22nd October 2021

The Directors
Angus Energy plc and Angus Energy Weald Basin No 3 Ltd
Building 3 Chiswick Park
566 Chiswick High Street
London
W4 5YA
Tel: +44 (0) 208 899 6380

Dear Sirs

RESERVES/RESOURCES REPORT & VALUATION OF CERTAIN ASSETS OF ANGUS ENERGY IN UK ONSHORE LICENCE, PEDL005

Summary: 1P and 2P Reserves and Valuation

In accordance with your instructions, Oilfield International ("OIL") has valued certain petroleum interests held and operated by Angus Energy Weald Basin No 3 Ltd (hereinafter "AEWB") on behalf of Angus Energy plc, namely a 51% working interest in the Saltfleetby Gas Field which is part of the UK onshore licence PEDL005. The effective date of this report is 1st October 2021, there being no material change on 22nd October 2021.

The remaining 49% Working interest in the Saltfleetby Gas Field is owned by Saltfleetby Energy Ltd ("SE").

OIL conducted its assessment in compliance with the SPE Petroleum Resource Management System (SPE-PRMS) sponsored by the Society of Petroleum Engineers/American Association of Petroleum Geologists/World Petroleum Council/Society of Petroleum Evaluation Engineers (SPE/ AAPG/ WPC/ SPEE) in 2018 and the PRMS Guidelines 2011[1]. Relevant sections of the SPE-2018 PRMS definitions and guidelines are quoted in the report[2].

This report reproduces relevant parts of the Saltfleetby Reserves/Resources Report, dated 4th March 2020[3] prepared by OIL. The P90 and P50 remaining recoverable volumes in that report were calculated from an analysis of 20 years of production data, and there has been no production since that report. Therefore, this report presents the same P90 and P50 remaining recoverable volumes for the Saltfleetby field.

OIL has attributed Proved ("1P") and Proved plus Probable ("2P") Reserves and future cash flows to AEWB. Table 0-1 refers.

There are additional remaining recoverable volumes attributable to AEWB but these are not classified and categorised here since this would requires a lengthy analysis of the operator's recently completed depth-migrated 3D seismic data, which the operator is still interpreting.

---

[1] Refer https://www.spe.org/en/industry/petroleum--management-system-2018/ ; and https://www.spe.org/industry/docs/PRMS_Guidelines_Nov2011.pdf. The 2011 guidelines are scheduled to be updated in 2020.

[2] **PRMS definitions** are bold titled and indented to separate them from the analysis.

[3] Refer https://www.angusenergy.co.uk/wp-content/uploads/2020/03/Reserves-Resources-Valuation-Report-Angus-Energy-Saltfleetby-Assets-Effective-Date-28th-February-2020-Report-Date-4th-March-2020.pdf

The results presented reflect OIL's judgement based on its understanding of petroleum legislation, taxation and other regulations that currently apply to AEWB and SE.

AEWB and SE are parties to a £12m loan agreement which includes a number of material loan costs, cash distribution restrictions, overriding royalty interests and hedging obligations. AEWB is bound by the terms of this loan agreement and so AEWB's net entitlement reserves reported here are net of the overriding royalty interest[4] and AEWB's future cash flows reported here reflect the loan costs, cash flow constraints and royalties.

OIL cannot attest to the certainty of property title or encumbrances related to AEWB.

OIL's estimates of value are based on datasets provided by AEWB. OIL conducted a site visit to PEDL005 in February 2020 before construction of the surface facilities and pipeline extension commenced. OIL has a Reasonable Expectation[5] of First Gas on or before 15th March 2022[6]. OIL has taken all reasonable steps to establish the integrity of source data as well as the accuracy and completeness of key subsurface data, production inventory and internal accounting records. OIL has not independently verified any information provided by or at the direction of AEWB (and/or obtained from other sources) and has accepted the accuracy and completeness of these data.

OIL notes that the data provided were acquired by reputable oilfield services providers. OIL has no reason to believe that any material facts have been withheld from it but does not warrant that its enquiries have revealed all the matters that a more extensive examination might otherwise disclose.

[4] With reference to p174 of PRMS Guidelines 2011, OIL has determined that the lenders' ORRI is an "Economic Interest" under clause (ii) of SEC Section S-X, Rule 4-10b Successful Efforts Method: Mineral Interests in Properties. Specifically, lenders have: (a) "the right to take produced volumes in kind *or share in the proceeds from their sale*; and (b) "*exposure to market risk and technical risk"*. Therefore, the lenders have entitlement reserves equivalent to the value of the royalty, and these entitlement reserves are given up by the licensees.

[5] PRMS 2018 Definitions, page 48 – a high degree of confidence.

[6] The Operator is targeting 14th February 2022, and OIL is being more cautious in its schedule assumptions.

Table 0-1 Resource structures identified on the Saltfleetby Gas Field

Name of Structure	**Reservoirs**
Reserves 1P, 2P (reported here)	
Saltfleetby Main Gas Field	Westphalian
Reserves 3P (Not reported here)	
Saltfleetby Main Gas Field	Westphalian
Contingent Resources (Not reported here)	
Saltfleetby Main Gas Field	Namurian
Southern Satellite Structure	Westphalian

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

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

Table 0-2 and Table 0-3 present the Gas and Condensate Liquids Reserves attributable to AEWB and net of the Overriding Royalty Interest and net of Gas Consumed in Operations.

Table 0-4 presents the post-tax NCF and NPV10 of the Reserves attributable to AEWB, net of the financing costs and constraints.

Table 0-5 presents the annual capex liability attributable to AEWB.

Table 0-2 Sales Gas Reserves: Gross and Net Attributable to AEWB

Saltfleetby Field	Gross		Net Attributable to AEWB		Operator
Sales Gas Reserves	**1P**	**2P**	**1P**	**2P**	
	BCF	BCF	BCF	BCF	
Main Field Westphalian Reservoir	18.0	31.8	8.5	15.0	AEWB

Effective Date: 1st October 2021

Source: Oilfield International

Table 0-3 Sales Condensate Liquids: Gross, and Net Attributable to AEWB

Saltfleetby Field	Gross		Net Attributable to AEWB		Operator
Condensate Liquids Reserves	**1P**	**2P**	**1P**	**2P**	
	M STB	M STB	M STB	M STB	
Main Field Westphalian Reservoir	107.2	189.8	50.8	89.5	AEWB

Effective Date: 1st October 2021

Source: Oilfield International

Table 0-4 Post-Tax NCF and NPV10 of Reserves discounted to October 1st, 2021: Net Attributable to AEWB

	Net Cash Flow Attributable to AEWB		NPV10 Attributable to AEWB		Operator
Scenario	**1P**	**2P**	**1P**	**2P**	
	£m MOD	£m MOD	£m MOD	£m MOD	
Including AEWB's Contractual Loan Terms	£31.7	£55.9	£25.4	£38.5	AEWB

MOD: money of the day

Effective Date: 1st October 2021

Source: Oilfield International

Table 0-5 Capex: Attributable to AEWB

Year	**P90**	**P50**
	£m MOD	£m MOD
31/5/21-30/9/21	*£2.4*	*£2.4*
Q4 2021	£1.8	£1.8
2022	£1.8	£1.8
2023	£0.2	£0.2
2024	£0.3	
2025		£0.1
2026		£0.2

Effective Date: 1st October 2021

Source: Oilfield International

Key Risks

<u>The volumetric analysis is intrinsically uncertain</u>

1. The main sources of uncertainty in the volumetric analysis relate to the seismic data quality and the reservoir quality (Figure 13 of main report). The reservoirs are mapped on poor-to-moderate quality 3D seismic data. All top-of-reservoir structure-maps were built using well data (more accurate but sampling locally) and strong seismic horizons, i.e., the Base of Permian and the Top of Dinantian (low resolution but sampled field-wide). In general, the uncertainty in time-depth conversion and horizon-picking still impose a risk on trap closure (10%). There are no risks in the source rock, migration, charge, and seal. However, there is a remaining risk in the reservoir effectiveness (20%) due to the highly faulted structure: the faulting could compartmentalise the reservoir leading to isolation of gas volumes.
2. There is ambiguity in the interpretation of the logs.

The operator is currently interpreting a new (2021) depth migration of the seismic data, and the results of this interpretation will reduce the uncertainty of the depth maps.

