphur
(2) International Petroleum Exchange British National Balancing Point
(3) Product sale prices will reflect these reference prices with further adjustments for quality and transportation to point of sale
(4) Inflation rates for forecasting prices and costs
(5) Exchange rates used to generate the benchmark reference prices in this table

Introduction

This Competent Person's Report ("CPR") was prepared by Sproule B.V. ("Sproule") at the request of Mr. Stephen A. Brown, CEO, Orcadian Energy PLC and of the Directors of W. H. Ireland Limited. Orcadian Energy PLC is hereinafter referred to as "the Company". W. H. Ireland Limited is the Nominated Advisor ("NOMAD") to the Company on their proposed public disclosure. The effective date of this report is April 1, 2021 and was prepared for the Company between February and April 2021 for the purpose of public disclosure and equity fundraising through admission of its shares to trading on the AIM market of the London Stock Exchange.

The preparation date of this report is July 8, 2021. This date is subsequent to the effective date and refers to the last date on which information, relating to the period ending on the effective date, was received and considered in the preparation of this report. As of the preparation date of this report, Sproule confirms that there has been no material change in the assets, of which we have been informed, since the Effective Date.

Evaluation Scope

Reserves and Resources Estimation Guidelines

Reserves and resources estimates presented here have been prepared according to the classifications and definitions of the Petroleum Resources Management System ("PRMS"), sponsored by Society of Petroleum Engineers ("SPE"), World Petroleum Council ("WPC"), American Association of Petroleum Geologists ("AAPG"), Society of Petroleum Evaluation Engineers ("SPEE"), Society of Exploration Geophysicists ("SEG"), Society of Petrophysicists and Well Log Analysts ("SPWLA"), and the European Association of Geoscientists & Engineers ("EAGE").

Properties

This report presents an evaluation of the P&NG reserves and resources of the Company's interests in the United Kingdom sector of the North Sea.

Specific properties evaluated in this report for reserves and resources are outlined in Table I-1. Additionally, twelve fields/prospects have been assessed for prospective resources.

Table I-1
Summary Table of Assets

Asset	Operator	Interest (%)	Status	License Expiry Date	License Area, km^2	Comments
Pilot Field (includes Pilot Main and Pilot South fields), UK, P2244, Block 21/27a	Orcadian Energy (CNS) Ltd	100	Exploration	November 30, 2040	43.16	Reserves and Contingent Resources. Initial development anticipated to commence early in 2022.
Blakeney Field, UK, P2320, Block 21/27b	No Operator License admin. Orcadian Energy (CNS) Ltd	100	Exploration	May 14, 2047	447.86	P2320 license also includes Blocks 21/22a, 21/26a, 21/28a Contingent Resources. Initial development anticipated to commence in approximately 2033.
Elke and Narwhal Fields, UK, P2482, Block 28/2a and 28/3a	No Operator License admin. Orcadian Energy (CNS) Ltd	100	Exploration	July 14, 2051	361.61	Contingent Resources. Initial development anticipated to commence in approximately 2030.
Fynn (Beauly) & Fynn (Andrew), UK, P2516, 14/20g, 15/16g	No Operator License admin. Parkmead (E&P) Limited	50	Exploration	November 30, 2050	19.85	No resources included in this report.

Taxation

An estimate of income taxes payable based on the offshore fiscal regime for the United Kingdom has been included in the Company Totals. No tax pools have been included in the evaluation.

Future Development

The development forecast presented in this evaluation was based on capital budgets and a development program as presented by the Company under the scope of this evaluation and engagement. The development forecast presented in this report may not represent the full development potential of the licences evaluated.

Evaluation Data and Procedures

Sources of Data

Various data, pertinent to the evaluation of the Company's oil and gas reserves, were obtained from the Company as follows:

- property descriptions
- preliminary development plan detailing operating plans and budgets
- interests and burdens
- capital development cost estimates
- maintenance cost schedules and capital
- abandonment, decommissioning and reclamation costs
- contracts and marketing

Accuracy and Reliance on Data

Property descriptions, details of interests held, and well data, as supplied by the Company, were accepted as represented. No investigation was made into either the legal titles held or any operating agreements in place relating to the subject properties.

Lessor and overriding royalties and other burdens were obtained from the Company. No further investigation was undertaken by Sproule.

Capital and operating cost estimates, as presented in third-party reports and supplied by the Company, were audited for reasonableness and consistency based on Sproule experience.

Maintenance capital cost estimates, as supplied by the Company, were accepted as represented. No further investigation was undertaken by Sproule.

Abandonment, decommissioning and reclamation ("ADR") cost estimates, as supplied by the Company, were audited for reasonableness and consistency based on Sproule experience.

Abandonment, Decommissioning and Reclamation Costs

The abandonment, decommissioning and reclamation ("ADR") costs associated with the Company's petroleum exploration and development operations in the properties evaluated in this report are as follows:

Future Development

Undeveloped Entities	Included
Producing Oil & Gas Wells	✓
Service Wells (Injectors, Disposal, Etc.)	✓
Gathering Systems and Facilities	✓
Processing Facilities	✓

Future economic development activities, scheduled for development within this report, include the estimated ADR costs in their assessment per PRMS guidance.

Well and Well Site ADR Estimates

The Company provided estimates of the ADR costs associated with their wells and well sites regarding their planned petroleum exploration, development, production and processing operations, for inclusion in this evaluation.

Gathering System and Processing Facility ADR Estimates

Estimates of ADR costs associated with the Company's gathering systems and processing facilities in forecast development activities, included in the report have been prepared by the Company.

For additional details regarding the abandonment, decommissioning and reclamation costs included in this report and their estimation, please refer to the abandonment, decommissioning and reclamation cost section located in Appendix D of this report.

Salvage Income

Inclusion of salvage income estimates associated with end of life disposal of equipment the Company holds a working interest contained in the report are as follows:

	Included	Excluded	Not Applicable
Producing Oil & Gas Wells	-	✓	-
Injection & Disposal & Other Wells	-	✓	-
Gathering Systems and Facilities	-	✓	-
Processing Facilities	-	✓	-

Investment Decisions

Budget and forecast development activity, such as drilling or other future capital investments, have been included in this report when the incremental project economics yielded a positive before tax future net revenue cash flows as per PRMS guidance.

Field Inspections

In the preparation of this evaluation, field inspections of the properties were not performed. The relevant engineering and geoscience data were made available by the Company or obtained from public sources and the non-confidential files at Sproule. No material information regarding the reserves evaluation would have been obtained by an on-site visit.

Product Price Forecasts

The forecasts of product prices used in this evaluation were based on Sproule's March 31, 2021 price forecasts. Further discussion is included in Appendix B.

Reserves Evaluation Software

For this evaluation, Sproule worked on the evaluation model, Value Navigator 2018.1.0.14. The functionality of the program is not the responsibility of Sproule, and results were accepted as calculated by the model. Sproule's responsibility is limited to the quality of the data input and reasonableness of the outcoming results.

Evaluation Results and Presentations

Evaluation Standards

This report has been prepared by Sproule using current geological and engineering knowledge, techniques and computer software. It has been prepared within the Code of Ethics of the Association of Professional Engineers and Geoscientists of Alberta ("APEGA"). This report was prepared in accordance with the guidelines and standards of the PRMS.

Report Contents

This report is included in one volume consisting of an Executive summary, Introduction, Overview of Region, Reserves and Resources, Other Assets, Conclusions, Qualifications and Basis of Opinion and Appendices. The Executive Summary includes high-level summaries of the evaluation; the Introduction includes the summary of evaluation standards and procedures; the Overview of Region includes details of the asset location and regional geology, the Reserves and Resources includes details pertaining to the evaluation of the P&NG reserves and resources, the Other Assets discusses the conclusions of Sproule's audit of the concept select report and associated cost estimates and the Qualifications and Basis of Opinion includes certification and pertinent author certificates. Reserves and resources definitions, product price forecasts, abbreviations, units, conversion factors and general evaluation parameters are included in Appendices A, B, C, and D, respectively. Appendix E presents details of the petroleum fiscal terms. A representation letter prepared by Officers of the Company, Appendix F, confirms the accuracy, completeness and availability of data requested by and furnished to Sproule during the preparation of this report.

Currency

The dollar values presented in the results throughout this report are United States dollars, unless otherwise stated. The inputs to the economic models are in United Kingdom pounds and converted within the model according the Sproule's exchange rate forecast.

Development Timing

Development forecasts documented in this report are consistent with PRMS recommended guidance regarding the development of undeveloped petroleum volumes within a reasonable time frame. Although five years is a recommended benchmark, assignment of reserves outside of that timeframe may be considered with appropriate justification and documentation. The assignment of contingent resources outside of the PRMS recommended guidance may be considered with a contingency regarding timing of development.

The following table lists the properties with future development plan timing that differ from the PRMS guidance listed above.

Properties	Final Year of Development Plan		Rationale for Development Timing
	Proved	Probable	
Pilot Main and Pilot South	2028	2028	A large capital project with facility constraints. The development plan is designed to optimize the operation and deliver supply to align with the proposed fluid handling capacity of the FPSO.

Abandonment, Decommissioning and Reclamation Costs

Forecasts of abandonment, decommissioning and reclamation costs presented in this report represent the total abandonment, decommissioning and reclamation costs associated with the Company's existing petroleum and natural gas portfolio evaluated, as represented by the Company.

Operating Costs

Forecasts of operating costs include payments associated with long term right-of-use assets, as if they are operating costs.

Erroneous Data

Sproule reserves the right to review all calculations made, referred to, or included in this report and to revise the estimates as a result of erroneous data supplied by the Company or information that exists but was not made available to us, which becomes known subsequent to the preparation of this report.

Cautionary Statements

Aggregation

The reserve and resources estimates are based on evaluations of performance methods and/or volumetric calculations of individual formations. These estimates are added up resulting in estimates by property. The process of cumulative summation is commonly referred to as "aggregation" (PRMS). The hydrocarbon reserves and resources presented in this report in Tables S-1, S-1A, S-1B, S-2A and S-2B are the results of arithmetic aggregation of reserves and resources by category.

Data Quality

The accuracy of reserves and resources estimates and associated economic analysis is, in part, a function of the quality and quantity of available data and of engineering and geological interpretation and judgment. Given the data provided at the time this report was prepared, the estimates presented herein are considered reasonable. However, they should be accepted with the understanding that reservoir and financial performance subsequent to the date of the estimates may necessitate revision. These revisions may be material.

Fair Market Value

The net present values of the reserves and contingent resources presented in this report simply represent discounted future cash flow values at several discount rates. Though net present values form an integral part of fair market value estimations, without consideration for other economic criteria, they are not to be construed as Sproule's opinion of fair market value.

Forward-Looking Statements

The evaluation process involves modeling to reasonably predict future outcomes. Inherent in the modeling process, however, are limitations which may indirectly affect the forecast of future events.

This report contains forward-looking statements including expectations of future production revenues and capital expenditures. Information concerning reserves and resources may also be deemed to be forward-looking as estimates involve the implied assessment that the reserves and resources described can be profitably produced in the future. These statements are based on current expectations that involve a number of risks and uncertainties, which could cause actual results to differ from those anticipated. These risks include, but are not limited to: the underlying risks of the oil and gas industry (i.e., corporate commitment, regulatory approval, operational risks in development, exploration and production); potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserves estimations; the uncertainty of estimates and projections relating to production; costs and expenses; health, safety and environmental factors; commodity prices; and exchange rate fluctuation.

Cashflows and Use

The cashflows presented in this report simply represent forecasts of the estimated production, revenues, royalties and costs based on a select set of entities yielding reserves and contingent resources which are economically producible. This model and the operating assumptions implied may not represent the actual operating practices of a company and the presentation may not include all petroleum operations, including but not limited to inactive and uneconomic properties. Although these cash flows may form an integral part of a proforma operating statement and forecast estimation, without consideration for other economic criteria and items which may not be included in the results presentation, they are not to be construed as Sproule's opinion of a proforma operating statement for the entity group evaluated.

Equivalent Volumes

BOE's (or 'McfGE's' or other applicable units of equivalency) may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl (or 'An McfGE conversion ratio of 1 bbl:6 Mcf') is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Rounding

Due to rounding, certain totals may not be consistent from one presentation to the next.

Overview of Region, Location and Assets

Description of Assets

The Company holds a 100 percent working interest, subject to the United Kingdom tax regime, in permits P2244, P2320 and P2482 together totalling some 852.6 km^2 in size and including the Pilot Main, Pilot South, Blakeney, Narwhal and Elke oil discoveries, located in the United Kingdom Continental Shelf (UKCS) North Sea Basin, approximately 150 kilometres east of Aberdeen, Scotland. The Company also holds a 50 percent interest in permit P2516 totalling some 19.9 km^2 in size including the Fynn (Beauly) and Fynn (Andrew) oil discoveries. Maps showing the Company-interest properties are presented as Figures 1 and 2. Table 1 presents the well list of the exploration and appraisal wells drilled in the discovery areas contained within the permit areas.

Petroleum Fiscal Terms

The United Kingdom petroleum fiscal regime is comprised of three taxes, namely, Petroleum Revenue Tax, Ring Fence Corporation Tax and Supplementary Charge Tax. The Company is exempt from Petroleum Revenue Tax. Additionally, no royalties are applicable to the fields.

Further discussion is included in Appendix E.

Production History

Pilot Field

The Pilot Field has been tested in the Tay Formation in the wells 21/27-2 and 21/27a-5X between 1989 and 1998. The reported oil quality was 12 to 17 °API. The 21/27a-5X well was tested at rates up to 1,850 bopd with an electric submersible pump. In well 21/27-2 only the top six feet of this reservoir section were perforated. During the test, the well flowed for 12 hours at the rate of 115 bopd.

Blakeney Field

No production test for the Tay Formation has been completed in the 21/27b-7 well in the Blakeney Field. Oil and water samples were obtained from the 21/27b-7 well with the reported oil quality of 14.5 °API and an average viscosity of 291 cP at reservoir pressure of 1,487 psia and reservoir temperature of 40.5 degrees Celsius.

Elke Field

No production test for the Tay Formation has been completed in the 28/3-1B well. An MDT oil sample was obtained from the 28/3-1B well with a reported oil quality of 12 °API and an average viscosity ranging from 300 to 800 cP at reservoir pressure of 1,558 psia and reservoir temperature of 45 degrees Celsius.

Narwhal Field

No production test for the Tay Formation has been completed in the 28/2-1 well in the Narwhal Field. An MDT oil sample was obtained from the 28/2-1 well with the reported oil quality of 14 °API and an average viscosity of 1,260 cP at reservoir pressure of 1,320 psia and reservoir temperature of 32 degrees Celsius.

Additional details regarding the assets are included in Table I-1 in the Introduction.

Geoscience

The primary oil target in the Pilot, Blakeney, Elke and Narwhal fields is the Eocene-aged Tay Formation. During the deposition of the Tay sandstone package, a gross trend of rising relative sea levels occurred with subordinate maximum flooding surfaces within the depositional sequence. This cycle is completed by falling relative sea levels in the mid to late Lutetian stage.

The Tay Formation is trapped in the area by a combined structural / stratigraphic trap, with the volumetrically significant stratigraphic element created by the updip shale-out of the main reservoir sand. The regional seal for the Eocene-aged sand fairway is provided by the argillaceous deposits of the overlying Hordaland Group.

Pilot

The Pilot oil accumulation in the Tay sandstone was discovered and appraised by 7 wells, 21/27a-5x, 21/27a-5z, 21/27a-5, 21/27a-6, 21/27-3, 21/27-2 and 21/27-4. The trap is a three-way structural closure with lithological seal formed by the Tay sand pinch out in the west as shown in Figure 3. A small gas cap is developed in local structural culminations penetrated by well 21/27a-5 well. There are four west-east oriented incised feeder channels connected to the Pilot Main and Pilot South accumulations and mapped from seismic, correspondingly named North, Central, South and Far South. Although these channels could be in communication with the Pilot Main and Pilot South accumulations, they were assessed as undiscovered prospects.

Sproule audited the Company's geological, geophysical and petrophysical interpretations based on the data provided in the Petrel database, well files and various reports. Average reservoir parameters for the wells from the Sproule independent petrophysical interpretation for the sand of the Tay reservoir is presented in the next table.

Well	Discovery	Gross Thickness, ft	Net-to - Gross Ratio	Net Pay Thickness, ft	Porosity, fraction	Water Saturation, fraction
21/27-2	Pilot Main	62	0.99	61	0.36	0.10
21/27-3	Pilot Main	7	0.99	7	0.27	0.37
21/27A-5	Pilot Main	49	0.98	48	0.36	0.12
21/27A-6	Pilot Main	54	1.00	54	0.36	0.04
21/27-4	Pilot South	8	0.82	7	0.23	0.37

Sproule audited the Pilot geocellular model provided by the Company. It was constructed by one of the previous operators of the block, EnQuest. The geomodelling workflow followed industry standards. A lithofacies model was populated first, followed by porosity, conditioned to the lithofacies, and water saturation calculated by a saturation height function. Volumetrics from the model was concluded to be reasonable.

Company-Provided Discovered OIIP	
Discovery	**OIIP MMbbl**
Pilot Main	230
Pilot South	33

The OIIP volumes assigned to reserve and resource polygons are presented in Tables 2.1 and 2.1A.
The total discovered OIIP estimates presented above differ from the OIIP volumes used for the assignment of reserves/resources as presented in Tables 2.1 and 2.1A because the areal extent of reserves/resources polygons is smaller than the total field area.

Blakeney

The Blakeney oil accumulation in the Tay sandstone was discovered by the 21/27b-7 well drilled at the crest of a four-way dip closure. There is a good root mean square (RMS) amplitude anomaly conforming with the structural closure as shown in Figure 4.

Sproule audited the Company's geological, geophysical and petrophysical interpretations based on the data in the Petrel database, well files and various reports. Average reservoir parameters for the 21/27b-7 well from Sproule independent petrophysical interpretation for the sand of the Tay reservoir are presented below:

Well	Gross Thickness, ft	Net-to -Gross Ratio	Net Pay Thickness, ft	Porosity, fraction	Water Saturation, fraction
21/27b-7	74	0.96	71	0.33	0.07

Sproule audited the probabilistic volumetrics provided by the Company and concluded it to be reasonable.

Company-Provided Probabilistic Discovered OIIP, MMbbls								
Case	Area	Gross Thickness, H	Net-to - Gross Ratio	Geometric Correction	Porosity,	Water Saturation	Oil Formation Volume Factor, Bo	Original Oil in Place, OIIP
	[acre]	*[ft]*	*[fr]*	*[fr]*	*[fr]*	*[fr]*	*[rb/stb]*	*[MMbbl]*
P10	1535	76	1.0	0.50	0.36	0.07	1.077	112
P50	1299	73	1.0	0.45	0.34	0.10	1.077	91
P90	1100	70	1.0	0.35	0.33	0.13	1.077	75

The OIIP volumes assigned to reserve and resource polygons are presented in Tables 2.1 and 2.1A.

Elke

The Elke oil accumulation is penetrated by a single well (well 28/3-1B) in the eastern portion of the field and consists of three structural culminations separated by gentle saddles. Three volumetric scenarios (Low, Best and High) were modelled by Sproule to account for the uncertainty in depth mapping and reservoir continuity as shown in Figure 5.

The reservoir quality in the Tay sandstone encountered in the 28/3-1B well is excellent. The reservoir lies at around 3,400 feet TVDSS, and the sands are consequently poorly consolidated. Poro-perm characteristics are excellent with an average porosity of 36 percent, permeabilities of three darcies and an associated water saturation of 12 percent.

A clear oil-water contact of 3,458 feet TVDSS can be observed in logs at the 28/3-1B well, as shown in Figure 6.

Sproule audited the Company's geological, geophysical and petrophysical interpretations based on the data in the Petrel database, well files and various reports. Average reservoir parameters for the 28/3-1B well from the Sproule independent petrophysical interpretation are presented below:

Well	Gross Thickness, ft	Net-to - Gross Ratio	Net Pay Thickness, ft	Porosity, fraction	Water Saturation, fraction
28/3-1B	102	0.99	100	0.36	0.12

The table below represents the OIIP volumes estimated for the Tay reservoir within the Elke Main Field.

Probabilistic Discovered OIIP							
Case	Area	Gross Thickness, H	Net-to - Gross Ratio	Porosity,	Water Saturation	Oil Formation Volume Factor, Bo	Original Oil in Place, OIIP
	[acre]	*[ft]*	*[fr]*	*[fr]*	*[fr]*	*[rb/stb]*	*[MMbbl]*
High	1592	61	0.99	0.36	0.12	1.011	232
Best	1061	51	0.99	0.36	0.12	1.011	130
Low	510	51	0.99	0.36	0.12	1.011	62

The best case OIIP estimate was used to assign 1C and 2C resources. The high case OIIP estimate was used to assign 3C resources. The OIIP volumes assigned to resource polygons are presented in Table 2.1A. The resource polygons for the Elke Field are presented in the Figure 9.

As successful exploitation or appraisal wells are drilled at locations stepping out from the existing discovery well, the area attributable to each of the Low, Best and High volumes is anticipated to change based on the results of each individual well which would have a corresponding impact on the OIIP volumes that could be attributed to each of the uncertainty levels.

Narwhal

The Narwhal accumulation is a four-way closure penetrated by 28/2-1 well as shown in Figure 7. Sproule audited the probabilistic volumetrics provided by the Company and concluded they were reasonable.

The reservoir quality of the Tay sandstone encountered in the 28/2-1 well is excellent. The reservoir sands are poorly consolidated. Poro-perm characteristics are excellent with an average porosity of 34 percent, expected permeabilities of several darcies and associated water saturation of 20 percent. A clear oil-water contact of 3,022 feet TVDSS can be observed in logs at the 28/2-1 well, as shown in Figure 6.

Sproule audited the Company's geological, geophysical and petrophysical interpretations based on the data in the Petrel database, well files and various reports. Average reservoir parameters for the 28/2-1 well from the Sproule independent petrophysical interpretation for the sand of the Tay reservoir are presented below:

Well	Gross Thickness, ft	Net-to -Gross Ratio	Net Pay Thickness, ft	Porosity, fraction	Water Saturation, fraction
28/2-1	81	0.99	81	0.34	0.20

Company-Provided Probabilistic Discovered OIIP						
Case	Area	Net Pay	Porosity	Water Saturation	Oil Formation Volume Factor, Bo	Original Oil in Place, OIIP
	[acre]	*[ft]*	*[fr]*	*[fr]*	*[rb/stb]*	*[MMbbl]*
P10	310	49	0.36	0.07	1.07	32
P50	270	45	0.34	0.14	1.05	26
P90	235	41	0.32	0.25	1.02	21

Reserves and Resources

The oil and natural gas reserves, contingent and prospective resources were estimated based on the technically recoverable resources, operating and capital costs and the terms of the fiscal regime. Forecasts of net revenue were prepared by predicting the annual production from the reserves/contingent resources and product prices.

No gas reserves/contingent resources have been assigned, as gas is currently proposed to only be used for fuel and flare and no expense has been included in the cash flows for the use of the solution gas as fuel gas.

The reserves, contingent resources and prospective resources associated with the Company's fields in the United Kingdom are presented in Tables R-1 through R-3.

Table R-1
Summary of Reserves

	Gross (Mbbls)			Net attributable (Mbbls)			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Oil & Liquids Reserves per asset							
Pilot Field Polymer Flood	58,436	78,819	110,531	58,436	78,819	110,531	Orcadian Energy (CNS) Ltd.[1]
Total for Oil & Liquids	58,436	78,819	110,531	58,436	78,819	110,531	

[1]Orcadian Energy (CNS) Ltd. is the new name for Pharis Energy Ltd., the original title holder.

Source: Sproule B.V.

Note:

All figures in barrels (Mbbls) or standard cubic feet (Mcf)

"Operator" is the name of the company that operates the asset.

"Gross" are 100% of the reserves and/or resources attributable to the license whilst "Net attributable" are those attributable to the Company.

Table R-2
Summary of Contingent Resources

	Gross, Mbbl			Net attributable, Mbbl			Maturity Sub-Class	Risk Factor, %	Operator
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate			
Oil & Liquids Contingent Resources per asset									
Blakeney Polymer Flood	-	25,113	41,497	-	25,113	41,497	Development On Hold	72	No Operator
Elke and Narwhal Polymer Flood	28,621	52,740	142,355	28,621	52,740	142,355	Development On Hold	79	No Operator
Total for Oil and Liquids	28,621	77,853	183,852	28,621	77,853	183,852			

Source: Sproule B.V.

Note:

All Contingent Resources above are only those which had economics run.

* Blakeney Polymer Flood Low Estimate volumes are uneconomic.

* Pilot Field Periphery Polymer Flood volumes are development unclarified and no economics have been considered; as such, they are not presented in this table.

All figures in barrels (Mbbls) or standard cubic feet (Mcf)

Risk Factor" for Contingent Resources means the estimated chance, or probability, that the volumes will be commercially extracted

"Operator" is name of the company that operates the asset

"Gross" are 100% of the reserves and/or resources attributable to the licence whilst "Net attributable" are those attributable to the AIM company

Table R-3 Summary of Prospective Resources								
	Gross, Mbbl			Net attributable, Mbbl			Risk Factor, %	Operator
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate		
Oil & Liquids Prospective Resources per asset								
North Channel	2,890	10,850	28,000	2,890	10,850	28,000	50	Orcadian Energy (CNS) Ltd.(1)
Central Channel	1,700	5,950	14,500	1,700	5,950	14,500	50	Orcadian Energy (CNS) Ltd.(1)
South Channel	850	3,850	11,000	850	3,850	11,000	20	Orcadian Energy (CNS) Ltd.(1)
Far South Channel	2,550	8,400	20,000	2,550	8,400	20,000	40	Orcadian Energy (CNS) Ltd.(1)
Elke Field Updip West	5,500	17,500	39,000	5,500	17,500	39,000	87	No Operator
Elke Field North	2,500	10,500	30,000	2,500	10,500	30,000	66	No Operator
Elke Field Area 2 and Area 3	8,667	25,550	53,350	8,667	25,550	53,350	64	No Operator
Elke Field Main Channel	1,667	7,000	19,500	1,667	7,000	19,500	64	No Operator
Bowhead	12,000	43,050	105,000	12,000	43,050	105,000	49	No Operator
Tiberius	5,750	28,350	110,400	5,750	28,350	110,400	19	No Operator
Bottlenose	6,250	30,400	83,400	6,250	30,400	83,400	18	No Operator
Total for Oil and Liquids	50,323	191,400	514,150	50,323	191,400	514,150		

Source: Sproule B.V.

(1)Orcadian Energy (CNS) Ltd. is the new name for Pharis Energy Ltd., the original title holder.

Note: Totals may not add due to rounding

Risk Factor" for Prospective Resources, means the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. This, then, is the chance or probability of the Prospective Resource maturing into a Contingent Resource

"Operator" is name of the company that operates the asset

"Gross" are 100% of the reserves and/or resources attributable to the licence whilst "Net attributable" are those attributable to the AIM company

Prospective Resources are Technically Recoverable Resources, prior to economic truncation.

Reserves and Contingent Resources

Technically Recoverable Resources

As defined in PRMS 1.1.08, Technically Recoverable Resources are those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations. Technically Recoverable Resources 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.

Pilot Main and Pilot South Fields

The technically recoverable oil resources are summarized in Tables 2 and 2A and are based on capital budgets and a development program as presented by the Company.

The Company plans to develop the Pilot Main and Pilot South fields using polymer flood technology. The selection of this technology has largely been driven by the success of polymer flooding in the Captain Field located approximately 180 kilometers north-west of the Pilot fields.

The Company plans to install two lightweight wellhead platforms each with 20 well slots to drill horizontal wells at 100-metre spacing in the North part of the field where oil viscosities have been determined to be higher and at 150 meter well spacing in the South part of the Main Field and in Pilot South.

Process equipment, water desalination and polymer storage facilities will be installed on a custom equipped Floating Production, Storage and Offloading (FPSO) vessel. Drilling services will be provided by a leased jack-up rig located over the wellhead platforms during the drilling campaign. The produced fluids will be pipelined directly to the FPSO moored nearby for separation, water treatment, storage and export.

As part of the front end engineering and design process, the Company intends to perform sample separation testing to finalize the design of the water and oil separation system, but is of the belief that wash tank technology for dewatering and desalting offers the greatest flexibility with regards to processing of the heavier crude to sales specification. The technology is in use on offshore locations in Angola, Nigeria and the Congo with success. Should this testing demonstrate alternate technologies might be employed, these will be considered as the design process proceeds. Sproule believes that various separation technologies are available and proven and will require final process confirmation prior to proceeding with any conversion work on the vessel selected as the FPSO, but should not create any significant delays in the project implementation.

The Company has also decided to proceed with a liquid emulsion based polymer which is blended into the injection water in a static mixer downstream of the flow control valve used to adjust injection rates into each well. This is to capitalize on the experience of the polymer supplier for the Captain Field in achieving the target polymer viscosities in an offshore operational environment. The Company has also identified that polymer costs can be substantially reduced if the salinity of the injection water is reduced. Pressurized membrane filtration and reverse osmosis units will be installed to reduce the salinity of sea water prior to mixing with polymer and injecting to the formation.

The Company also has selected to study further the deployment of viscous oil downhole pumping technology that is in use in a number of fields in North and South America. The use of these pumps in Pilot will require the construction of downhole units larger than any in use at present, but the technology is proven in similar conditions and the supplier is committed to make the required modifications to their existing design.

Sproule has assigned reserves to the Pilot Main and Pilot South fields based on analog fields under polymer flood in Western Canada as well as the results of the polymer flood pilot and published information on the Captain Field in the UK North Sea.

Reserves Area

Oil

The technically recoverable oil resources forecast to be produced from the Reserves Area were estimated volumetrically using a detailed geological model, reservoir petrophysical parameters and recovery factors as presented in Table 2.1. A single OIIP estimate was used for all reserves categories due to the high certainty related to reservoir homogeneity and sufficient well control.

Sproule reviewed the Company-provided reservoir simulation sector models for the polymer flood scenario. The Company's sector models estimated recovery factors ranging from 38 percent to 54 percent with an average of 45 percent. Sproule has reviewed the simulation model results and considers them to be reasonable although the higher recovery factors appear to be optimistic. Sproule notes that potential upsides that have not been considered in the assessment of the recovery factor include:

1) product enhancements that the polymer supplier has undertaken to reduce the concentration of polymer required to achieve the target viscosity;
2) polymer viscosities used in the model are similar to those established by lab testing at water salinities considerably higher than those being considered by the Company. Reduction of the salinity will increase the polymer viscosity offering opportunities to further reduce polymer volumes required and to improve the effectiveness of the polymer injected.

Recovery factors were estimated based on the analog data and the simulation model results. The range of assigned recovery factors is presented in Table 2.1.

All assigned technically recoverable resources are undeveloped. Proved plus probable and proved plus probable plus possible technically recoverable oil resources have been assigned based on probable and possible upside.

Solution Gas

No technically recoverable solution gas resources were estimated as all gas is consumed in operations and no expense has been included in the cash flow for the use of solution gas.

Blakeney Field

The technically recoverable oil resources are summarized in Table 2A and are based on capital budgets and a development program as presented by the Company.

The development scenario of the field is based on that of Pilot. The Company plans to develop the Blakeney Field with 13 horizontal producers and 10 horizontal injectors under a polymer flood scenario with first production in 2034. The wells will be drilled from a jack-up and the jack-up will depart once the drilling program is completed. The Blakeney facilities will tie-in to the Pilot FPSO and make use of the existing gas import facilities.

1C contingent resources for the Blakeney Field are uneconomic.

Contingent Resources Area

Oil

The technically recoverable oil resources forecast to be produced from the Contingent Resources Area under polymer flooding development scenario were estimated volumetrically using a detailed geological model, reservoir petrophysical parameters and recovery factors as presented in Table 2.1A.

Recovery factors were estimated using analog data with the assigned recovery factors from the Pilot Field used for guidance. Recovery factors differ from Pilot due to reservoir petrophysical parameters, a range of oil viscosities and development well spacing. The range of assigned recovery factors is presented in Table 2.1A.

Solution Gas

No technically recoverable solution gas resources were estimated as all gas is consumed in operations and no expense has been included in the cash flow for the use of solution gas.

Elke Field

The technically recoverable oil resources are summarized in Table 2A and are based on capital budgets and a development program as presented by the Company.

The development scenario of the field is based on that of Pilot. The Company plans to develop the Elke Field with 13 horizontal producers and 11 horizontal injectors under a polymer flood scenario with first production in 2031. The wells will be drilled from a jack-up and the jack-up will depart once the drilling program is completed. The Elke facilities will tie-in to the Pilot FPSO and make use of the existing gas import facilities. The facilities will essentially duplicate the facilities proposed for the Pilot Field. The Elke Field will share facilities with the Narwhal Field. The Elke-Narwhal facilities would tie-in to the Pilot Field FPSO and make use of the existing gas import facilities.

Contingent Resources Area

Oil

The technically recoverable oil resources forecast to be produced from the Contingent Resources Area under the polymer flood development scenario were estimated volumetrically using a detailed geological model, reservoir petrophysical parameters and recovery factors as presented in Table 2.1A.

The resource area polygon for 1C and 2C contingent resource categories was set based on limited well control. A larger resource polygon area was considered for the 3C category. Consequently, the number of undeveloped locations differs between 3C and the 1C and 2C resource categories. The 1C and 2C resource categories consider 9 producers and 7 injectors, while the 3C resource category considers 13 producers and 11 injectors for development. The resource polygons for the Elke Field are presented in Figure 9.

Recovery factors were estimated using analog data with the assigned recovery factors from the Pilot Field used for guidance. Recovery factors differ from Pilot due to differing reservoir petrophysical parameters, a range of oil viscosities and development well spacing. The range of assigned recovery factors is presented in Table 2.1A.

Solution Gas

No technically recoverable solution gas resources were estimated as all gas is consumed in operations and no expense has been included in the cash flow for the use of solution gas.

Narwhal Field

The technically recoverable oil resources are summarized in Table 2A and are based on capital budgets and a development program as presented by the Company.

The development scenario of the field is based on that of Pilot. The Company plans to develop the Narwhal Field with 4 horizontal producers and 3 horizontal injectors under a polymer flood scenario with first production in 2033. The wells will be drilled from a jack-up and the jack-up will depart once the drilling program is completed. The facilities will essentially duplicate the facilities proposed for the Pilot Field. The Narwhal Field will share facilities with the Elke Field. The Elke-Narwhal facilities would tie-in to the Pilot Field FPSO and make use of the existing gas import facilities.

Contingent Resources Area

Oil

The technically recoverable oil resources forecast to be produced from the Contingent Resources Area under the polymer flood development scenario were estimated volumetrically using a detailed geological model, reservoir petrophysical parameters and recovery factors as presented in Table 2.1A.

Recovery factors were estimated using analog data with the assigned recovery factors from the Pilot Field used for guidance. Recovery factors differ from Pilot due to reservoir petrophysical parameters, a range of oil viscosities, bottom water, and development well spacing. In general, the higher the viscosity, the lower the recovery factor. The range of assigned recovery factors is presented in Table 2.1A.

Solution Gas

No technically recoverable solution gas resources were estimated as all gas is consumed in operations and no expense has been included in the cash flow for the use of solution gas.

Pilot Periphery Area

The technically recoverable oil resources are summarized in Table 2A and are based on conceptual expansion and development of the periphery of the Pilot Main and Pilot South fields.

No specific development scenario has been presented, however, the Company would consider field expansion, under polymer flood, into the Peripheral area, dependent on the results in Pilot Main and South.

Contingent Resources Area

Oil

The technically recoverable oil resources forecast to be produced from the Contingent Resources Area under the polymer flood development scenario were estimated volumetrically using a detailed geological model, reservoir petrophysical parameters and recovery factors as presented in Table 2.1A.

Recovery factors were estimated using analog data with the assigned recovery factors from the Pilot Field used for guidance. Recovery factors differ from Pilot due to reservoir petrophysical parameters, a range of oil viscosities, bottom water, and development well spacing. The range of assigned recovery factors is presented in Table 2.1A.

Solution Gas

No technically recoverable solution gas resources were estimated as all gas is consumed in operations.

Production Forecasts

Pilot Field

Reserves Area

Oil

Oil production was forecast to decline from an initial rate presented in Table 2.2. Additional details regarding the oil production forecast, including the forecast start date, is also presented.

Sproule considered the Company-provided forecasts and simulation model results as provided by the Company to create the production forecasts for the wells. Type wells were created for the proved, proved plus probable, and proved plus probable plus possible reserves categories based on the simulation model results. The development timing for each well is based on the development plan provided by the Company.

Proved plus probable oil production was forecast from a higher rate and at a lower decline rate than the proved production forecast. The same considerations were made for the proved plus probable plus possible oil production forecast. The probable production forecast was created by subtracting the proved production forecast from the proved plus probable production forecast and the possible production forecast was created by subtracting the proved plus probable production forecast from the proved plus probable plus possible production forecast. Production forecasts for the Pilot Field are presented in Figures 10 and 11.