<u>Remaining uncertainty about structure and faults</u>

1. It is uncertain whether the saddle between the Main Field and the Southern Satellite isolates pressures. It appears to for the timescales of field development. If it does not, production profiles from the three wells of the development plan may be different to those presented
2. It is uncertain whether faulting seals the structure at 2338m. Again, the depth migration data will help resolve this uncertainty. This is not significant to the 1P and 2P reserves reported here but is to those resources omitted from this report (3P reserves and contingent resources).

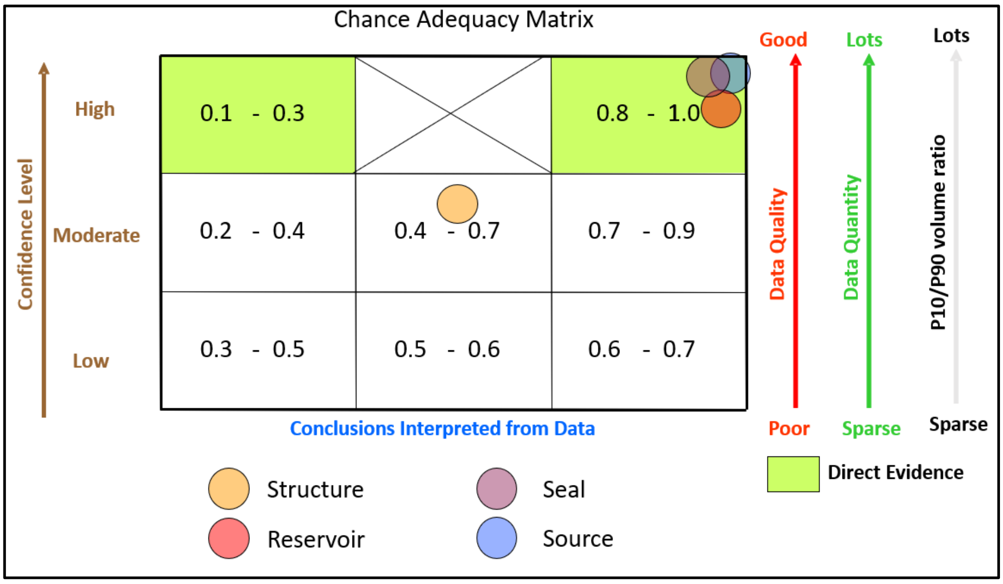

Figure 13: Chance of adequacy matrix of Saltfleetby Gas Field model

Remaining uncertainty about reservoir quality and performance

1. There may be sub-seismic resolution baffles to production which reduce the pressure responsiveness of the Main Reservoir and adversely affect the production profile.
2. Condensate banking may increase the skin (excess pressure drop) of the wells, reducing the gas productivity index and the economic condensate recovery.
3. The reservoir penetrated by the horizontal sidetrack of well SF7V may be of poorer or better quality than expected.
4. Water production may increase more quickly than expected, reducing performance and life expectancy of one or more of the wells; and potentially requiring a well workover to remedy the problem.

Licence Extension Risk

PEDL005 expires in 2027 (31 years' duration). Although there is no contractual right to extend it, from the evidence we have reviewed, the probability that an application for extension will be refused is less than 10%. In compliance with PRMS 2018[7], we have therefore assigned Reserves to volumes economically recoverable after 2027 for the current development plan of three wells draining the Main Field, Westphalian Reservoir.

If, either at the time of the authorisation of a Field Development Plan or during the period of production, it appears that production is likely to continue beyond the term of the licence(s) involved, it is the responsibility of the operator to apply for an extension to the licence, and this extension will, among other considerations, be subject to the continuing satisfactory performance of obligations under the licence[8].

Project Execution

1. First gas is estimated to be March 15th, 2022, though this date is subject to the following risks:
    a. Delay in installation and commissioning of surface facilities equipment, including package manufacturers' delivery dates and potential lost time arising from simultaneous drilling and construction operations
    b. Delay in connection to the National Gas Grid
    c. Problems during the start-up of the wells
2. The timing of first production from the SF7V sidetrack could be delayed by
    a. Drilling rig top drive delivery from USA affecting the scheduled 4th January 2022 spud date.
    b. Potential lost time from simultaneous drilling and construction operations
    c. Technical difficulties during the drilling and completing phase

[7] **Section 3.3.3.2 of PRMS 2018 pertains**:
Reserves cannot be claimed for those quantities that will be produced beyond the expiration date of the current agreement unless there is Reasonable Expectation *(refer to definition above)* that an extension, a renewal, or a new contract will be granted. Such Reasonable Expectation may be based on the status of renewal negotiations and historical treatment of similar agreements by the license-issuing jurisdiction. Otherwise, forecast production beyond the contract term must be classified as Contingent Resources with an associated reduced chance of commercialization. Moreover, it may not be reasonable to assume that the fiscal terms in a negotiated extension will be similar to existing terms.

[8] Page 38 final paragraph, "Consolidated Onshore Guidance", June 2018 v 2.2, Oil & Gas Authority, UK

   d. Delays in receiving Environment Agency permissions for the surface facilities (expected latest 17th December 2021); awaiting the results of noise modelling and flare gas system details.
   e. Delays in receiving HSE permissions for the drilling operations (expected early December 2021); the HSE plan has been submitted and the hazop is scheduled for 5th November 2021.
3. The deliverability of the SF7V sidetrack may be reduced by
   a. Lower than expected mechanical completion quality
   b. Technical difficulties during the drilling phase resulting in a shorter horizontal section than the 450m design
4. The project costs may be higher (or lower) than forecast. In particular, the operator is currently completing its tendering for drilling and completion services for the SF7V sidetrack and the accuracy of its £2.8m + 20% contingency cost estimate will not be known until the process is concluded. And since the contracts have significant daily rate components, the unavoidable uncertainty in the time duration of the well construction increases cost uncertainty (both higher and lower).
   a. By contrast, 50% of the surface facilities procurement and construction cost has been incurred, and the pipeline extension is completed except 100m, which will commence w/c 25th October 2021.
5. The process plant may not perform to specification.

Exogenous

1. Commodity prices
   a. The National Balancing Point Forward Curve (NBP) dated 1st October 2021, escalated after December 2026 by 1.5% pa. Realised NBP gas prices may be higher or lower.
   b. The Brent Forward Curve dated 1st October 2021, escalated after March 2029 by 1.5% pa. Realised Brent prices may be higher or lower.
   c. The £5/bbl discount to Brent of the Condensate Liquids offered by the off taker at the refinery is subject to firm quotation.
2. Cost Escalation for Oilfield services and equipment is assumed to be 1.5% pa. It may be higher or lower.
3. Uncertainty over the equity and debt markets.
4. Uncertainty over Public Opinion regarding future onshore gas extraction

Qualifications

OIL is a privately-owned energy consultancy founded in 1990 that has advised on oil and gas projects in over 40 countries. This CPR was produced by two earth scientists: Mr David Curia and Dr Kanad Kulkarni who are independent of shareholders, management, and staff of AEWB.

Mr David Curia has over 30 years' experience in geophysical interpretation and reserves determination and is responsible for resource valuation / competent person's reports in OIL's Buenos Aires office. He holds a M.Sc. in Geology, a M.Sc. in Mathematics from the University of Buenos Aires, and a "Post-Degree" in Geophysics (12 geophysical subjects examined over 18 months, without a doctoral thesis) from the University of Mendoza. He has held lectureships in Numerical Analysis and in Geostatistics. He is the author of over 20 papers for a.o. the European

Association of Geoscientists and Engineers and the American Association of Petroleum Geologists.

Dr Kanad Kulkarni has 9 years' experience in Petrophysics and log interpretation. He holds a Ph.D. in Petroleum Engineering from University of Portsmouth, M.Sc. in Petroleum Engineering from London South Bank University, a M.Sc. in Geology from University of Pune, India. He has held a lectureship in Formation and Well Logging at the University of Portsmouth for 8 years. He has co- authored 7 papers in various publications. He was University Section Director at the SPE London Section from 2013 – 2018. He is an Associate Member of Energy Institute, (AMEI), and the London Petrophysical Society.

Basis of Opinion

The reserves and NPVs presented are based on Oilfield International's understanding of the current petroleum legislation, taxation and other regulations pertaining to the United Kingdom. They are also based on a forecast of gas and oil prices.

It is emphasised that legislation, taxation, and commodity-price forecasts can be subject to significant change even in the short term and that any of these could have a significant effect on the NPVs presented in this valuation report.