Blakeney Field

Contingent Resources Area

Oil

Oil production was forecast to decline from an initial rate presented in Table 2.2A. Additional details regarding the oil production forecast, including the forecast start date, is also presented.

The production forecast for the polymer flood was created using the Pilot type wells as analogs. The start of production for each well is based on the development plan provided by the Company and the polymer injection capacity of the facilities.

The best case oil production was forecast from a higher rate than the low case production forecast and at a lower decline rate. The same considerations were made for the high case oil production forecast. Production forecasts are presented in Figures 12 and 13.

Elke and Narwhal Fields

Contingent Resources Area

Oil

Oil production was forecast to decline from an initial rate presented in Table 2.2A. Additional details regarding the oil production forecast, including the date of the forecast, is also presented. Although individual details are provided for Elke and Narwhal in Table 2.2A, all economic calculations group them together.

The production forecast for the polymer flood was created using the Pilot type wells as analogs. The start of production for each well is based on the development plan provided by the Company and the polymer injection capacity of the facilities.

The best case oil production was forecast from a higher rate than the low case production forecast and at a lower decline rate. The same considerations were made for the high case oil production forecast. The high case also includes four additional Elke wells in the development plan. Production forecasts are presented in Figures 14 and 15.

Economics

Data provided by the Company was used to estimate the economic parameters for the evaluation. Summaries of the economic parameters, reserves, net present values and forecasts are presented in Tables 3 through 6.

The fiscal terms are presented in the Overview of Region, Location and Assets section of the Report.

Pricing

Oil

Sproule's price forecast for Brent crude oil, as of March 31, 2021, as shown in Table S-3 and Appendix B, was used in the evaluation. Publicly available information suggests the produced crude is of comparable quality to other crudes produced in the region that are being sold into fuel oil markets at prices equal to or better than the Brent market price. As a result, Sproule has not applied any discounts or premiums to the Brent marker price in this evaluation.

At the request of the Company, Sproule has also run price sensitivity cases starting at each of $50, $60 and $70 for Brent crude, with escalation applied at Sproule's forecast rate for the life of reserves. Tables showing the results of these price sensitivities are shown in Table 7 for reserves and Table 7A for contingent resources.

Operating Costs (2021 UK pounds)

The operating costs used in the evaluation were based on the proposed development plan provided by the Company, reviewed by Sproule, and are presented in Table 3 (Reserves) and Table 3A (Contingent Resources).

Capital Costs (2021 UK pounds)

The capital costs used in the evaluation were based on the conceptual development plan provided by the Company, reviewed by Sproule and are presented in Table 3 (Reserves) and Table 3A (Contingent Resources).

Abandonment, Decommissioning and Reclamation Costs (2021 UK pounds)

The abandonment, decommissioning and reclamation ("ADR") costs associated with the Company's petroleum exploration, development, production and processing operations in the evaluated area contained in this report are as outlined in the Introduction section of this report and were provided by the Company in their conceptual development plan.

The abandonment, decommissioning and reclamation costs used in the evaluation are presented in Table 3 (Reserves) and Table 3A (Resources).

Net Present Values

The estimates of the P&NG reserves and contingent resources project maturity sub-class development on hold and their respective net present values, summarized by property and by category, before income taxes, are presented in Tables 4 and 4A. The risked estimates of contingent resources and net present values, summarized by property and by category, before income taxes, are presented in Table 4B. Detailed forecasts of production and net revenue for the various reserves and contingent resources categories for the Company, before and after income tax, are presented in Tables 5 and 6. There have not been any tax pools, hedges or Company items included in this report at either the company or property level.

Income Taxes

At the request of the Company, an after tax evaluation was prepared based on the United Kingdom Ring Fence Corporate tax rate of 30 percent on profits and the Supplementary Charge rate of 10 percent. No tax pools have been included in this evaluation.

Sproule recognizes the Company has options available to them regarding the treatment of polymer purchase costs as a Capital expenditure or an Operating expenditure with resulting effect on the after tax evaluation results. Sproule has treated the polymer throughout as an Operating expenditure and has not evaluated the effect of this difference in cost treatment.

Economic Status

Sproule evaluated the Company's development plan for the contingent resources in the Blakeney, Elke and Narwhal fields. A summary of the economic status of the contingent resources by field is included in Table R-4.

Table R-4 Economic Status (Contingent Resources)	
Field	**Economic Status**
Pilot Periphery Polymer flood	Undetermined
Blakeney Polymer flood	Economically Marginal
Elke Polymer flood	Economic
Narwhal Polymer flood	Economic

No development plan has been provided for Pilot Periphery Area Polymer flood Development. Consequently, Sproule did not evaluate the Company's development plan for the contingent resources for this area.

Sproule evaluated the Company's development plan for the contingent resources of the Blakeney Field and found these contingent resources to be economically marginal based on the best estimate forecast, but uneconomic for the low case (1C).

Sproule evaluated the Company's development plan for the contingent resources of the Elke and Narwhal fields and found these contingent resources to be economically viable based on the best estimate forecast.

Although the contingent resources were found to be economically viable in aggregate for Blakeney, Elke and Narwhal fields, there may be individual locations within each project which are uneconomic.

Contingencies

Pilot Periphery

Three contingencies are identified for the Pilot Field Periphery polymer flood development scenario: Corporate Commitment, Economic Factors and Timing of Production and Development.

Corporate Commitment

There has been no final investment decision and endorsement from the Company to move forward with commercial development of this asset. It is likely that a final investment decision to approve this project will not occur for several years. Development of the Pilot Periphery area is contingent on the successful development of the Pilot Field. Additionally, a detailed development plan has not been created and further work needs to be completed to confirm how the resources will be developed. It is anticipated that as the development plan is refined the Company would be able to make a final investment decision, at which point this contingency would be removed.

Economic Factors

Economic viability is to be determined and dependent on the development and success of the Pilot Main ad South areas. The reservoir for the Pilot Periphery is thinner, with less OOIP and may not justify capital expenditure for drilling into this area of the field.

Timing of Production and Development

The Pilot peripheral areas are less defined than the Pilot Main and Pilot South areas proposed for development and their development is dependent on a number of factors, including the results of the polymer flooding on the first wells to be developed in those areas. As a result the timing of the production and development is uncertain. This contingency could be removed as more information becomes available.

Criteria considered in PRMS Section 2.1.2 but not identified as contingencies to the Pilot Periphery area development at this time include Evaluation Drilling, Regulatory Approval, Technology Under Development, Legal Factors, Market Access, Political Factors and Social License.

Blakeney

Two contingencies are identified for the Blakeney Field polymer flood development scenario: Corporate Commitment and Economic Factors.

Corporate Commitment

There has been no final investment decision and endorsement from the Company to move forward with commercial development of this asset. It is likely that a final investment decision to approve this project will not occur for several years. Development of the Blakeney Field is contingent on the successful development of the Pilot Field. Additionally, a detailed development plan has not been created and further work needs to be completed to confirm how the resources will be developed. It is anticipated that as the development plan is refined the Company would be able to make a final investment decision, at which point this contingency would be removed.

Economic Factors

Economic viability is to be determined and dependent on the development and success of Pilot. The Blakeney low case is uneconomic and the decision to proceed is based on positive results and favorable economics from the Pilot Field.

Criteria considered in PRMS Section 2.1.2 but not identified as contingencies to the Blakeney area development at this time include Evaluation Drilling, Regulatory Approval, Technology Under Development, Legal Factors, Market Access, Political Factors, Social License, and Timing of Production and Development.

Elke

Two contingencies are identified for the Elke Field polymer flood development scenario: Corporate Commitment and Economic Factors.

Corporate Commitment

There has been no final investment decision and endorsement from the Company to move forward with commercial development of this asset. It is likely that a final investment decision to approve this project will not occur for several years. Development of the Elke Field is contingent on the successful development of the Pilot Field. Additionally, a detailed development plan has not been created and further work needs to be completed to confirm how the resources will be developed. It is anticipated that as the development plan is refined the Company would be able to make a final investment decision, at which point this contingency would be removed.

Economic Factors

Economic viability is to be determined and dependent on the development and success of Pilot. The decision to proceed is based on positive results and favorable economics from the Pilot Field.

Criteria considered in PRMS Section 2.1.2 but not identified as contingencies to the Elke area development at this time include Evaluation Drilling, Regulatory Approval, Technology Under Development, Legal Factors, Market Access, Political Factors, Social License, and Timing of Production and Development.

Narwhal

Two contingencies are identified for the Narwhal Field polymer flood development scenario: Corporate Commitment and Economic Factors.

Corporate Commitment

There has been no final investment decision and endorsement from the Company to move forward with commercial development of this asset. It is likely that a final investment decision to approve this project will not occur for several years. Development of the Narwhal Field is contingent on the successful development of the Pilot and Elke fields. Additionally, a detailed development plan has not been created and further work needs to be completed to confirm how the resources will be developed. It is anticipated that as the development plan is refined the Company would be able to make a final investment decision, at which point this contingency would be removed.

Economic Factors

Economic viability is to be determined and dependent on the development and success of Pilot. The decision to proceed is based on positive results and favorable economics from the Pilot Field.

Criteria considered in PRMS Section 2.1.2 but not identified as contingencies to the Narwhal area development at this time include Evaluation Drilling, Regulatory Approval, Technology Under Development, Legal Factors, Market Access, Political Factors, Social License, and Timing of Production and Development.

Project Maturity Sub-Class

The project maturity sub-class for the Contingent resource volumes are classified by field as outlined in Table R-5.

Table R-5
Project Maturity Sub-class (Contingent Resources)

Field	Project Maturity Sub-class
Pilot Periphery Polymer flood	Development Unclarified
Blakeney Polymer flood	Development On Hold
Elke Polymer flood	Development On Hold
Narwhal Polymer flood	Development On Hold

Chance of Development

In recognition of the risk of development of the Contingent resource volumes, a chance of development factor has been applied to the total recoverable resources and net present values of the Contingent resources as outlined in Table R-6.

Table R-6
Chance of Development (Contingent Resources)

Field	Chance of Development (percent)
Pilot Periphery Polymer flood	39
Blakeney Polymer flood	72
Elke Polymer flood	79
Narwhal Polymer flood	79

Risk factors for each field were assigned taking into consideration maturity sub-class of the project and relevant contingencies identified earlier in the Report.

Positive and Negative Factors

Key positive factors relevant to the development in the Contingent Resource areas include:

- The fields are in reasonable proximity to the proposed Pilot development, reducing the initial facility capital cost outlay associated with the development of these fields;
- The fields are in the general vicinity of other commercial oilfield developments in the UK sector of the North Sea and thus should not be subject to conditions significantly different than previous developments;
- A successful Pilot field development will reduce the technical and economic uncertainties associated with the development of the Contingent Resource areas.

Key negative factors relevant to development in the Contingent Resource areas include:

- Economic parameters, including capital costs and product prices, are subject to fluctuation and could affect the decision to proceed with the project;
- Results in the development of the Pilot Field could be worse than expected and could cause cancellation of the development of the Contingent Resource fields.

Prospective Resources

The technically recoverable oil/gas resources for prospective resources are summarized in Tables 2B and 2.1B.

Sproule estimates the chance of development for each of the prospective resources prospects is approximately 50 percent. The chance of commerciality of prospective resources is the product of the chance of geological discovery and the chance of development. The chance of geological discovery for each of the prospects is outlined in the following discussion for each area.

Elke Satellites (Tay) Prospects

The Eocene Tay Formation is the main target reservoir for the Western Platform development which includes the Elke (28/3-1B) and Narwhal (28/2-1) discoveries and satellite prospects.

Prospect Definition

Ultra-far stack seismic amplitude anomalies within the 28/3 Block provide a good basis for prospect identification (Figure 16). The Company used this map to delineate the different sand bodies within the block and create the prospect inventory. Most of the defined prospect areas, in particular Elke Updip, Elke Area 2 and Elke Area 3, exhibit the same seismic character as the Elke discovery and can be considered as lower risk prospects.

Volumetrics

The prospects were grouped by the Company into two areas (western and eastern) for the volume estimation. The western area is based on the Elke and Narwhal wells, where high reservoir quality sands are found. To the east of the Elke and Narwhal fields, reservoir properties are anticipated to degrade slightly as the sands become more distal. The following tables present the Company's petrophysical and recovery input parameters for the two areas.

Western Area	Units	P90	P50	P10
Net-to-Gross Ratio	fraction	0.93	0.97	1.00
Porosity	fraction	0.33	0.34	0.36
Oil Saturation	fraction	0.75	0.86	0.93
Oil Formation Volume Factor	rb/stb	1.06	1.011	1.17
Gas-Oil Ratio	Scf/bbl	45	122	200
Applied to:	Elke Updip West, Elke Area 2 and 3, Elke North			

Eastern Area	Units	P90	P50	P10
Porosity	fraction	0.30	0.33	0.36
Oil Saturation	fraction	0.75	0.84	0.92
Oil Formation Volume Factor	rb/stb	1.03	1.07	1.12
Gas-Oil Ratio	Scf/bbl	33	184	320
Applied to:	Elke Main Channel			

Prospect	Input Parameters	Units	P90	P50	P10
Elke Updip West	Productive Area	ac	345.8	1.61	1.84
	Net Pay	ft	40	54	90
Elke Area 2	Gross Rock Volume	ac*ft	1260	17025	23510
Elke Area 3	Gross Rock Volume	ac*ft	12970	18320	25940
Elke Main Channel	Productive Area	acres	298.9	1.42	1.66
	Net Pay	ft	15	29	55
Elke North	Productive Area	acres	261.8	1.49	3.57
	Net Pay	ft	21	29	40

The Company's Undiscovered oil in-place resources by prospect are presented in the next table.

	Undiscovered OIIP MMbbls		
Prospect	**P90**	**P50**	**P10**
Elke Updip West	33	51	78
Elke North	15	30	60
Elke Area 2	25	35	50
Elke Area 3	27	38	57
Elke Main Channel	10	20	39

Sproule audited the Company's assessment methodology, input parameters and output results and found them to be reasonable.

Chance of Geological Discovery

The Company's risking of the Tay prospects is driven by the AVO response with geophysical modifiers, an adjustment factor based on the quality of seismic amplitude. This risk factor modifier ranges from 165 percent to 200 percent. The largest risks otherwise are Seal and Preservation. The risk methodology used by the Company was audited by Sproule and found to be reasonable.

The Company's risking parameters by prospect along with the resulting chance of geological discovery (Pg) are presented in the next table.

Risk Factor	Prospect				
	Elke Updip West	Elke North	Elke Area 2	Elke Area 3	Elke Main Channel
Source	100%	100%	100%	100%	100%
Migration and Timing	90%	90%	90%	90%	95%
Trap	90%	95%	70%	70%	70%
Reservoir Presence	90%	70%	90%	90%	90%
Reservoir Quality	90%	70%	80%	80%	80%
Seal and Preservation	60%	95%	70%	70%	70%
Geophysical Modifier*	200%	165%	200%	200%	190%
Pg	**87%**	**66%**	**64%**	**64%**	**64%**

*An adjustment factor based on the quality of seismic amplitude

Bottlenose and Tiberius Prospects

Tiberius is an Upper Jurassic Fulmar prospect in the Block 28/3a (Figure 17). Upper Jurassic reservoir preservation (or deposition) is not well-understood due to lack of well data as no wells have been drilled down to Jurassic, which is expected to be a critical risk factor. The Bottlenose prospect is a four-way dip closure located in the eastern part of Block 28/3a. (Figure 17). The prospective interval is anticipated to be within the Paleocene-aged Lista Formation.

The following tables present the Company's petrophysical and recovery input parameters for the two prospect areas.

Tiberius	Distribution	Units	P90	P50	P10
Gross Rock Volume	Lognormal	ac*ft	20268	57317	162142
Net-to-Gross Ratio	Lognormal	fraction	0.67	0.77	0.89
Porosity	Lognormal	fraction	0.22	0.26	0.30
Oil Saturation	Lognormal	fraction	0.82	0.86	0.89
Oil Formation Volume Factor	Normal	rb/stb	1.08	1.14	1.2
Bottlenose	**Distribution**	**Units**	**P90**	**P50**	**P10**
Gross Rock Volume	Lognormal	ac*ft	24321	72964	213865
Net-to-Gross Ratio	Lognormal	fraction	0.44	0.65	0.88
Porosity	Lognormal	fraction	0.25	0.30	0.34
Oil Saturation	Lognormal	fraction	0.75	0.82	0.89
Oil Formation Volume Factor	Normal	rb/stb	1.08	1.14	1.2

Sproule audited the Company's assessment methodology, input parameters and output results and found them reasonable. The following table shows the Company's undiscovered oil in-place estimates for the Tiberius and Bottlenose prospects.

	OIIP [MMbbls]		
Prospect	**P90**	**P50**	**P10**
Tiberius	23	63	184
Bottlenose	25	76	239

Chance of Geological Discovery

Due to the poor offset data, a chance of geological discovery (Pg) has been assigned by the Company for these two prospects (19 percent for Tiberius and 18 percent for Bottlenose). The methodology used by the Company was audited by Sproule and found to be reasonable. The principal risks for these two prospects are reservoir and migration.

The risking parameters by prospect used by the Company are presented below.

Risk Factor	**Prospect**	
	Tiberius	**Bottlenose**
Source	100%	100%
Migration and Timing	50%	50%
Trap	100%	90%
Reservoir Presence	60%	55%
Reservoir Quality	80%	90%
Seal and Preservation	80%	80%
Pg	**19%**	**18%**

Pilot Area

The Pilot area prospects consist of four feeder channels connecting from the west into the Pilot discovery. These four mapped channel-form bodies appear to be contiguous with the reservoir sands of the Pilot discovery (Figure 18). These are best highlighted using spectral decomposition (Figure 19). A brightening on the far offset stack is observed within the North, Central and Far South channels, which is an oil indicator in the adjacent Pilot discovery. This brightening is absent in the South channel (Figure 20). Given that the South channel separates Pilot Main and Pilot South with different oil-water contacts in each, the Company believes that the South channel is likely to contain a significant portion of non-reservoir lithologies.

The Company's input parameters used for volumetrics along with the resulting of undiscovered oil in-place estimates are summarized in the table below.

Probabilistic Undiscovered OIIP [MMbbls]								
Prospect	**Case**	**Area**	**Gross Thickness**	**Net-to-Gross Ratio**	**Porosity**	**Water Saturation**	**Oil Formation Volume Factor**	**OIIP**
		(acre)	*(ft)*	*(fraction)*	*(fraction)*	*(fraction)*	*(rb/stb)*	*(MMstb)*
North Channel	P10	598.0	75	0.93	0.35	0.11	1.10	56
	P50	365.7	61	0.80	0.32	0.15	1.09	31
	P90	222.4	50	0.65	0.28	0.20	1.07	17
Central Channel	P10	464.5	50	0.93	0.35	0.11	1.10	29
	P50	331.1	39	0.80	0.32	0.15	1.09	17
	P90	234.7	30	0.65	0.28	0.20	1.07	10
South Channel	P10	733.9	45	0.45	0.35	0.11	1.10	22
	P50	444.8	34	0.34	0.32	0.15	1.09	11
	P90	269.3	25	0.25	0.28	0.20	1.07	5
Far South Channel	P10	415.1	75	0.93	0.35	0.11	1.10	40
	P50	294.0	61	0.80	0.32	0.15	1.09	24
	P90	207.6	50	0.65	0.28	0.20	1.07	15

Sproule audited the Company's assessment methodology, input parameters and output results and found them reasonable.

Chance of Geological Discovery

The prospects, except for the South channel, are assigned a relatively low risk as shown in the table below. This is primarily due to the seismic amplitude response. The South channel is interpreted to be filled with predominantly non-reservoir lithologies, and any sands present may be isolated from oil charge. The primary risk factors are reservoir quality for all prospects and migration and timing, particularly for the South channel prospect. The methodology used by the Company to estimate the chance of geological discovery was audited by Sproule and found to be reasonable.

Risk Factor	**Prospect**			
	North	**Central**	**South**	**Far South**
Source	100%	100%	100%	100%
Migration and Timing	100%	100%	65%	100%
Trap	100%	100%	100%	100%
Reservoir Presence	100%	100%	100%	100%
Reservoir Quality	50%	50%	30%	40%
Seal and Preservation	100%	100%	100%	100%
Pg	**50%**	**50%**	**20%**	**40%**

Bowhead Prospect

The Bowhead prospect is a Tay Sandstone stratigraphic trap with a Class II AVO anomaly. It sits immediately along-strike from Pilot and is separated from it by a salt swell.

As in the Pilot discovery, the turbiditic Tay Sandstone pinches out towards the west. A structural closure is produced by an embayment feature, and the AVO anomaly is used to define the extent of the prospect, with structural conformance to the AVO response seen (Figure 21).

The following table presents the Company's reservoir and fluid properties input parameters for Bowhead prospect.

Parameter	**Distribution**	**Units**	**P90**	**P50**	**P10**
Gross Volume Rock	Lognormal	ac*ft	48,050	79,851	132,700
Net-to-Gross Ratio	Lognormal	fraction	0.65	0.78	0.94
Porosity	Lognormal	fraction	0.28	0.31	0.34
Oil Saturation	Lognormal	fraction	0.81	0.86	0.89
Oil Formation Volume Factor	Normal	rb/stb	1.03	1.05	1.065

Sproule audited the Company's assessment methodology, input parameters and output results and found them reasonable. The following table shows the corresponding Company's undiscovered oil in-place estimates.

	OIIP [MMbbls]		
Prospect	**P90**	**P50**	**P10**
Bowhead	72	123	213

Chance of Geological Discovery

The Company's risking parameters by prospect along with the resulting chance of geological discovery (Pg) are presented in the next table.

Risk Factor	**Bowhead**
Source	100%
Migration and Timing	100%
Trap	100%
Reservoir Presence	90%
Reservoir Quality	78%
Seal and Preservation	70%
Pg	**49%**

Upside Potential

Sproule did not assess minor discoveries Harbour, Feugh, Dandy and Crinan, but consider them as upside potential. The table below presents a range of oil volumes for the mentioned properties as presented by the Company.

Property	Block	Formation	OIIP, MMbbl			Recovery Factor, %	Technically Recoverable Oil Volume, MMbbl
			Low	Best	High	Best	Best
Harbour	21/27b	Tay	7.3	9.0	11.8	20	1.8
Feugh	21/27b	Tay	23.0	30.0	38.0	20	6.0
Dandy North and Dandy South	21/28a	Tay	4.0	12.2	30.5	15	1.8
Crinan	21/28a	Tay	4.7	14.9	42.5	15	2.2
Fynn (Andrew)	14/20g	Andrew	42.2	49.5	57.6	20	9.9
Fynn (Beauly)	14/20g & 15/16g	Beauly	76.9	137.4	202.2	35	48.1

Note:
Volumes above represent Gross Technically Recoverable Volumes, as presented by the Company.

Other Assets

The Company does not own a material interest in any other exploration or production assets. The following section considers the physical surface related assets that are being considered for the development of the properties.

Sproule has conducted an in-depth review of the Company's Concept Select Study Report for the Pilot Field, specifically in relation to the planned well completions and the subsea and above sea level equipment and facilities.

The selected concept considers the use of a turret-moored Aframax size FPSO and two Normally Unmanned Installations (NUI) wellhead platforms accessible by helicopter and by "walk to work" from support ships. The FPSO will be connected to the NUI's by subsea cables and pipelines to supply them with electrical power, low salinity (Lo-Sal) and high salinity (Hi-Sal) processed and pressurized water ready for injection, as well as raw polymer to be mixed into the injection water onboard the NUI's. The FPSO will process the produced fluids using associated gas for heating and for power generation, with top-up fuel gas imported by pipeline. Crude will be transferred to shuttle tankers by tandem loading.

To manage the challenges presented by the high viscosity and low API gravity of Pilot crude in relation to artificial lift and crude dehydration, the Company has selected two technologies that are new to the North Sea, although established elsewhere: the V-pump for artificial lift and the conversion of a tank in the FPSO hull as a "wash tank" for crude dehydration.

The selection process, as presented in the referenced study report is based on thorough analysis and evaluation by the Company and its outside engineering contractors and suppliers. In Sproule's opinion the development concept is robust and fit for purpose. Sproule is also of the opinion that The V-pump and "wash tank" appear to be a good fit for this application.

The Company has worked closely with the UK Oil and Gas Authority (OGA) which the Company indicates *"explicitly agrees with the concept selection"*.

Capital, Operating and Abandonment Cost Estimates

The Concept Select Study Report includes detailed definition and analysis of the capital, operating and abandonment costs. Sproule reviewed these estimates as a "Class 4" level of cost estimating accuracy, as defined per Association for the Advancement of Cost Engineering International (AACEI) classification system and consistent with the Concept Select stage. AACEI Class 4 applies at 1% to 15% of complete project definition, with uncertainty of the cost estimate range Low -15 to -30% and High +20 to +50%.

The Company has elected to request that the evaluation is based upon a scenario in which they purchase a vessel and convert the vessel to an FPSO as a capital item. Another scenario, which has not been evaluated, is that the Company would seek to engage an FPSO company to undertake this work and then lease the FPSO to the Company as part of its overall project financing arrangements. Sproule is of the opinion the economic results provide an order of magnitude indication of the value of the project and are sufficiently robust to support progressing the project to the next stage. During the equipment procurement process, it is anticipated the Company would select either of the FPSO purchase or lease scenario that provides the best combination of risk reduction and economic results, which may be modestly better or worse than those provided herein. Overall, differences in the economic results that may be encountered due to final design decisions are not expected at this time to be materially significant.

For the evaluated scenario, the Company has provided detailed capital expenditure estimates for the FPSO, wells and pipeline/flowlines. The assumed rig rates of $85K/d for the drilling of the wells and assumed $40MM purchase cost of a 5 year-old Aframax tanker and associated FPSO conversion, appear to be consistent with the current market (March 2021). The Company has also provided a weight and cost summary for the NUI platforms. All of the above has allowed Sproule to perform checks for completeness, market rate assumptions and comparison to benchmarks.

In Sproule's opinion the Capex numbers are consistent with a Class 4 estimate in the current market.

The Company has provided details for all elements of the operating cost stream, which has allowed Sproule to perform comparison to benchmark and market costs resulting in a reconciliation of all the operating cost components. The Company has assumed the cost of imported fuel gas at 0.55 UK pound per therm and carbon emission fees at 30 UK pound per tonne, which appears reasonable.

Sproule considers the Opex assumptions for the Pilot development to be consistent with a Class 4 estimate in the current market. Sproule identified a minor math error in one of the operating cost components resulting in a minor increase in the Company's operating cost estimates, but within the accuracy of a Class 4 estimate.

Sproule has also reviewed the abandonment costs estimates and consider them consistent with a Class 4 estimate.

Schedule Review

The Concept Select Study Report indicates two parallel post-FDP critical paths, one running through the platform construction and installation followed by drilling and the other one running through the FPSO conversion and installation. If an FPSO suitable for re-deployment is found, then the post-sanction critical path will still run through the platform construction/installation and drilling.

The Company has indicated they are on schedule to receive final approval of the FDP and to make a final investment decision by the end of 2021.

In Sproule's opinion the schedule is reasonable in the current market.

The terms of the agreements for each of the licence areas require the Company to meet certain milestones to progress the licence towards the production periods. Should the stated milestones not be met, extensions and continuations to the milestones must be approved by the UK Oil and Gas Authority (OGA). Sproule is of the understanding that approvals of extensions and continuations by the OGA are granted as long as progress towards the production period is continuing in a reasonable fashion satisfactory to the OGA. Relatively minor delays in progress do occur for projects of this nature which may result in the Company not receiving final approval of the FDP and making a final investment decision by the end of 2021. In such case, the Company has advised that appropriate applications for extensions or continuations will be made and efforts will be taken to reach those milestones as soon as possible following that date. Such delays are expected to have minimal or no affect on reaching the final on production milestone.

Risk and Project Management

In Sproule's opinion the risks, opportunities and uncertainties for the project have been well recognized by the Company, as per the risk management section of the Pilot Field Concept Select Study Report.

The Company has defined a path forward to manage the remaining uncertainties related to the V-pump and the sizing/efficiency of the wash tanks for the Pilot crude. Sproule is of the opinion that these risks are low and that the mitigation plan is adequate.

The Company has not specifically addressed the risks related to its lack of experience as a corporate entity and the lack of technical and operational teams, potentially affecting project management, drilling and production operations. However, the Company has indicated their intended use of the very experienced support services teams involved in the conduct of the Concept Select Study as putative "well Operator" and "facilities Operator". Sproule is of the opinion that this proposed approach effectively mitigates any of these "experience" risks.

Conclusions

Reserves and resource estimates presented herein have been prepared according to the classifications and definitions of the 2018 PRMS. The estimates of the reserves, contingent resources, and prospective resources is included in Tables R-1 through R-3. The net present values of the reserves and contingent resources is included in Tables 5 and 6.

The development forecasts presented in this evaluation were based on capital budgets and development programs as presented by the Company under the scope of this evaluation and engagement. The development forecast presented in this report may not represent the full development potential of the lands evaluated.

Sproule

Qualifications and Basis of Opinions

Certification

Report Preparation

The report entitled “Competent Person’s Report of the P&NG of Orcadian Energy PLC (As of April 1, 2021)”” was prepared and is authenticated by the following Sproule personnel:

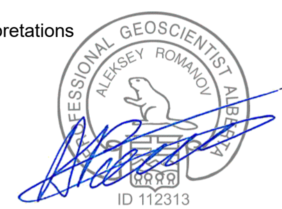
Project Leader
Preparation of:
Technical Volumes and Economics

Jul. 08, 2021
Barrett R. Hanson, P.Eng.
Senior Petroleum Engineer

Preparation of:
Technical Volumes and Economics

Jul. 08, 2021
Jeffrey McKeeman, P.Eng.
Petroleum Engineer

Preparation of:
Geological Interpretations



Jul. 08, 2021
Alexey Romanov, Ph.D., P. Geo.
Senior Geoscientist

Responsible Member Validation

This report has been reviewed and validated in accordance with the Professional Practice Management Plan of Sproule by the following Responsible Members of Sproule B.V.

Engineering

Gary R. Finnis, P.Eng.
Senior Manager, Engineering
DATE: Jul. 08, 2021 **RM APEGA ID #:** 62965

Geoscience

Alec Kovaltchouk, P.Geo.
VP, Geoscience
DATE: Jul. 08, 2021 **RM APEGA ID #:** 72150

Legal Authorization

Danilo Bandiziol Jul. 08, 2021

Certificate of Qualification

Barrett R. (Barry) Hanson, P.Eng., SPEC

I, Barrett R. Hanson, Senior Petroleum Engineer, of Sproule, 900, 140 Fourth Avenue SW, Calgary, Alberta, declare the following:

1. I hold the following degree:
   a. B.Sc., Chemical Engineering (1979), University of Saskatchewan, Saskatoon, Saskatchewan, Canada

2. I am a registered professional:
   a. Professional Engineer (P.Eng.), Province of Alberta, Canada
   b. Certified SPE Petroleum Engineer

3. I am a member of the following professional organizations:
   a. Association of Professional Engineers and Geoscientists of Alberta (APEGA)
   b. Society of Petroleum Engineers (SPE)

4. I am a qualified reserves evaluator and reserves auditor as defined in:
   a. the “Canadian Oil and Gas Evaluation Handbook” as promulgated by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and,
   b. the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” as promulgated by the Society of Petroleum Engineers and incorporated into the “Petroleum Resource Management System” (SPE-PRMS).

5. My contribution to the report entitled “Competent Person’s Report of the P&NG of Orcadian Energy PLC (As of April 1, 2021)” is based on my engineering knowledge and the data provided to me by the Company, from public sources, and from the non-confidential files of Sproule.

6. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of Orcadian Energy PLC.

Jul. 08, 2021

Barrett R. Hanson, P.Eng., SPEC

Certificate of Qualification

Jeffrey McKeeman, P.Eng.

I, Jeffrey McKeeman, Petroleum Engineer, of Sproule, 900, 140 Fourth Avenue SW, Calgary, Alberta, declare the following:

1. I hold the following degree:
   a. B.Sc., Mechanical Engineering (2012), University of Calgary, Calgary, Alberta, Canada

2. I am a registered professional:
   a. Professional Engineer (P.Eng.), Province of Alberta, Canada

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Jul. 08, 2021

Jeffrey McKeeman, P.Eng.

Sproule

Certificate of Qualification

Alexey Romanov, Ph.D., P.Geo.

I, Alexey Romanov, Senior Geoscientist of Sproule, 900, 140 Fourth Avenue SW, Calgary, Alberta, declare the following:

1. I hold the following degrees:
   a. Ph.D. Eng. (2007), Kazan State Technological University, Kazan, Russia
   b. M.Sc. Reservoir Evaluation and Management (2004), Heriot-Watt University, Edinburgh, UK
   c. M.Sc. (Honours), Petroleum Geology (2003), Kazan State University, Kazan, Russia

2. I am a registered professional:
   a. Professional Geoscientist (P.Geo.), Province of Alberta, Canada

3. I am a member of the following professional organizations:
   a. Society of Petroleum Engineers (SPE)
   b. Association of Professional Engineers and Geoscientists of Alberta (APEGA)
   c. Canadian Society of Petroleum Geologists (CSPG)

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Jul. 08, 2021

Alexey Romanov, Ph.D., P.Geo.

Certificate of Qualification

Gary R. Finnis, P.Eng.

I, Gary R. Finnis, Senior Manager, Engineering of Sproule, 900, 140 Fourth Avenue SW, Calgary, Alberta, declare the following:

1. I hold the following degree:
   a. B.Sc. Civil Engineering (1998) University of Alberta, Edmonton, AB, Canada

2. I am a registered professional:
   a. Professional Engineer (P.Eng.), Province of Alberta, Canada

3. I am a member of the following professional organizations:
   a. Association of Professional Engineers and Geoscientists of Alberta (APEGA)
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Jul. 08, 2021

Gary R. Finnis, P.Eng.

Certificate of Qualification

Alec Kovaltchouk, P.Geo.

I, Alec Kovaltchouk, VP, Geoscience of Sproule, 900, 140 Fourth Avenue SW, Calgary, Alberta, declare the following:

1. I hold the following degree:
   a. M.Sc. Geochemistry (1981) University of Lviv, Lviv, Ukraine

2. I am a registered professional:
   a. Professional Geoscientist (P.Geo.), Province of Alberta, Canada

3. I am a member of the following professional organizations:
   a. Association of Professional Engineers and Geoscientists of Alberta (APEGA)
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Jul. 08, 2021

Alec Kovaltchouk, P.Geo.

Table 1
Orcadian Energy PLC
Blakeney, Elke, Narwhal and Pilot Fields, North Sea, United Kingdom
Well List and Production Summary
(As of April 01, 2021)

					Well Test Results				
Well Name	Field	Zone	Well Current Status	Current Well Status Date	Daily Oil Rate (bopd)	Daily Gas Rate (Mcfpd)	Water Cut (%)	Gas-Oil Ratio (scf/bbl)	Water-Gas Ratio (bbl/MMcf)
28/3-1B	Elke	Tay	Abandoned Oil	2000					
28/2-1	Narwhal	Tay	Abandoned Oil	1993					
28/2a-2	Narwhal	Tay	Dry	2007					
21/27b-7	Blakeney	Tay	Abandoned Oil	2010					
21/27a-5x	Pilot Main	Tay	Abandoned Oil	1998	1,850				
21/27a-5z	Pilot Main	Tay	Abandoned Oil	1998					
21/27a-5	Pilot Main	Tay	Abandoned Oil	1998					
21/27a-6	Pilot Main	Tay	Abandoned Oil	2007					
21/27-3	Pilot Main	Tay	Abandoned Oil	1990					
21/27-2	Pilot Main	Tay	Abandoned Oil	1989	115				
21/27-4	Pilot South	Tay	Abandoned Oil	1990					
21/27-1A*	Harbour	Tay	Abandoned Oil	1989					
21/28-1*	Feugh	Tay	Abandoned Oil	1971					
21/28a-4*	Crinan	Tay	Abandoned Oil	1987					
21/28a-6*	Dandy	Tay	Abandoned Oil	1990	1,016				
21/28a-8*	Dandy	Tay	Abandoned Oil	1998					
21/28a-8z*	Dandy	Tay	Abandoned Oil	1998	1,080				

Note: * Wells that penetrated Harbour, Feugh, Crinan and Dandy discoveries were included into this table for completeness. These fields were outside of the scope of the evaluation and were not evaluated by Sproule.

Table 2 Orcadian Energy PLC Pilot Field , North Sea, United Kingdom Summary of Technically Recoverable Resources in Reserves-Related Area (As of April 01, 2021)							
					Oil		
Well/Entity Name	Field	Zone	Method	Well Zone Current Status	Estimated Ultimate Recoverable Oil Volume (Mbbl)	Cumulative Oil Production as of 2021-04-01 (Mbbl)	Remaining Recoverable Oil as of 2021-04-01 (Mbbl)
Proved Undeveloped							
Pilot Field - Polymer flood (17 producers and 15 injectors)	Pilot Field	Tay Sands	Volumetric	Undeveloped Oil	61,500	0	61,500
Total					**61,500**	**0**	**61,500**
Total Proved							
Pilot Field - Polymer flood (17 producers and 15 injectors)	Pilot Field	Tay Sands	Volumetric	Undeveloped Oil	61,500	0	61,500
Total					**61,500**	**0**	**61,500**
Proved + Probable Undeveloped							
Pilot Field - Polymer flood (17 producers and 15 injectors)	Pilot Field	Tay Sands	Volumetric	Undeveloped Oil	82,000	0	82,000
Total					**82,000**	**0**	**82,000**
Total Proved + Probable							
Pilot Field - Polymer flood (17 producers and 15 injectors)	Pilot Field	Tay Sands	Volumetric	Undeveloped Oil	82,000	0	82,000
Total					**82,000**	**0**	**82,000**
Proved + Probable + Possible Undeveloped							
Pilot Field - Polymer flood (17 producers and 15 injectors)	Pilot Field	Tay Sands	Volumetric	Undeveloped Oil	112,750	0	112,750
Total					**112,750**	**0**	**112,750**
Total Proved + Probable+ Possible							
Pilot Field - Polymer flood (17 producers and 15 injectors)	Pilot Field	Tay Sands	Volumetric	Undeveloped Oil	112,750	0	112,750
Total					**112,750**	**0**	**112,750**

NOTES:
All values are technical, meaning they are before any commercial and/or economic truncation.
Values may not be consistent from one presentation to the next due to rounding.

Table 2A
Orcadian Energy PLC
Blakeney, Elke, Narwhal and Pilot Fields, North Sea, United Kingdom
Summary of Technically Recoverable Resources (Unrisked) in Contingent Resources-Related Areas
(As of April 01, 2021)

Well/Entity Name	Field	Zone	Method	Well Zone Current Status	Oil: Estimated Ultimate Recoverable Oil Volume (Mbbl)	Oil: Cumulative Oil Production as of 2021-04-01 (Mbbl)	Oil: Remaining Recoverable Oil as of 2021-04-01 (Mbbl)
Contingent Resources - 1C							
Blakeney-Polymerflood (13 producers and 10 injectors)	Blakeney	Tay Sands	Volumetric	Undeveloped Oil	15,000	0	15,000
Elke-Polymerflood (9 producers and 7 injectors)	Elke	Tay Sands	Volumetric	Undeveloped Oil	26,000	0	26,000
Narwhal-Polymerflood (4 producers and 3 injectors)	Narwhal	Tay Sands	Volumetric	Undeveloped Oil	4,280	0	4,280
Pilot Field - Polymerflood Peripheral Area	Pilot	Tay Sands	Volumetric	Undeveloped Oil	5,850	0	5,850
Total					**51,130**	**0**	**51,130**
Contingent Resources - 2C							
Blakeney-Polymerflood (13 producers and 10 injectors)	Blakeney	Tay Sands	Volumetric	Undeveloped Oil	27,300	0	27,300
Elke-Polymerflood (9 producers and 7 injectors)	Elke	Tay Sands	Volumetric	Undeveloped Oil	45,500	0	45,500
Narwhal-Polymerflood (4 producers and 3 injectors)	Narwhal	Tay Sands	Volumetric	Undeveloped Oil	9,240	0	9,240
Pilot Field - Polymerflood Peripheral Area	Pilot	Tay Sands	Volumetric	Undeveloped Oil	9,750	0	9,750
Total					**91,790**	**0**	**91,790**
Contingent Resources - 3C							
Blakeney-Polymerflood (13 producers and 10 injectors)	Blakeney	Tay Sands	Volumetric	Undeveloped Oil	44,800	0	44,800
Elke-Polymerflood (13 producers and 11 injectors)	Elke	Tay Sands	Volumetric	Undeveloped Oil	127,600	0	127,600
Narwhal-Polymerflood (4 producers and 3 injectors)	Narwhal	Tay Sands	Volumetric	Undeveloped Oil	17,600	0	17,600
Pilot Field - Polymerflood Peripheral Area	Pilot	Tay Sands	Volumetric	Undeveloped Oil	17,550	0	17,550
Total					**207,550**	**0**	**207,550**

NOTES:
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Table 2B
Orcadian Energy PLC
Propsective Fields, North Sea, United Kingdom
Summary of Technically Recoverable Resources (Unrisked) in Prospective Resources-Related Areas
(As of April 01, 2021)

Well/Entity Name	Field	Zone	Recovery Mechanism	Method	Well Zone Current Status	Oil: Estimated Ultimate Recoverable Oil Volume (Mbbl)	Oil: Cumulative Oil Production as of 2021-04-01 (Mbbl)	Oil: Remaining Recoverable Oil as of 2021-04-01 (Mbbl)
Prospective Resources - 1U								
Pilot Channels	Pilot	Tay Sands	Polymerflood	Volumetric	Undeveloped Oil	7,990	0	7,990
Elke Updip West	Elke	Tay Sands	Polymerflood	Volumetric	Undeveloped Oil	5,500	0	5,500
Elke North	Elke	Tay Sands	Polymerflood	Volumetric	Undeveloped Oil	2,500	0	2,500
Elke Area 2 and Area 3	Elke	Tay Sands	Polymerflood	Volumetric	Undeveloped Oil	8,667	0	8,667
Elke Main Channel	Elke	Tay Sands	Polymerflood	Volumetric	Undeveloped Oil	1,667	0	1,667
Bowhead	Bowhead	Tay Sands	Polymerflood	Volumetric	Undeveloped Oil	12,000	0	12,000
Tiberius	Tiberius	Fulmar	Polymerflood	Volumetric	Undeveloped Oil	5,750	0	5,750
Bottlenose	Bottlenose	Lista	Polymerflood	Volumetric	Undeveloped Oil	6,250	0	6,250
Total						**50,323**	**0**	**50,323**
Prospective Resources - 2U								
Pilot Channels	Pilot	Tay Sands	Polymerflood	Volumetric	Undeveloped Oil	29,050	0	29,050
Elke Updip West	Elke	Tay Sands	Polymerflood	Volumetric	Undeveloped Oil	17,500	0	17,500
Elke North	Elke	Tay Sands	Polymerflood	Volumetric	Undeveloped Oil	10,500	0	10,500
Elke Area 2 and Area 3	Elke	Tay Sands	Polymerflood	Volumetric	Undeveloped Oil	25,550	0	25,550
Elke Main Channel	Elke	Tay Sands	Polymerflood	Volumetric	Undeveloped Oil	7,000	0	7,000
Bowhead	Bowhead	Tay Sands	Polymerflood	Volumetric	Undeveloped Oil	43,050	0	43,050
Tiberius	Tiberius	Fulmar	Polymerflood	Volumetric	Undeveloped Oil	28,350	0	28,350
Bottlenose	Bottlenose	Lista	Polymerflood	Volumetric	Undeveloped Oil	30,400	0	30,400
Total						**191,400**	**0**	**191,400**
Prospective Resources - 3U								
Pilot Channels	Pilot	Tay Sands	Polymerflood	Volumetric	Undeveloped Oil	73,500	0	73,500
Elke Updip West	Elke	Tay Sands	Polymerflood	Volumetric	Undeveloped Oil	39,000	0	39,000
Elke North	Elke	Tay Sands	Polymerflood	Volumetric	Undeveloped Oil	30,000	0	30,000
Elke Area 2 and Area 3	Elke	Tay Sands	Polymerflood	Volumetric	Undeveloped Oil	53,350	0	53,350
Elke Main Channel	Elke	Tay Sands	Polymerflood	Volumetric	Undeveloped Oil	19,500	0	19,500
Bowhead	Bowhead	Tay Sands	Polymerflood	Volumetric	Undeveloped Oil	105,000	0	105,000
Tiberius	Tiberius	Fulmar	Polymerflood	Volumetric	Undeveloped Oil	110,400	0	110,400
Bottlenose	Bottlenose	Lista	Polymerflood	Volumetric	Undeveloped Oil	83,400	0	83,400
Total						**514,150**	**0**	**514,150**

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Table 2.1
Orcadian Energy PLC
Pilot Field , North Sea, United Kingdom
Summary of Oil Volumetric Parameters in Reserves-Related Area (Polymer)
(As of April 01, 2021)

Well/Entity Name	Field	Zone	Area (acres)	Net Pay (ft)	Porosity (%)	Water Saturation (%)	Oil Formation Volume Factor (rb/stb)	Oil Initially-In-Place (Mbbl)	Recovery Factor (%)	Estimated Ultimate Recoverable Oil Volume (Mbbl)	Cumulative Oil Production as of 2021-04-01 (Mbbl)	Remaining Recoverable Oil as of 2021-04-01 (Mbbl)
Proved Undeveloped												
Development of Pilot Main	Pilot Main	Tay Sands	1,420	54	34	8	1.03	181,000				
Development of Pilot South	Pilot South	Tay Sands	300	37	31	8	1.03	24,000				
Total Pilot Field (17 producers and 15 injectors)								**205,000**	**30**	**61,500**	**0**	**61,500**
Total Proved												
Development of Pilot Main	Pilot Main	Tay Sands	1,420	54	34	8	1.03	181,000				
Development of Pilot South	Pilot South	Tay Sands	300	37	31	8	1.03	24,000				
Total Pilot Field (17 producers and 15 injectors)								**205,000**	**30**	**61,500**	**0**	**61,500**
Proved + Probable Undeveloped												
Development of Pilot Main	Pilot Main	Tay Sands	1,420	54	34	8	1.03	181,000				
Development of Pilot South	Pilot South	Tay Sands	300	37	31	8	1.03	24,000				
Total Pilot Field (17 producers and 15 injectors)								**205,000**	**40**	**82,000**	**0**	**82,000**
Total Proved + Probable												
Development of Pilot Main	Pilot Main	Tay Sands	1,420	54	34	8	1.03	181,000				
Development of Pilot South	Pilot South	Tay Sands	300	37	31	8	1.03	24,000				
Total Pilot Field (17 producers and 15 injectors)								**205,000**	**40**	**82,000**	**0**	**82,000**
Proved + Probable + Possible Undeveloped												
Development of Pilot Main	Pilot Main	Tay Sands	1,420	54	34	8	1.03	181,000				
Development of Pilot South	Pilot South	Tay Sands	300	37	31	8	1.03	24,000				
Total Pilot Field (17 producers and 15 injectors)								**205,000**	**55**	**112,750**	**0**	**112,750**
Total Proved + Probable + Possible												
Development of Pilot Main	Pilot Main	Tay Sands	1,420	54	34	8	1.03	181,000				
Development of Pilot South	Pilot South	Tay Sands	300	37	31	8	1.03	24,000				
Total Pilot Field (17 producers and 15 injectors)								**205,000**	**55**	**112,750**	**0**	**112,750**

NOTES:
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Table 2.1A
Orcadian Energy PLC
Blakeney, Elke, Narwhal and Pilot Fields, North Sea, United Kingdom
Summary of Oil Volumetric Parameters in Contingent Resources-Related Areas (Polymer)
(As of April 01, 2021)

Well/Entity Name	Field	Zone	Area (acres)	Net Pay (ft)	Porosity (%)	Water Saturation (%)	Oil Formation Volume Factor (rb/stb)	Oil Initially-In-Place (Mbbl)	Recovery Factor (%)	Estimated Ultimate Recoverable Oil Volume (Mbbl)	Cumulative Oil Production as of 2021-04-01 (Mbbl)	Remaining Recoverable Oil as of 2021-04-01 (Mbbl)
Contingent Resources - 1C												
Development - Blakeney (13 producers and 10 injectors)	Blakeney	Tay Sands			Estimated probabilistically*			75,000	20	15,000	0	15,000
Development - Elke (9 producers and 7 injectors)	Elke	Tay Sands	1,061	51	36	12	1.01	130,000	20	26,000	0	26,000
Development - Narwhal (4 producers and 3 injectors)	Narwhal	Tay Sands			Estimated probabilistically*			21,400	20	4,280	0	4,280
Pilot Field - Peripheral Area	Pilot	Tay Sands	778	24	33	16	1	39,000	15	5,850	0	5,850
Total								**265,400**		**51,130**	**0**	**51,130**
Contingent Resources - 2C												
Development - Blakeney (13 producers and 10 injectors)	Blakeney	Tay Sands			Estimated probabilistically*			91,000	30	27,300	0	27,300
Development - Elke (9 producers and 7 injectors)	Elke	Tay Sands	1,061	51	36	12	1.01	130,000	35	45,500	0	45,500
Development - Narwhal (4 producers and 3 injectors)	Narwhal	Tay Sands			Estimated probabilistically*			26,400	35	9,240	0	9,240
Pilot Field - Peripheral Area	Pilot	Tay Sands	778	24	33	16	1	39,000	25	9,750	0	9,750
Total								**286,400**		**91,790**	**0**	**91,790**
Contingent Resources - 3C												
Development - Blakeney (13 producers and 10 injectors)	Blakeney	Tay Sands			Estimated probabilistically*			112,000	40	44,800	0	44,800
Development - Elke (13 producers and 11 injectors)	Elke	Tay Sands	1,592	61	36	12	1.01	232,000	55	127,600	0	127,600
Development - Narwhal (4 producers and 3 injectors)	Narwhal	Tay Sands			Estimated probabilistically*			32,000	55	17,600	0	17,600
Pilot Field - Peripheral Area	Pilot	Tay Sands	778	24	33	16	1	39,000	45	17,550	0	17,550
Total								**415,000**		**207,550**	**0**	**207,550**

* Range of parameters used for probalistic OIIP estimate is discussed in the Geoscience Section of the Report

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Table 2.1B
Orcadian Energy PLC
Prospective Fields, North Sea, United Kingdom
Summary of Oil Volumetric Parameters in Prospective Resources-Related Areas (Polymer)
(As of April 01, 2021)

Well/Entity Name	Field	Zone	Area (acres)	Net Pay (ft)	Porosity (%)	Water Saturation (%)	Oil Formation Volume Factor (rb/stb)	Oil Initially-In-Place (Mbbl)	Recovery Factor (%)	Estimated Ultimate Recoverable Oil Volume (Mbbl)	Cumulative Oil Production as of 2021-04-01 (Mbbl)	Remaining Recoverable Oil as of 2021-04-01 (Mbbl)
Prospective Resources - 1U												
Pilot Channels	Pilot	Tay Sands			Estimated probabilistically*			47,000	17	7,990	0	7,990
Elke Updip West	Elke	Tay Sands			Estimated probabilistically*			33,000	17	5,500	0	5,500
Elke North	Elke	Tay Sands			Estimated probabilistically*			15,000	17	2,500	0	2,500
Elke Area 2 and Area 3	Elke	Tay Sands			Estimated probabilistically*			52,000	17	8,667	0	8,667
Elke Main Channel	Elke	Tay Sands			Estimated probabilistically*			10,000	17	1,667	0	1,667
Bowhead	Bowhead	Tay Sands			Estimated probabilistically*			72,000	17	12,000	0	12,000
Tiberius	Tiberius	Fulmar			Estimated probabilistically*			23,000	25	5,750	0	5,750
Bottlenose	Bottlenose	Lista			Estimated probabilistically*			25,000	25	6,250	0	6,250
Total								**277,000**		**50,323**	**0**	**50,323**
Prospective Resources - 2U												
Pilot Channels	Pilot	Tay Sands			Estimated probabilistically*			83,000	35	29,050	0	29,050
Elke Updip West	Elke	Tay Sands			Estimated probabilistically*			50,000	35	17,500	0	17,500
Elke North	Elke	Tay Sands			Estimated probabilistically*			30,000	35	10,500	0	10,500
Elke Area 2 and Area 3	Elke	Tay Sands			Estimated probabilistically*			73,000	35	25,550	0	25,550
Elke Main Channel	Elke	Tay Sands			Estimated probabilistically*			20,000	35	7,000	0	7,000
Bowhead	Bowhead	Tay Sands			Estimated probabilistically*			123,000	35	43,050	0	43,050
Tiberius	Tiberius	Fulmar			Estimated probabilistically*			63,000	45	28,350	0	28,350
Bottlenose	Bottlenose	Lista			Estimated probabilistically*			76,000	40	30,400	0	30,400
Total								**518,000**		**191,400**	**0**	**191,400**
Prospective Resources - 3U												
Pilot Channels	Pilot	Tay Sands			Estimated probabilistically*			147,000	50	73,500	0	73,500
Elke Updip West	Elke	Tay Sands			Estimated probabilistically*			78,000	50	39,000	0	39,000
Elke North	Elke	Tay Sands			Estimated probabilistically*			60,000	50	30,000	0	30,000
Elke Area 2 and Area 3	Elke	Tay Sands			Estimated probabilistically*			106,700	50	53,350	0	53,350
Elke Main Channel	Elke	Tay Sands			Estimated probabilistically*			39,000	50	19,500	0	19,500
Bowhead	Bowhead	Tay Sands			Estimated probabilistically*			210,000	50	105,000	0	105,000
Tiberius	Tiberius	Fulmar			Estimated probabilistically*			184,000	60	110,400	0	110,400
Bottlenose	Bottlenose	Lista			Estimated probabilistically*			139,000	60	83,400	0	83,400
Total								**963,700**		**514,150**	**0**	**514,150**

* Range of parameters used for probalistic OIIP estimate is discussed in the Prospective Resources Section of the Report

NOTES:
All values are technical, meaning they are before any commercial and/or economic truncation.
Values may not be consistent from one presentation to the next due to rounding.

Table 2.2
Orcadian Energy PLC
Pilot Field, North Sea, United Kingdom
Summary of Oil Decline Parameters in Reserves-Related Area
(As of April 01, 2021)

Well/Entity Name	Field	Zone	Method	Well Current Status	Estimated Ultimate Recoverable Oil Volume (Mbbl)	Cumulative Oil Production at Data as of 2021-04-01 (Mbbl)[1]	Cumulative Oil Production as of 2021-04-01 (Mbbl)[1]	Remaining Recoverable Oil as of 2021-04-01 (Mbbl)	Forecast Start Date (YYYY-MM-DD)	Forecast Initial Rate[2] (bopd)	Final Rate[3] (bopd)	Exponential / Hyperbolic / Harmonic	Nominal Decline Rate[4] (%/Year)	Decline Exponent[5]
Proved Undeveloped														
Pilot Field - Polymer Flood	Pilot Field	Tay Sands	Volumetrics	Undeveloped Oil	61,500	0	0	61,500	2024-06-01	7,400	200	Hyperbolic	0	0.5
Total					**61,500**	**0**	**0**	**61,500**			**200**			
Total Proved														
Pilot Field - Polymer Flood	Pilot Field	Tay Sands	Volumetrics	Undeveloped Oil	61,500	0	0	61,500	2024-06-01	7,400	200	Hyperbolic	0	0.5
Total					**61,500**	**0**	**0**	**61,500**			**200**			
Proved + Probable Undeveloped														
Pilot Field - Polymer Flood	Pilot Field	Tay Sands	Volumetrics	Undeveloped Oil	82,000	0	0	82,000	2024-06-01	8,000	200	Hyperbolic	0	0.5
Total					**82,000**	**0**	**0**	**82,000**			**200**			
Total Proved + Probable														
Pilot Field - Polymer Flood	Pilot Field	Tay Sands	Volumetrics	Undeveloped Oil	82,000	0	0	82,000	2024-06-01	8,000	200	Hyperbolic	0	0.5
Total					**82,000**	**0**	**0**	**82,000**			**200**			
Proved + Probable + Possible Undeveloped														
Pilot Field - Polymer Flood	Pilot Field	Tay Sands	Volumetrics	Undeveloped Oil	112,750	0	0	112,750	2024-06-01	10,000	200	Hyperbolic	0	0.5
Total					**112,750**	**0**	**0**	**112,750**			**200**			
Total Proved + Probable + Possible														
Pilot Field - Polymer Flood	Pilot Field	Tay Sands	Volumetrics	Undeveloped Oil	112,750	0	0	112,750	2024-06-01	10,000	200	Hyperbolic	0	0.5
Total					**112,750**	**0**	**0**	**112,750**			**200**			

NOTE:
1. The cumulative production in this table does not include abandoned or suspended wells.
All values are technical, meaning they are before any commercial and/or economic truncation.
Values may not be consistent from one presentation to the next due to rounding.
2. Forecast initial rate is for field level roll-up.
3. Forecast final rate represents individual well final rate.
4. Nominal Decline of 0% represents individual well decline rate, initially producing on plateau.
5. Decline Exponent represents individual well decline exponent, post plateau.

Table 2.2A
Orcadian Energy PLC
Blakeney, Elke, Narwhal Fields, North Sea, United Kingdom
Summary of Oil Decline Parameters in Contingent Resources-Related Areas
(As of April 01, 2021)

Well/Entity Name	Field	Zone	Method	Well Current Status	Estimated Ultimate Recoverable Oil Volume (Mbbl)	Cumulative Oil Production at Data as of 2021-04-01 (Mbbl)[1]	Cumulative Oil Production as of 2021-04-01 (Mbbl)[1]	Remaining Recoverable Oil as of 2021-04-01 (Mbbl)	Forecast Start Date (YYYY-MM-DD)	Forecast Initial Rate[2] (bopd)	Final Rate[3] (bopd)	Exponential / Hyperbolic / Harmonic	Nominal Decline Rate[4] (%/Year)	Decline Exponent[5]
Contingent Resources - 1C														
Blakeney Polymer Flood	Blakeney	Tay Sands	Volumetrics	Undeveloped Oil	15,000	0	0	15,000	2034-03-01	1,000	100	Hyperbolic	0	0.5
Elke Polymer Flood	Elke	Tay Sands	Volumetrics	Undeveloped Oil	26,000	0	0	26,000	2031-06-01	9,000	200	Hyperbolic	0	0.5
Narwhal Polymer Flood	Narwhal	Tay Sands	Volumetrics	Undeveloped Oil	4,280	0	0	4,280	2033-07-01	950	100	Hyperbolic	0	0.5
Total					**45,280**	**0**	**0**	**45,280**						
Contingent Resources - 2C														
Blakeney Polymer Flood	Blakeney	Tay Sands	Volumetrics	Undeveloped Oil	27,300	0	0	27,300	2034-03-01	1,750	100	Hyperbolic	0	0.5
Elke Polymer Flood	Elke	Tay Sands	Volumetrics	Undeveloped Oil	45,500	0	0	45,500	2031-06-01	12,000	200	Hyperbolic	0	0.5
Narwhal Polymer Flood	Narwhal	Tay Sands	Volumetrics	Undeveloped Oil	9,240	0	0	9,240	2033-07-01	1,850	100	Hyperbolic	0	0.5
Total					**82,040**	**0**	**0**	**82,040**						
Contingent Resources - 3C														
Blakeney Polymer Flood	Blakeney	Tay Sands	Volumetrics	Undeveloped Oil	44,800	0	0	44,800	2034-03-01	2,800	100	Hyperbolic	0	0.5
Elke Polymer Flood	Elke	Tay Sands	Volumetrics	Undeveloped Oil	127,600	0	0	127,600	2031-06-01	21,000	200	Hyperbolic	0	0.5
Narwhal Polymer Flood	Narwhal	Tay Sands	Volumetrics	Undeveloped Oil	17,600	0	0	17,600	2033-07-01	3,700	100	Hyperbolic	0	0.5
Total					**190,000**	**0**	**0**	**190,000**						

NOTE:
1. The cumulative production in this table does not include abandoned or suspended wells.
All values are technical, meaning they are before any commercial and/or economic truncation.
Values may not be consistent from one presentation to the next due to rounding.
2. Forecast initial rate is for field level roll-up.
3. Forecast final rate represents individual well final rate.
4. Nominal Decline of 0% represents individual well decline rate, initially producing on plateau.
5. Decline Exponent represents individual well decline exponent, post plateau.
Note that although Elke and Narwhal are shown separately here, all economic calculations consider them together, as one development project.

Table 3
Orcadian Energy PLC
Pilot Field, North Sea, United Kingdom in Reserves-Related Area (Polymer flood)
Summary of Economic Parameters
(As of April 01, 2021)

All Costs Presented as 100% Project Gross in United Kingdom Pounds

Field Development Plan (Reserves):

The field will be developed using Polymer flood.
The development of the field includes drilling of 17 producers and 15 injectors.

Company Interest:

The Company's working interest is 100%.

Pricing:

Oil:

Sproule Brent oil price forecast as of March 31, 2021.

Oil price offset:	0%
Quality:	13-17 degree API

Operating Costs:

Base OPEX (FPSO, Ops, Insure, Platform, Contingency)	3,500	M£/month
Well Cost	57	M£/month/well
CO2 Cost	180 - 2,052	M£/year
Oil Variable	1.11	£/bbl
Licence	300	M£/year

Table 3 Continued
Orcadian Energy PLC
Pilot Field, North Sea, United Kingdom in Reserves-Related Area (Polymer flood)
Summary of Economic Parameters
(As of April 01, 2021)

All Costs Presented as 100% Project Gross in United Kingdom Pounds

Operating Costs (cont'd):

Fuel Gas Purchase Cost, M£/year

Year	Cost
2024	100
2025	993
2026	2,459
2027	4,341
2028	6,177
2029	7,588
2030	8,800
2031	9,487
2032	9,914
2033	10,192
2034	10,223
2035	5,946
2036	4,675
2037	2,597
2038	982
2039	**continues constant for 3P*
2040	
2041	
2042	
2043	
2044	
2045	

Polymer Purchase Cost, M£/year

Year	Cost
2024	3,436
2025	9,970
2026	15,139
2027	23,618
2028	31,906
2029	31,745
2030	23,996
2031	16,299
2032	12,063
2033	9,280
2034	7,285
2035	4,068
2036	2,757
2037	1,394
2038	472
2039	**continues constant for 3P*
2040	
2041	
2042	
2043	
2044	
2045	

Capital Costs 1P/2P/3P:

Year	Description	Capital Costs M£
2023	WHP, Facilities	294,590
2024	FPSO	437,330
2024	Drilling first 4 wells	51,040
2024-2028	Drilling of remaining 28 wells	357,280
Total		1,140,240

Abandonment & Reclamation Costs 1P/2P/3P:

78,300 M£ *(at end of Economic Life)*

Table 3A-1
Orcadian Energy PLC
Blakeney Field, North Sea United Kingdom in Contingent Resources - Related Areas (Blakeney Polymer flood)
Summary of Economic Parameters
(As of April 01, 2021)

All Costs Presented as 100% Project Gross in United Kingdom Pounds

Field Development Plan (Resources):

The field will be developed using Polymer flood.
The development of the field includes drilling of 13 producers and 10 injectors.

Company Interest:

The Company's working interest is 100%.

Pricing:

Oil:

Sproule Brent oil price forecast as of March 31, 2021.

Oil price offset:	0%
Quality:	15 degree API

Operating Costs:

Fixed Platform Cost	243	M£/month
Well Cost	57	M£/month/well
FSO/Base Ops Cost (post Pilot end of life)	153 - 2,634	M£/month
CO2 Cost	59 - 761	M£/year
Oil Variable	1.11	£/bbl
Licence	300	M£/year

Table 3A-1 Continued
Orcadian Energy PLC
Blakeney Field, North Sea United Kingdom in Contingent Resources - Related Areas (Blakeney Polymer flood)
Summary of Economic Parameters
(As of April 01, 2021)

All Costs Presented as 100% Project Gross in United Kingdom Pounds

Operating Costs (cont'd):

Fuel Gas Purchase Cost, M£/year

Year	Cost
2034	44
2035	219
2036	837
2037	1,424
2038	2,011
2039	2,599
2040	3,131
2041	3,490
2042	3,697
2043	3,834
2044	2,719
2045	2,169
2046	1,536
2047	936
2048	319
2049	**continues constant for High case*
2050	
2051	

Polymer Purchase Cost, M£/year

Year	Cost
2034	1,856
2035	3,074
2036	4,179
2037	5,226
2038	6,245
2039	6,819
2040	6,731
2041	6,162
2042	4,496
2043	3,437
2044	2,197
2045	1,506
2046	941
2047	510
2048	157
2049	**continues constant for High case*
2050	
2051	

Capital Costs 1C/2C/3C:

Year	Description	Capital Costs M£
2033	WHP/Facilities/FSO Flowlines	116,890
2034	Drilling 2 wells	28,580
2034-2038	Drill remaining 21 wells	300,120
Total		445,590

Abandonment & Reclamation Costs 1C/2C/3C:

42,980 M£ *(at end of Economic Life)*

Table 3A-2
Orcadian Energy PLC
Elke and Narwhal Fields, North Sea, United Kingdom in Contingent Resources-Related Areas (Elke and Narwhal Polymer flood)
Summary of Economic Parameters
(As of April 01, 2021)

All Costs Presented as 100% Project Gross in United Kingdom Pounds

Field Development Plan (Resources):

The field will be developed using Polymer flood.
The development of the field includes drilling of 13 producers and 10 injectors for Low and Best cases, (1C, 2C).
The development of the field includes drilling of 17 producers and 14 injectors for the High case (3C).

Company Interest:

The Company's working interest is 100%.

Pricing:

Oil:

Sproule Brent oil price forecast as of March 31, 2021.

Oil price offset :	0%
Quality:	14 degree API

Operating Costs:

Fixed Platform Cost	243	M£/month
Well Cost	57	M£/month/well
FSO/Base Ops Cost (post Pilot end of life)	393 - 1,701	M£/month
CO2 Cost	87 - 1,358	M£/year
Oil Variable	1.11	£/bbl
Licence	300	M£/year

Table 3A-2 Continued
Orcadian Energy PLC
Elke and Narwhal Fields, North Sea, United Kingdom in Contingent Resources-Related Areas (Elke and Narwhal Polymer flood)
Summary of Economic Parameters
(As of April 01, 2021)

All Costs Presented as 100% Project Gross in United Kingdom Pounds

Operating Costs (cont'd):

1C/2C
Fuel Gas Purchase Cost, M£/year

Year	Cost
2031	152
2032	986
2033	2,327
2034	3,884
2035	5,116
2036	6,052
2037	6,484
2038	6,735
2039	6,948
2040	7,162
2041	7,326
2042	5,887
2043	1,862
2044	473
2045	
2046	
2047	

1C/2C
Polymer Purchase Cost, M£/year

Year	Cost
2031	3,600
2032	10,118
2033	11,030
2034	12,250
2035	12,076
2036	12,240
2037	10,822
2038	8,210
2039	6,449
2040	5,217
2041	4,288
2042	2,948
2043	939
2044	223
2045	
2046	
2047	

3C
Fuel Gas Purchase Cost, M£/year

Year	Cost
2031	78
2032	823
2033	2,918
2034	5,678
2035	8,303
2036	10,543
2037	11,669
2038	12,298
2039	12,711
2040	13,093
2041	13,369
2042	13,657
2043	13,932
2044	14,237
2045	14,459
2046	14,460
2047	12,268
2048	5,615
2049	2,426

3C
Polymer Purchase Cost, M£/year

Year	Cost
2031	6,547
2032	26,614
2033	45,179
2034	56,458
2035	51,914
2036	43,911
2037	31,110
2038	23,237
2039	18,058
2040	14,490
2041	11,836
2042	9,879
2043	8,374
2044	7,208
2045	6,240
2046	5,372
2047	3,980
2048	1,762
2049	714

Table 3A-2 Continued
Orcadian Energy PLC
Elke and Narwhal Fields, North Sea, United Kingdom in Contingent Resources-Related Areas (Elke and Narwhal Polymer flood)
Summary of Economic Parameters
(As of April 01, 2021)

All Costs Presented as 100% Project Gross in United Kingdom Pounds

Capital Costs:

1C/2C:

Year	Description	Capital Costs M£
2030	WHP/Facilities/FSO Flowlines	293,030
2031	Drilling 6 Elke Wells	85,747
2031-2032	Drill remaining 10 Elke Wells	142,911
2033	Drill 7 Narwhal Wells	100,038
Total		621,726

3C:

Year	Description	Capital Costs M£
2030	WHP/Facilities/FSO Flowlines	293,030
2031	Drilling 6 Elke Wells	85,747
2031-2033	Drill remaining 18 Elke Wells	257,240
2033	Drill 7 Narwhal Wells	100,038
Total		736,055

Abandonment & Reclamation Costs

1C/2C:
42,980 M£ *(at end of Economic Life)*

3C:
57,930 M£ *(at end of Economic Life)*

Table 4
Orcadian Energy PLC
Pilot Field Reserves, North Sea, United Kingdom
Estimates of Oil Reserves and Net Present Values[1]
(As of April 01, 2021)

Reserves Category	Original Recoverable Oil Reserves	Cumulative Oil Production as of 2021-04-01	Remaining Recoverable[2] Oil Reserves	Company Working Interest	Company Gross[3] Oil Reserves	Lessor Royalties and Burdens	Company Net[4] Oil Reserves	Net Present Value of Future Net Production Revenue at Several Discount Rates Before Taxes (M$)				
	Mbbl	Mbbl	Mbbl	%	Mbbl	Mbbl	Mbbl	0%	5%	10%	15%	20%
Pilot Field Reserves, North Sea, United Kingdom												
Proved Undeveloped	58,436	0	58,436	100	58,436	0	58,436	666,224	359,460	159,525	29,278	-55,020
Total Proved	58,436	0	58,436	100	58,436	0	58,436	666,224	359,460	159,525	29,278	-55,020
Probable	20,383	0	20,383	100	20,383	0	20,383	971,825	685,606	494,380	363,856	272,901
Total Proved Plus Probable	78,819	0	78,819	100	78,819	0	78,819	1,638,049	1,045,066	653,905	393,134	217,881
Possible	31,712	0	31,712	100	31,712	0	31,712	1,409,082	972,193	693,266	509,172	383,752
Total Proved Plus Probable Plus Possible	110,531	0	110,531	100	110,531		110,531	3,219,119	2,150,314	1,447,893	977,986	658,505

Notes:
1. Values may not add or be consistent from one presentation to the next due to rounding.
2. "Remaining Recoverable Reserves" are the total remaining recoverable reserves associated with the acreage in which the Company has an interest.
3. "Company Gross" means the Company's working interest share of the remaining reserves, before deduction of royalties.
4. "Company Net" means the Company Gross reserves, less all Crown, freehold, and overriding royalties and interests owned by others.

Table 4A
Orcadian Energy PLC
Blakeney, Elke and Narwhal Resources, North Sea, United Kingdom
Estimates of Oil Contingent Resources and Net Present Values[1,2] (Unrisked)
(As of April 01, 2021)

Resources Category	Maturity Sub-Class	Chance of Development (Risk Factor) % [3]	Original Recoverable Oil Resources	Cumulative Oil Production as of 2021-04-01	Remaining Recoverable[4] Oil Resources	Company Working Interest	Company Gross[5] Oil Resources	Lessor Royalties and Burdens	Company Net[6] Oil Resources	Net Present Value of Future Net Production Revenue at Several Discount Rates Before Taxes (M$)				
			Mbbl	Mbbl	Mbbl	%	Mbbl	Mbbl	Mbbl	0%	5%	10%	15%	20%
Blakeney Polymer Flood														
Best Estimate (2C)	Development on Hold	72	25,113	0	25,113	100	25,113	0	25,113	488,596	185,997	69,808	24,795	7,512
High Estimate (3C)	Development on Hold	72	41,497	0	41,497	100	41,497	0	41,497	1,578,123	669,535	294,742	133,969	62,572
Elke and Narwhal fields Polymer Flood														
Low Estimate (1C)	Development on Hold	79	28,621	0	28,621	100	28,621	0	28,621	339,364	149,655	62,052	21,944	4,121
Best Estimate (2C)	Development on Hold	79	52,740	0	52,740	100	52,740	0	52,740	1,679,467	855,364	446,820	238,510	129,610
High Estimate (3C)	Development on Hold	79	142,355	0	142,355	100	142,355	0	142,355	6,481,214	3,289,623	1,734,116	945,334	530,902
Total Blakeney, Elke and Narwhal fields														
Low Estimate (1C)			28,621	0	28,621	100	28,621	0	28,621	339,364	149,655	62,052	21,944	4,121
Best Estimate (2C)			77,854	0	77,854	100	77,854	0	77,854	2,168,063	1,041,361	516,628	263,305	137,122
High Estimate (3C)			183,852	0	183,852	100	183,852	0	183,852	8,059,337	3,959,158	2,028,858	1,079,303	593,474

Notes:
1. Values may not add or be consistent from one presentation to the next due to rounding.
2. Contingent resources with project maturity sub-class Development not Viable and Development Unclarified excluded.
3. “Chance of Development” (CoD) for Contingent Resources is the estimated chance, or probability, that a known accumulation will be commercially developed. CoD shown is for informational purposes only. All resources and values represent unrisked numbers.
4. "Remaining Recoverable Resources" are the total remaining recoverable resources associated with the acreage in which the Company has an interest.
5. "Company Gross" means the Company's working interest share of the remaining resources, before deduction of royalties.
6. "Company Net" means the Company Gross resources, less all Crown, freehold, and overriding royalties and interests owned by others.