The reported hydrocarbon volumes and values are estimates based on professional judgement and are subject to future revisions, upward or downward, as additional information becomes available. The NPVs presented do not represent Oilfield International's opinion of the open market value of AEWB's Petroleum Assets. Oilfield International does not confirm AEWB's legal right to title to PEDL005; the detail or the enforceability of that legal title; and the absence or nature of any liens or other encumbrances that might affect AEWB's rights to, or value in, PEDL005.

Yours sincerely

David Curia, Chief Geoscientist, Oilfield International

CONTENTS

Summary: 1P and 2P Reserves and Valuation 1
Key Risks 6
Qualifications 8
Basis of Opinion 9
1. Licence History and Current Status 12
2. Geological Description 19
3. Development Plan (3 wells – 2 existing, 1 new sidetrack) 25
4. Determination of Remaining Recoverable Sales Gas and Liquids 37
   4.1. Monte Carlo simulation 37
   4.2. Material balance calculations 37
5. Development Plan Production Profiles 44
6. Discounted Cash Flow Valuation 46
   6.1. Terms of Licensees' Loan 48
   6.2. Calculation of Gas Price forecast at the Theddlethorpe Sales Point 48
   6.3. Calculation of Condensate Sales Price forecast at Immingham Refinery 51
7. Determination of Reserves of Sales Gas and Liquids 58
8. Glossary 60

TABLES

Table 0-1 Resource structures identified on the Saltfleetby Gas Field 3
Table 0-2 Sales Gas Reserves: Gross and Net Attributable to AEWB 4
Table 0-3 Sales Condensate Liquids: Gross, and Net Attributable to AEWB 4
Table 0-4 Post-Tax NCF and NPV10 of Reserves discounted to October 1st, 2021: Net Attributable to AEWB 5
Table 0-5 Capex: Attributable to AEWB 5
Table 1-1 Summary of PEDL005 Licence, Extant Planning Permissions and Significant Agreements 17
Table 3-1 Outstanding Planning Applications and Permitting 25
Table 4-1 : Saltfleetby Gas Field: Sales Gas Initially in Place: Gross 39
Table 4-2 Saltfleetby Gas Field: Condensate Liquids Initially in Place: Gross 39
Table 4-3 Saltfleetby Gas Field: Sales Gas and Condensate Liquids Produced 40
Table 4-4 : Saltfleetby Gas Field: Remaining Sales Gas in Place: Gross 41
Table 4-5 Saltfleetby Gas Field: Remaining Condensate Liquids in Place: Gross 41
Table 4-6 Saltfleetby Gas Field: Sales Gas and Condensate Liquids Percentage Recovery to Date 42
Table 4-7 Saltfleetby Gas Field: Sales Gas and Condensate Liquids Estimated Ultimate % Recovery Factor 42
Table 4-8 Saltfleetby Gas Field: Remaining Recoverable Sales Gas: Gross, and Net Attributable to AEWB 43
Table 4-9 Saltfleetby Gas Field: Remaining Recoverable Condensate Liquids: Gross, and Net Attributable to AEWB 43
Table 5-1 Gas, Condensate and Water Production Profiles 44
Table 6-1 Remaining Capex Assumptions for Cash Flow Forecasts, Saltfleetby Field 46
Table 6-2 Opex and Economics assumptions for Cash Flow Forecasts 47
Table 6-3 Licensees' Loan Terms 48
Table 6-4 Hedged Prices, Hedged Volumes 49
Table 6-5 NBP Forward Prices: Calculation of Net Gas price at Sales Point £/MMSCF 50
Table 6-6 Calculation of Condensate Price £/bbl 51
Table 6-7 P90 Cash Flow Forecast £m on a project basis; effective date October 1st, 2021 52
Table 6-8 P90 Cash Flow Forecast £m including loan terms; effective date October 1st, 2021 53

Table 6-9 P50 Cash Flow Forecast £m on a project basis; effective date October 1st, 2021 54
Table 6-10 P50 Cash Flow Forecast £m including loan terms; effective date October 1st, 2021 55
Table 6-11 P90 Pre- and Post-Tax NPV £m on a project basis; effective date and discounting date October 1st, 2021 56
Table 6-12 P90 Pre- and Post-Tax NPV £m including loan terms; effective date and discounting date October 1st, 2021 56
Table 6-13 P50 Pre- and Post-Tax NPV £m on a project basis; effective date and discounting date October 1st, 2021 57
Table 6-14 P50 Pre- and Post-Tax NPV £m including loan terms; effective date and discounting date October 1st, 2021 57
Table 7-1 Sales Gas Reserves: Gross and Net Attributable to AEWB..... 59
Table 7-2 Condensate Liquids Reserves: Gross and Net Attributable to AEWB 59

FIGURES

Figure 1 Geographic and Geological Setting of PEDL005; source: DECC 13
Figure 2 Location Map of PEDL005, source OGA, 2020 14
Figure 3 Saltfleetby Development Sites and Existing Gas Pipeline to (Decommissioned) Theddlethorpe Gas Terminal, Source Roc Oil 15
Figure 4 Surface Map of Saltfleetby Field, source OIL 16
Figure 5 Structural Map of the Top of Westphalian Reservoir (Unit 2b). Source: OIL..... 20
Figure 6 3D View of the stacked Westphalian and Namurian reservoirs (green arrow is north). Source: OIL 21
Figure 7 3D View of the Saltfleetby Gas Field structure at the top of Westphalian (Unit-2b) reservoir (green arrow is north). Source: OIL 22
Figure 8 Well-Seismic tie. Seismic line in NS direction. Source: OIL 23
Figure 9 Structural at Top of Dinantian Limestone (Base of productive zone). Source: OIL..... 24
Figure 10 Proposed Gas and Liquid Processing Facility. Source: AEWB..... 26
Figure 11 Condensate storage, oily water collection and flare system. Source: AEWB 27
Figure 12 Fuel Gas System. Source: AEWB..... 28
Figure 13 Site A: Existing equipment Layout including SF4 wellhead. Source: AEWB..... 29
Figure 14 Site A: Aerial photograph. Source: AEWB 30
Figure 15 Site B and Site B Extension: Existing Equipment Layout. Source: AEWB 31
Figure 16 Aerial Photograph of Site B including SF2 Wellhead; and Site B Extension including SF6, SF7 & SF8 Wellheads. Source: AEWB 32
Figure 17 Location of New Processing Equipment on Site B Extension. Source AEWB 33
Figure 18 SF7V Completion Design - the 450m lateral is open hole. Source AEWB 34
Figure 19 SF7V Side-track to run parallel with the abandoned SF1U well, but approaching from Site B rather than Site A. The 450m lateral is open hole. Source: AEWB. 35
Figure 20 3D Dimensional Trajectory of well SF7V Sidetrack - Source AEWB 36
Figure 21 Extrapolation of historical pressure response (psia) to cumulative production (BCF): Westphalian Reservoir all wells, Source: AEWB 38
Figure 22 Extrapolation of historical pressure response (psia) to cumulative production (BCF): Westphalian Reservoir excluding SF6 & SF8, Source: AEWB 38
Figure 23 P90, P50 Production Profiles for Sales Gas. Source: AEWB, verified by OIL 45

1. Licence History and Current Status

Onshore Exploration and Production Licence PEDL005 was created on 4th April 1996 and granted to Candecca Resources Ltd and Cambrian Exploration Ltd on 18th October 1996, who discovered gas after re-entering a well drilled in 1986. The licence was acquired by Roc Oil who brought the Saltfleetby gas field on production in December 1999 from the Westphalian reservoir at a depth of 2300m, achieving a peak rate of 54 MMSCFD and 1100 bbl/d condensate in February 2000. In 2003, part of the original Licence was relinquished and Roc Oil retained 545.42km2. In 2004 Roc Oil sold, for £44m, the part of the license area containing the Saltfleetby gas field to Wingas Storage (UK) Ltd, a joint venture between Wintershall AG and Gazprom. Wingas planned to develop Saltfleetby as a gas storage facility, but this did not occur.

Eight wells and several sidetracks have been drilled on the Saltfleetby gas field of which seven, with horizontal sections, were completed and licensed for production. Gas and liquids were transported by a single pipeline to the ConocoPhillips Theddlethorpe Gas Terminal for separation, stabilisation, compression and sale.

In 2018 the Theddlethorpe Gas Terminal ceased operation, stranding Saltfleetby. In total 68 BCF of raw gas and 1.1 MM bbls of condensate were produced from the Saltfleetby gas field until it ceased production in December 2017, with a last-recorded aggregate flowrate of 6.5 MMSCFD from Wells SF2 and SF4.