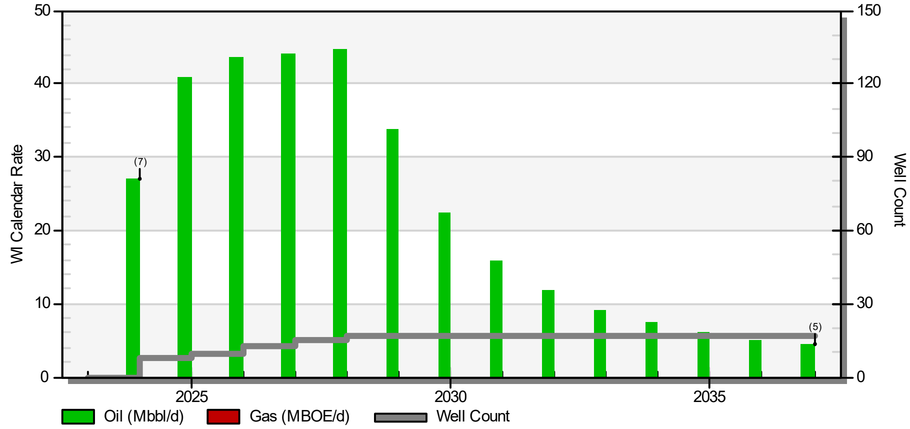
Table 4B Orcadian Energy PLC Blakeney, Elke and Narwhal Resources, North Sea, United Kingdom Estimates of Oil Contingent Resources and Net Present Values[1,2] (Risked) (As of April 01, 2021)														
Resources Category	Maturity Sub-Class	Chance of Development (Risk Factor) % [3]	Original Recoverable Oil Resources	Cumulative Oil Production as of 2021-04-01	Remaining Recoverable[4] Oil Resources	Company Working Interest	Company Gross[5] Oil Resources	Lessor Royalties and Burdens	Company Net[6] Oil Resources	Net Present Value of Future Net Production Revenue at Several Discount Rates Before Taxes (M$)				
			Mbbl	Mbbl	Mbbl	%	Mbbl	Mbbl	Mbbl	0%	5%	10%	15%	20%
Blakeney Polymer Flood														
Best Estimate (2C)	Development on Hold	72	18,081	0	18,081	100	18,081	0	18,081	351,789	133,918	50,262	17,852	5,409
High Estimate (3C)	Development on Hold	72	29,878	0	29,878	100	29,878	0	29,878	1,136,249	482,065	212,214	96,458	45,052
Elke and Narwhal fields Polymer Flood														
Low Estimate (1C)	Development on Hold	79	22,611	0	22,611	100	22,611	0	22,611	268,098	118,227	49,021	17,336	3,256
Best Estimate (2C)	Development on Hold	79	41,665	0	41,665	100	41,665	0	41,665	1,326,779	675,738	352,988	188,423	102,392
High Estimate (3C)	Development on Hold	79	112,461	0	112,461	100	112,461	0	112,461	5,120,159	2,598,802	1,369,952	746,814	419,413
Total Blakeney, Elke and Narwhal fields														
Low Estimate (1C)			22,611	0	22,611	100	22,611	0	22,611	268,098	118,227	49,021	17,336	3,256
Best Estimate (2C)			59,746	0	59,746	100	59,746	0	59,746	1,678,568	809,655	403,250	206,275	107,801
High Estimate (3C)			142,338	0	142,338	100	142,338	0	142,338	6,256,408	3,080,867	1,582,166	843,272	464,464

Notes:
1. Values may not add or be consistent from one presentation to the next due to rounding.
2. Contingent resources with project maturity sub-class Development not Viable and Development Unclarified excluded.
3. “Chance of Development” (CoD) for Contingent Resources is the estimated chance, or probability, that a known accumulation will be commercially developed. CoD shown is incorporated into this table. All resources and values represent risked numbers.
4. "Remaining Recoverable Resources" are the total remaining recoverable resources associated with the acreage in which the Company has an interest.
5. "Company Gross" means the Company's working interest share of the remaining resources, before deduction of royalties.
6. "Company Net" means the Company Gross resources, less all Crown, freehold, and overriding royalties and interests owned by others.

Orcadian Energy
As of April 1, 2021
Pilot Polymer Flood
Proved + Prob. + Poss. Undeveloped

Evaluation Parameters

Reserves Category	Proved + Prob. + Poss. Undeveloped
Plan	Working
Reference Date	April-01-21
Discount Date	April-01-21
Econ. Calc. Date	January-01-20
Country	United Kingdom
State	N/A
Company Share	100.00 %
Price Deck	2021-03-31 SAL Prices
Price Set	N/A
Economic Limit	Applied - BTCF 0.00%
Scenario	<Current Options>
BOE Ratio	6:1 Mcf/bbl
Chance of Success	100.0 %
Chance of Occurrence	100.0 %
Oil Reserves Type	Light and Medium Oil
Gas Reserves Type	N/A



Remaining Reserves / Net Revenue NPV (M$US) / Price

		Gross	WI	RI	Net		0.00 %	5.00 %	8.00 %	10.00 %	15.00 %	20.00 %	Average
Oil	Mbbl	110,530.8	110,530.8	-	110,530.8	Oil	6,742,820.5	4,706,674.5	3,857,071.2	3,398,419.5	2,524,026.6	1,919,717.9	61.00
Gas	MMcf	-	-	-	-	Gas	-	-	-	-	-	-	-
Condensate	Mbbl	-	-	-	-	Condensate	-	-	-	-	-	-	-
Liquids	Mbbl	-	-	-	-	Liquids	-	-	-	-	-	-	-
NGL	Mbbl	-	-	-	-	NGL	-	-	-	-	-	-	-
C2	Mbbl	-	-	-	-	C2	-	-	-	-	-	-	-
C3	Mbbl	-	-	-	-	C3	-	-	-	-	-	-	-
C4	Mbbl	-	-	-	-	C4	-	-	-	-	-	-	-
C5+	Mbbl	-	-	-	-	C5+	-	-	-	-	-	-	-
Sulphur	LT	-	-	-	-	Sulphur	-	-	-	-	-	-	-
Total	**MBOE**	**110,530.8**	**110,530.8**	**-**	**110,530.8**	**Total**	**6,742,820.5**	**4,706,674.5**	**3,857,071.2**	**3,398,419.5**	**2,524,026.6**	**1,919,717.9**	**61.00**

Cash Flow NPV (M$US)

	0.00 %	5.00 %	8.00 %	10.00 %	15.00 %	20.00 %
BT Cash Flow	3,219,119	2,150,314	1,694,921	1,447,893	977,986	658,505
Tax Payable*	1,169,937	772,285	610,155	524,149	364,482	258,935
AT Cash Flow*	**2,049,182**	**1,378,029**	**1,084,766**	**923,744**	**613,504**	**399,570**

Risked Capital Costs (M$US)

	Gross	Co. Share
G&G	-	-
Prop. & Leasehold	-	-
Tangible	1,019,605.2	1,019,605.2
Intangible	587,410.6	587,410.6
Other Capital	-	-
Total	**1,607,015.8**	**1,607,015.8**

Cash Flow (M$US)

	Co. Share	% of Sales Rev.
Revenue	6,742,820.5	
Royalties/Burdens	-	-
Operating Cost	1,774,882.8	26.3
Abandonment/Salvage	141,803.2	2.1
Oth. Rev./Oth. Deduct.	-	-
Capital	1,607,015.8	23.8
(Credit)/Surcharge	-	-
BT Cash Flow	**3,219,118.7**	**47.7**
Tax Paid*	1,169,936.6	17.4
AT Cash Flow*	**2,049,182.0**	**30.4**

Economic Indicators

	Before Tax	After Tax
Rate of Return (%)	50.9	42.7
Payout (yrs from Nov 2023)	2.9	3.0
Payout (date)	Oct 2026	Oct 2026
P/I - 0.0 % Discount	2.00	1.28
P/I - 10.0 % Discount	1.25	0.80
Init. Value (M$US/BOE/d)	-	-

	WI	Co. Share	Net
Op. Cost ($US/BOE)	16.06	16.06	16.06
Cap. Cost ($US/BOE)	14.54	14.54	14.54

Annual Co. Share Cash Flow

Year	Well Count	Rate BOE/d	Avg. Price $US/BOE	Comp Sales Revenue M$US	Royalty M$US	GOR (non Reserve) M$US	Revenue After Royalty M$US	Additional Taxable Revenue M$US	Additional Non-Taxable Revenue M$US	Other expenses M$US	Opex M$US	Capex M$US	Aband M$US	BTax Cash Flow M$US	Total Taxes* M$US	ATax Cash Flow* M$US
2023	-	-	-	-	-	-	-	-	-	-	-	408,357	-	-408,357	-	-408,357
2024 (7)	8.0	27,150	56.10	325,941	-	-	325,941	-	-	-	77,050	898,133	-	-649,242	-	-649,242
2025	9.0	40,906	57.22	854,344	-	-	854,344	-	-	-	109,717	36,683	-	707,944	-	707,944
2026	13.0	43,668	58.37	930,353	-	-	930,353	-	-	-	126,504	148,871	-	654,979	24,753	630,226
2027	15.0	44,202	59.53	960,450	-	-	960,450	-	-	-	148,098	57,154	-	755,198	163,416	591,782
2028	17.0	44,572	60.72	990,545	-	-	990,545	-	-	-	170,109	57,818	-	762,619	270,523	492,095
2029	17.0	33,921	61.94	766,892	-	-	766,892	-	-	-	169,105	-	-	597,787	256,912	340,875
2030	17.0	22,444	63.18	517,578	-	-	517,578	-	-	-	154,729	-	-	362,849	176,465	186,384
2031	17.0	15,795	64.44	371,512	-	-	371,512	-	-	-	142,144	-	-	229,369	109,545	119,824
2032	17.0	11,790	65.73	283,634	-	-	283,634	-	-	-	136,061	-	-	147,573	69,935	77,637
2033	17.0	9,169	67.04	224,362	-	-	224,362	-	-	-	132,769	-	-	91,593	44,101	47,492
2034	17.0	7,351	68.38	183,490	-	-	183,490	-	-	-	130,747	-	-	52,743	26,277	26,466
2035	17.0	6,034	69.75	153,611	-	-	153,611	-	-	-	117,947	-	-	35,664	16,543	19,121
2036	17.0	5,044	71.15	131,351	-	-	131,351	-	-	-	114,567	-	-	16,784	9,231	7,553
2037 (5)	17.0	4,449	72.57	48,755	-	-	48,755	-	-	-	45,336	-	141,803	-138,384	2,236	-140,620
13.00 yr			**61.00**	**6,742,820**	**-**	**-**	**6,742,820**	**-**	**-**	**-**	**1,774,883**	**1,607,016**	**141,803**	**3,219,119**	**1,169,937**	**2,049,182**

* Tax pro-rated to start at 4/1/2021

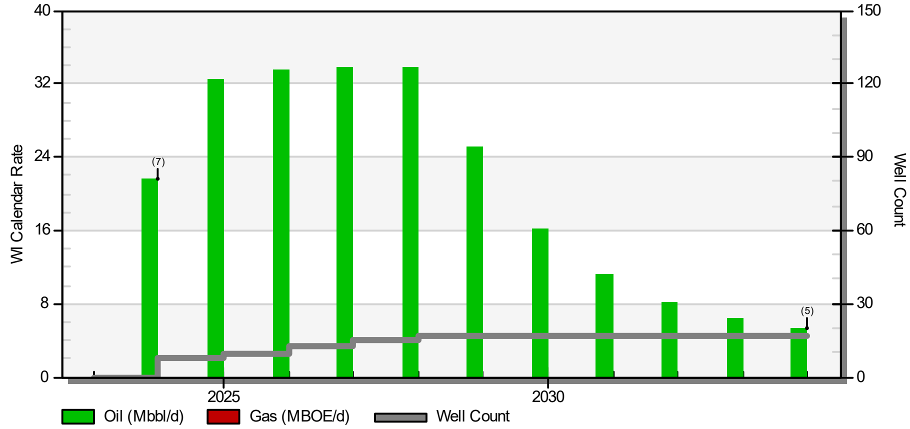
Table 5B

Orcadian Energy

As of April 1, 2021
Pilot Polymer Flood
Proved + Prob. Undeveloped

Evaluation Parameters

Reserves Category	Proved + Prob. Undeveloped
Plan	Working
Reference Date	April-01-21
Discount Date	April-01-21
Econ. Calc. Date	January-01-20
Country	United Kingdom
State	N/A
Company Share	100.00 %
Price Deck	2021-03-31 SAL Prices
Price Set	N/A
Economic Limit	Applied - BTCF 0.00%
Scenario	<Current Options>
BOE Ratio	6:1 Mcf/bbl
Chance of Success	100.0 %
Chance of Occurrence	100.0 %
Oil Reserves Type	Light and Medium Oil
Gas Reserves Type	N/A



Remaining Reserves / Net Revenue NPV (M$US) / Price

		Gross	WI	RI	Net		0.00 %	5.00 %	8.00 %	10.00 %	15.00 %	20.00 %	Average
Oil	Mbbl	78,819.3	78,819.3	-	78,819.3	Oil	4,756,209.8	3,403,303.4	2,821,231.5	2,502,099.0	1,883,181.8	1,446,581.7	60.34
Gas	MMcf	-	-	-	-	Gas	-	-	-	-	-	-	-
Condensate	Mbbl	-	-	-	-	Condensate	-	-	-	-	-	-	-
Liquids	Mbbl	-	-	-	-	Liquids	-	-	-	-	-	-	-
NGL	Mbbl	-	-	-	-	NGL	-	-	-	-	-	-	-
C2	Mbbl	-	-	-	-	C2	-	-	-	-	-	-	-
C3	Mbbl	-	-	-	-	C3	-	-	-	-	-	-	-
C4	Mbbl	-	-	-	-	C4	-	-	-	-	-	-	-
C5+	Mbbl	-	-	-	-	C5+	-	-	-	-	-	-	-
Sulphur	LT	-	-	-	-	Sulphur	-	-	-	-	-	-	-
Total	**MBOE**	**78,819.3**	**78,819.3**	**-**	**78,819.3**	**Total**	**4,756,209.8**	**3,403,303.4**	**2,821,231.5**	**2,502,099.0**	**1,883,181.8**	**1,446,581.7**	**60.34**

Cash Flow NPV (M$US)

	0.00 %	5.00 %	8.00 %	10.00 %	15.00 %	20.00 %
BT Cash Flow	1,638,049	1,045,066	791,463	653,905	393,134	217,881
Tax Payable*	517,496	340,066	267,505	229,004	157,626	110,652
AT Cash Flow*	**1,120,553**	**705,000**	**523,958**	**424,902**	**235,508**	**107,229**

Risked Capital Costs (M$US)

	Gross	Co. Share
G&G	-	-
Prop. & Leasehold	-	-
Tangible	1,019,605.2	1,019,605.2
Intangible	587,410.6	587,410.6
Other Capital	-	-
Total	**1,607,015.8**	**1,607,015.8**

Cash Flow (M$US)

	Co. Share	% of Sales Rev.
Revenue	4,756,209.8	
Royalties/Burdens	-	-
Operating Cost	1,377,520.4	29.0
Abandonment/Salvage	133,624.3	2.8
Oth. Rev./Oth. Deduct.	-	-
Capital	1,607,015.8	33.8
(Credit)/Surcharge	-	-
BT Cash Flow	**1,638,049.3**	**34.4**
Tax Paid*	517,496.4	10.9
AT Cash Flow*	**1,120,552.9**	**23.6**

Economic Indicators

	Before Tax	After Tax
Rate of Return (%)	31.6	26.5
Payout (yrs from Nov 2023)	3.6	3.6
Payout (date)	Jun 2027	Jun 2027
P/I - 0.0 % Discount	1.02	0.70
P/I - 10.0 % Discount	0.56	0.37
Init. Value (M$US/BOE/d)	-	-

	WI	Co. Share	Net
Op. Cost ($US/BOE)	17.48	17.48	17.48
Cap. Cost ($US/BOE)	20.39	20.39	20.39

Annual Co. Share Cash Flow

Year	Well Count	Rate BOE/d	Avg. Price $US/BOE	Comp Sales Revenue M$US	Royalty M$US	GOR (non Reserve) M$US	Revenue After Royalty M$US	Additional Taxable Revenue M$US	Additional Non-Taxable Revenue M$US	Other expenses M$US	Opex M$US	Capex M$US	Aband M$US	BTax Cash Flow M$US	Total Taxes* M$US	ATax Cash Flow* M$US
2023	-	-	-	-	-	-	-	-	-	-	-	408,357	-	-408,357	-	-408,357
2024 (7)	8.0	21,720	56.10	260,753	-	-	260,753	-	-	-	75,230	898,133	-	-712,610	-	-712,610
2025	9.0	32,552	57.22	679,859	-	-	679,859	-	-	-	104,870	36,683	-	538,305	-	538,305
2026	13.0	33,607	58.37	716,001	-	-	716,001	-	-	-	120,551	148,871	-	446,580	-	446,580
2027	15.0	33,801	59.53	734,435	-	-	734,435	-	-	-	141,821	57,154	-	535,459	34,914	500,545
2028	17.0	33,836	60.72	751,960	-	-	751,960	-	-	-	163,483	57,818	-	530,659	123,589	407,070
2029	17.0	25,172	61.94	569,088	-	-	569,088	-	-	-	163,615	-	-	405,474	141,249	264,225
2030	17.0	16,139	63.18	372,167	-	-	372,167	-	-	-	150,694	-	-	221,473	103,151	118,322
2031	17.0	11,164	64.44	262,575	-	-	262,575	-	-	-	139,120	-	-	123,455	62,451	61,004
2032	17.0	8,240	65.73	198,216	-	-	198,216	-	-	-	133,690	-	-	64,525	33,667	30,858
2033	17.0	6,356	67.04	155,537	-	-	155,537	-	-	-	130,858	-	-	24,678	15,184	9,494
2034 (5)	17.0	5,386	68.38	55,619	-	-	55,619	-	-	-	53,589	-	133,624	-131,594	3,291	-134,885
10.00 yr			**60.34**	**4,756,210**	**-**	**-**	**4,756,210**	**-**	**-**	**-**	**1,377,520**	**1,607,016**	**133,624**	**1,638,049**	**517,496**	**1,120,553**

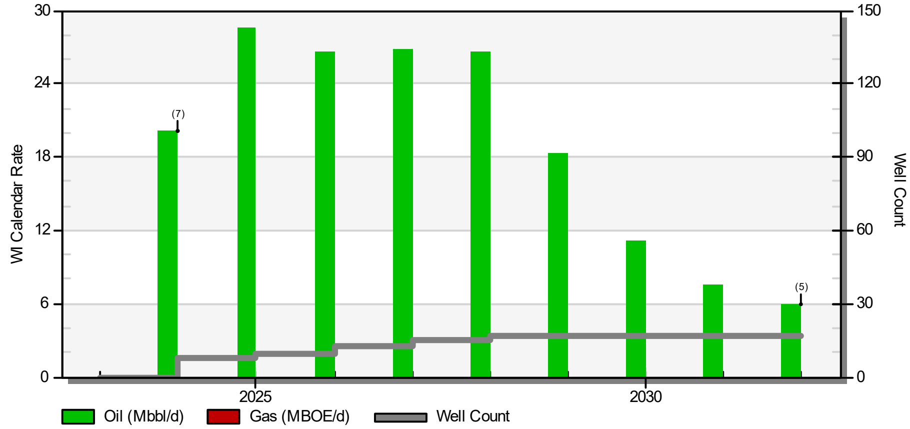
* Tax pro-rated to start at 4/1/2021

Sproule

Orcadian Energy
As of April 1, 2021
Pilot Polymer Flood
Proved Undeveloped

Evaluation Parameters

Reserves Category	Proved Undeveloped
Plan	Working
Reference Date	April-01-21
Discount Date	April-01-21
Econ. Calc. Date	January-01-20
Country	United Kingdom
State	N/A
Company Share	100.00 %
Price Deck	2021-03-31 SAL Prices
Price Set	N/A
Economic Limit	Applied - BTCF 0.00%
Scenario	<Current Options>
BOE Ratio	6:1 Mcf/bbl
Chance of Success	100.0 %
Chance of Occurrence	100.0 %
Oil Reserves Type	Light and Medium Oil
Gas Reserves Type	N/A



Remaining Reserves

		Gross	WI	RI	Net
Oil	Mbbl	58,436.0	58,436.0	-	58,436.0
Gas	MMcf	-	-	-	-
Condensate	Mbbl	-	-	-	-
Liquids	Mbbl	-	-	-	-
NGL	Mbbl	-	-	-	-
C2	Mbbl	-	-	-	-
C3	Mbbl	-	-	-	-
C4	Mbbl	-	-	-	-
C5+	Mbbl	-	-	-	-
Sulphur	LT	-	-	-	-
Total	**MBOE**	**58,436.0**	**58,436.0**	**-**	**58,436.0**

Net Revenue NPV (M$US)

	0.00 %	5.00 %	8.00 %	10.00 %	15.00 %	20.00 %	Price Average
Oil	3,490,363.5	2,558,231.5	2,146,769.5	1,918,021.8	1,467,052.9	1,142,138.1	59.73
Gas	-	-	-	-	-	-	-
Condensate	-	-	-	-	-	-	-
Liquids	-	-	-	-	-	-	-
NGL	-	-	-	-	-	-	-
C2	-	-	-	-	-	-	-
C3	-	-	-	-	-	-	-
C4	-	-	-	-	-	-	-
C5+	-	-	-	-	-	-	-
Sulphur	-	-	-	-	-	-	-
Total	**3,490,363.5**	**2,558,231.5**	**2,146,769.5**	**1,918,021.8**	**1,467,052.9**	**1,142,138.1**	**59.73**

Cash Flow NPV (M$US)

BT Cash Flow	666,224	359,460	229,427	159,525	29,278	-55,020
Tax Payable*	158,544	103,750	81,309	69,403	47,360	32,908
AT Cash Flow*	**507,680**	**255,710**	**148,119**	**90,123**	**-18,081**	**-87,927**

Risked Capital Costs (M$US)

	Gross	Co. Share
G&G	-	-
Prop. & Leasehold	-	-
Tangible	1,019,605.2	1,019,605.2
Intangible	587,410.6	587,410.6
Other Capital	-	-
Total	**1,607,015.8**	**1,607,015.8**

Cash Flow (M$US)

	Co. Share	% of Sales Rev.
Revenue	3,490,363.5	
Royalties/Burdens	-	-
Operating Cost	1,088,688.1	31.2
Abandonment/Salvage	128,435.5	3.7
Oth. Rev./Oth. Deduct.	-	-
Capital	1,607,015.8	46.0
(Credit)/Surcharge	-	-
BT Cash Flow	**666,224.2**	**19.1**
Tax Paid*	158,543.8	4.5
AT Cash Flow*	**507,680.4**	**14.5**

Economic Indicators

	Before Tax	After Tax
Rate of Return (%)	16.5	14.0
Payout (yrs from Nov 2023)	4.3	4.3
Payout (date)	Feb 2028	Feb 2028
P/I - 0.0 % Discount	0.41	0.32
P/I - 10.0 % Discount	0.14	0.08
Init. Value (M$US/BOE/d)	-	-

	WI	Co. Share	Net
Op. Cost ($US/BOE)	18.63	18.63	18.63
Cap. Cost ($US/BOE)	27.50	27.50	27.50

Annual Co. Share Cash Flow

Year	Well Count	Rate BOE/d	Avg. Price $US/BOE	Comp Sales Revenue M$US	Royalty M$US	GOR (non Reserve) M$US	Revenue After Royalty M$US	Additional Taxable Revenue M$US	Additional Non-Taxable Revenue M$US	Other expenses M$US	Opex M$US	Capex M$US	Aband M$US	BTax Cash Flow M$US	Total Taxes* M$US	ATax Cash Flow* M$US
2023	-	-	-	-	-	-	-	-	-	-	-	408,357	-	-408,357	-	-408,357
2024 (7)	8.0	20,091	56.10	241,196	-	-	241,196	-	-	-	74,684	898,133	-	-731,620	-	-731,620
2025	9.0	28,549	57.22	596,245	-	-	596,245	-	-	-	102,543	36,683	-	457,019	-	457,019
2026	13.0	26,724	58.37	569,353	-	-	569,353	-	-	-	116,479	148,871	-	304,004	-	304,004
2027	15.0	26,817	59.53	582,682	-	-	582,682	-	-	-	137,606	57,154	-	387,921	-	387,921
2028	17.0	26,586	60.72	590,831	-	-	590,831	-	-	-	159,009	57,818	-	374,004	24,389	349,615
2029	17.0	18,354	61.94	414,948	-	-	414,948	-	-	-	159,335	-	-	255,613	63,317	192,296
2030	17.0	11,147	63.18	257,058	-	-	257,058	-	-	-	147,499	-	-	109,559	47,473	62,086
2031	17.0	7,573	64.44	178,133	-	-	178,133	-	-	-	136,776	-	-	41,357	19,227	22,130
2032 (5)	17.0	5,997	65.73	59,918	-	-	59,918	-	-	-	54,758	-	128,436	-123,276	4,137	-127,413
8.00 yr			**59.73**	**3,490,364**	**-**	**-**	**3,490,364**	**-**	**-**	**-**	**1,088,688**	**1,607,016**	**128,436**	**666,224**	**158,544**	**507,680**

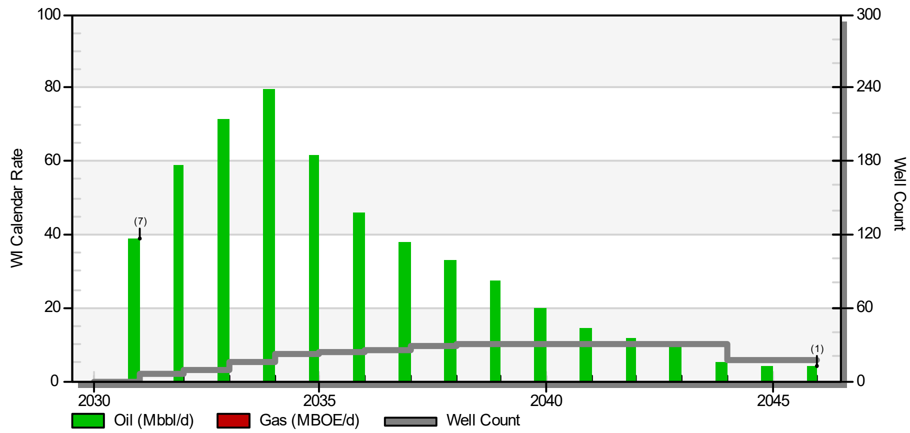
* Tax pro-rated to start at 4/1/2021

Sproule

Orcadian Energy
As of April 1, 2021
CR - Blakeney, Elke and Narwhal
3C

Evaluation Parameters

Reserves Category	3C
Plan	Working
Reference Date	April-01-21
Discount Date	April-01-21
Econ. Calc. Date	January-01-20
Country	United Kingdom
State	N/A
Company Share	100.00 %
Price Deck	2021-03-31 SAL Prices
Price Set	N/A
Economic Limit	Applied - BTCF 0.00%
Scenario	<Current Options>
BOE Ratio	6:1 Mcf/bbl
Chance of Success	100.0 %
Chance of Occurrence	100.0 %
Oil Reserves Type	Light and Medium Oil
Gas Reserves Type	N/A



Remaining Reserves / Net Revenue NPV (M$US) / Price

		Gross	WI	RI	Net		0.00 %	5.00 %	8.00 %	10.00 %	15.00 %	20.00 %	Average
Oil	Mbbl	183,852.1	183,852.1	-	183,852.1	Oil	12,987,101.3	6,323,133.0	4,215,845.5	3,249,424.6	1,748,307.0	978,467.1	70.64
Gas	MMcf	-	-	-	-	Gas	-	-	-	-	-	-	-
Condensate	Mbbl	-	-	-	-	Condensate	-	-	-	-	-	-	-
Liquids	Mbbl	-	-	-	-	Liquids	-	-	-	-	-	-	-
NGL	Mbbl	-	-	-	-	NGL	-	-	-	-	-	-	-
C2	Mbbl	-	-	-	-	C2	-	-	-	-	-	-	-
C3	Mbbl	-	-	-	-	C3	-	-	-	-	-	-	-
C4	Mbbl	-	-	-	-	C4	-	-	-	-	-	-	-
C5+	Mbbl	-	-	-	-	C5+	-	-	-	-	-	-	-
Sulphur	LT	-	-	-	-	Sulphur	-	-	-	-	-	-	-
Total	**MBOE**	**183,852.1**	**183,852.1**	**-**	**183,852.1**	**Total**	**12,987,101.3**	**6,323,133.0**	**4,215,845.5**	**3,249,424.6**	**1,748,307.0**	**978,467.1**	**70.64**

Cash Flow NPV (M$US)

	0.00 %	5.00 %	8.00 %	10.00 %	15.00 %	20.00 %
BT Cash Flow	8,059,338	3,959,159	2,638,336	2,028,858	1,079,302	593,474
Tax Payable*	3,118,902	1,496,275	985,796	753,087	395,310	215,348
AT Cash Flow*	**4,940,436**	**2,462,883**	**1,652,540**	**1,275,771**	**683,992**	**378,126**

Risked Capital Costs (M$US)

	Gross	Co. Share
G&G	-	-
Prop. & Leasehold	-	-
Tangible	664,225.0	664,225.0
Intangible	1,302,758.0	1,302,758.0
Other Capital	-	-
Total	**1,966,983.1**	**1,966,983.1**

Cash Flow (M$US)

	Co. Share	% of Sales Rev.
Revenue	12,987,101.3	
Royalties/Burdens	-	-
Operating Cost	2,747,548.6	21.2
Abandonment/Salvage	213,231.9	1.6
Oth. Rev./Oth. Deduct.	-	-
Capital	1,966,983.1	15.1
(Credit)/Surcharge	-	-
BT Cash Flow	**8,059,337.7**	**62.1**
Tax Paid*	3,118,902.0	24.0
AT Cash Flow*	**4,940,435.8**	**38.0**

Economic Indicators

	Before Tax	After Tax
Rate of Return (%)	N/A	135.4
Payout (yrs from Dec 2030)	2.2	2.4
Payout (date)	Feb 2033	Apr 2033
P/I - 0.0 % Discount	4.10	2.51
P/I - 10.0 % Discount	3.15	1.98
Init. Value (M$US/BOE/d)	-	-

	WI	Co. Share	Net
Op. Cost ($US/BOE)	14.94	14.94	14.94
Cap. Cost ($US/BOE)	10.70	10.70	10.70

Annual Co. Share Cash Flow

Year	Well Count	Rate BOE/d	Avg. Price $US/BOE	Comp Sales Revenue M$US	Royalty M$US	GOR (non Reserve) M$US	Revenue After Royalty M$US	Additional Taxable Revenue M$US	Additional Non-Taxable Revenue M$US	Other expenses M$US	Opex M$US	Capex M$US	Aband M$US	BTax Cash Flow M$US	Total Taxes* M$US	ATax Cash Flow* M$US
2030	-	-	-	-	-	-	-	-	-	-	-	467,360	-	-467,360	-	-467,360
2031 (7)	5.6	39,023	64.44	538,138	-	-	538,138	-	-	-	43,172	322,510	-	172,456	-	172,456
2032	8.5	58,833	65.73	1,415,324	-	-	1,415,324	-	-	-	121,411	188,314	-	1,105,598	155,100	950,498
2033	14.8	71,723	67.04	1,755,112	-	-	1,755,112	-	-	-	174,947	412,891	-	1,167,274	371,619	795,655
2034	22.0	79,663	68.38	1,988,415	-	-	1,988,415	-	-	-	229,803	243,326	-	1,515,287	540,972	974,314
2035	24.0	61,739	69.75	1,571,848	-	-	1,571,848	-	-	-	231,821	100,001	-	1,240,026	523,476	716,550
2036	26.0	45,893	71.15	1,195,052	-	-	1,195,052	-	-	-	224,875	101,833	-	868,344	390,569	477,775
2037	28.0	37,714	72.57	998,979	-	-	998,979	-	-	-	214,662	77,774	-	706,544	298,829	407,715
2038	30.0	32,822	74.02	886,780	-	-	886,780	-	-	-	214,448	52,974	-	619,358	255,540	363,818
2039	30.0	27,393	75.50	754,890	-	-	754,890	-	-	-	214,077	-	-	540,813	225,694	315,119
2040	30.0	19,850	77.01	559,503	-	-	559,503	-	-	-	207,201	-	-	352,303	166,056	186,247
2041	30.0	14,625	78.55	419,314	-	-	419,314	-	-	-	202,035	-	-	217,279	104,915	112,364
2042	30.0	11,424	80.12	334,095	-	-	334,095	-	-	-	197,226	-	-	136,869	65,469	71,400
2043	30.0	9,253	81.73	276,013	-	-	276,013	-	-	-	212,820	-	88,676	-25,484	11,454	-36,937
2044	17.0	4,924	83.36	150,225	-	-	150,225	-	-	-	124,214	-	-	26,011	2,859	23,152
2045	17.0	4,274	85.03	132,636	-	-	132,636	-	-	-	124,578	-	-	8,058	5,277	2,781
2046 (1)	16.5	4,009	86.73	10,778	-	-	10,778	-	-	-	10,259	-	124,555	-124,037	1,073	-125,110
14.67 yr			**70.64**	**12,987,101**	**-**	**-**	**12,987,101**	**-**	**-**	**-**	**2,747,549**	**1,966,983**	**213,232**	**8,059,338**	**3,118,902**	**4,940,436**

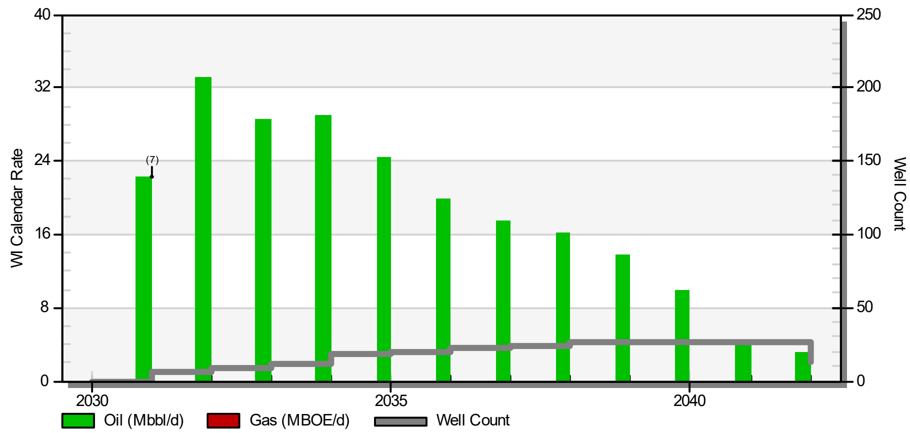
* Tax pro-rated to start at 4/1/2021

Sproule

Orcadian Energy
As of April 1, 2021
CR - Blakeney, Elke and Narwhal
2C

Evaluation Parameters

Reserves Category	2C
Plan	Working
Reference Date	April-01-21
Discount Date	April-01-21
Econ. Calc. Date	January-01-20
Country	United Kingdom
State	N/A
Company Share	100.00 %
Price Deck	2021-03-31 SAL Prices
Price Set	N/A
Economic Limit	Applied - BTCF 0.00%
Scenario	<Current Options>
BOE Ratio	6:1 Mcf/bbl
Chance of Success	100.0 %
Chance of Occurrence	100.0 %
Oil Reserves Type	Light and Medium Oil
Gas Reserves Type	N/A



Remaining Reserves / Net Revenue NPV (M$US) / Price

		Gross	WI	RI	Net		0.00 %	5.00 %	8.00 %	10.00 %	15.00 %	20.00 %	Average
Oil	Mbbl	77,853.5	77,853.5	-	77,853.5	Oil	5,448,385.6	2,709,990.1	1,825,400.2	1,415,438.5	771,487.1	436,500.0	69.98
Gas	MMcf	-	-	-	-	Gas	-	-	-	-	-	-	-
Condensate	Mbbl	-	-	-	-	Condensate	-	-	-	-	-	-	-
Liquids	Mbbl	-	-	-	-	Liquids	-	-	-	-	-	-	-
NGL	Mbbl	-	-	-	-	NGL	-	-	-	-	-	-	-
C2	Mbbl	-	-	-	-	C2	-	-	-	-	-	-	-
C3	Mbbl	-	-	-	-	C3	-	-	-	-	-	-	-
C4	Mbbl	-	-	-	-	C4	-	-	-	-	-	-	-
C5+	Mbbl	-	-	-	-	C5+	-	-	-	-	-	-	-
Sulphur	LT	-	-	-	-	Sulphur	-	-	-	-	-	-	-
Total	**MBOE**	**77,853.5**	**77,853.5**	**-**	**77,853.5**	**Total**	**5,448,385.6**	**2,709,990.1**	**1,825,400.2**	**1,415,438.5**	**771,487.1**	**436,500.0**	**69.98**

Cash Flow NPV (M$US)

	0.00 %	5.00 %	8.00 %	10.00 %	15.00 %	20.00 %
BT Cash Flow	2,168,063	1,041,361	681,416	516,628	263,305	137,122
Tax Payable*	744,021	349,909	227,471	172,162	88,211	46,875
AT Cash Flow*	**1,424,042**	**691,452**	**453,945**	**344,465**	**175,095**	**90,247**