On 19th June 2019, AEWB announced its acquisition of a 51% working interest and operatorship from Wingas (renamed Saltfleetby Energy, "SE") for a nominal consideration (together, "the Licensees"). The UK Oil and Gas Authority ("OGA") formally consented to AEWB's 51% acquisition and the operatorship on 29th November 2019 and the Deed of Assignment between AEWB and the existing PEDL005 owners followed on 27th January 2020.

Figure 1 to Figure 4 show the location of Licence PEDL005 onshore UK, which itself is split into several Blocks/Subareas owned by different parties. The local topography is flat and near sea-level. Table 1-1 summarises the licence and planning permissions, which confirm the Licensees' right to continue to produce gas from the eight wells and to use the existing pipeline to Theddlethorpe.

Table 1-1 summarise the licence information for PEDL005.

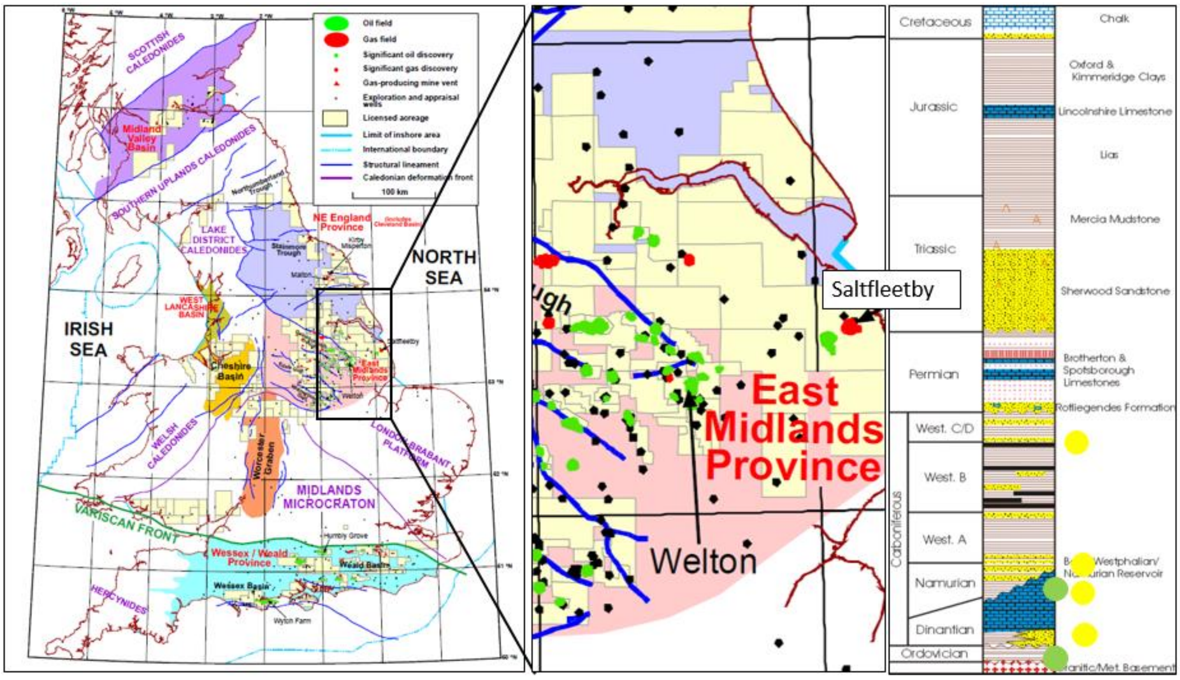

Figure 1 Geographic and Geological Setting of PEDL005; source: DECC[9]

[9] The Hydrocarbon Prospectivity of Britain's Onshore Basins, Department of Energy and Climate Change, 2013