Risked Capital Costs (M$US)

	Gross	Co. Share
G&G	-	-
Prop. & Leasehold	-	-
Tangible	664,225.0	664,225.0
Intangible	1,113,192.4	1,113,192.4
Other Capital	-	-
Total	**1,777,417.5**	**1,777,417.5**

Cash Flow (M$US)

	Co. Share	% of Sales Rev.
Revenue	5,448,385.6	
Royalties/Burdens	-	-
Operating Cost	1,332,267.8	24.5
Abandonment/Salvage	170,637.6	3.1
Oth. Rev./Oth. Deduct.	-	-
Capital	1,777,417.5	32.6
(Credit)/Surcharge	-	-
BT Cash Flow	**2,168,062.7**	**39.8**
Tax Paid*	744,020.6	13.7
AT Cash Flow*	**1,424,042.2**	**26.1**

Economic Indicators

	Before Tax	After Tax
Rate of Return (%)	64.8	55.5
Payout (yrs from Dec 2030)	3.4	3.5
Payout (date)	Apr 2034	Jun 2034
P/I - 0.0 % Discount	1.22	0.80
P/I - 10.0 % Discount	0.89	0.59
Init. Value (M$US/BOE/d)	-	-

	WI	Co. Share	Net
Op. Cost ($US/BOE)	17.11	17.11	17.11
Cap. Cost ($US/BOE)	22.83	22.83	22.83

Annual Co. Share Cash Flow

Year	Well Count	Rate BOE/d	Avg. Price $US/BOE	Comp Sales Revenue M$US	Royalty M$US	GOR (non Reserve) M$US	Revenue After Royalty M$US	Additional Taxable Revenue M$US	Additional Non-Taxable Revenue M$US	Other expenses M$US	Opex M$US	Capex M$US	Aband M$US	BTax Cash Flow M$US	Total Taxes* M$US	ATax Cash Flow* M$US
2030	-	-	-	-	-	-	-	-	-	-	-	467,360	-	-467,360	-	-467,360
2031 (7)	5.6	22,299	64.44	307,508	-	-	307,508	-	-	-	31,693	322,510	-	-46,696	-	-46,696
2032	8.4	33,076	65.73	795,689	-	-	795,689	-	-	-	76,052	46,768	-	672,869	12,134	660,735
2033	12.0	28,487	67.04	697,110	-	-	697,110	-	-	-	81,860	364,872	-	250,379	56,143	194,236
2034	18.0	29,116	68.38	726,745	-	-	726,745	-	-	-	108,563	243,326	-	374,857	100,009	274,847
2035	20.0	24,453	69.75	622,571	-	-	622,571	-	-	-	123,009	100,001	-	399,561	125,394	274,167
2036	22.0	19,944	71.15	519,332	-	-	519,332	-	-	-	134,413	101,833	-	283,087	115,201	167,886
2037	24.0	17,586	72.57	465,811	-	-	465,811	-	-	-	146,233	77,774	-	241,804	96,864	144,940
2038	26.0	16,155	74.02	436,474	-	-	436,474	-	-	-	156,365	52,974	-	227,136	88,982	138,153
2039	26.0	13,805	75.50	380,431	-	-	380,431	-	-	-	163,333	-	-	217,098	87,074	130,024
2040	26.0	9,844	77.01	277,465	-	-	277,465	-	-	-	162,427	-	-	115,037	59,623	55,414
2041	26.0	4,506	78.55	129,192	-	-	129,192	-	-	-	77,348	-	83,700	-31,856	6,843	-38,699
2042	13.0	3,079	80.12	90,058	-	-	90,058	-	-	-	70,973	-	86,938	-67,853	-4,248	-63,605
11.58 yr			**69.98**	**5,448,386**	**-**	**-**	**5,448,386**	**-**	**-**	**-**	**1,332,268**	**1,777,417**	**170,638**	**2,168,063**	**744,021**	**1,424,042**

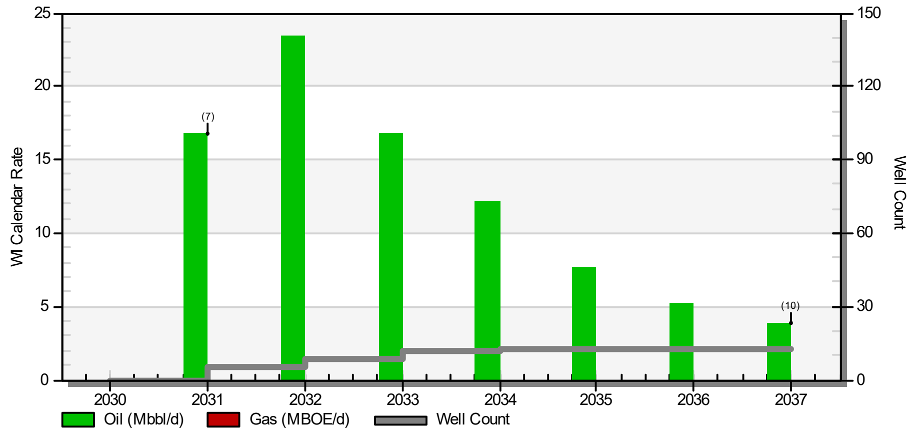
* Tax pro-rated to start at 4/1/2021

Sproule

Orcadian Energy
As of April 1, 2021
CR - Blakeney, Elke and Narwhal
1C

Evaluation Parameters

Reserves Category	1C
Plan	Working
Reference Date	April-01-21
Discount Date	April-01-21
Econ. Calc. Date	January-01-20
Country	United Kingdom
State	N/A
Company Share	100.00 %
Price Deck	2021-03-31 SAL Prices
Price Set	N/A
Economic Limit	N/A
Scenario	<Current Options>
BOE Ratio	6:1 Mcf/bbl
Chance of Success	100.0 %
Chance of Occurrence	100.0 %
Oil Reserves Type	Light and Medium Oil
Gas Reserves Type	N/A



Remaining Reserves / Net Revenue NPV (M$US) / Price

		Gross	WI	RI	Net		0.00 %	5.00 %	8.00 %	10.00 %	15.00 %	20.00 %	Average
Oil	Mbbl	28,621.3	28,621.3	-	28,621.3	Oil	1,926,123.1	1,051,009.3	742,742.1	593,010.7	344,779.8	205,944.5	67.30
Gas	MMcf	-	-	-	-	Gas	-	-	-	-	-	-	-
Condensate	Mbbl	-	-	-	-	Condensate	-	-	-	-	-	-	-
Liquids	Mbbl	-	-	-	-	Liquids	-	-	-	-	-	-	-
NGL	Mbbl	-	-	-	-	NGL	-	-	-	-	-	-	-
C2	Mbbl	-	-	-	-	C2	-	-	-	-	-	-	-
C3	Mbbl	-	-	-	-	C3	-	-	-	-	-	-	-
C4	Mbbl	-	-	-	-	C4	-	-	-	-	-	-	-
C5+	Mbbl	-	-	-	-	C5+	-	-	-	-	-	-	-
Sulphur	LT	-	-	-	-	Sulphur	-	-	-	-	-	-	-
Total	**MBOE**	**28,621.3**	**28,621.3**	**-**	**28,621.3**	**Total**	**1,926,123.1**	**1,051,009.3**	**742,742.1**	**593,010.7**	**344,779.8**	**205,944.5**	**67.30**

Cash Flow NPV (M$US)

BT Cash Flow	339,364	149,655	89,252	62,052	21,944	4,121
Tax Payable*	86,812	43,275	28,977	22,323	11,879	6,502
AT Cash Flow*	**252,551**	**106,380**	**60,275**	**39,729**	**10,066**	**-2,382**

Risked Capital Costs (M$US)

	Gross	Co. Share
G&G	-	-
Prop. & Leasehold	-	-
Tangible	467,360.4	467,360.4
Intangible	537,285.3	537,285.3
Other Capital	-	-
Total	**1,004,645.7**	**1,004,645.7**

Cash Flow (M$US)

	Co. Share	% of Sales Rev.
Revenue	1,926,123.1	
Royalties/Burdens	-	-
Operating Cost	503,631.0	26.1
Abandonment/Salvage	78,482.7	4.1
Oth. Rev./Oth. Deduct.	-	-
Capital	1,004,645.7	52.2
(Credit)/Surcharge	-	-
BT Cash Flow	**339,363.7**	**17.6**
Tax Paid*	86,812.5	4.5
AT Cash Flow*	**252,551.2**	**13.1**

Economic Indicators

	Before Tax	After Tax
Rate of Return (%)	22.2	18.6
Payout (yrs from Dec 2030)	3.0	3.0
Payout (date)	Nov 2033	Dec 2033
P/I - 0.0 % Discount	0.34	0.25
P/I - 10.0 % Discount	0.17	0.11
Init. Value (M$US/BOE/d)	-	-

	WI	Co. Share	Net
Op. Cost ($US/BOE)	17.60	17.60	17.60
Cap. Cost ($US/BOE)	35.10	35.10	35.10

Annual Co. Share Cash Flow

Year	Well Count	Rate BOE/d	Avg. Price $US/BOE	Comp Sales Revenue M$US	Royalty M$US	GOR (non Reserve) M$US	Revenue After Royalty M$US	Additional Taxable Revenue M$US	Additional Non-Taxable Revenue M$US	Other expenses M$US	Opex M$US	Capex M$US	Aband M$US	BTax Cash Flow M$US	Total Taxes* M$US	ATax Cash Flow* M$US
2030	-	-	-	-	-	-	-	-	-	-	-	467,360	-	-467,360	-	-467,360
2031 (7)	5.6	16,724	64.44	230,631	-	-	230,631	-	-	-	29,548	322,510	-	-121,428	-	-121,428
2032	8.4	23,417	65.73	563,327	-	-	563,327	-	-	-	69,596	46,768	-	446,963	-	446,963
2033	12.0	16,813	67.04	411,420	-	-	411,420	-	-	-	73,924	168,007	-	169,489	-	169,489
2034	13.0	12,190	68.38	304,271	-	-	304,271	-	-	-	80,431	-	-	223,840	26,341	197,498
2035	13.0	7,731	69.75	196,819	-	-	196,819	-	-	-	85,642	-	-	111,177	35,406	75,771
2036	13.0	5,198	71.15	135,356	-	-	135,356	-	-	-	88,865	-	-	46,491	20,416	26,075
2037 (10)	13.0	3,821	72.57	84,298	-	-	84,298	-	-	-	75,624	-	78,483	-69,809	4,649	-74,458
6.42 yr			**67.30**	**1,926,123**	**-**	**-**	**1,926,123**	**-**	**-**	**-**	**503,631**	**1,004,646**	**78,483**	**339,364**	**86,812**	**252,551**

* Tax pro-rated to start at 4/1/2021

Table 7

Price Sensitivity Comparisons - Reserves
Orcadian Energy PLC
Mutliple Price Forecasts, Inflated
(As of April 1, 2021)

	Total Proved + Probable Reserves			Net Present Values	IRR	Payout
	Project	Company		After Income Taxes (M$ US)[1]		
	Gross Oil (Mbbl)	Gross Oil (Mbbl)	Net Oil (Mbbl)	At 10% Discount Rate	After Income Tax (%)	(Years)
Scenario						
March 31, 2021 Sproule Price Forecast	78,819	78,819	78,819	424,902	27%	3.6
$50 Brent Price Forecast	78,180	78,180	78,180	339,015	23%	3.8
$60 Brent Price Forecast	79,571	79,571	79,571	640,071	34%	3.2
$70 Brent Price Forecast	79,945	79,945	79,945	936,836	45%	2.9

Breakeven Oil Price estimated at $31.65 on an Undiscounted basis and $38.65 on a 10% discounted basis.

Values may not add due to rounding
1 - The values presented for Oil under the various scenarios are after income taxes, at a 10% discount rate.

Table 7A

Price Sensitivity Comparisons - Contingent Resources Total
Orcadian Energy PLC
Mutliple Price Forecasts, Inflated
(As of April 1, 2021)

	Best Estimate Contingent Resources			Net Present Values	IRR	Payout
	Project	Company		After Income Taxes (M$ US)[1]		
	Gross Oil (Mbbl)	Gross Oil (Mbbl)	Net Oil (Mbbl)	At 10% Discount Rate	After Income Tax (%)	(Years)
Scenario						
March 31, 2021 Sproule Price Forecast	77,854	77,854	77,854	344,465	56%	3.5
$50 Brent Price Forecast	77,346	77,346	77,346	296,541	50%	3.7
$60 Brent Price Forecast	79,139	79,139	79,139	463,196	69%	3.2
$70 Brent Price Forecast	79,857	79,857	79,857	631,230	88%	2.8

Breakeven Oil Price estimated at $30 on an Undiscounted basis and $32 on a 10% discounted basis.

Values may not add due to rounding
1 - The values presented for Oil under the various scenarios are after income taxes, at a 10% discount rate.

Table 7B

Price Sensitivity Comparisons - Elke and Narwhal Contingent Resources
Orcadian Energy PLC
Mutliple Price Forecasts, Inflated
(As of April 1, 2021)

	Best Estimate Contingent Resources			Net Present Values	IRR	Payout
	Project	Company		After Income Taxes (M$ US)[1]		
	Gross Oil (Mbbl)	Gross Oil (Mbbl)	Net Oil (Mbbl)	At 10% Discount Rate	After Income Tax (%)	(Years)
Scenario						
March 31, 2021 Sproule Price Forecast	52,740	52,740	52,740	358,381	66%	2.1
$50 Brent Price Forecast	52,233	52,233	52,233	320,243	60%	2.2
$60 Brent Price Forecast	53,944	53,944	53,944	457,619	80%	2.0
$70 Brent Price Forecast	54,149	54,149	54,149	597,795	99%	1.8

Breakeven Oil Price estimated at $27 on a 10% discounted basis.

Values may not add due to rounding
1 - The values presented for Oil under the various scenarios are after income taxes, at a 10% discount rate.

Table 7C

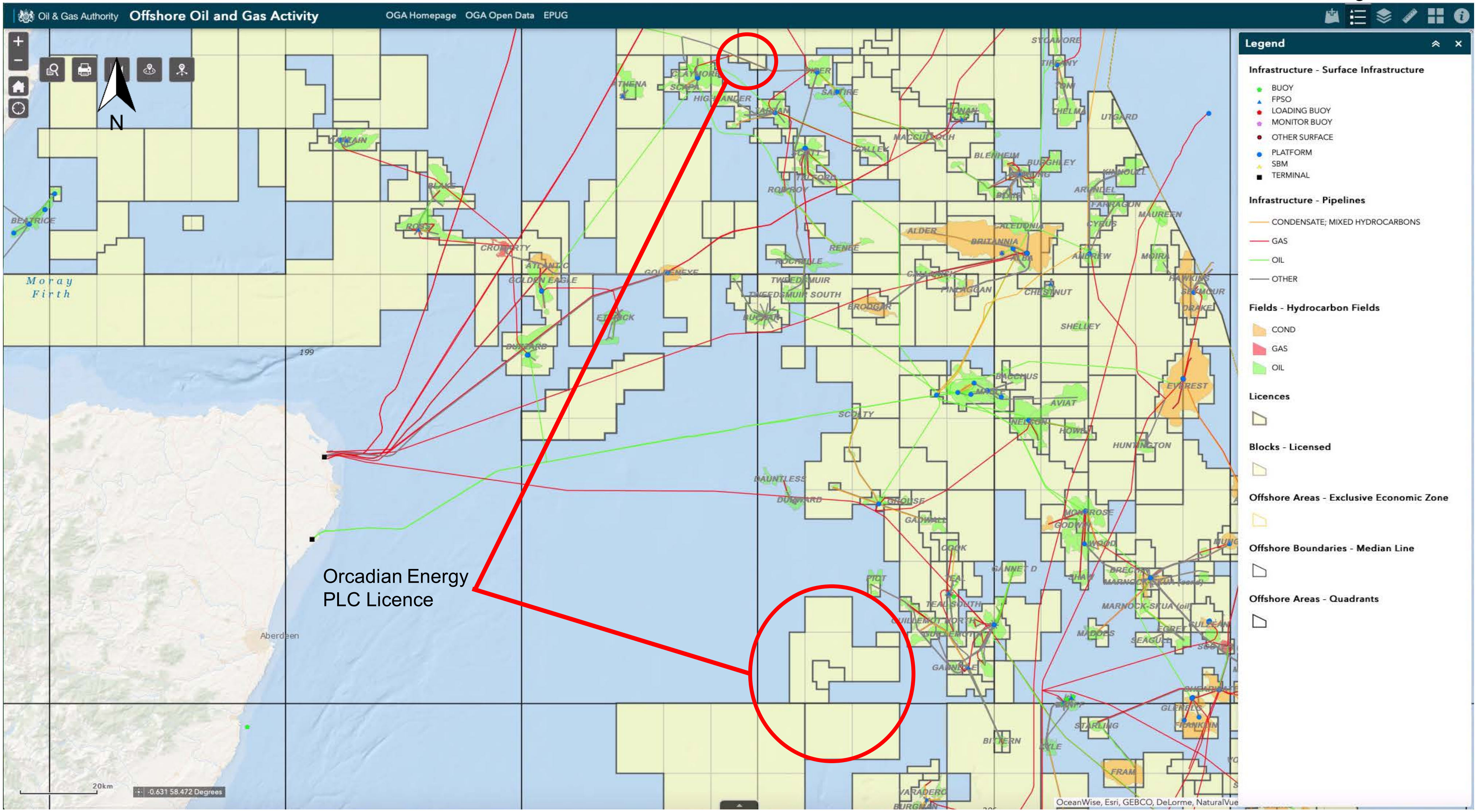
Price Sensitivity Comparisons - Blakeney Contingent Resources
Orcadian Energy PLC
Mutliple Price Forecasts, Inflated
(As of April 1, 2021)

	Best Estimate Contingent Resources			Net Present Values	IRR	Payout
	Project	Company		After Income Taxes (M$ US)[1]		
	Gross Oil (Mbbl)	Gross Oil (Mbbl)	Net Oil (Mbbl)	At 10% Discount Rate	After Income Tax (%)	(Years)
Scenario						
March 31, 2021 Sproule Price Forecast	25,113	25,113	25,113	-13,916	7%	5.9
$50 Brent Price Forecast	25,113	25,113	25,113	-23,702	4%	6.1
$60 Brent Price Forecast	25,196	25,196	25,196	5,577	11%	5.5
$70 Brent Price Forecast	25,708	25,708	25,708	33,436	16%	5.1

Breakeven Oil Price estimated at $59 on a 10% discounted basis

Values may not add due to rounding
1 - The values presented for Oil under the various scenarios are after income taxes, at a 10% discount rate.

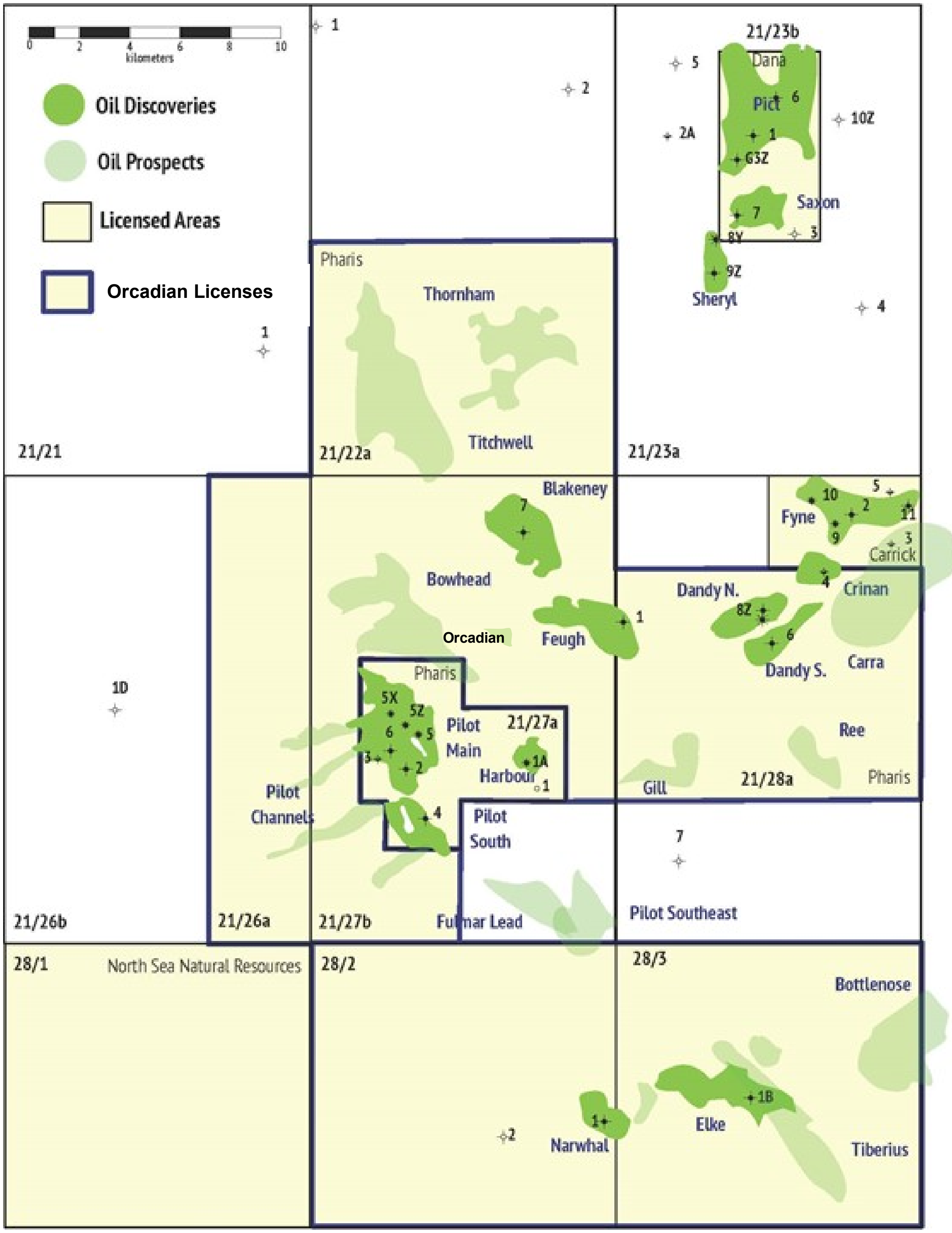
Figure 1



United Kingdom Continental Shelf (UKCS) Offshore Infrastructure Map
Source: www.gov.uk

Location Map

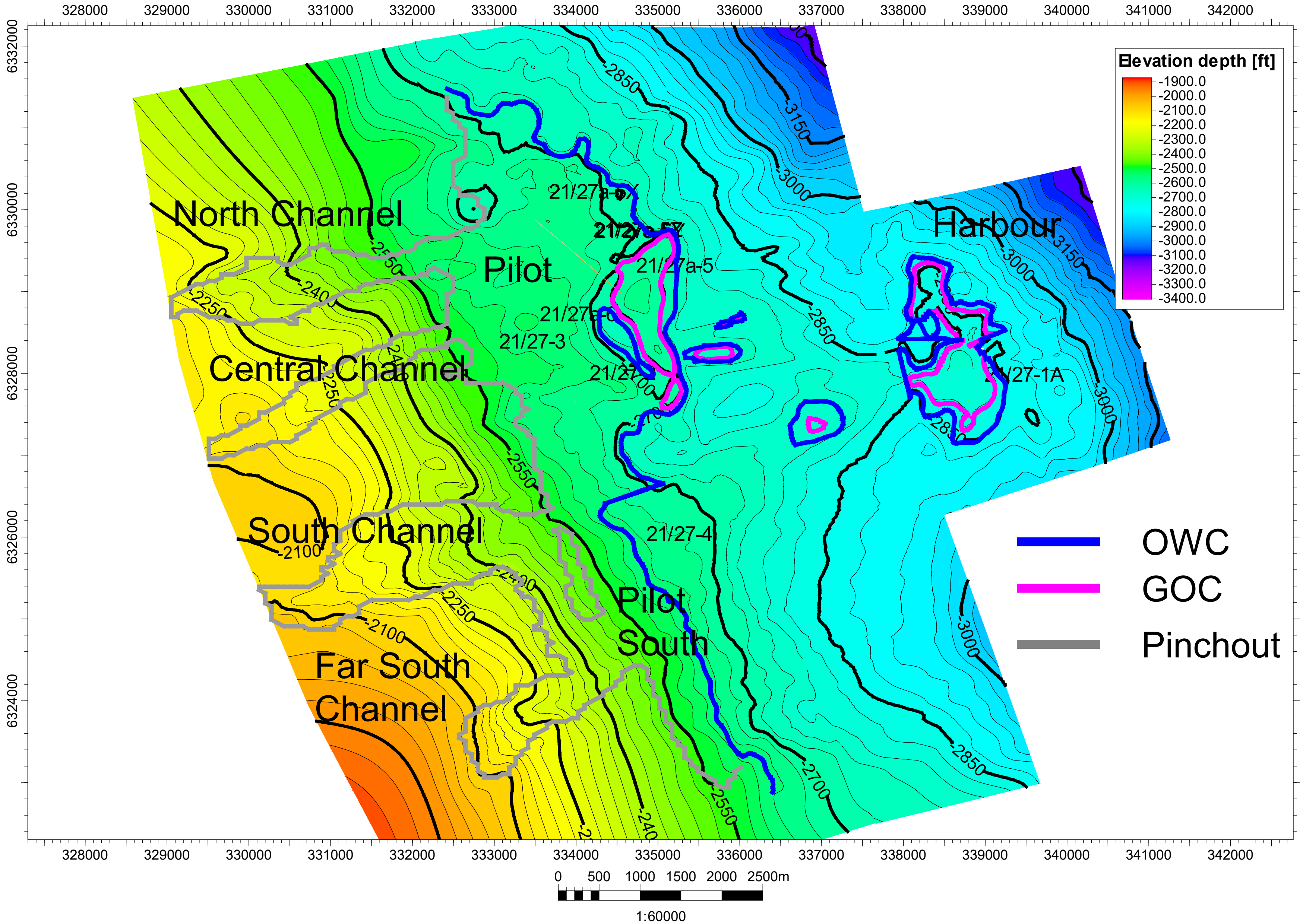
Figure 2



Source: Orcadian Energy PLC

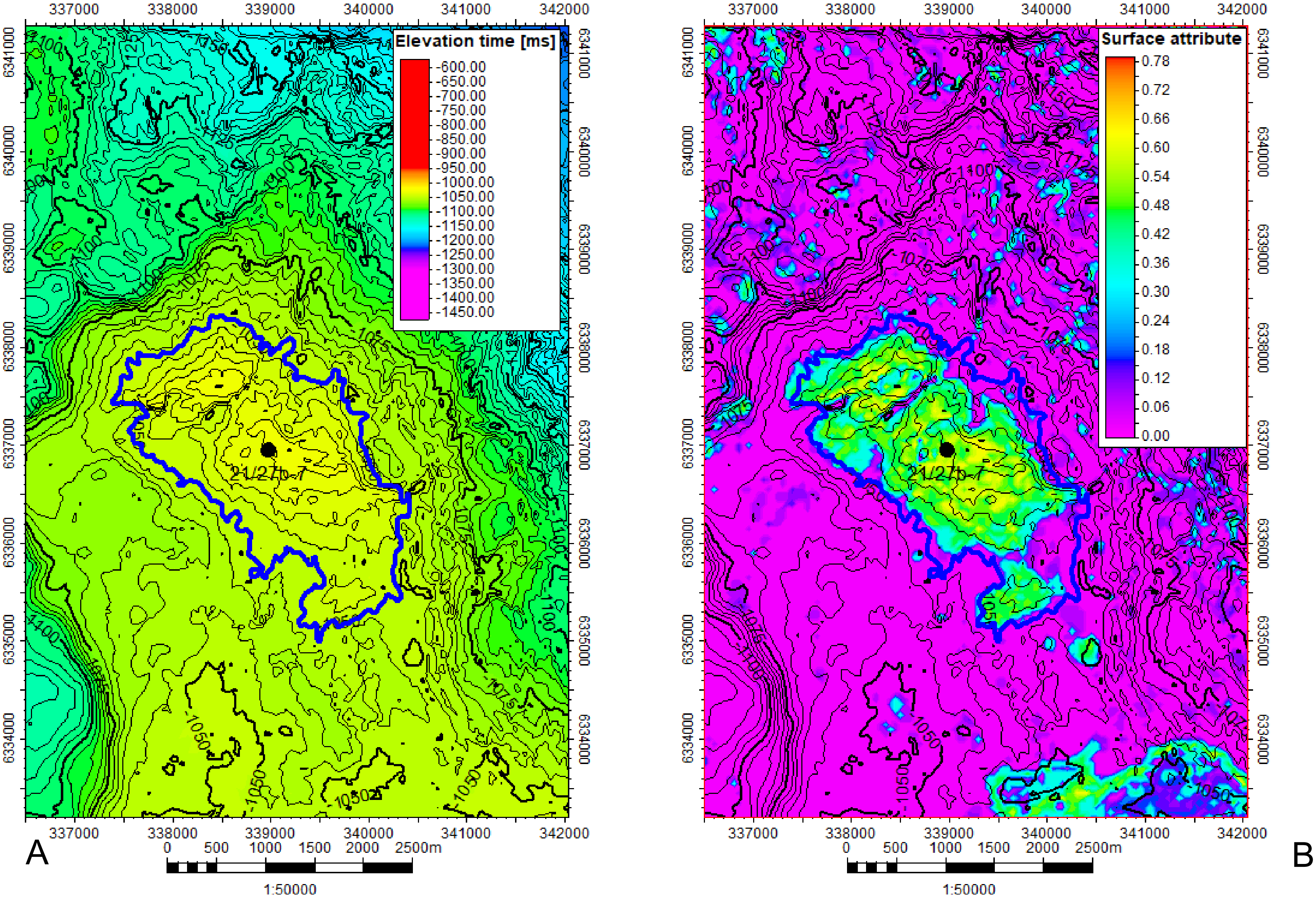
Permit Detail Map

Figure 3

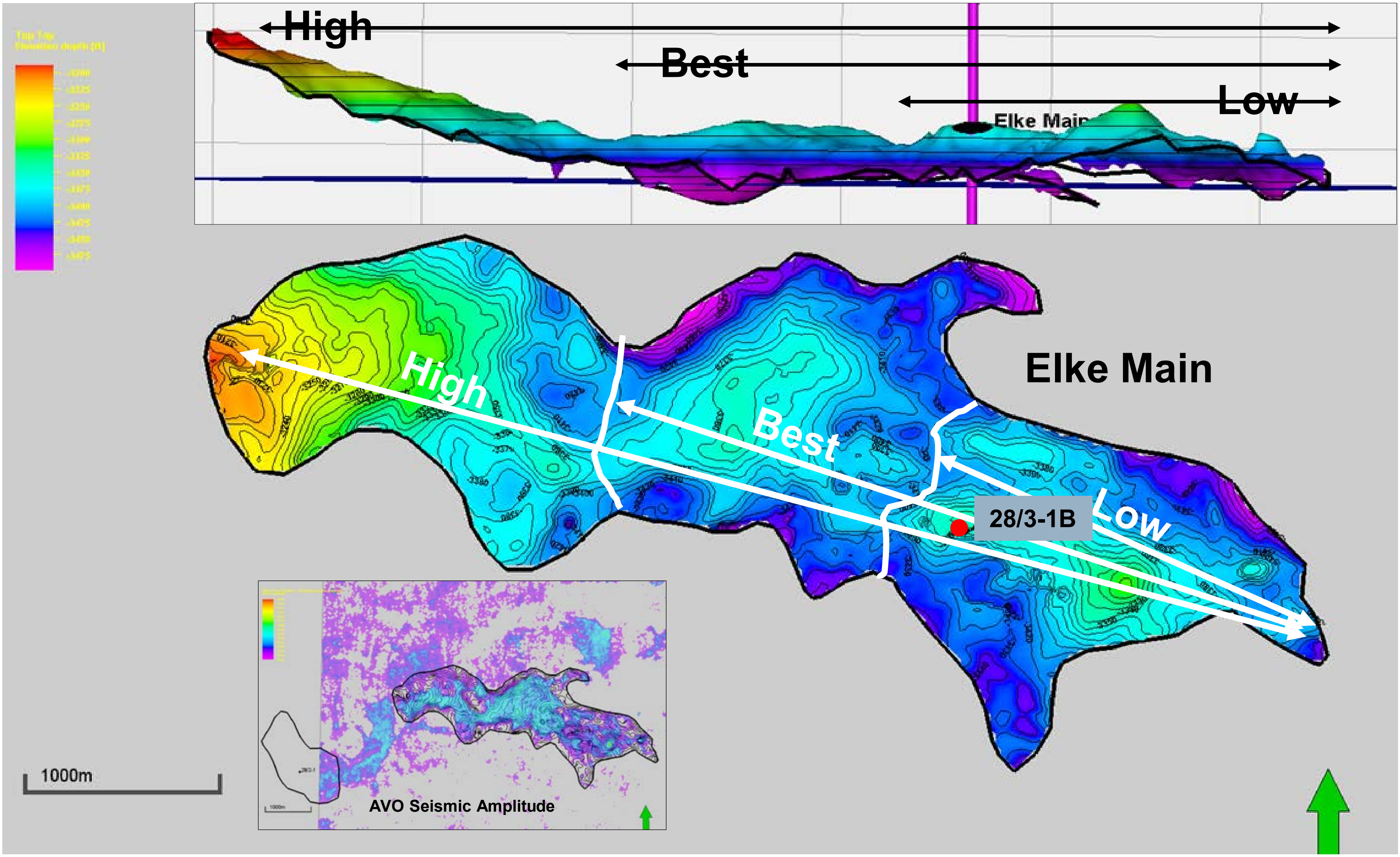


Pilot Discovery Tay Depth Structure

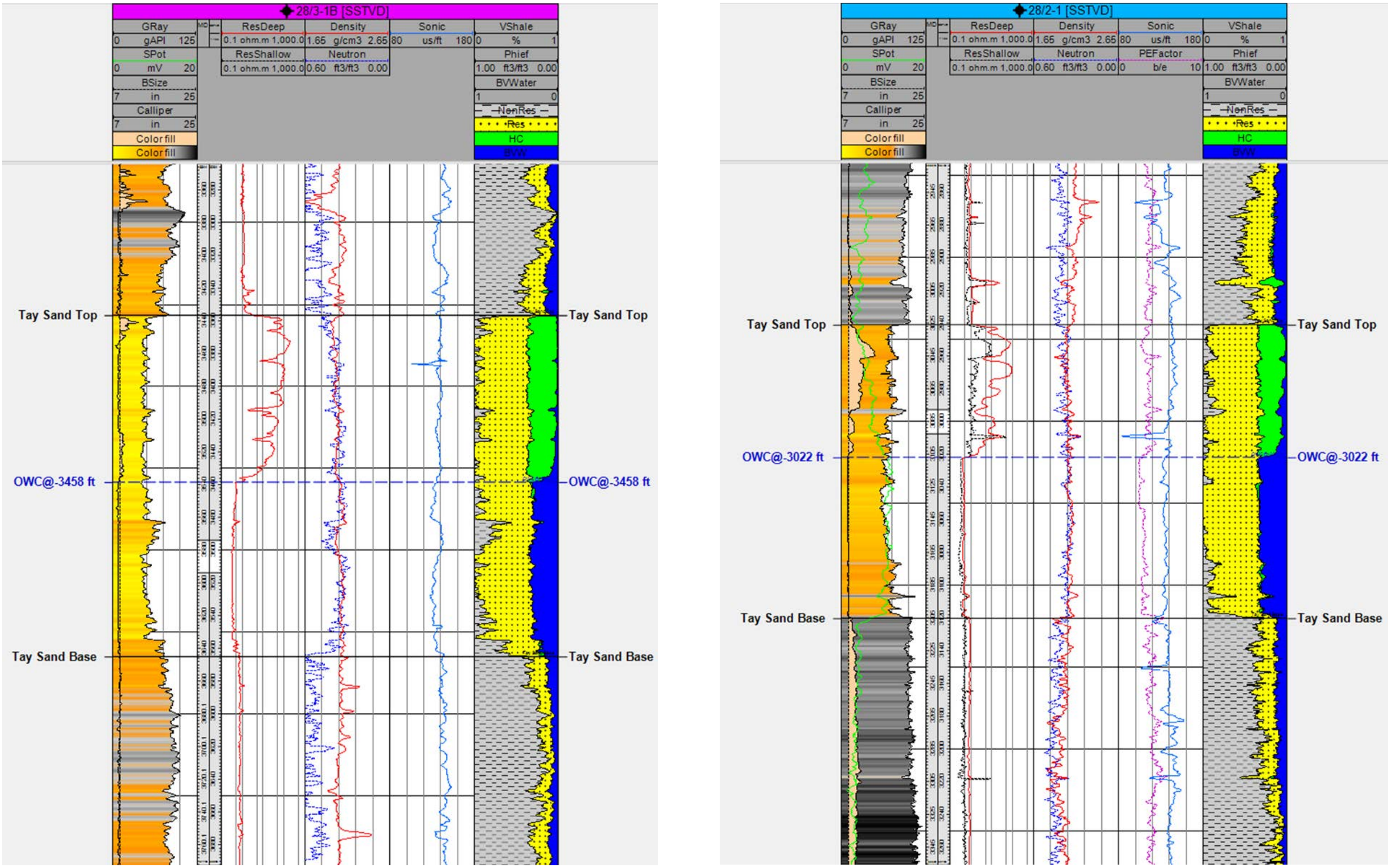
Figure 4



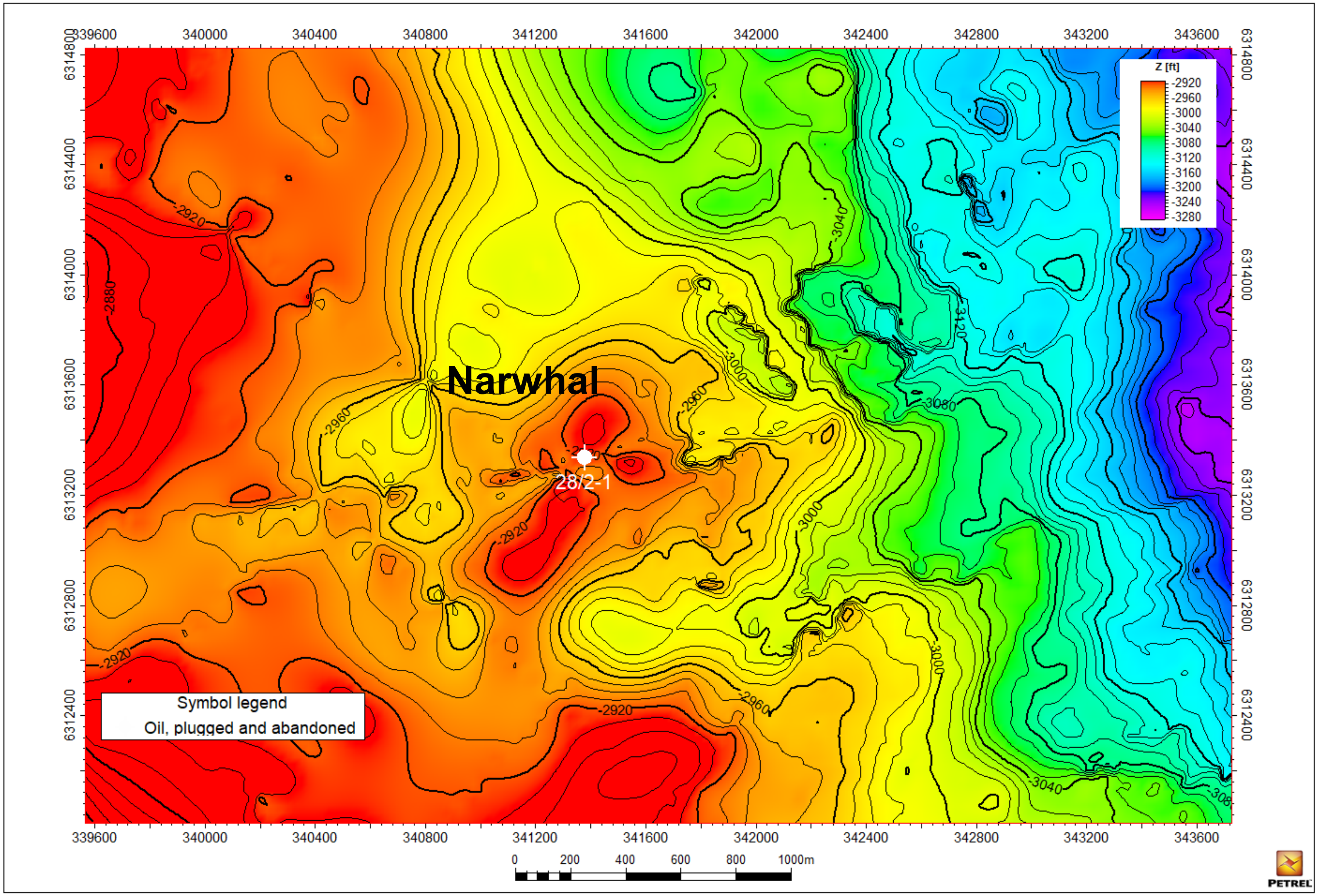
Blakeney Discovery Tay Time Structure Map (A) and RMS Amplitude Map (B)



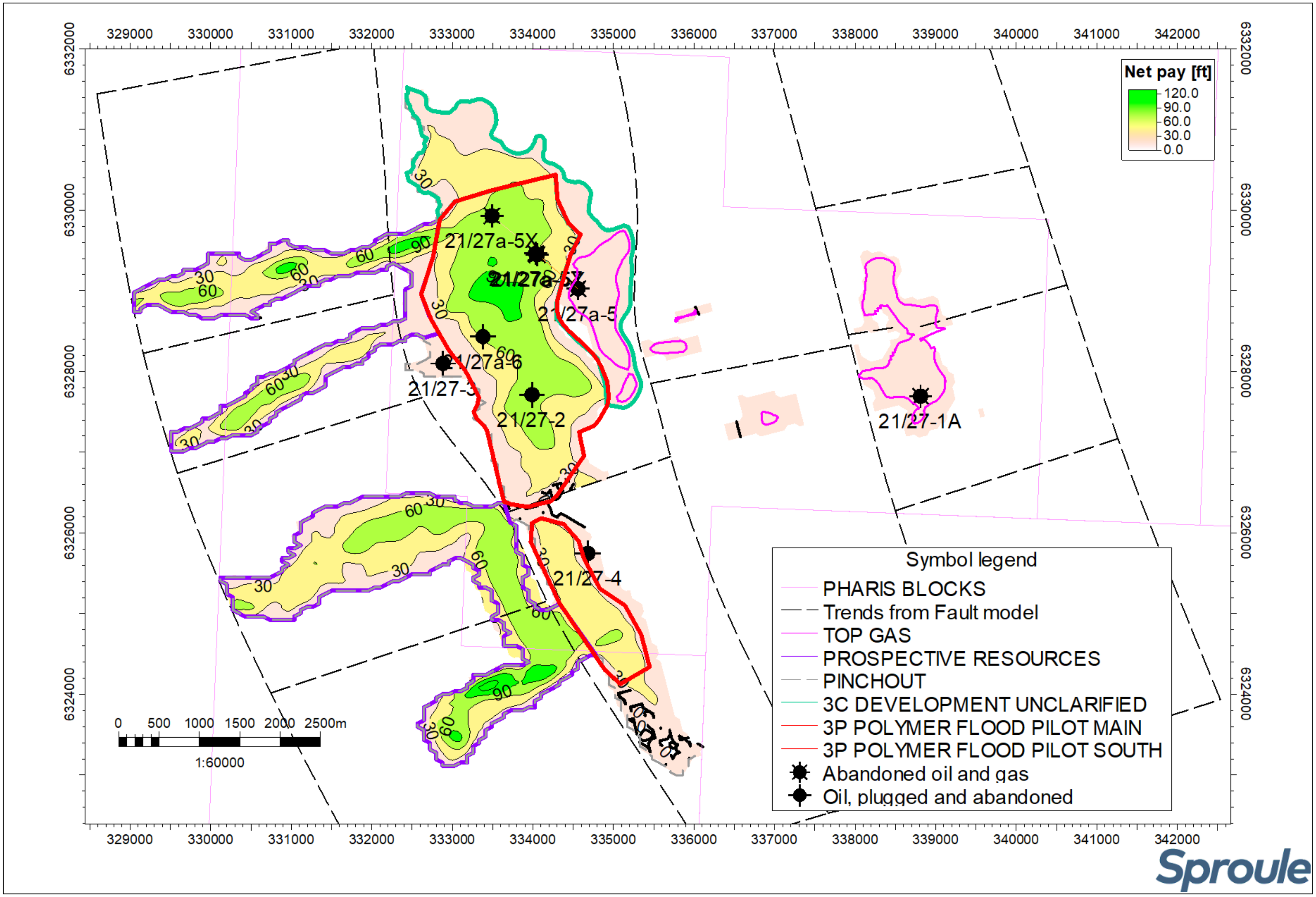
Elke Tay Reservoir Depth Structure Surface (Map and Cross Section Views)



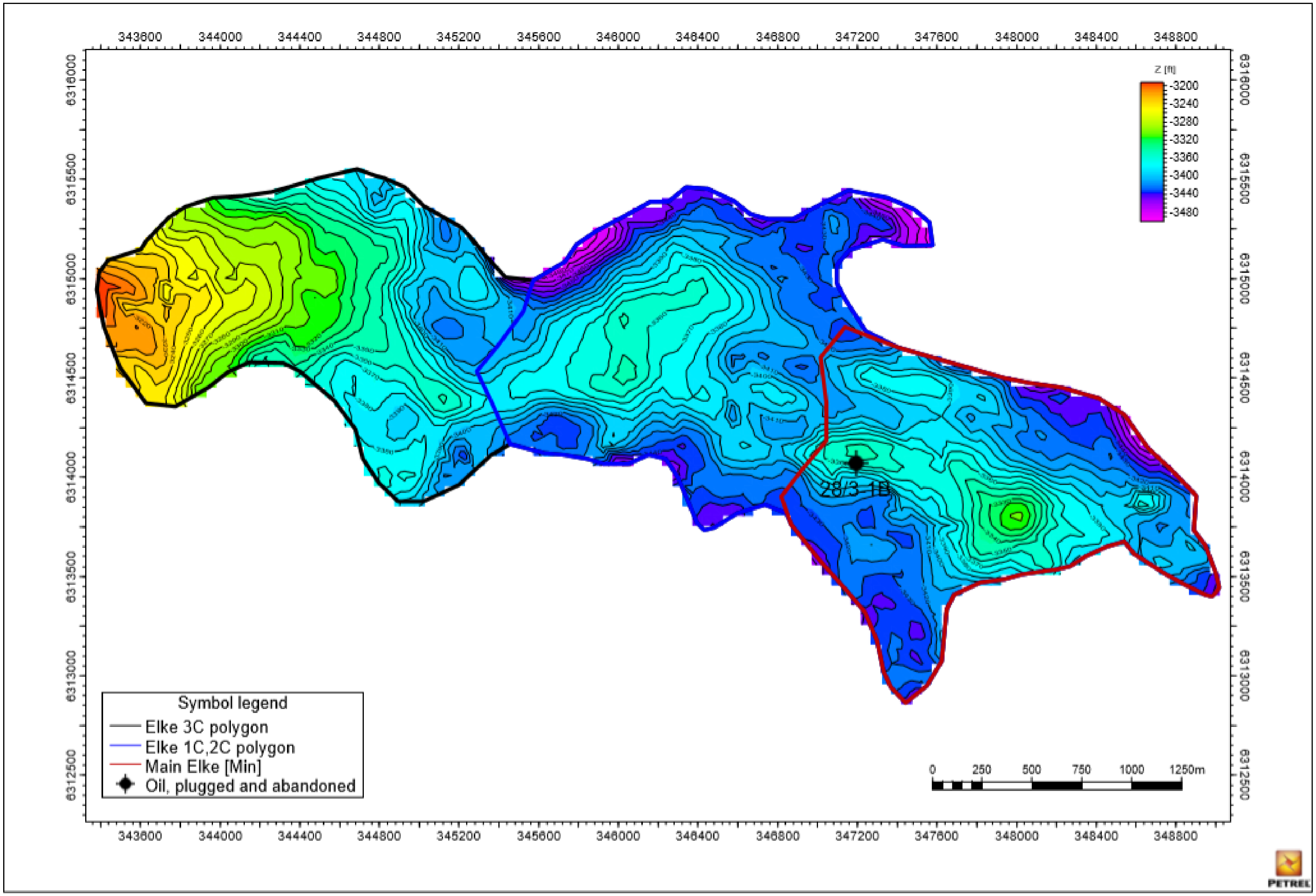
Elke and Narwhal Fields Petrophysical Well Plots (28/3-1B Well and 28/2-1 Well)



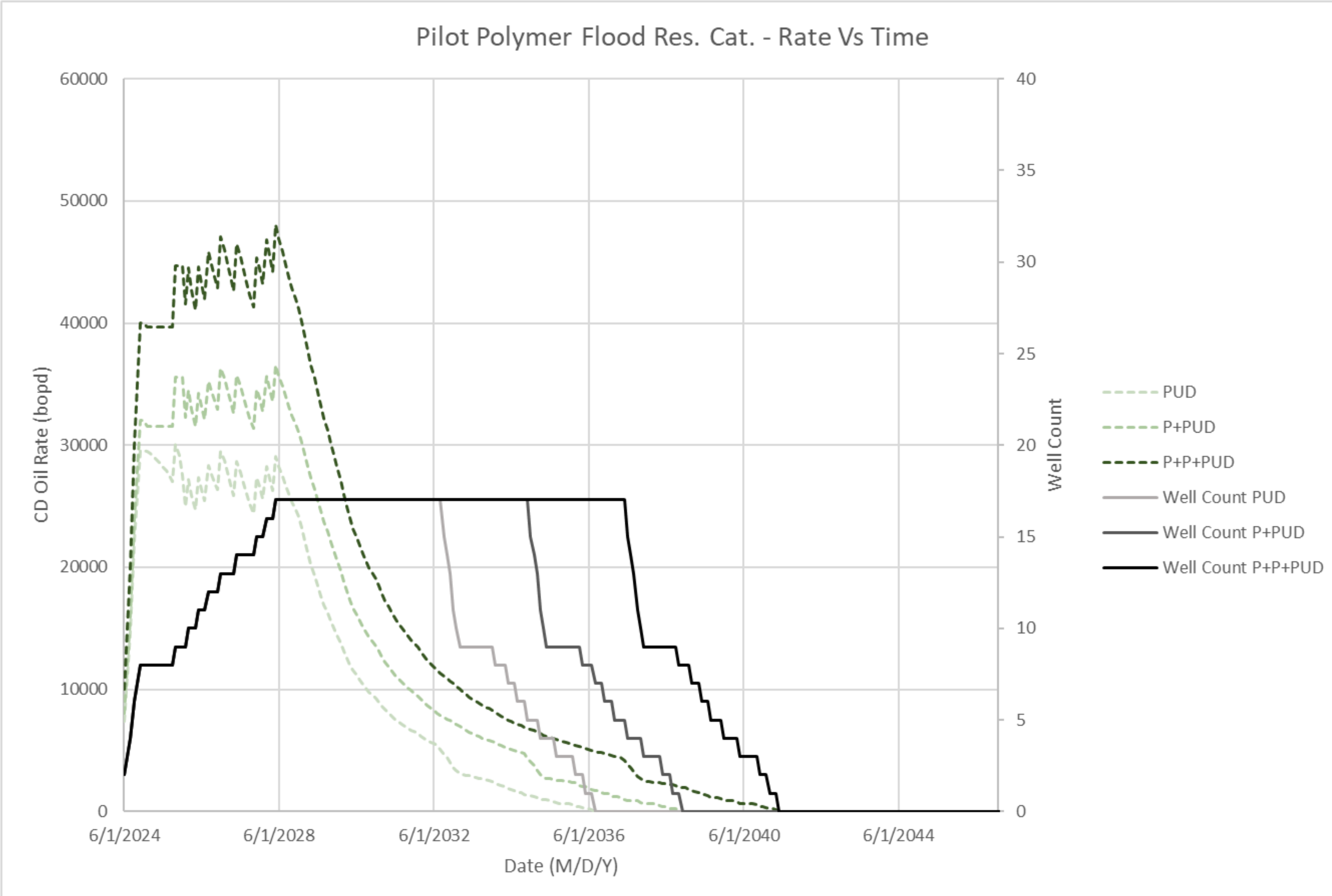
Narwhal Tay Depth Structure



Pilot Field Reserves, Contingent and Prospective Resources Areas

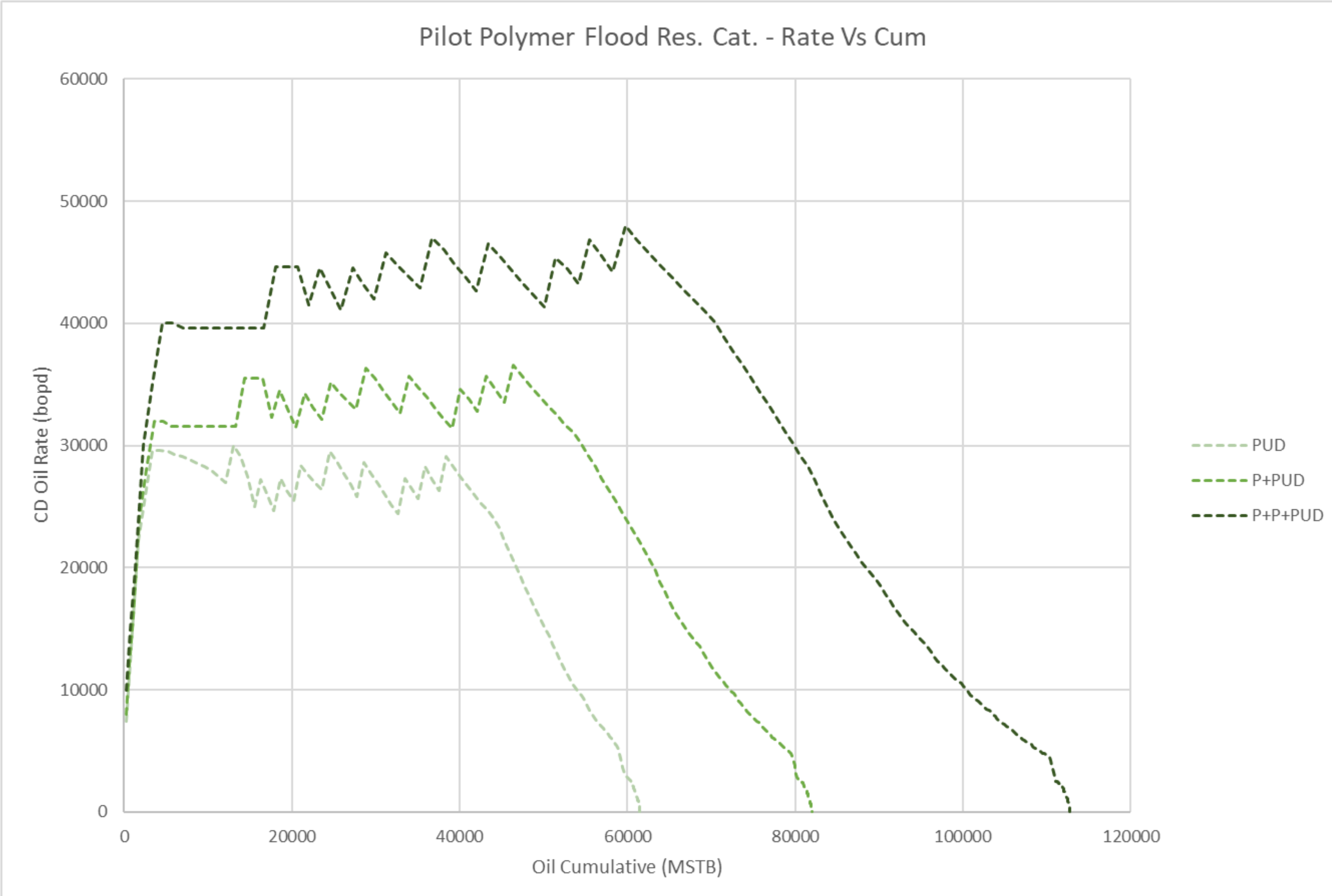


Elke Field Resource Polygons



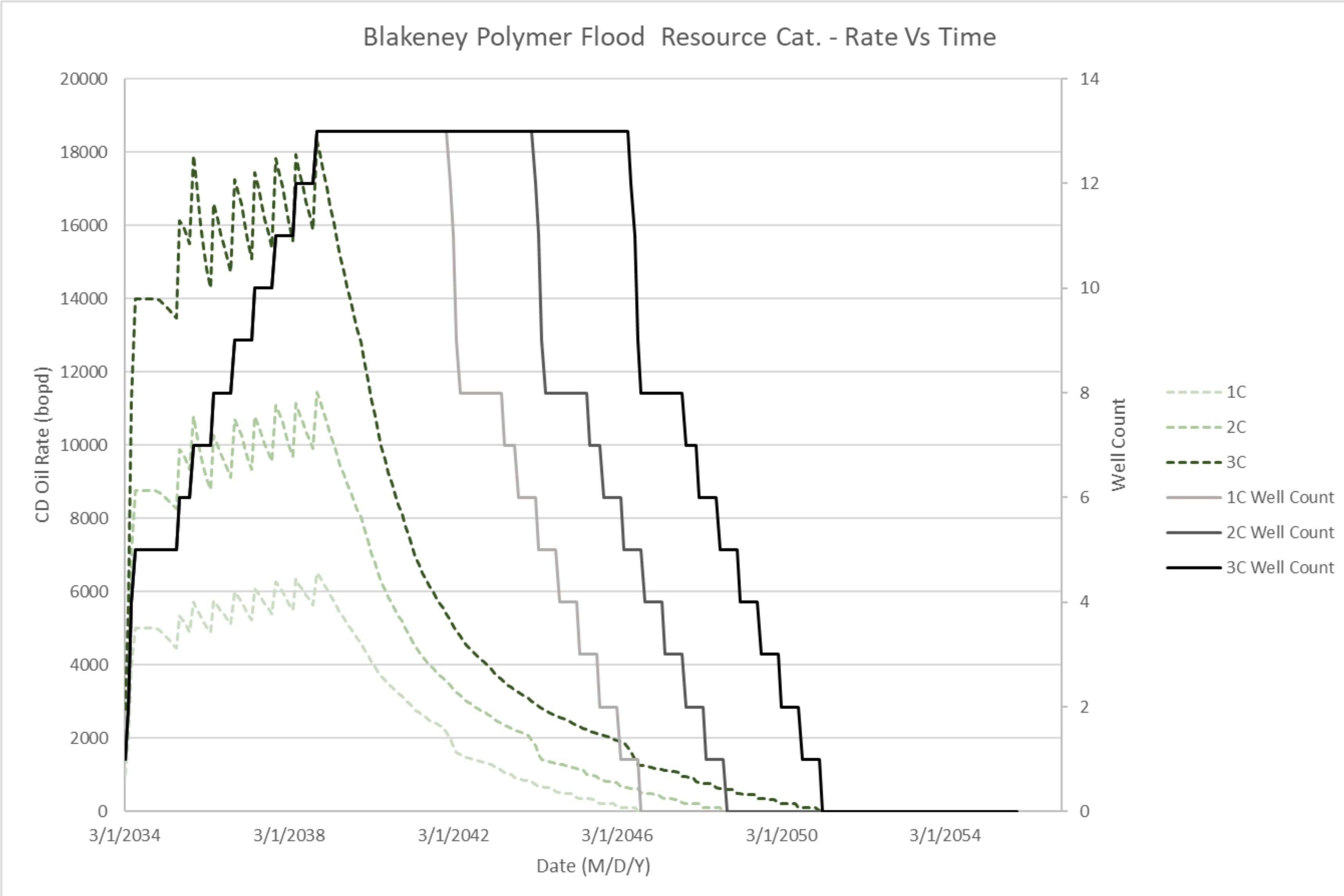
Pilot Field Reserves Oil Production Forecasts vs. Time

Figure 11

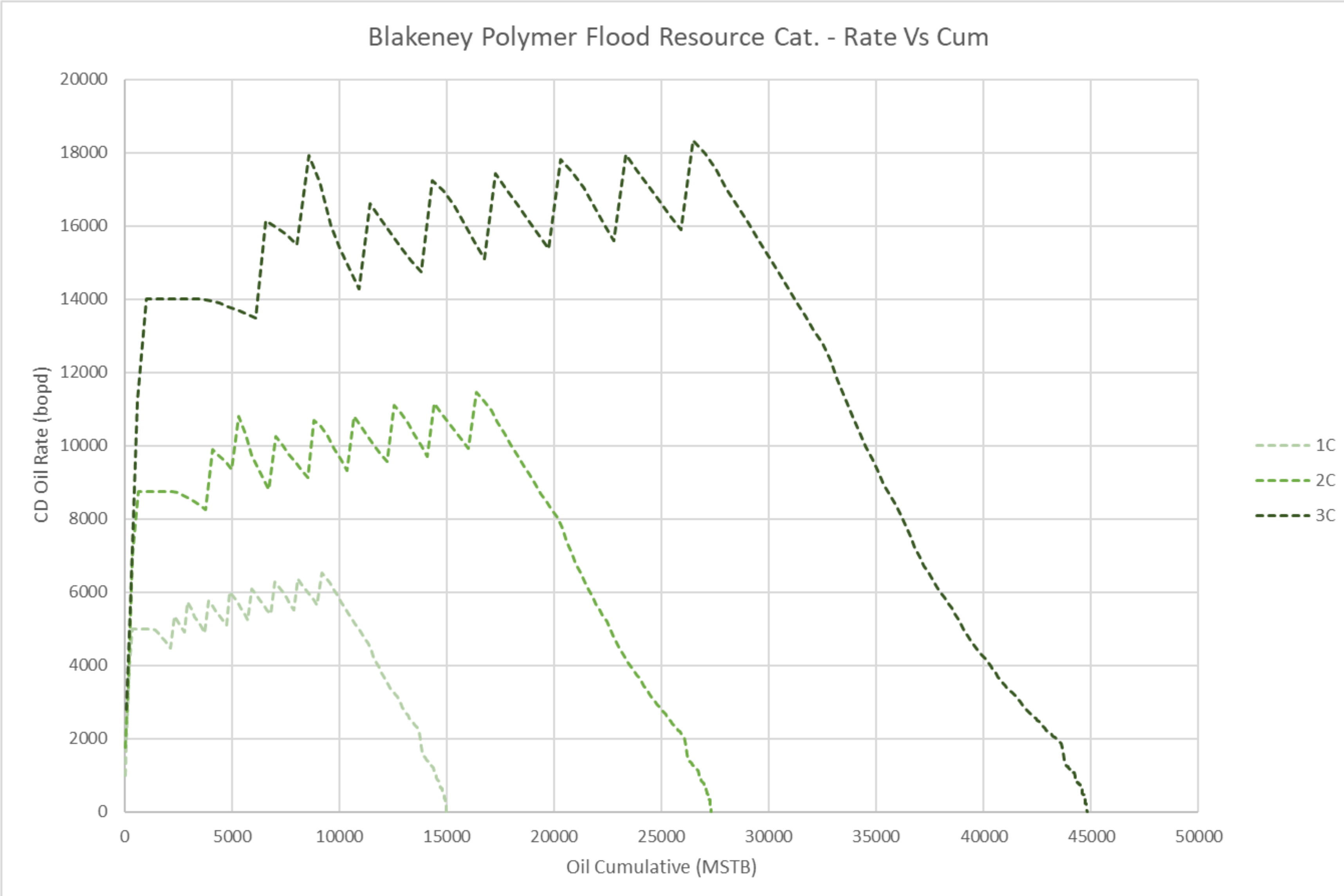


Pilot Field Reserves Oil Production Forecasts vs. Cumulative Oil Production

Figure 12

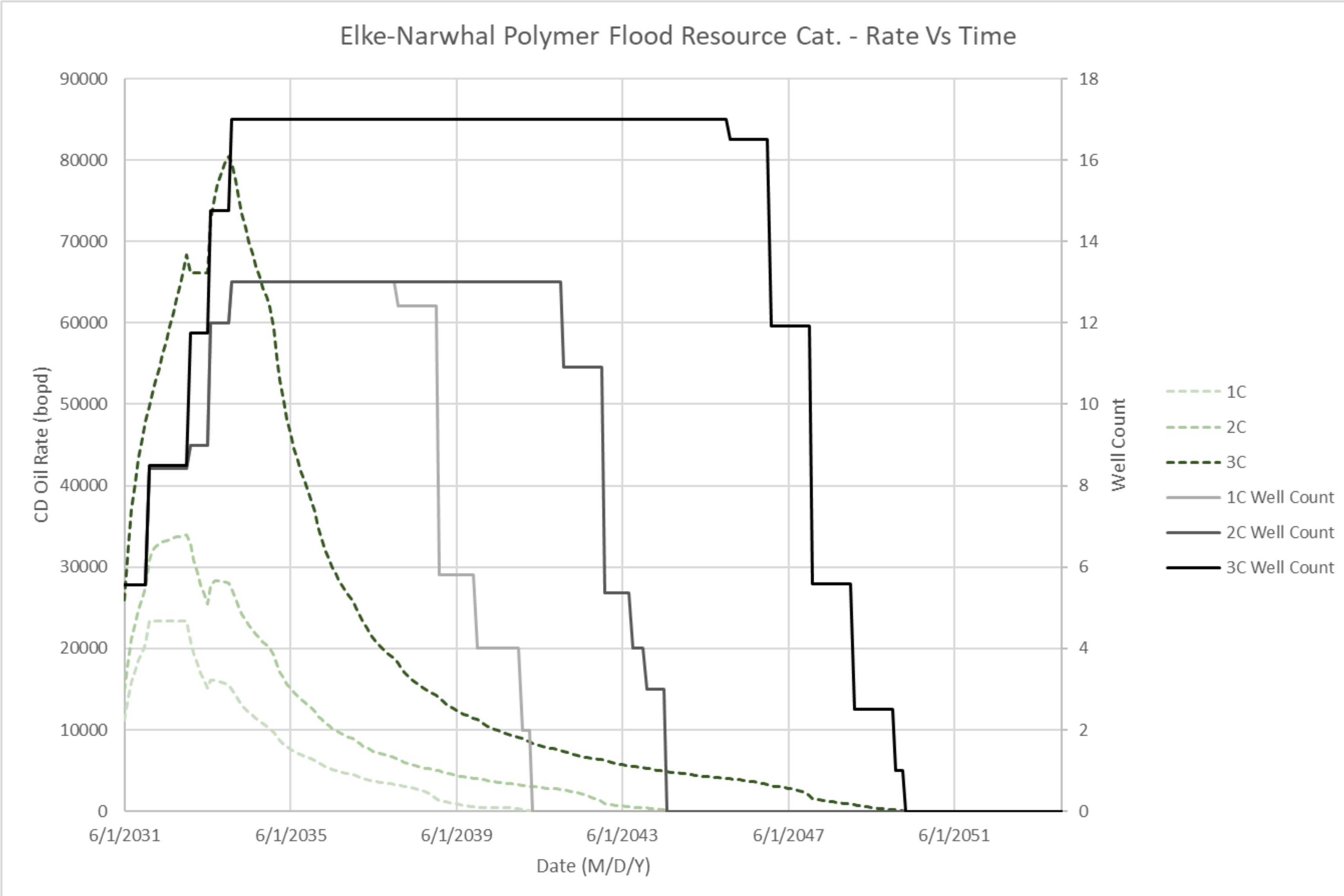


Blakeney Field Contingent Resources Oil Production Forecasts vs. Time

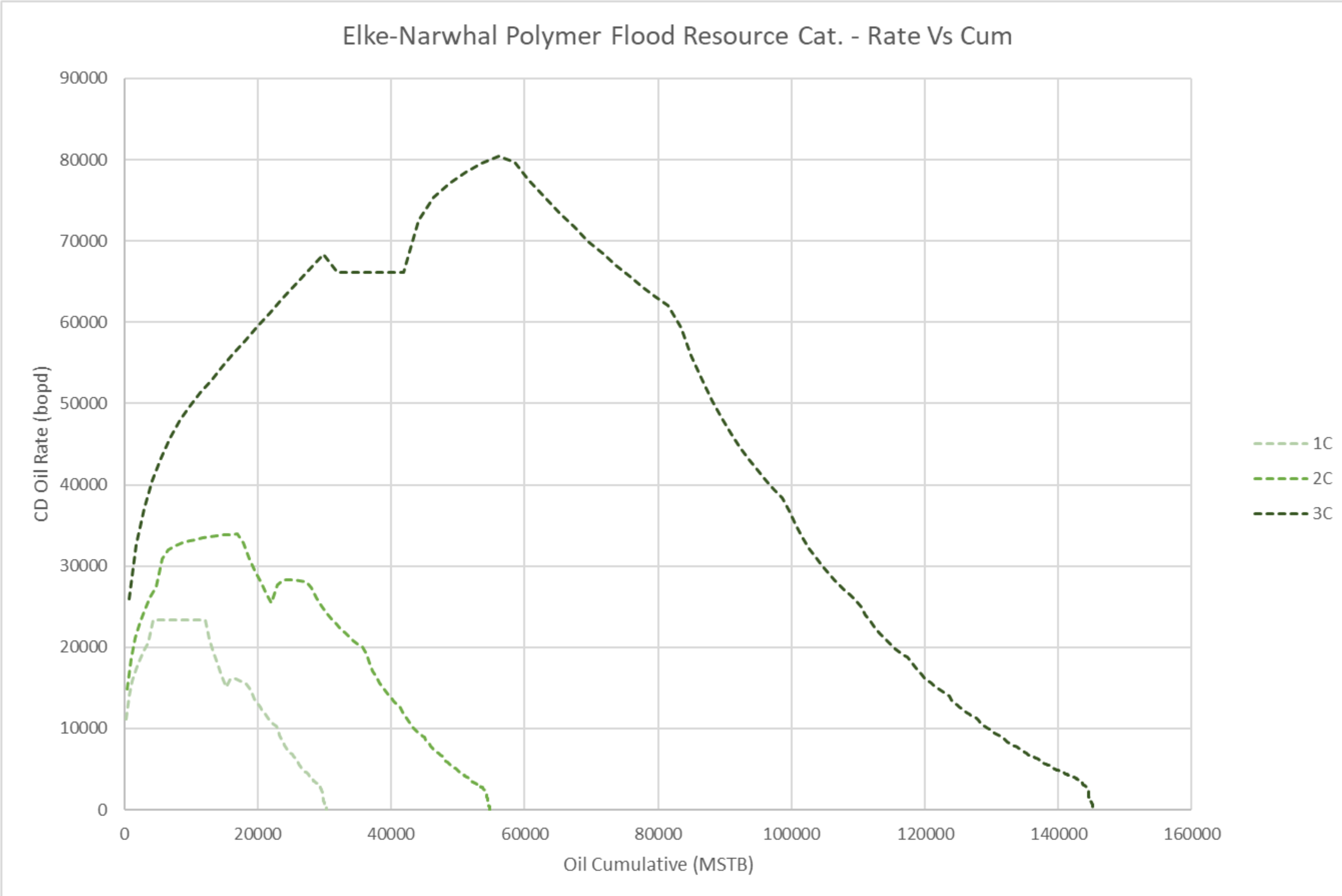


Blakeney Field Contingent Resources Oil Production Forecasts vs. Cumulative Oil Production