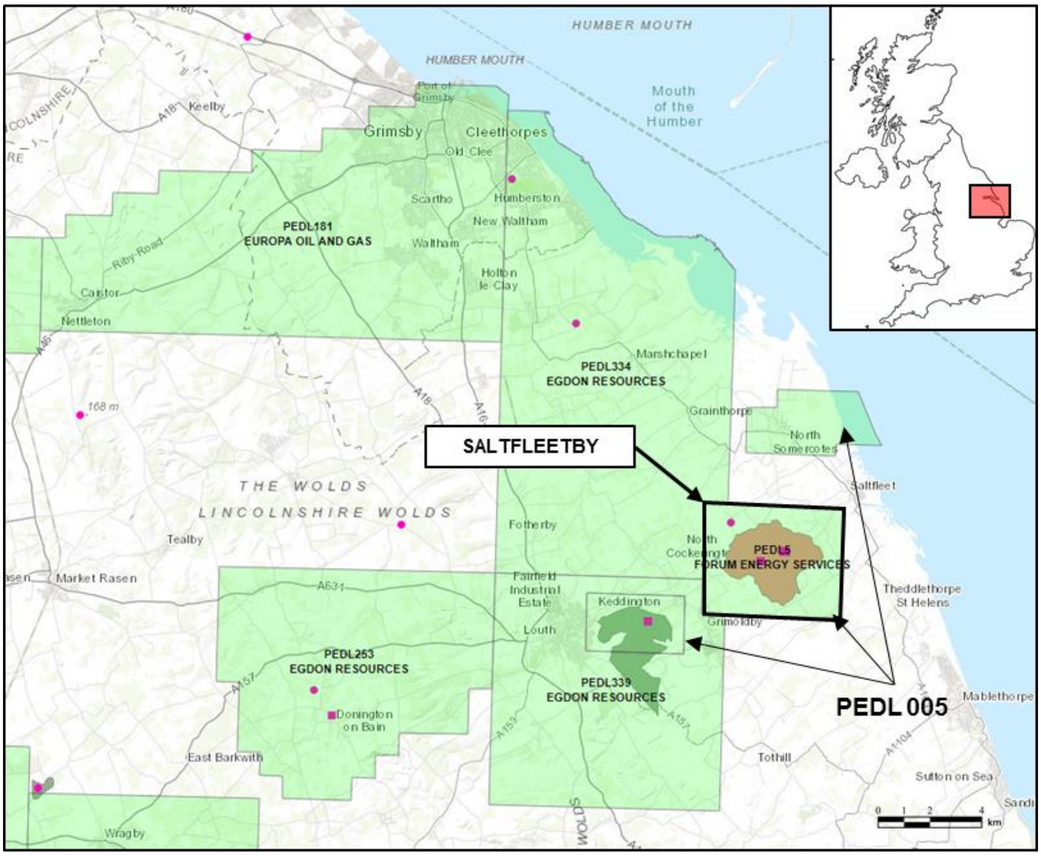

Figure 2 Location Map of PEDL005, source OGA, 2020

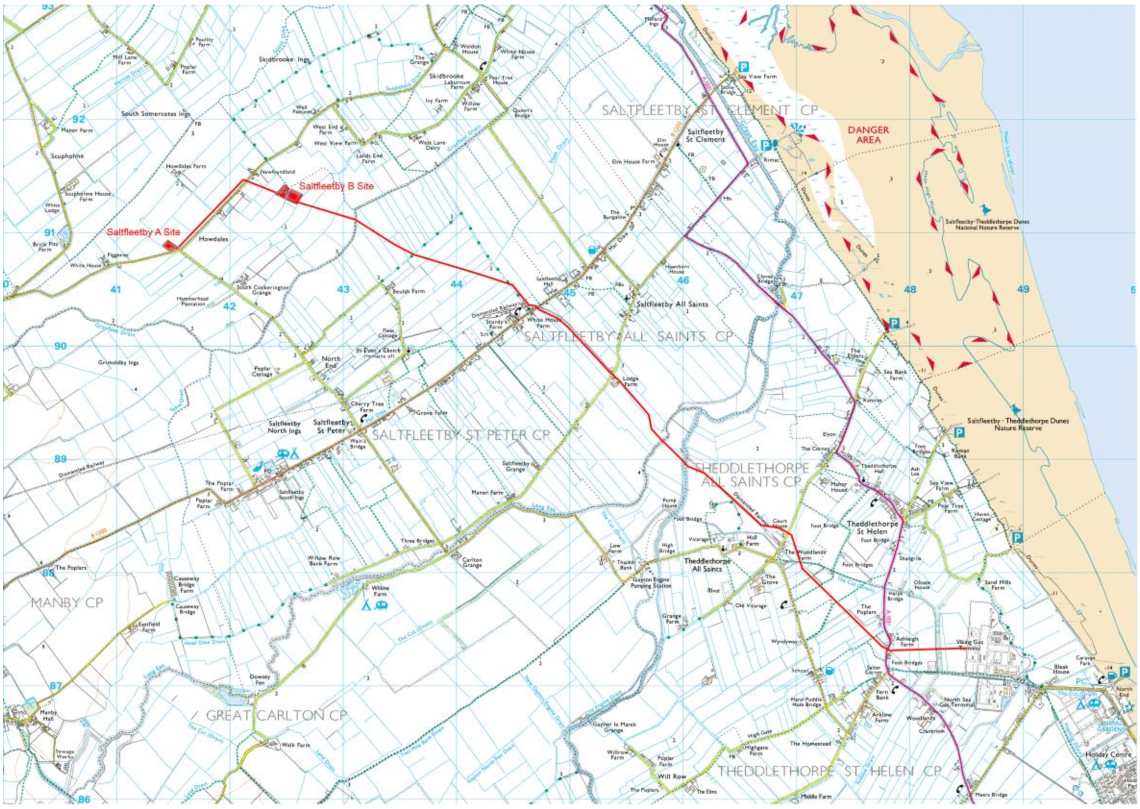

Figure 3 Saltfleetby Development Sites and Existing Gas Pipeline to (Decommissioned) Theddlethorpe Gas Terminal, Source Roc Oil

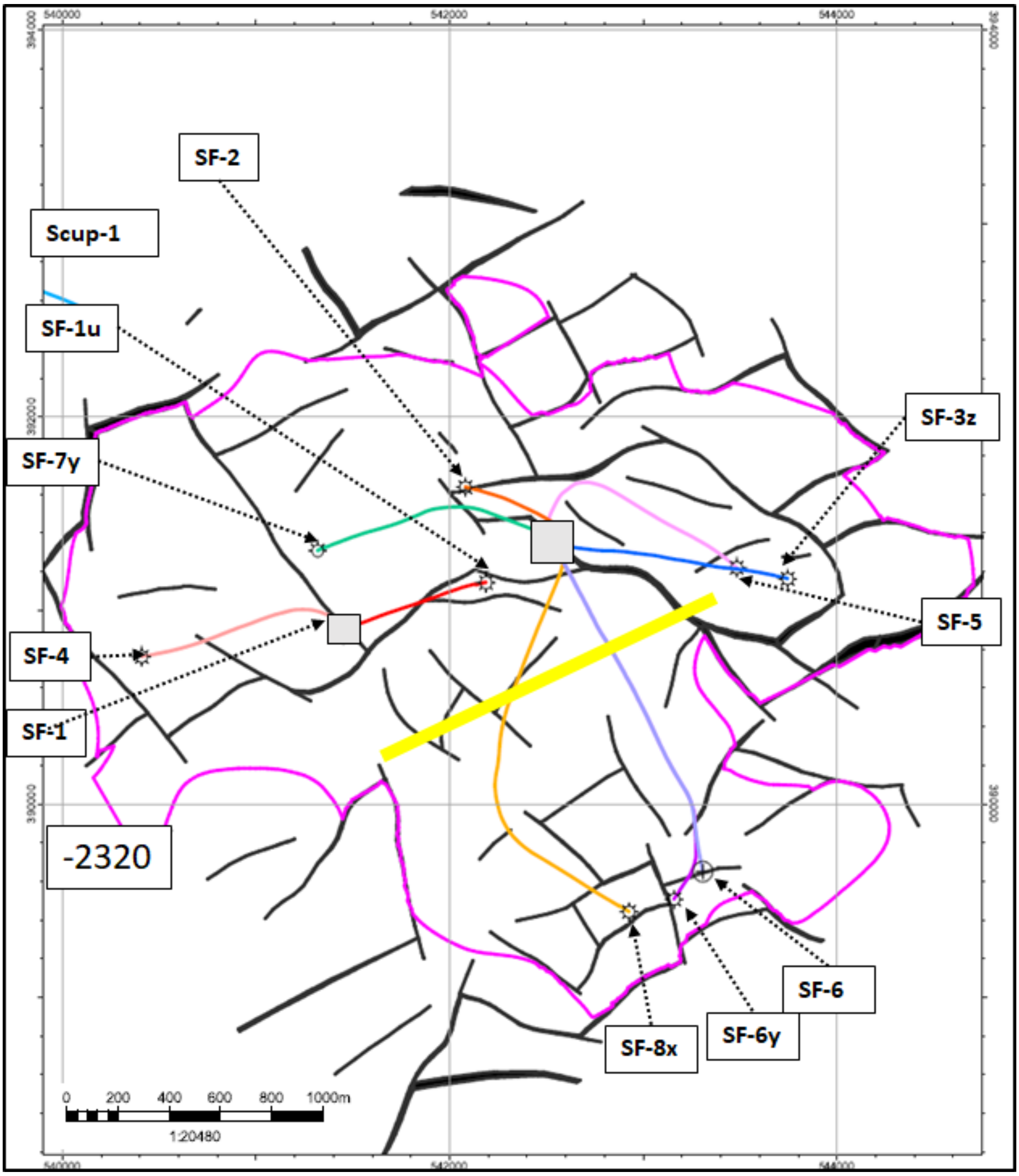

Figure 4 Surface Map of Saltfleetby Field, source OIL

Table 1-1 Summary of PEDL005 Licence, Extant Planning Permissions and Significant Agreements

Name of Licence	PEDL005 Exploration and Production Licence
Location of Licence	Block L47/16 South Cockerington, Lincolnshire, UK, in the Humber basin
Area of Licence km2	52.53km2 across all PEDL005 Blocks/Subareas, owned as follows:
AEWB / Saltfleetby Energy Blocks/Subareas	TF38a (all), TF39a (all), TF48a (all), TF49a (all), Saltfleetby Field (all). Working Interests: i) Angus Energy Weald Basin No 3 ('AEWB'): 51% (Operator) (ii) Saltfleetby Energy (formerly Wingas Storage (UK) Ltd): 49%
Egdon Resources / Terrain Energy / Union Jack Oil Blocks/Subareas	TF38b Keddington, TF38b Louth, TF49b (all)
Royalty Interests	None
Licence Start Date	04/04/1996
Licence Expiry Date	03/04/2027 (Anticipated)
Licence Extensions	Although the OGA will not fetter its statutory rights to grant/refuse an extension, it has stated that: "*if an Onshore Licensee is in production or has "line of sight" to production – i.e., has set in motion the requisite actions to move toward production, then the OGA will presently want to see that Licensee continue on that path and will renew the Licence accordingly.*" AEWB has identified over 30 instances where the OGA and its predecessors have extended the license duration. The PEDL005 license would need to be extended in its entirety, not just the AEWB / Saltfleetby Blocks/Subareas. All owners are obliged under their agreement to assist in any application to extend.
Extant Planning permissions (Saltfleetby Gas Field)	
Planning Permission: E_2143_91Decision Notice	Build and operate gas terminal at land adjoining Viking Gas Terminal
Planning Permission: E_0073_99 Decision Notice	Build and operate pipeline from Saltfleetby to Theddlethorpe gas terminal

Planning Permission: EE_0096_99 Decision Notice	Build and operate production facilities to produce gas from the existing well and from up to six additional exploratory wells at Saltfleetby - B Exploration Site (2.7 acres), Newfoundland Farm, Howdales, South Cockerington
Planning Permission: PL_0116_09 Decision Notice	Produce petroleum from one (1) existing borehole (Saltfleetby 8) and the potential drilling of one (1) additional production borehole at Saltfleetby Operations, Howdales, South Cockerington.
Planning Permission: PL_0045_14 Decision Notice	Continue use of the site for gas production and all associated matters relating to gas production. The use hereby permitted shall cease no later than 15 March 2059 or when gas production ceases.
Planning Permission: PL_0106_15 Decision Notice	Sidetrack gas production borehole, including drilling, testing and production phases. The development hereby permitted shall cease on or before 30 September 2025.
Planning Permission, N/158/00804/20, 12th June 2020	Approval for development ancillary to mining operations comprising the installation of processing facilities, including metering refrigeration unit manifold, glycol dehydration unit, acoustically-housed compression and generation equipment, pipework and manifold at the Saltfleetby 'B' site.
Planning Permission, N/180/00971/20 PL/0060/20, 7th August 2020	Planning Permission for Saltfleetby-Theddlethorpe Pipeline Extension. Installation and operation of an underground gas pipeline up to 750 metres in length, connecting the existing Saltfleetby/Theddlethorpe underground gas pipeline to the National Grid National Transmission System, Theddlethorpe via the Uniper gas distribution terminal.
Planning Permission, N/158/1011/21 PL/0073/21, 26th July 2021	Planning Permission for Saltfleetby – Theddlethorpe. For a sidetrack drilling operation from an existing borehole at Saltfleetby B wellsite to enable a lateral borehole to be drilled up to 1500m to the SW at Saltfleetby B Wellsite.
Other Permissions and Contracts	
Offtake Agreement, announced 12th August 2020	The operator entered into an off-take agreement for the entire production from the Saltfleetby Gas Field with Shell Energy Europe Limited, a division of Royal Dutch Shell plc.
Loan Agreement, 13th May 2021	Aleph Energy and Mercuria Trading agree to loan AEWB and SE £12m
Oil and Gas Authority 9 June 2021	Approved the development plans for the Saltfleetby gas field which includes the sidetrack of well SF07.