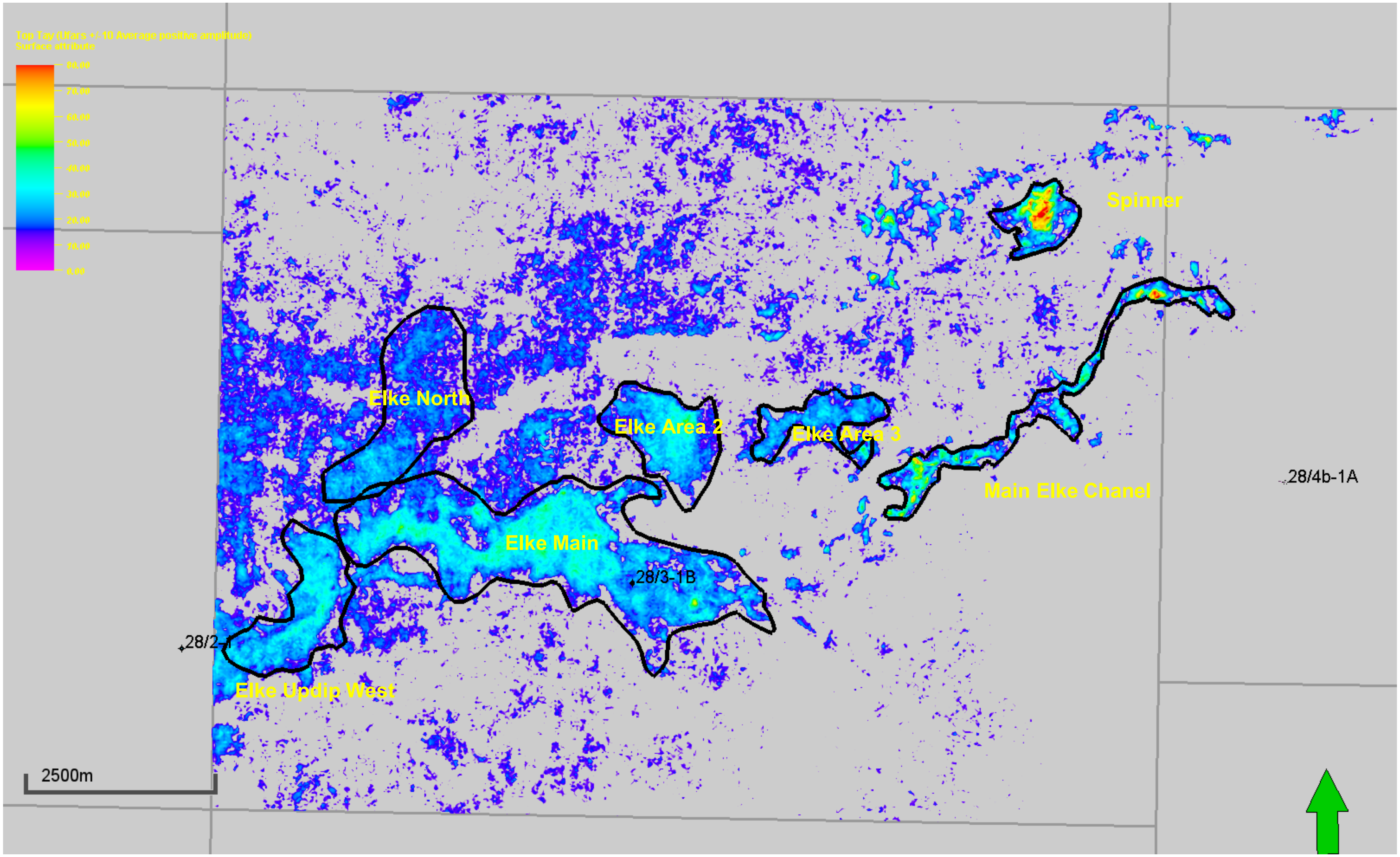
Figure 14



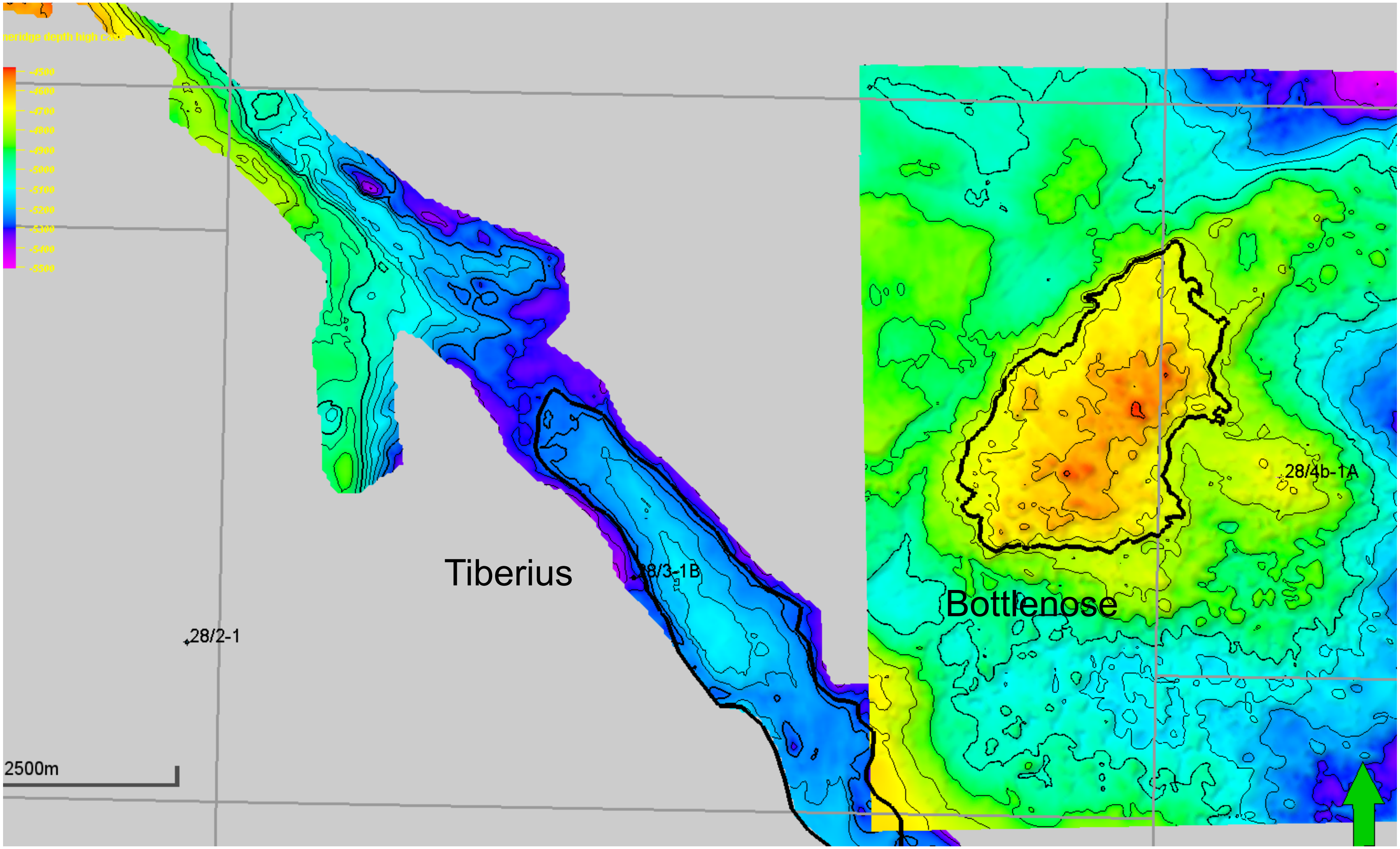
Elke and Narwhal Fields Contingent Resources Oil Production Forecasts vs. Time



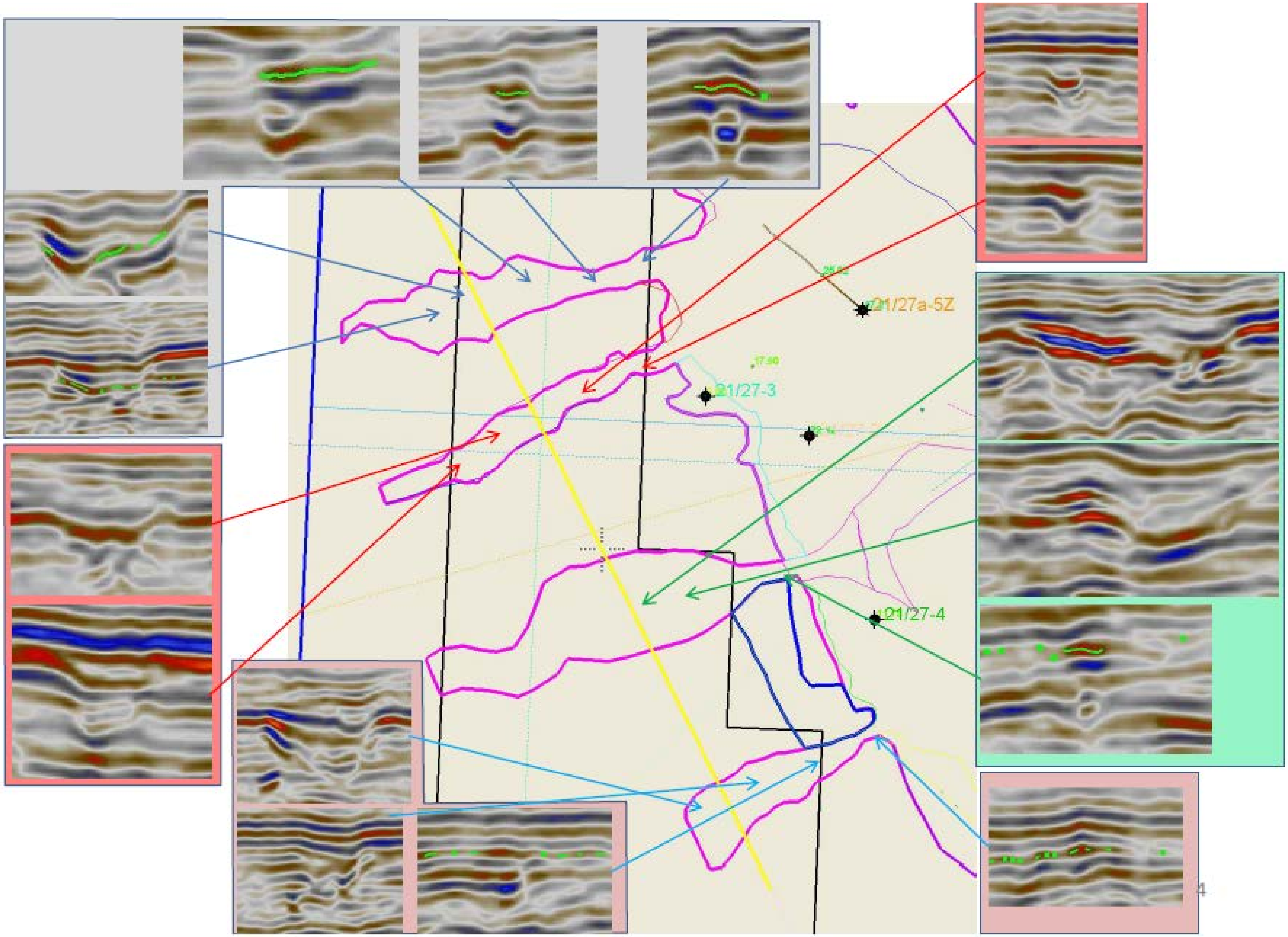
Elke and Narwhal Fields Contingent Resources Oil Production Forecasts vs. Cumulative Oil Production



AVO Seismic Amplitude Extraction with Elke Satellites Prospect Outlines

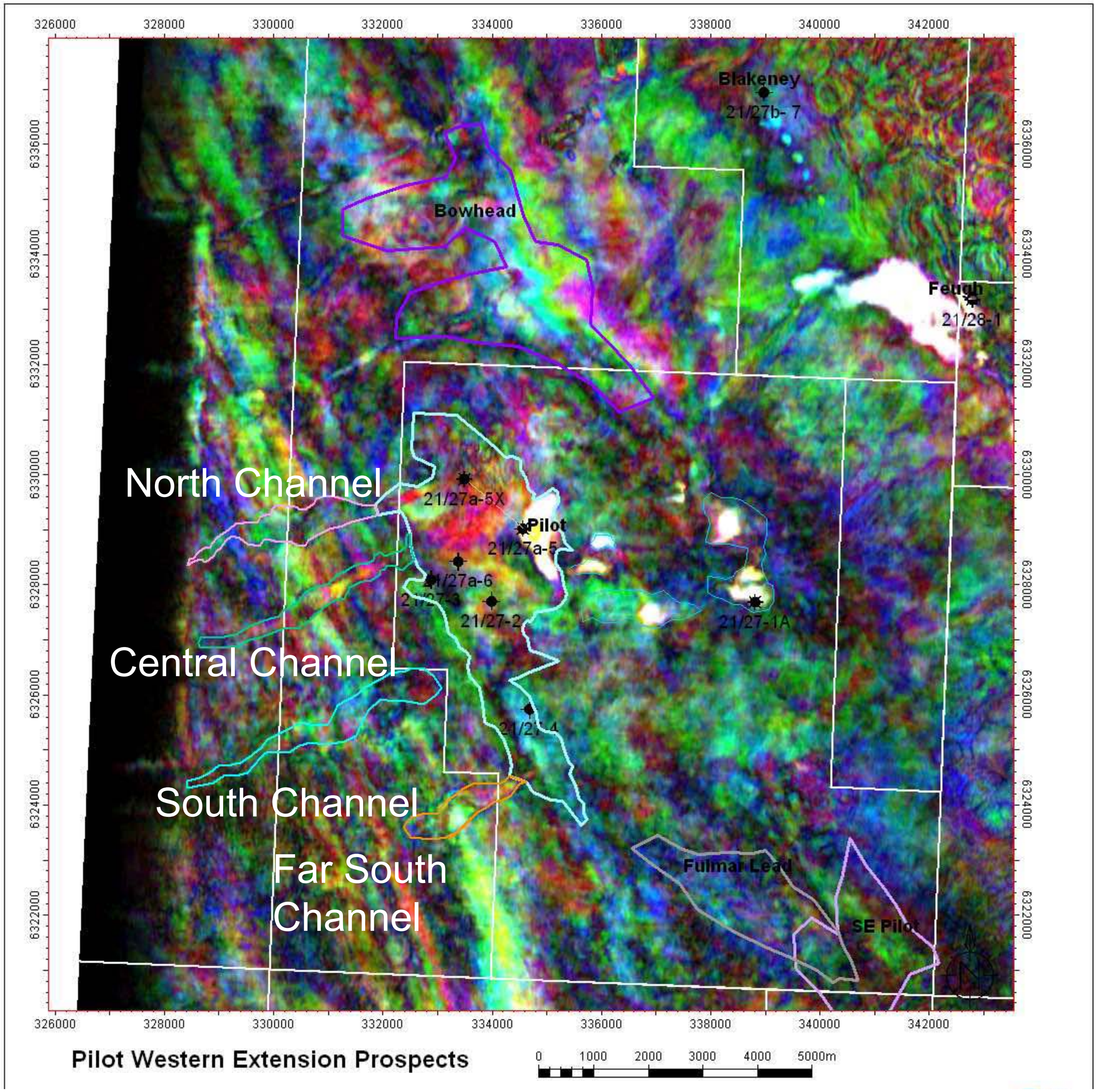


Tiberius and Bottlenose Prospects Outline and Location



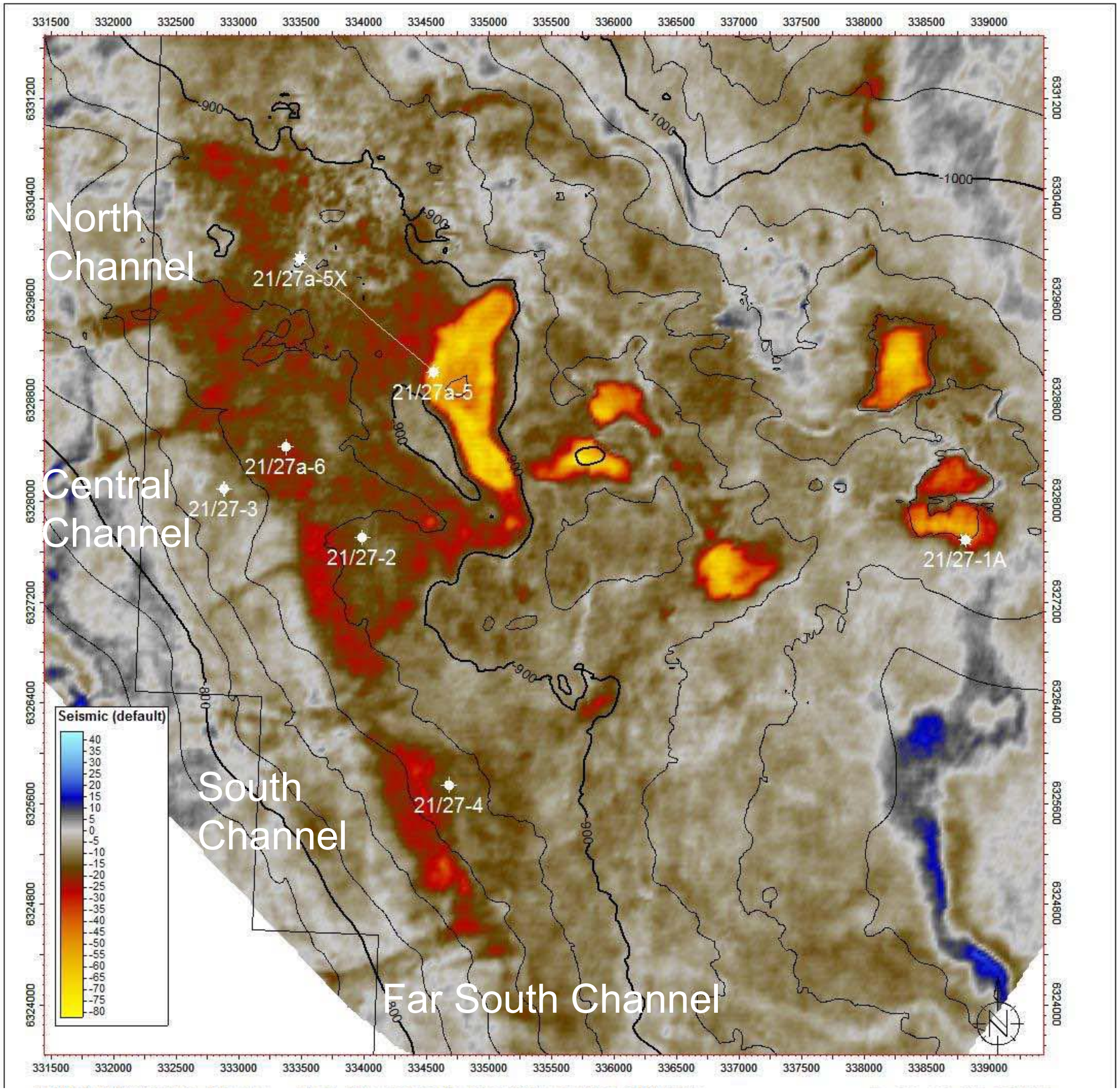
Pilot Channels: Feeder Channels Morphology

Figure 19

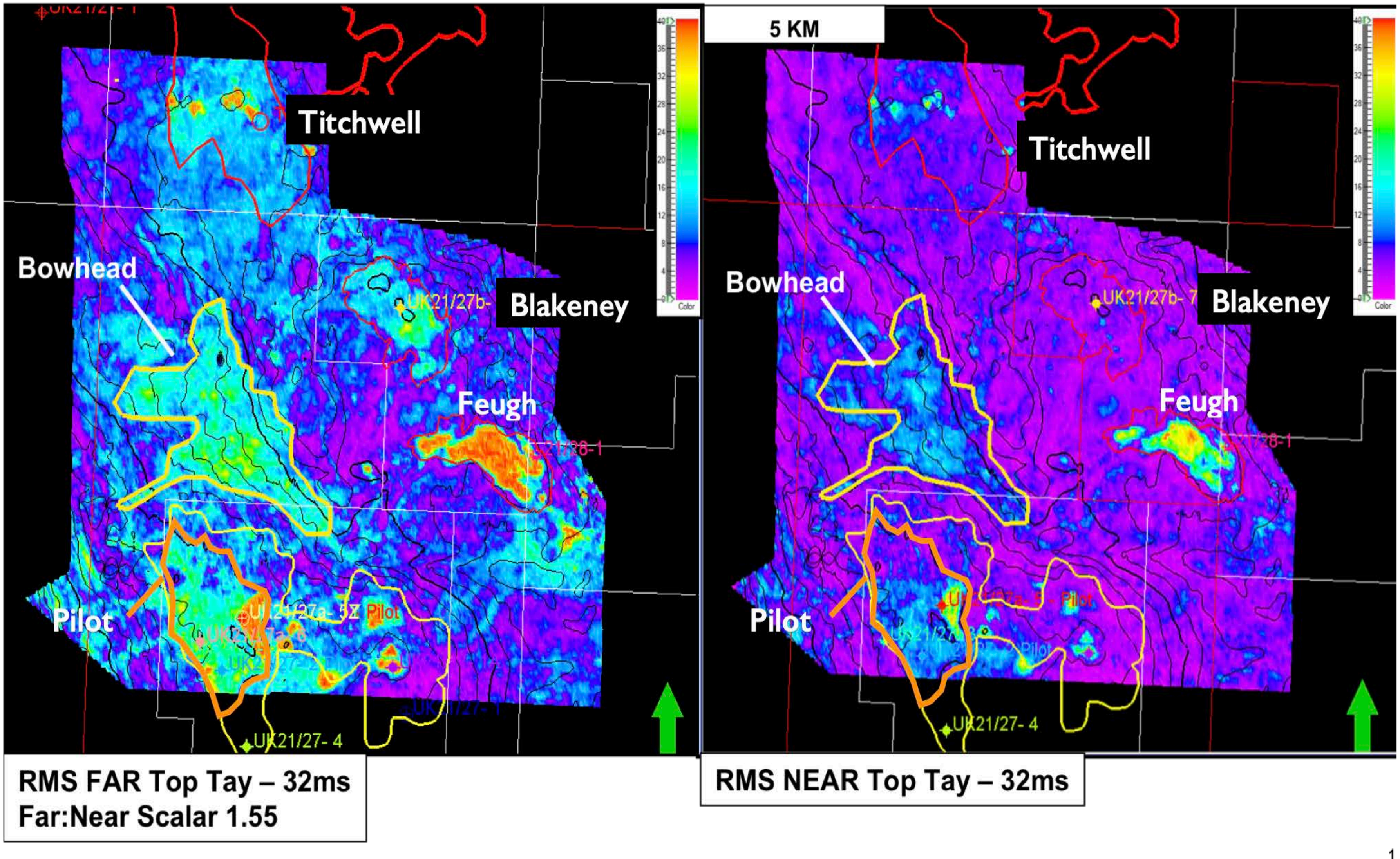


Pilot Channels: Spectral Decomposition Colour Blend (regional Top Tay +15ms)

Figure 20



Pilot Channels: Top Tay Reservoir Far Stack Amplitude



Bowhead Prospect: Top Tay Reservoir Seismic Attributes

Appendix A - Resources Definitions

The table below identifies the categories that form the basis of our classification of resources and values presented in this report. The definitions used in this report are those set out in the Petroleum Resources Management System (SPE-PRMS) as sponsored by Society of Petroleum Engineers ("SPE"), World Petroleum Council ("WPC"), American Association of Petroleum Geologists ("AAPG"), Society of Petroleum Evaluation Engineers ("SPEE"), Society of Exploration Geophysicists ("SEG"), Society of Petrophysicists and Well Log Analysts ("SPWLA"), and the European Association of Geoscientists & Engineers ("EAGE").

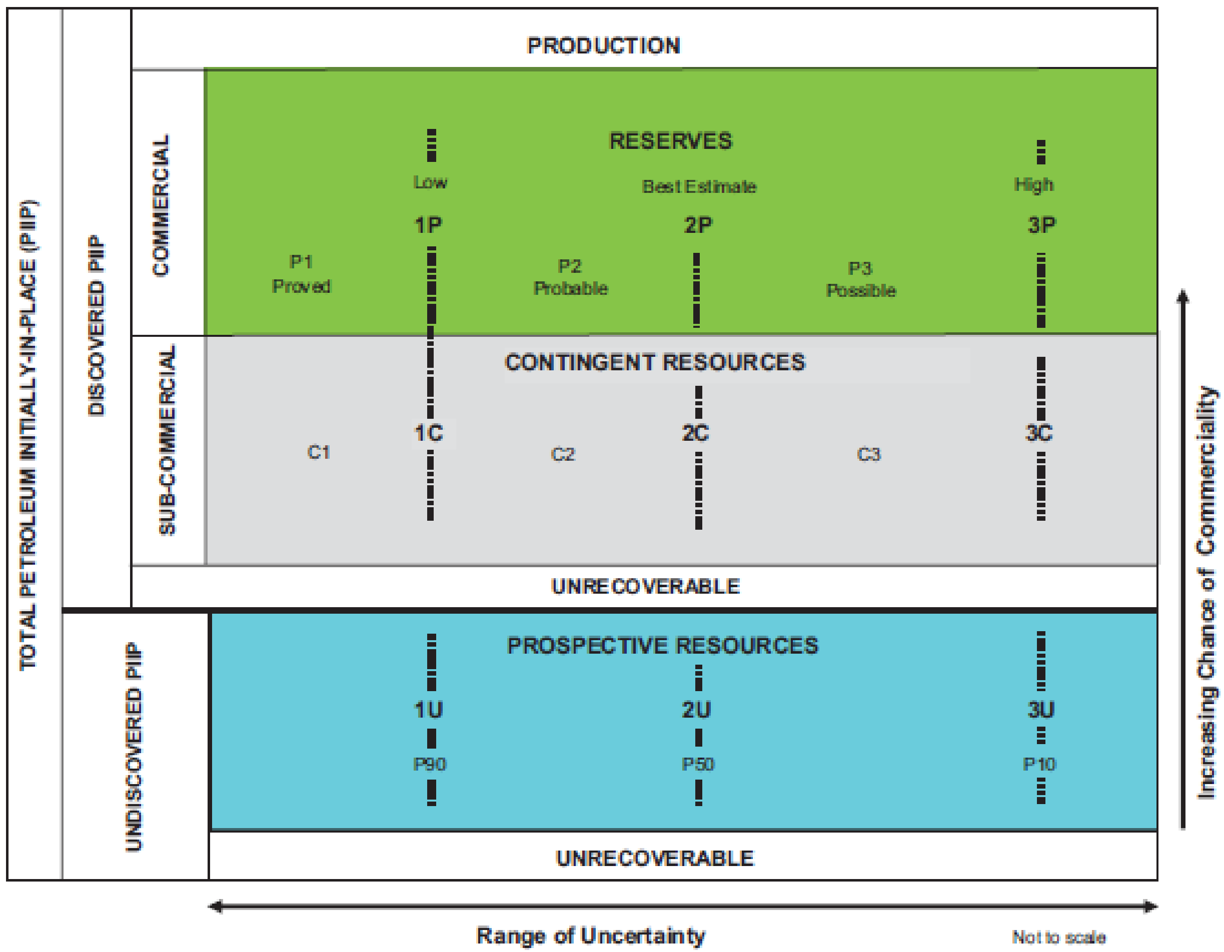
These definitions have been adopted by the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook"), maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and incorporated into Canadian National Instrument 51-101 (NI 51-101) by reference. The product types are as defined in NI 51-101 and are only applicable to reports prepared according to NI 51-101 requirements as identified in the Introduction section of this report.

Although not all the definition groupings may be applicable to this report, they have been included here to ensure appropriate context of the definitions that do apply to this report. Guidance on the application of, and further explanation of, the definitions in this Appendix can be found in either PRMS or the COGE Handbook as applicable.

Resources Categories	Included	Excluded
Petroleum Initially-in-Place	✓	-
Prospective Resources	✓	-
Contingent Resources	✓	-
Reserves	✓	-

1. **Resources** encompass all petroleum quantities that originally existed on or within the earth's crust in naturally occurring accumulations, including discovered and undiscovered plus quantities already produced. Total Resource is equivalent to Petroleum Initially-in-Place (PIIP).

The following figure illustrates the relationship of the different resources within the PRMS Resources classification framework and aids in placing the subsequent definitions in context.



2. Total **Petroleum Initially-in-Place** is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations and is potentially producible. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered.

3. **Undiscovered Petroleum Initially-in-Place** is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The potentially recoverable portion of Undiscovered PIIP is referred to as Prospective Resources; the remainder is unrecoverable

4. **Discovered Petroleum Initially-in-Place** is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. Discovered PIIP includes production, Reserves and Contingent Resources; the remainder is unrecoverable.

5. **Discovery** is the confirmation of the existence of an accumulation of a significant quantity of potentially recoverable petroleum.

6. A **Known Accumulation** is one that has been penetrated by a well that has demonstrated the existence of a significant quantity of potentially recoverable petroleum.

7. **Prospective Resources** are those quantities of petroleum estimated, as of a give 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.

8. **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 projects not currently considered to be commercial due to one or more contingencies. Contingent Resources have an associated chance of development.

9. **Reserves** are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

   - analysis of drilling, geological, geophysical, and engineering data;
   - the use of established technology;
   - specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed; and
   - a maximum remaining reserve life of 50 years.

   Reserves are classified according to the degree of certainty associated with the estimates.

10. **Proved Reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

11. **Probable Reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

12. **Possible Reserves** are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

Other criteria that must also be met for the categorization of reserves are provided in Section 3.1 of PRMS or Section 1.4.7.2.1 of the COGE Handbook.

Each of the reserves categories (proved, probable, and possible) may be divided into developed or undeveloped categories.

13. **Developed Reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

14. **Developed Producing Reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

15. **Developed Non-Producing Reserves** are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

16. **Undeveloped Reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling and completing a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned and are expected to be developed within a limited time.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities, and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels contained in the definitions 10, 11 and 12 are applicable to individual reserves entities, which refers to the lowest level at which reserves estimates are made, and to reported reserves, which refers to the highest level sum of individual entity estimates for which reserve estimates are made.

Reported total reserves estimated by deterministic or probabilistic methods, whether comprised of a single reserves entity or an aggregate estimate for multiple entities, should target the following levels of certainty under a specific set of economic conditions:

a. There is a 90% probability that at least the estimated proved reserves will be recovered.

b. There is a 50% probability that at least the sum of the estimated proved reserves plus probable reserves will be recovered.

c. There is a 10% probability that at least the sum of the estimated proved reserves plus probable reserves plus possible reserves will be recovered.

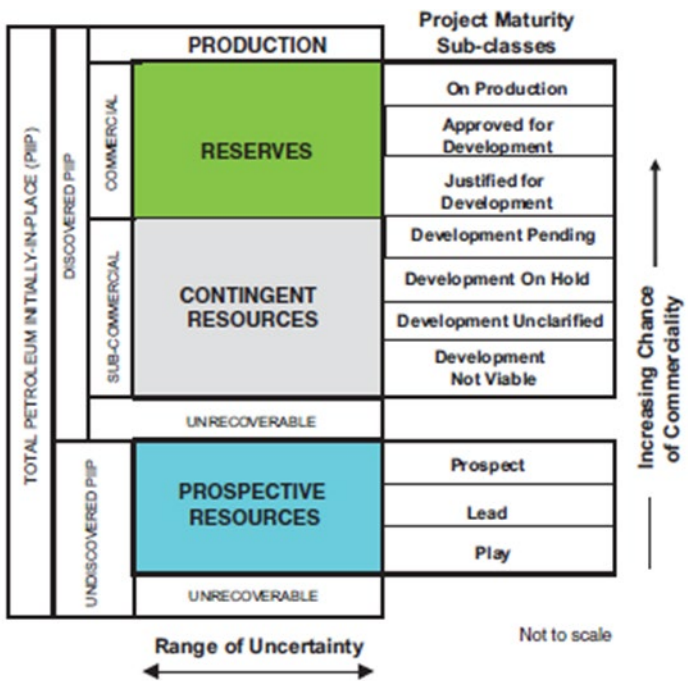
A quantitative measure of the probability associated with a reserves estimate is generated only when a probabilistic estimate is conducted. The majority of reserves estimates will be performed using deterministic methods that do not provide a quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Levels of Certainty for Resources

The same levels of certainty as described above for reserves, represented by a probability distribution of the low, best, and high volume estimates, can be applied to Contingent and Prospective Resources as reflected with the 1C, 2C, 3C, C1, C2 and C3; or 1U, 2U and 3U resources categories and shown on the resources classification figure on the horizontal axis.

Additional clarification of certainty levels associated with resources estimates and the effect of aggregation is provided in Sections 2.2 and 4.2 of PRMS or Section 5.7 of the COGE Handbook. Whether deterministic or probabilistic methods are used, evaluators are expressing their professional judgement as to what are reasonable estimates.

17. **Chance of Commerciality** is the product of the chance of geologic discovery and the chance of development and is used to estimate risked resources by multiplying with the resource volumes. The chance of geologic discovery for Contingent Resources is 100 percent, thus the Chance of Commerciality of Contingent Resources is equal to the chance of development. The Chance of Commerciality is used to estimate the level of maturity of the resource classification as reflected by its' use as an axis on the right side of the Resources Classification Framework as shown in the following figure.



18. **Chance of Development** is the estimated probability that a known accumulation, once discovered, will be commercially developed. The Chance of Development is the product of the contingencies applicable to a particular project. The applicable contingencies may include one or more of the following:

   a. **Evaluation Drilling –** the geological continuity of the reservoir needs to be confirmed to reduce the distance from proven productivity;

   b. **Regulatory Approval** – Approval from the applicable regulatory agency or agencies has not been received;

   c. **Economic Factors –** The future product pricing and capital costs may not be at a level or sufficiently defined - and may also include other underlying factors including market conditions, exchange rates, fiscal terms, and taxes - to establish the economic viability of the project;

   d. **Corporate Commitment –** The final investment decision and endorsement from the Company and / or the project co-venturers has not been made, nor is there a reasonable expectation these can be arranged in a reasonable time frame, such that the project can move forward. A technically mature and feasible field development plan may also need to be developed;

   e. **Timing of Production or Development –** The current development plan may not commence within a reasonable time period;

f. **Market Access –** Infrastructure or access to existing facilities may not be in place or sales contracts have not been executed that will allow the production products to access viable markets;

g. **Technology Under Development –** The technology required to commercially develop the area is not currently available nor is it under active development;

h. **Legal Factors –** Factors that have been brought forward regarding the ability to explore, produce, and sell the hydrocarbons;

i. **Political Factors –** Political unrest may impede the development in the area;

j. **Social License –** One or more of the jurisdictions in which the project area is located has policies in place that restrict certain types of development due to environmental concerns.

19. **Chance of Geologic Discovery** (or just Chance of Discovery) is the estimated probability that exploration activities will confirm the existence of a significant accumulation or potentially recoverable petroleum. The Chance of Geologic Discovery is the product of one or more applicable geologic factors which include:

a. **Source** – The presence of source rock in reasonable proximity to the target that has generated, or is generating, hydrocarbon from organic material trapped in the rock;

b. **Migration –** There is a path that allowed for the migration of the hydrocarbon from the source to the reservoir;

c. **Reservoir** – The presence of rock with sufficient thickness, porosity, and permeability to be commercially productive;

d. **Trap (or Seal) –** The reservoir rock is bounded by impermeable layers prior to the time of migration that has allowed the migrating hydrocarbon to accumulate within the reservoir rock;

e. **Structure –** the geometry of the anticipated accumulation is able to contain the migrating hydrocarbons in the form of a stratigraphic and / or structural trap. This factor may not apply to unconventional resources, or accumulations that are pervasive throughout a large area and not significantly affected by hydrodynamic influences such as coal-bed methane, gas hydrates, natural bitumen, tight oil, tight gas, or oil shale.

20. The **Project Maturity Sub-class** represents the maturity of the project and sets out the associated actions required to move the project towards commercial production. The boundaries between the different levels of project maturity are normally project decision gates and can vary from organization to organization dependent upon the established internal approval process for project expenditures.

    a. A **Play** is the lowest and least defined level of Prospective Resources and is a project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation to define specific leads or prospects.

    b. A **Lead** is the next level or Prospective Resources and is a project that is poorly defined and requires additional data acquisition and/or evaluation.

    c. A **Prospect** is the best defined level of Prospective Resources and represents a project that is sufficiently well defined to represent a viable drilling target, although remains undiscovered.

21. **Development Not Viable** is the lowest level of Contingent Resources and represents a discovered accumulation for which there are contingencies resulting in there being no current plans to develop or acquire additional data at the time due to limited commercial potential.

22. **Development Not Clarified** is the second lowest level of Contingent Resources and is a discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information. A plan for future evaluation should exist but further study or appraisal work will be ongoing in order to establish the actions necessary to move the project forward to commercial maturity.

23. **Development On Hold** is the second highest level of Contingent Resources and represents a discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.

24. **Development Pending** is the highest level of Contingent Resources and represents a discovered accumulation where development activities are ongoing to justify commercial development in the foreseeable future.

25. **Justified for Development** is the lowest level of Reserves and represents a development project that has reasonable forecast commercial conditions at the time or reporting and there are reasonable expectations that all necessary approvals/contracts will be obtained.

26. **Approved for Development** is the second level of Reserves and represents a development project that is commercial under the current and/or forecast conditions, has received all approvals and/or contracts necessary for development including the commitment of capital funds and implementation of the development of the project is underway.

27. **On Production** is the highest level of Reserves and reflects the operational execution phase of one or more development projects with the Reserves currently producing or capable of production, including Developed Producing and Developed Non-Producing Reserves.

28. **Remaining Recoverable Reserves** are the total remaining recoverable reserves associated with the acreage in which the Company has an interest.

29. **Company Gross Reserves** are the Company's working interest share of the remaining reserves before deduction of any royalties.

32. **Company Net Reserves** are the gross remaining reserves of the properties in which the Company has an interest, less all Crown, freehold, and overriding royalties and interests owned by others plus all royalty interest volumes received.

33. **Net Production Revenue** is income derived from the sale of net reserves of oil, non-associated and associated gas, and gas by-products, less all capital and operating costs.

34. **Fair Market Value** is defined as the price at which a purchaser seeking an economic and commercial return on investment would be willing to buy, and a vendor would be willing to sell, where neither is under compulsion to buy or sell and both are competent and have reasonable knowledge of the facts.

35. **Barrels of Oil Equivalent (BOE) Reserves** is the sum of the oil reserves, plus the gas reserves divided by a conversion factor, plus the natural gas liquid reserves, all expressed in barrels or thousands of barrels. Equivalent reserves can also be expressed in thousands of cubic feet of gas equivalent (McfGE) using the same conversion factor. Normally the conversion factor represents an approximation of the nominal heating content or calorific value equivalent to a barrel of oil.

36. **Oil (or Crude Oil)** is a mixture consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons, but does not include liquids obtained from the processing of natural gas. Crude oil volumes are further divided into Product Types, for reporting purposes.