2. Geological Description

Figure 5 illustrates the structural map at the top of the principal reservoir, the Unit 2b of the Westphalian sequence. It presents:

- Well location and trajectory of the eight production wells
- Split structures and structural saddle (yellow straight line)
- Well pad (grey square)
- Contour lines in TVDSS (m).

The structural saddle between the Main Field and the Southern Satellite Structure does not cause a complete separation.

Figure 6 - Figure 9 illustrate the elevation and relief of the principal gas-bearing Saltfleetby reservoirs. In the left hand image of Figure 7 the flat blue surface is the Gas Water Contact (GWC) at 2338m TVDSS, which is the upper bound of the GWC seen in the well log data. In the right side the same structure is shown with the interpreted fault model. At 2338m TVDSS the structure is open to the southwest and the fault pattern could compromise the seal integrity of the trap at this depth. Therefore, 2338m TVDSS is our upper limit interpretation although this is clearly evident on the Well SF6 logs, as is a Free Water Level at 2360m TVDSS. The lower bound for GWC is 2320m TVDSS, identified from a pressure gradient study conducted by the operator and verified by Oilfield International.

The left hand image of Figure 9 shows the main four way dip closure structure of the Saltfleetby Gas Field as well as the satellite structure to the south. The right presents the Stratigraphic column of the Huram Basin and detailed Westphalian isolated from the deeper Namurian sandstones by a regionally persistent shale (the Subcrenatum). The large majority of the remaining gas in place is in the Westphalian reservoirs and the Development Plan targets this reservoir only, in the Main Reservoir.

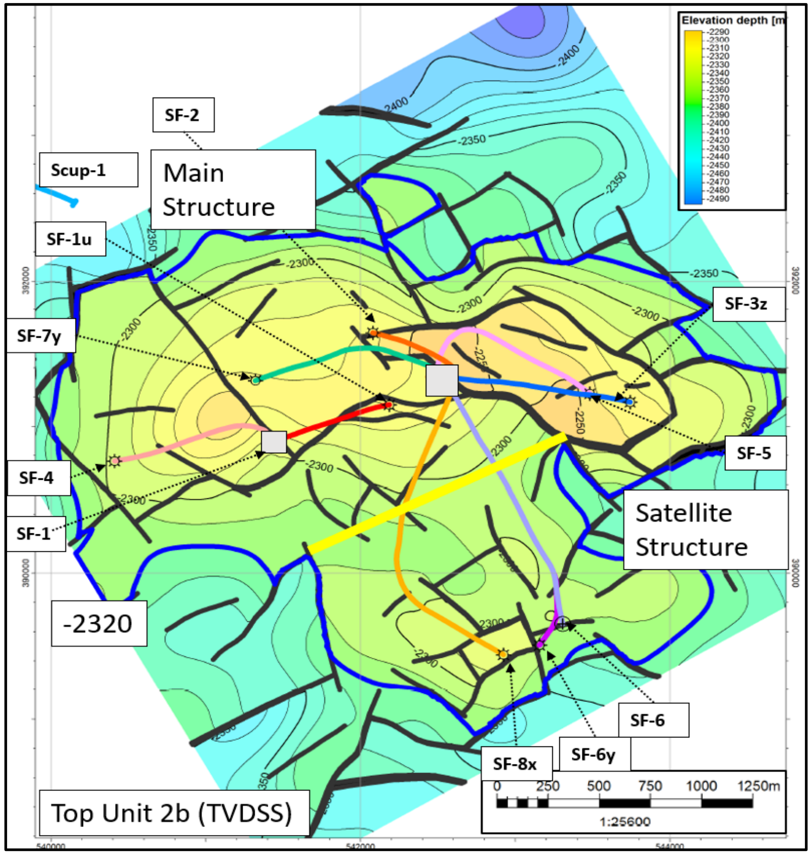

Figure 5 Structural Map of the Top of Westphalian Reservoir (Unit 2b). Source: OIL

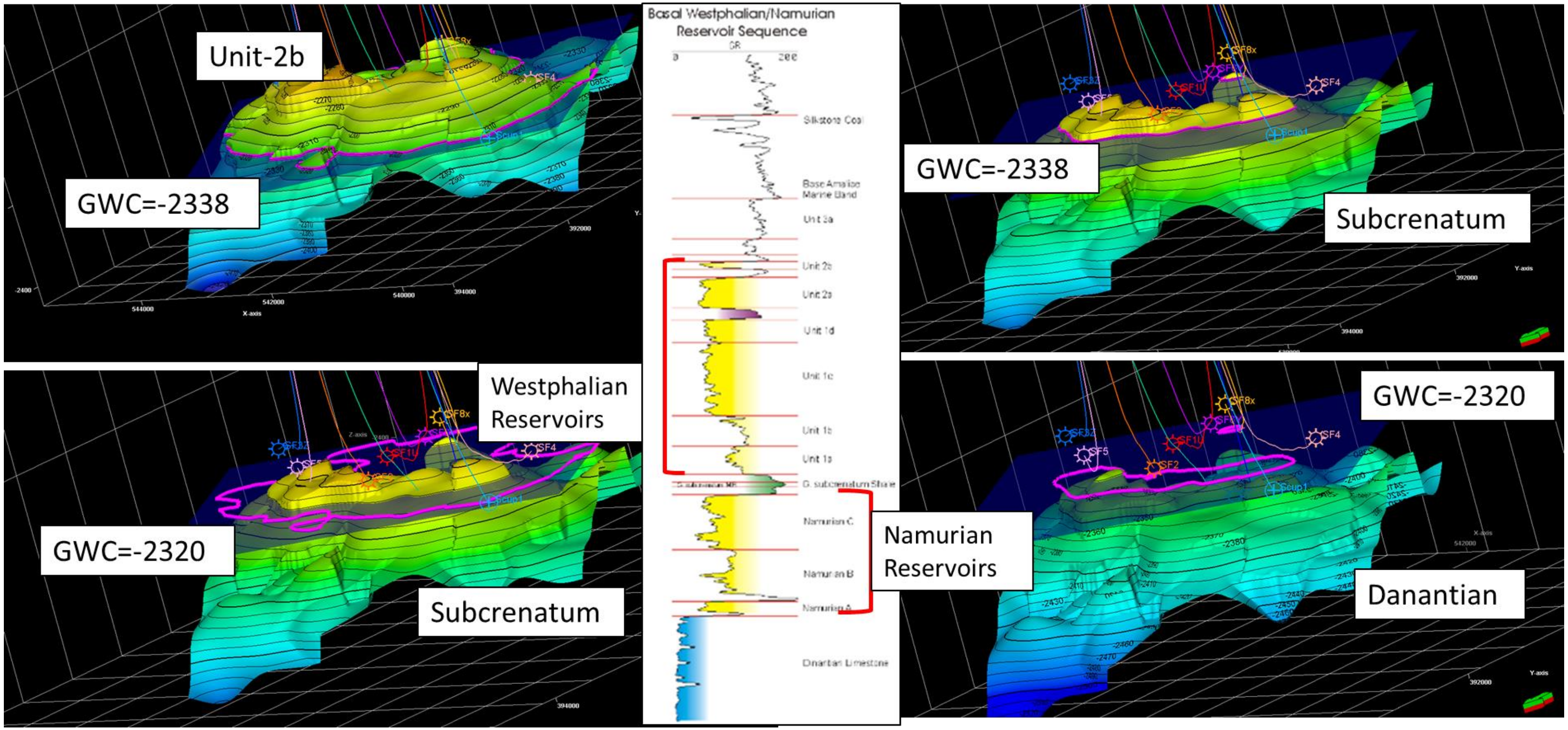

Figure 6 3D View of the stacked Westphalian and Namurian reservoirs (green arrow is north). Source: OIL