37. Gas (or Natural Gas) is a mixture of lighter hydrocarbons that exist either in the gaseous phase or in solution in crude oil in reservoirs, but are gaseous at atmospheric conditions. Natural gas may contain sulphur or other non-hydrocarbon compounds. Natural Gas volumes are further divided into Product Types, for reporting purposes.

38. Non-Associated Gas is an accumulation of natural gas in a reservoir where there is no crude oil.

39. Associated Gas – the gas cap overlying a crude oil accumulation in a reservoir.

40. Solution Gas – gas dissolved in crude oil.

41. Natural Gas By-Products – those components that can be removed from natural gas including, but not limited to, ethane, propane, butanes, pentanes plus, condensate, and small quantities of non-hydrocarbons.

Product Types sub-classify the principle product types of petroleum, crude oil, gas, and by-products, into specific groupings based on the properties of the hydrocarbon and the properties of the accumulation and reservoir rock from which it is found. Regulatory agencies may define in legislation the product types they require to be used for reporting purposes in their jurisdiction. The Canadian Securities Associations (CSA) defines the following Product Types for reporting purposes in National Instrument 51-101, effective July 1, 2015.

Crude Oil

I) **Light Crude Oil** means crude oil with a relative density greater than 31.1 degrees API gravity;

II) **Medium Crude Oil** means crude oil with a relative density greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity;

III) **Heavy Crude Oil** means crude oil with a relative density greater than 10 degrees API gravity and less than or equal to 22.3 degrees API gravity;

IV) **Tight Oil** means crude oil:

a. contained in dense organic rich rocks, including low-permeability shales, siltstones, and carbonates, in which the crude oil is primarily contained in microscopic pore spaces that are poorly connected to one another, and

b. that typically requires the use of hydraulic fracturing to achieve economic production rates;

V) **Bitumen** means a naturally occurring solid or semi-solid hydrocarbon:

a. consisting mainly of heavier hydrocarbons, with a viscosity greater than 10,000 millipascal-seconds (mPa·s) or 10,000 centipoise (cP) measured at the hydrocarbon's original temperature in the reservoir and at atmospheric pressure on a gas-free basis, and

b. that is not primarily recoverable at economic rates through a well without the implementation of enhanced recovery methods;

VI) **Synthetic Crude Oil** means a mixture of liquid hydrocarbons derived by upgrading bitumen, kerogen, or other substances such as coal, or derived from gas to liquid conversion and may contain sulphur or other compounds;

Natural Gas

VII) **Conventional Natural Gas** means natural gas that has been generated elsewhere and has migrated as a result of hydrodynamic forces and is trapped in discrete accumulations by seals that may be formed by localized structural, depositional, or erosional geological features;

VIII) **Coal Bed Methane** means natural gas that

a) primarily consists of methane, and

b) is contained in a coal deposit;

IX) **Shale Gas** means natural gas:

a) contained in dense organic-rich rocks, including low-permeability shales, siltstones, and carbonates, in which the natural gas is primarily adsorbed on the kerogen or clay minerals, and

b) that usually requires the use of hydraulic fracturing to achieve economic production rates;

X) **Synthetic Gas** means a gaseous fluid:

a) generated as a result of the application of an in-situ transformation process to coal or other hydrocarbon-bearing rock, and

b) comprised of not less than 10% by volume of methane;

XI) **Gas Hydrate** means a naturally occurring crystalline substance composed of water and gas in an ice-lattice structure;

By-Products

XII) **Natural Gas Liquids** means those hydrocarbon components that can be recovered from natural gas as a liquid including, but not limited to, ethane, propane, butanes, pentanes plus, and condensates.

XIII) **Sulphur** is a non-hydrocarbon elemental by-product of gas processing and oil refining.

Appendix B — Prices (As of March 31, 2021)

Sproule's short-term outlook for oil and gas prices is based on information obtained from various sources, including government agencies, industry publications, oil refiners, and natural gas marketers as well as consideration for the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE) futures markets. The forecast used in this evaluation was derived as of **March 31, 2021.**

Oil Prices

The oil price forecasts set out in Table P-1 are based on the ICE Brent contract; a light, sweet crude blend produced in the North Sea.

The actual wellhead price of oil will vary with the quality of the crude and the cost of the transportation from the wellhead to the specified terminal. This cost, which is referred to as the price differential, is based on the actual difference between the revenue received at the wellhead and the contract price for the benchmark crude. In the absence of actual crude oil price statistics, the differential is based on the price of similar quality crude in the area.

2020 saw significant volatility in global crude markets, having been hit hard by the impacts of the COVID-19 pandemic. COVID-19 caused unprecedented crude demand disruption across Q2, with demand averaging over 15 million bbl/d below the 2019 average. Demand has started on a path to recovery and we exit the year roughly 6 million bbl/d below the 2019 average; however, with a second wave of COVID-19 cases spreading across many parts of the world, the trajectory of global crude demand recovery is still uncertain. Longer term, questions remain over the possibility of structural demand destruction from COVID-19 related unemployment, reduced travel and increased remote work solutions. This could impact what the new normal will look like and the timing of returning to pre-virus demand levels. In terms of demand destruction drivers looking beyond the forecast period, electric vehicles represent the first major market segment with significant potential for crude oil market disruption. Electric vehicle sales continue to grow but will not become a viable substitute for internal combustion engine vehicles until the lithium-ion battery cost falls below $100/kWh, which is anticipated in the 2025 timeframe. Based on our estimates, by 2030 we expect 0.5 - 3.0mmbbl/d of crude demand disruption from electric vehicles, with the potential to expand beyond 7.0mmbbl/d disruption by 2040. The potential impacts of Electric Vehicles on global crude demand have not been incorporated into our price forecast yet, but Sproule is continuing to monitor the progress of energy transition and the impacts on oil and gas markets going forward.

On the supply side, supply growth over the last several years has been led by US Light Tight Oil (LTO) producers. The US added roughly 1.2 million bbl/d of production growth in 2019 which, although robust, was roughly 75% of the growth seen in 2018 – a downward trend we saw continuing even before the onset of COVID-19 as producers face limited access to capital and diminishing per-well productivity. COVID-19 has accelerated this trend, and US LTO production exits the year over 1 million bbl/d (15%) below 2019 levels. Looking forward, a recovery of US LTO production to pre-pandemic levels is unlikely to materialize over the forecast period due to the combination of lower commodity prices, reduced access to capital, focus on cash flow generation, and steep natural declines. Given its short-cycle nature, however, U.S. shale is likely to grow production when prices reach the break-even threshold for individual producers. Our view is that U.S. shale economics will continue to place a natural ceiling on prices in the long term. Outside of the US, Sproule anticipates supply growth to be modest as access to capital remains limited, and reduced global demand decreases the appetite for levels of Non-OPEC, Non-US LTO growth required in recent years.

In April 2020, OPEC+ met and agreed to implement another round of production curtailments – 9.7 million bbl/d May to June 2020, 7.7 million bbl/d for the remainder of 2020, and 5.8 million bbl/d for the following 16 months, ending in Q2 of 2022. Thus far, compliance to these curtailments has averaged at roughly 100%, which has been critical for the balancing of the global crude supply-demand equation. In the medium term, compliance to the agreed upon OPEC+ curtailment levels will continue to be vital to achieving their designed purpose, which is to facilitate a balanced crude market. However, a price recovery will also heighten the potential for non-compliance.

Combining the natural ceiling on price created by U.S. shale economics, OPEC+'s continued extraordinary willingness to intervene and support the market, and the expectation for a meaningful demand recovery, Sproule's long-term forecast is set at **$55** US per barrel for Brent in 2023 with an escalation rate of 2.0% thereafter.

Natural Gas Prices

After averaging over $5.00 US/MMbtu in Q4 2019, the price for NBP and TTF European gas fell precipitously to sub-$1.50 US/MMBtu lows by May 2020. Led by a record build out of US Gulf Coast LNG export capacity in recent years (3.5 bcf/d per annum 2015 – 2019), combined with a warmer than expected winter in Asia and Europe and exacerbated by demand weakness caused by the COVID-19 pandemic, the European and Asian gas markets were significantly oversupplied for the first half of 2020. In a response to low prices and resulting negative netbacks, by mid-Q2 US LNG exporters began cancelling cargos destined for European and Asian markets, with total US LNG exports falling from Q1 highs of 7.5 bcf/d to below 3 bcf/d by July. All the while, resilient Asian LNG demand, led by China and India, remained at or above pre-pandemic levels throughout 2020. Combining this continued robust demand for LNG and the reduced supply over Q2 and Q3, European and Asian gas markets were brought back into balance, and the price responded accordingly. Since Q2 lows, we have seen a rapid increase in prices back to above $5.00 US/MMbtu as of the end of December 2020.

Looking forward, the risk of lasting LNG oversupply is likely minimal, considering the expectation for more modest LNG export growth of 2bcf/d per annum from 2020 to 2025 (a 60% reduction in annual growth seen from 2015 to 2019) and continued Asian LNG demand growth into the mid-decade. In our view, considering the recently demonstrated operational flexibility and willingness of US Gulf Coast LNG exporters to cancel

LNG cargoes during periods of low European gas prices, there is likely a floor of roughly $4.00 US/MMbtu on European gas prices. On the high-end, if European gas prices rise to $6.00 US/MMbtu and above, CCGT power plants are likely to switch to the less expensive coal option, thus placing a ceiling on upward NBP and TTF price momentum. Overall, with European gas prices rangebound at between $4.00 and $6.00 US per MMbtu, we see European gas prices stabilizing around the marginal cost of US LNG supplied to Europe. Reflecting these views, Sproule expects NBP to trade at **$5.76** US per MMbtu by 2023 and TTF to trade at **$5.71** US per MMbtu by 2023, with an escalation rate of 2.0% thereafter.

Detailed price forecasts for natural gas are set out in Table P-1. The actual plantgate price will vary with the heat content of the natural gas and the cost of transportation from the plantgate to the trading hub. In the absence of actual natural gas price statistics, the differential is based on the price of natural gas in the area.

Table P-1
Oil Price Forecasts, Inflation and Exchange Rates ($Cdn)
Effective March 31, 2021

Year	UK Brent 38°API(1,3) ($US/bbl)	UK Forties 41 API $US/Bbl	IPE Britain NBP ($US/MMbtu)	Operating Cost Inflation Rate4) (%/Yr)	Capital Cost Inflation Rate(4) (%/Yr)	Exchange Rate(5) ($US/£UK)
Historical						
2016	45.04	45.04	4.73	1.2%	-9.7%	1.36
2017	54.83	54.83	5.86	1.7%	2.4%	1.29
2018	71.53	71.53	7.87	2.4%	4.2%	1.34
2019	64.17	64.17	4.85	-0.7%	0.4%	1.28
2020	43.21	43.21	3.31	-5.0%	-5.0%	1.28
Forecast						
2021	60.00	60.00	6.21	0.0%	0.0%	1.35
2022	57.50	57.50	6.08	1.0%	1.0%	1.35
2023	55.00	55.00	6.08	2.0%	2.0%	1.35
2024	56.10	56.10	6.20	2.0%	2.0%	1.35
2025	57.22	57.22	6.32	2.0%	2.0%	1.35
2026	58.37	58.37	6.45	2.0%	2.0%	1.35
2027	59.53	59.53	6.58	2.0%	2.0%	1.35
2028	60.72	60.72	6.71	2.0%	2.0%	1.35
2029	61.94	61.94	6.84	2.0%	2.0%	1.35
2030	63.18	63.18	6.98	2.0%	2.0%	1.35
2031	64.44	64.44	7.12	2.0%	2.0%	1.35
Escalation rate of 2.0% percent per year thereafter						

Appendix C — Abbreviations, Units and Conversion Factors

This appendix contains a list of abbreviations found in Sproule reports, a table comparing Imperial and Metric units, and conversion tables used to prepare this report.

Abbreviations

ADR	abandonment, decommissioning and reclamation
AFE	authority for expenditure
AOF	absolute open flow
APO	after pay out
B_g	gas formation volume factor
B_o	oil formation volume factor
BOE	barrels of oil equivalent
bpd	barrels per day
bopd	barrels of oil per day
boepd	barrels of oil equivalent per day
bfpd	barrels of fluid per day
BPO	before pay out
BS&W	basic sediment and water
BTU	British thermal unit
bwpd	barrels of water per day
CF	casing flange
CGR	condensate-gas ratio
cP	centipoise
D&A	dry and abandoned
DCQ	daily contract quantity
DPIIP	discovered petroleum initially-in-place
DSU	drilling spacing unit
DST	drill stem test
EOR	enhanced oil recovery
EPSA	exploration and production sharing agreement
FPSO	floating production, storage and off-loading vessel
FVF	formation volume factor
g/cc	gram per cubic centimetre
GIIP	gas initially-in-place
GOR	gas-oil ratio
GORR	gross overriding royalty
GRV	gross rock volume
GWC	gas-water contact
HCPV	hydrocarbon pore volume

ID	inside diameter
IOR	improved oil recovery
IPR	inflow performance relationship
IRR	internal rate of return
k	permeability
KB	kelly bushing
LKH	lowest known hydrocarbons
LKO	lowest known oil
LNG	liquefied natural gas
LPG	liquefied petroleum gas
McfGE	thousands of cubic feet of gas equivalent
Mcfpd	thousands of cubic feet per day
md	millidarcies
MDT	modular formation dynamics tester
MPR	maximum permissive rate
MRL	maximum rate limitation
NCI	net carried interest
NGL	natural gas liquids
NORR	net overriding royalty
NPI	net profits interest
NRA	no reserves assigned
NRI	net revenue interest
NPV	net present value
NRV	net rock volume
NTG	net-to-gross
NUI	normally unmanned installations
OD	outside diameter
OGIP	original gas in place
OIIP	oil initially-in-place
OOIP	original oil in place
ORRI	overriding royalty interest
OWC	oil-water contact
P1	proved
P2	probable
P3	possible
P&NG	petroleum and natural gas
PI	productivity index
ppm	parts per million
PSU	production spacing unit
PSA	production sharing agreement
PSC	production sharing contract
PVT	pressure-volume-temperature

RFT	repeat formation tester
RT	rotary table
SCAL	special core analysis
SS	subsea
TPIIP	total petroleum initially-in-place
TVD	true vertical depth
UPIIP	undiscovered petroleum initially-in-place
WGR	water-gas ratio
WHP	wellhead platform
WI	working interest
WOR	water-oil ratio
2D	two-dimensional
3D	three-dimensional
4D	four-dimensional
1P	proved
2P	proved plus probable
3P	proved plus probable plus possible
°API	degrees API (American Petroleum Institute)

Imperial and Metric Units

Imperial Units			Metric Units	
M (10^3)	thousand	**Prefixes**	k (10^3)	kilo
MM (10^6)	million		M (10^6)	mega
B (10^9)	billion		G (10^9)	giga
T (10^{12})	trillion		T (10^{12})	tera
Q (10^{15})	quadrillion		P (10^{15})	peta
in.	inches	**Length**	cm	centimetres
ft	feet		m	metres
mi	miles		km	kilometres
ft^2	square feet	**Area**	m^2	square metres
ac	acres		ha	hectares
cf or ft^3	cubic feet	**Volume**	m^3	cubic metres
scf	standard cubic feet			
gal	gallons		L	litres
Mcf	thousand cubic feet			
MMcf	million cubic feet			
Bcf	billion cubic feet		e^6m^3	million cubic metres
bbl	barrels		m^3	cubic metres
Mbbl	thousand barrels		e^3m^3	thousand cubic metres
stb	stock tank barrels		stm^3	stock tank cubic metres
bbl/d	barrels per day	**Rate**	m^3/d	cubic metre per day
Mbbl/d	thousand barrels per day		e^3m^3/d	thousand cubic metres
Mcf/d	thousand cubic feet per day		e^3m^3/d	thousand cubic metres
MMcf/d	million cubic feet per day		e^6m^3/d	million cubic metres
Btu	British thermal units	**Energy**	J	joules
oz	ounces	**Mass**	g	grams
lb	pounds		kg	kilograms
ton	tons		t	tonnes
lt	long tons			
psi	pounds per square inch	**Pressure**	Pa	pascals
			kPa	kilopascals (10^3)
psia	pounds per square inch absolute			
psig	pounds per square inch gauge			
°F	degrees Fahrenheit	**Temperature**	°C	degrees Celsius
°R	degrees Rankine		K	degrees Kelvin
M$	thousand dollars	**Dollars**	k$	1 kilodollar

Imperial and Metric Units (Cont'd)

Imperial Units			Metric Units	
sec	second	**Time**	s	second
min	minute		min	minute
hr	hour		h	hour
d	day		d	day
wk	week			week
mo	month			month
yr	year		a	annum

Conversion Tables

Conversion Factors — Metric to Imperial		
cubic metres (m^3) (@ 15°C)	x 6.29010	= barrels (bbl) (@ 60°F), water
m^3 (@ 15°C)	x 6.3300	= bbl (@ 60°F), Ethane
m^3 (@ 15°C)	x 6.30001	= bbl (@ 60°F), Propane
m^3 (@ 15°C)	x 6.29683	= bbl (@ 60°F), Butanes
m^3 (@ 15°C)	x 6.29287	= bbl (@ 60°F), oil, Pentanes Plus
m^3 (@ 101.325 kPaa, 15°C)	x 0.0354937	= thousands of cubic feet (Mcf) (@ 14.65 psia, 60°F)
1,000 cubic metres (10^3m^3) (@ 101.325 kPaa, 15°C)	x 35.49373	= Mcf (@ 14.65 psia, 60°F)
hectares (ha)	x 2.4710541	= acres
1,000 square metres (10^3m^2)	x 0.2471054	= acres
10,000 cubic metres (ha·m)	x 8.107133	= acre feet (ac-ft)
$m^3/10^3m^3$ (@ 101.325 kPaa, 15° C)	x 0.0437809	= Mcf/Ac.ft. (@ 14.65 psia, 60°F)
joules (j)	x 0.000948213	= Btu
megajoules per cubic metre (MJ/m^3) (@ 101.325 kPaa, 15°C)	x 26.714952	= British thermal units per standard cubic foot (Btu/scf) (@ 14.65 psia, 60°F)
dollars per gigajoule ($/GJ)	x 1.054615	= $/Mcf (1,000 Btu gas)
metres (m)	x 3.28084	= feet (ft)
kilometres (km)	x 0.6213712	= miles (mi)
dollars per 1,000 cubic metres ($\$/10^3m^3$)	x 0.0288951	= dollars per thousand cubic feet ($/Mcf) (@ 15.025 psia) B.C.
($\$/10^3m^3$)	x 0.02817399	= $/Mcf (@ 14.65 psia) Alta.
dollars per cubic metre ($\$/m^3$)	x 0.158910	= dollars per barrel ($/bbl)
gas/oil ratio (GOR) (m^3/m^3)	x 5.640309	= GOR (scf/bbl)
kilowatts (kW)	x 1.341022	= horsepower
kilopascals (kPa)	x 0.145038	= psi
tonnes (t)	x 0.9842064	= long tons (LT)
kilograms (kg)	x 2.204624	= pounds (lb)
litres (L)	x 0.2199692	= gallons (Imperial)
litres (L)	x 0.264172	= gallons (U.S.)
cubic metres per million cubic metres ($m^3/10^6m^3$) (C_3)	x 0.177496	= barrels per million cubic feet (bbl/MMcf) (@ 14.65 psia)
$m^3/10^6m^3$) (C_4)	x 0.1774069	= bbl/MMcf (@ 14.65 psia)
$m^3/10^6m^3$) (C_{5+})	x 0.1772953	= bbl/MMcf (@ 14.65 psia)
tonnes per million cubic metres ($t/10^6m^3$) (sulphur)	x 0.0277290	= LT/MMcf (@ 14.65 psia)
millilitres per cubic meter (mL/m^3) (C_{5+})	x 0.0061974	= gallons (Imperial) per thousand cubic feet (gal (Imp)/Mcf)
(mL/m^3) (C_{5+})	x 0.0074428	= gallons (U.S.) per thousand cubic feet (gal (U.S.)/Mcf)
Kelvin (K)	x 1.8	= degrees Rankine (°R)
millipascal seconds (mPa·s)	x 1.0	= centipoise
density (kg/m3), ρ	ρ÷1000x141.5-131.5	= °API

Conversion Tables (Cont'd)

Conversion Factors — Imperial to Metric		
barrels (bbl) (@ 60°F)	x 0.15898	= cubic metres (m^3) (@ 15°C), water
bbl (@ 60°F)	x 0.15798	= m^3 (@ 15°C), Ethane
bbl (@ 60°F)	x 0.15873	= m^3 (@ 15°C), Propane
bbl (@ 60°F)	x 0.15881	= m^3 (@ 15°C), Butanes
bbl (@ 60°F)	x 0.15891	= m^3 (@ 15°C), oil, Pentanes Plus
thousands of cubic feet (Mcf) (@ 14.65 psia, 60°F)	x 28.17399	= m^3 (@ 101.325 kPaa, 15°C)
Mcf (@ 14.65 psia, 60°F)	x 0.02817399	= 1,000 cubic metres (10^3m^3) (@ 101.325 kPaa, 15°C)
acres	x 0.4046856	= hectares (ha)
acres	x 4.046856	= 1,000 square metres (10^3m^2)
acre feet (ac-ft)	x 0.123348	= 10,000 cubic metres (10^4m^3) (ha·m)
Mcf/ac-ft (@ 14.65 psia, 60°F)	x 22.841028	= $10^3m^3/m^3$ (@ 101.325 kPaa, 15°C)
Btu	x 1054.615	= joules (J)
British thermal units per standard cubic foot (Btu/Scf)	x 0.03743222	= megajoules per cubic metre (MJ/m^3)
(@ 14.65 psia, 60°F)		(@ 101.325 kPaa, 15°C)
$/Mcf (1,000 Btu gas)	x 0.9482133	= dollars per gigajoule ($/GJ)
$/Mcf (@ 14.65 psia, 60°F) Alta.	x 35.49373	= $/$10^3m^3$ (@ 101.325 kPaa, 15°C)
$/Mcf (@ 15.025 psia, 60°F), B.C.	x 34.607860	= $/$10^3m^3$ (@ 101.325 kPaa, 15°C)
feet (ft)	x 0.3048	= metres (m)
miles (mi)	x 1.609344	= kilometres (km)
dollars per barrel ($/bbl)	x 6.29287	= dollars per cubic metre ($/$m^3$)
GOR (scf/bbl)	x 0.177295	= gas/oil ratio (GOR) (m^3/m^3)
horsepower	x 0.7456999	= kilowatts (kW)
psi	x 6.894757	= kilopascals (kPa)
long tons (LT)	x 1.016047	= tonnes (t)
pounds (lb)	x 0.453592	= kilograms (kg)
gallons (Imperial)	x 4.54609	= litres (L) (.001 m^3)
gallons (U.S.)	x 3.785412	= litres (L) (.001 m^3)
barrels per million cubic feet (bbl/MMcf) (@ 14.65 psia) (C_3)	x 5.6339198	= cubic metres per million cubic metres ($m^3/10^6m^3$)
bbl/MMcf (C_4)	x 5.6367593	= ($m^3/10^6m^3$)
bbl/MMcf (C_{5+})	x 5.6403087	= ($m^3/10^6m^3$)
LT/MMcf (sulphur)	x 36.063298	= tonnes per million cubic metres ($t/10^6m^3$)
gallons (Imperial) per thousand cubic feet (gal (Imp)/Mcf) (C_{5+})	x 161.3577	= millilitres per cubic meter (mL/m^3)
gallons (U.S.) per thousand cubic feet (gal (U.S.)/Mcf) (C_{5+})	x 134.3584	= (mL/m^3)
degrees Rankine (°R)	x 0.555556	= Kelvin (K)
centipoises	x 1.0	= millipascal seconds (mPa·s)
°API	(°APIx131.5)x 1000/141.5	= density (kg/m3)

Appendix D — General Evaluation Parameters

Royalties and Mineral Taxes

The lessor and overriding royalties, if applicable, were based on existing agreements and government regulations.

Operating, Maintenance and Capital Costs

Operating, maintenance and capital cost forecasts were based on the detailed analysis of the project in the Pilot Concept Select Study report which is based upon historical cost analysis of comparable equipment and facility type and size within the applicable region for comparative analysis and were escalated to the dates when these costs would be incurred. When escalated, the operating costs and capital costs were escalated based upon the schedule of escalation factors included in Appendix B, Table P-1. Value Navigator applies escalation incrementally, on a yearly basis.

Value Navigator applies escalation incrementally, on a yearly basis.

Abandonment, Decommissioning and Reclamation

Abandonment, decommissioning and reclamation (ADR) costs represent all the end of life costs associated with restoring an asset where petroleum exploration, development, production and processing operations have been conducted, to a standard imposed by applicable government or regulatory authorities.

Estimating ADR costs on existing development requires detailed knowledge of the property, the history of each well and facility, and may require site visits. Without detailed scrutiny of existing development in its entirety, the ADR cost estimates presented in an evaluation may be misleading or imply a level of due diligence evaluators do not typically undertake. ADR costs included in an asset evaluation must be properly assessed with reliance on those with the requisite expertise.

Best practice would use an ADR estimate which includes all costs required to restore existing development from the well's bottom hole to custody transfer point, to the standards imposed by applicable government or regulatory authorities and include the ADR costs for both active and inactive development included in the assets evaluated.

The extent to which ADR costs are included in this report, and the source of the estimates contained herein, is documented in the Introduction section of this report in the Evaluation Data and Procedures section and is based on the Scope and Purpose of the report, as stipulated by the Company.

Active and Inactive Assets and Properties

Active properties or assets are those properties or assets which contain planned development activity which is economic within a reasonable time period.

Inactive properties have no current production and typically consist of shut-in, suspended and capped wells, various land holdings, suspended gathering systems and shut-in processing facilities. These assets typically have no development plans which may be assigned reserves however they do incur ongoing operating expenses within a company's oil and gas asset portfolio, the magnitude of which may be material.

The extent to which active and inactive assets are included in the evaluation including related costs on inactive assets or properties is documented in the Introduction section of this report under the Evaluation Data and Procedures section.

Uneconomic Assets or Properties

Uneconomic assets or properties are those assets and properties which are currently producing however do not yield net positive cash flows under the economic model. These assets have no assigned reserves and would incur inactive asset costs once actually shut-in. The method by which the ongoing operating expenses associated with these assets has been modelled and included in the report is documented in the Introduction of this report under the Evaluation Data and Procedures section.

Orphan Well Fund Levies

Cash flows do not include Company payment to various jurisdictional orphan well fund programs.

Overhead Expenses

Operating Cost Overhead

Operating cost overhead charges and recoveries associated with the Company's properties, whether operated or non-operated, have been excluded for the purposes of this evaluation.

Capital Cost Overhead

Capital cost overhead charges and/or recoveries have not been included in the evaluation and forecast of future capital cost spending.

Other Items

Carbon Taxes

Carbon tax payments or carbon tax credit as outlined in the UK government guidance and detailed explanation is included in the operating costs in this evaluation.

Revenues generated from carbon tax credit sales have not been incorporated into our evaluation.

Financial Instruments

Cash flows and corporate runs do not include the effects of various financial instruments the Company may hold, such as pricing hedging contracts and/or various put and call options.

Compensatory Royalty

Cash flows do not include the payment of compensatory royalties to hold various leases or permits, or the receipt of compensatory royalties paid by others to the Company, to hold the rights to develop the Company's properties.

Appendix E — Petroleum Fiscal Terms

This appendix summarizes the fiscal terms in the United Kingdom ("UK"). The ring fence fiscal regime applies to the exploration for, and production of, oil, gas and gas by-products in the UK and UK Continental Shelf (UKCS) and comprises of two taxes, namely Ring Fence Corporation Tax and Supplementary Charge Tax.

The Company is subject to United Kingdom Ring Fence Corporation Tax at 30 percent of profits and Supplementary Charge at 10 percent of profits. The Supplementary Charge Tax is calculated on the same basis as the Ring Fence Corporation Tax. Payments are scheduled so that two-thirds of the payments are made the year the liability is incurred and one-third is paid the following year.

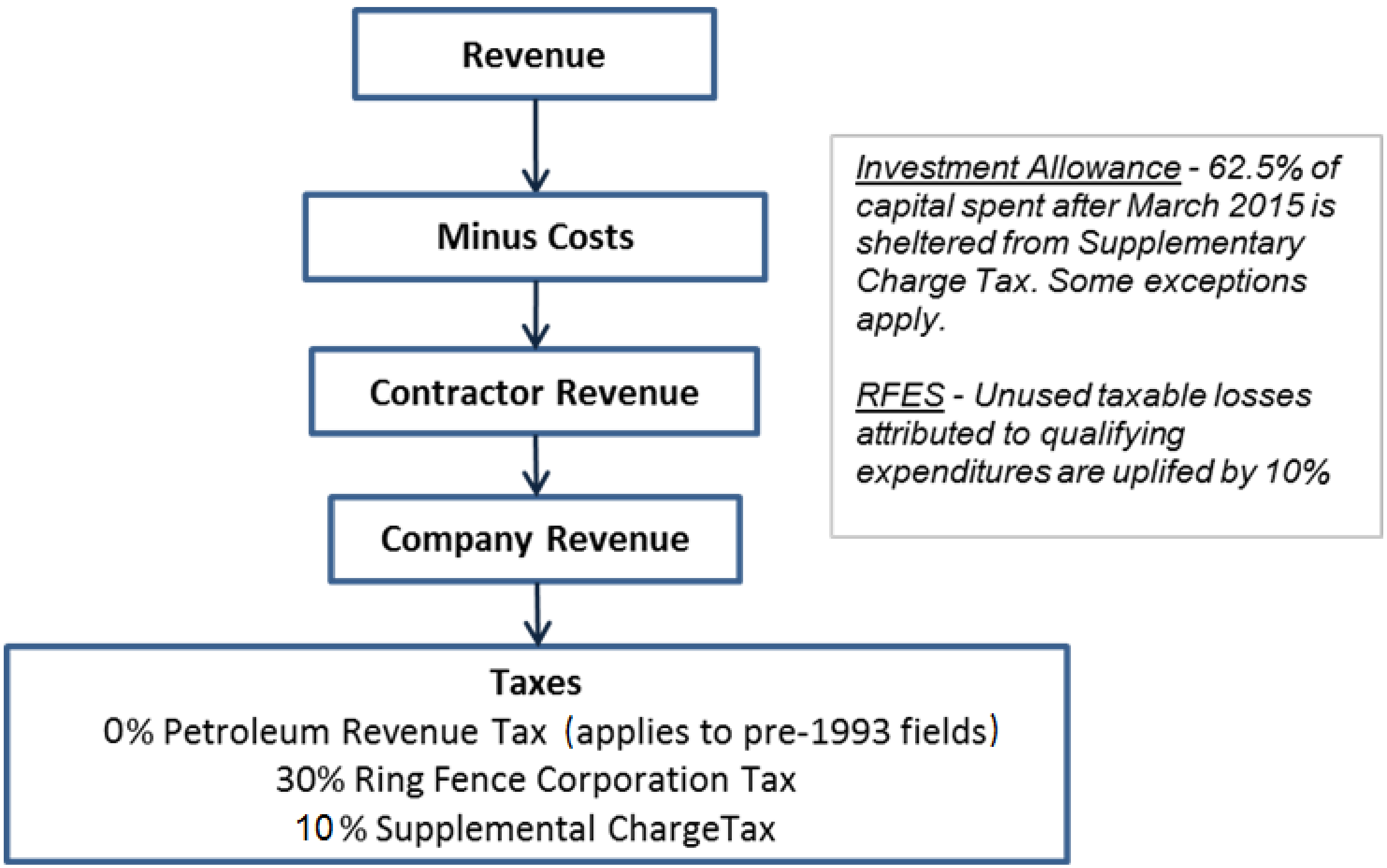
The premise of the ring fence is that corporate tax on profits from oil and gas extraction activities should be paid in full, undiluted by any losses or any other form of relief arising from any other business activities whether in the United Kingdom or elsewhere. Oil and gas extraction activities are treated as a separate trade (ring-fenced), distinct from all other activities carried out by the Company. An enhanced first year capital allowance (i.e., 100 percent write-down) is available for ring fence operating and capital expenditures. Acquisition costs and losses from other non-ring-fenced activities are not allowed. A Ring Fence Expenditure Supplement (RFES) increases the value of unused qualifying expenditures carried forward from one period to the next by a compound 10 percent per year for a maximum of ten years.

In December 2014, the UK government announced a new basin-wide investment allowance to simplify and replace the previous system of offshore field allowances over time. The investment allowance operates in a similar manner as the previous system and exempts 62.5 percent of qualifying capital expenditures made by the Company from its adjusted ring fence profits which are subject to Supplementary Charge Tax. The investment allowance applies to qualifying capital expenditures the Company makes on or after April 1, 2015 in a field that is considered to be materially complete. First commercial production is usually used to determine if a field is materially complete, except in phased projects where much of the originally contemplated expenditure is scheduled after first production (such as brownfield projects on producing fields).

For an existing field that was in receipt of a small field allowance, any unactivated field allowance is converted to an investment allowance pool. If a field is not materially complete, only the portion of capital expenditures that exceeds 160 percent of the gross field allowance spent between April 1, 2015 and the date it is deemed to be materially complete, can be applied as an investment allowance. The same methodology applies for a field in receipt of a brownfield allowance.

For a field that is not producing by the effective date of this report and is not eligible for field value allowances, all capital required to develop the field is eligible to be included in the calculation of an investment allowance.

A schematic diagram of the petroleum fiscal terms is presented in Figure E-1.



Schematic Diagram of Fiscal Regime

Appendix F – Representation Letter

The Representation Letter has been included as Appendix F it was prepared by Officers of the Company and confirms the accuracy, completeness and availability of all data requested by Sproule and or otherwise furnished to Sproule during the course of our evaluation of the Company's assets, herein reported on.

Orcadian Energy PLC
70 Claremont Road
Surbiton
Surrey
KT6 4RH
Tel: +44 203 603 1941
Email : steve.brown@orcadian.energy
Web : https://www.orcadian.energy

17th June 2021

Sproule B.V.
President Kennedylaan 19
2517 JK – Den Haag,
The Netherlands

Dear Sir:

Re: Orcadian Energy PLC,
6th Floor 60 Gracechurch Street,
London,
United Kingdom, EC3V 0HR

Regarding the evaluation of our Company's oil and gas reserves and resources and the Competent Person's Report of these reserves and resources (the "CPR") as of April 1, 2021 (the "Effective Date"), we herein confirm, to the best of our knowledge and belief after due inquiry, as of the Effective Date and, as applicable, as of today, the following representations and information made available to you during the conduct of the CPR:

1. We (the Client) have made available to you (the Evaluator) certain records, information, and data relating to the evaluated properties that we confirm is, with the exception of immaterial items, complete and accurate as of the Effective Date of the CPR, including, where applicable, the following:

    - accounting, financial, tax, and contractual data;
    - asset ownership and related encumbrance information;
    - details concerning product marketing, transportation, and processing arrangements;
    - details concerning maintenance capital
    - all technical information including geological, engineering, and production and test data; !
    - estimates of future abandonment, decommissioning and reclamation costs, excluding adjustments for salvage.

2. We confirm that all financial and accounting information provided to you is, both on an individual entity basis and in total, entirely consistent with that reported by our Company for public disclosure and audit purposes.

3. We confirm that our Company has satisfactory title to all of the assets, whether tangible, intangible, or otherwise, for which accurate and current ownership information has been provided.

4. With respect to all information provided to you regarding product marketing, transportation, and processing arrangements, we confirm that we have disclosed to you all anticipated changes, terminations, and additions to these arrangements that could reasonably be expected to have a material effect on the evaluation of our Company's reserves and resources and future net revenues. 5. With the possible exception of items of an immaterial nature, we confirm the following as of the Effective Date:

   - For all operated properties that you have evaluated, no changes have occurred or are reasonably expected to occur to the operating conditions or methods that have been used by our Company over the past twelve (12) months, except as disclosed to you. In the case of non-operated properties, we have advised you of any such changes of which we have been made aware.

   - All regulatory approvals, permits, and licenses required to allow continuity of future operations and production from the evaluated properties are in place and, except as disclosed to you, there are no directives, orders, penalties, or regulatory rulings in effect or expected to come into effect relating to the evaluated properties.

   - Except as disclosed to you, the producing trend and status of each evaluated well or entity in effect throughout the three-month period preceding the Effective Date are consistent with those that existed for the same well or entity immediately prior to this three-month period.

   - Except as disclosed to you, we have no plans or intentions related to the ownership, development, or operation of the evaluated properties that could reasonably be expected to materially affect the production levels or recovery of reserves from the evaluated properties.

   - If material changes of an adverse nature occur in the Company's operating performance subsequent to the Effective Date and prior to the report date, we will inform you of such material changes prior to requesting your approval for any public disclosure of any reserves information.

Between the Effective Date and the date of this letter nothing has come to our attention that has materially affected or could materially affect our reserves and resources and the economic value of these reserves and resources that has not been disclosed to you.

Yours very truly,

Orcadian Energy PLC

Stephen A. Brown
Chief Executive Officer