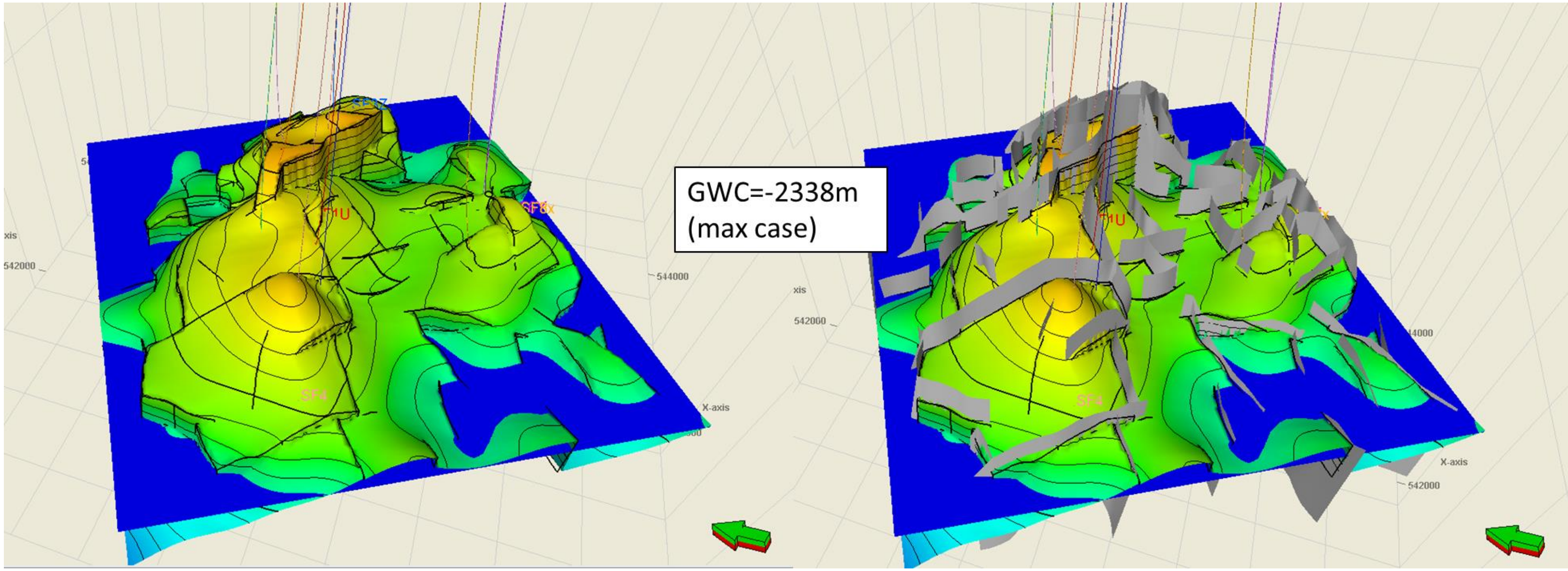

Figure 7 3D View of the Saltfleetby Gas Field structure at the top of Westphalian (Unit-2b) reservoir (green arrow is north). Source: OIL

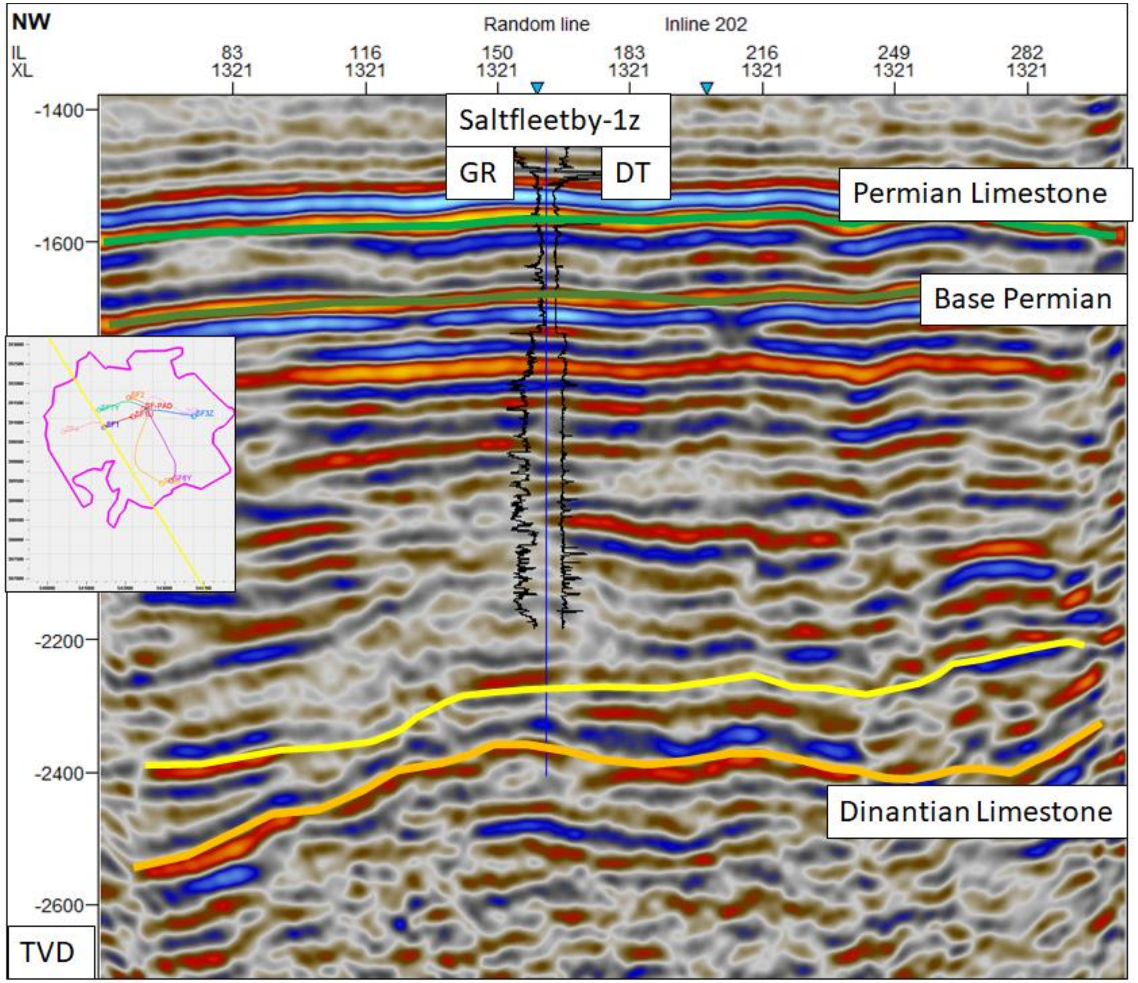

Figure 8 Well-Seismic tie. Seismic line in NS direction. Source: OIL

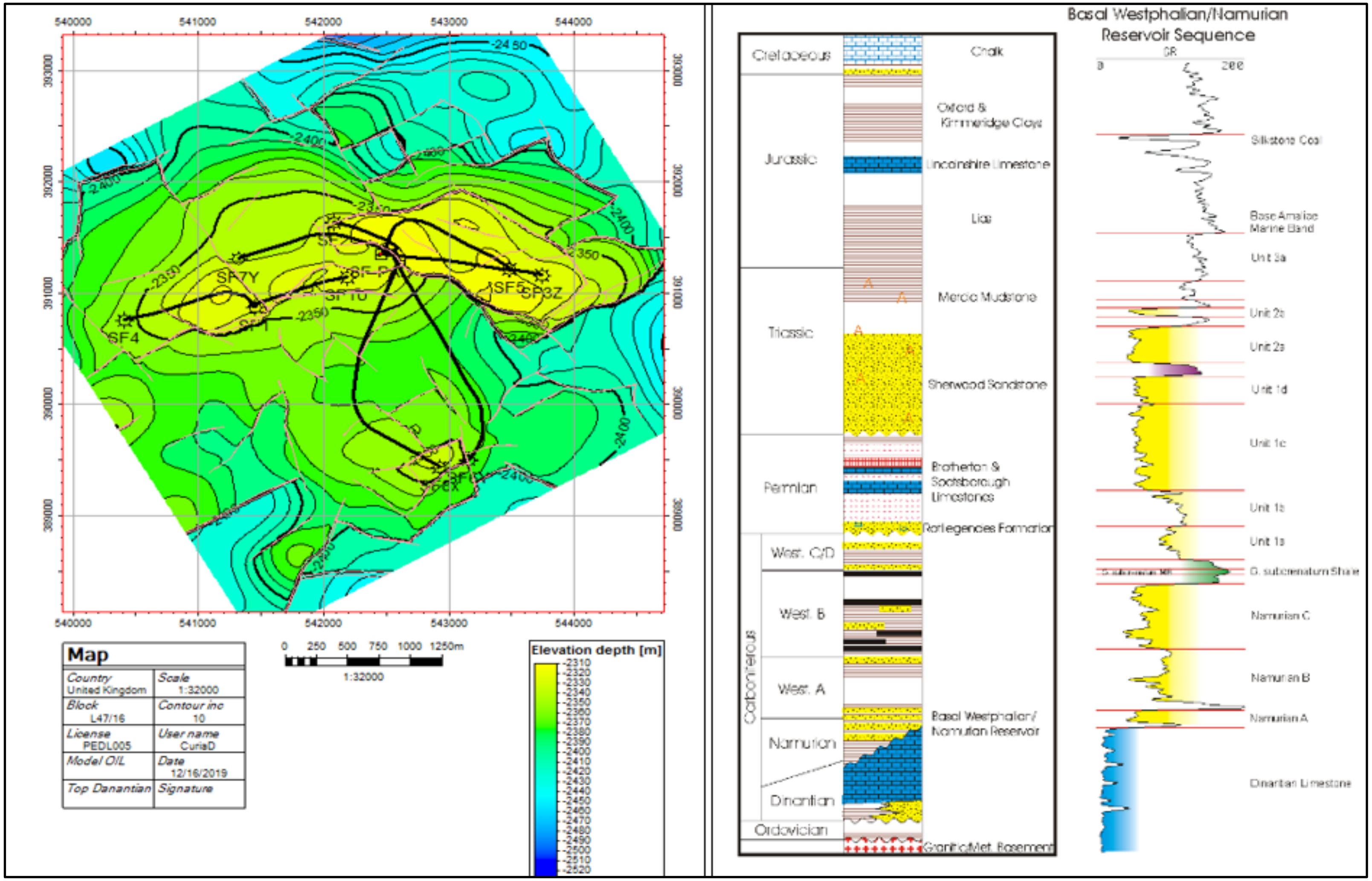

Figure 9 Structural at Top of Dinantian Limestone (Base of productive zone). Source: OIL

3. Development Plan (3 wells – 2 existing, 1 new sidetrack)

The operator has confirmed that wells SF2 and SF4 are ready to produce gas as soon as the process plant and grid connection are commissioned, and First Gas is estimated to be March 15th 2022. The operator will drill a 450m horizontal side-track from the existing SF7 well, targeting completion before First Gas and increasing the deliverability of the facilities to over 10 MMSCFD.

Table 3-1 summarises the scope of the remaining planning and permitting applications required. to restart and ramp-up production to 10 MMSCFD. Gas and liquids produced from two existing wells (SF2, SF4) and the SF7V side-track will be processed at a new plant on Site B Extension to meet the specifications for the National Grid Gas system to supply both domestic and industrial consumers. Stabilised condensate liquids will be hauled by truck for sale to Phillips 66 at Immingham Refinery. Produced water will be hauled to one of two confirmed sites authorised to dispose of it. The operator has built a gas pipeline spur to the National Grid Gas system from the terminus of its gas pipeline at the (now decommissioned) Theddlethorpe Gas Terminal.

Table 3-1 Outstanding Planning Applications and Permitting

Permissions and Approvals Outstanding	Status
HSE (Surface facilities) HSE (Pipeline repressurisation)	Hazop completed. Awaiting final signoff of Safety Case (largely agreed) and MAPD. Expected approval date: early December 2021.
HSE SF7 sidetrack	Actions: HSE plan submitted; awaiting independent well engineer certificate; layout drawing; and hazop early November 2021. Expected approval date: early December 2021.
Environment Agency (to operate process equipment) Environment Agency (Pipeline repressurisation)	Actions: Application submitted February 2021; Noise modelling; Flare gas system details requested. Expected approval date: December 17th 2021.
National Grid plc Network Entry Agreement and Acceptance	National Grid attend the metering factory acceptance tests, hazop and all relevant inspections.

Figure 10 to Figure 20 present the proposed process schematic, aerial views of the Saltfleetby Gas Field, a plot plan, SF7V completion design and well trajectory.

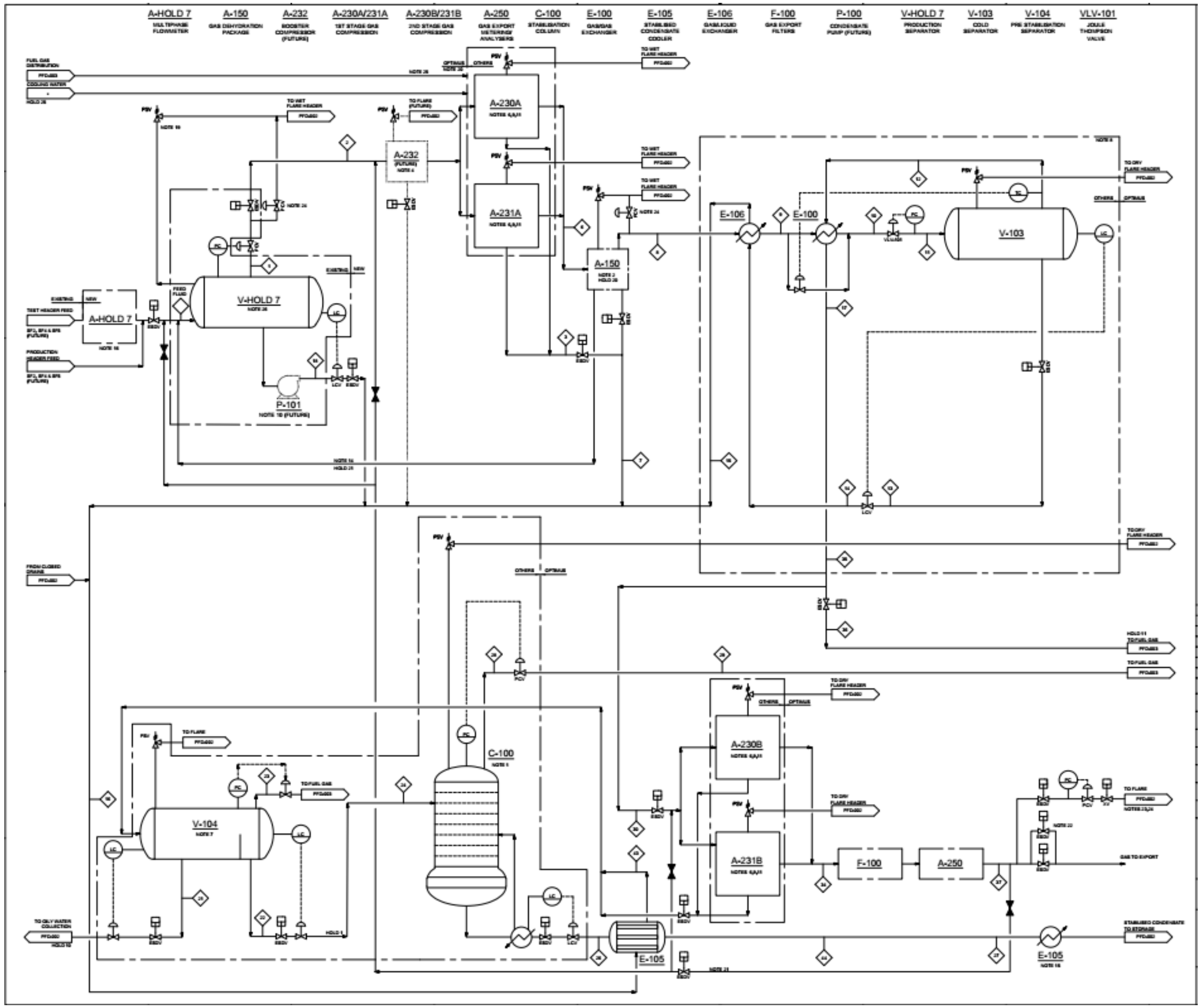

Figure 10 Proposed Gas and Liquid Processing Facility. Source: AEWB

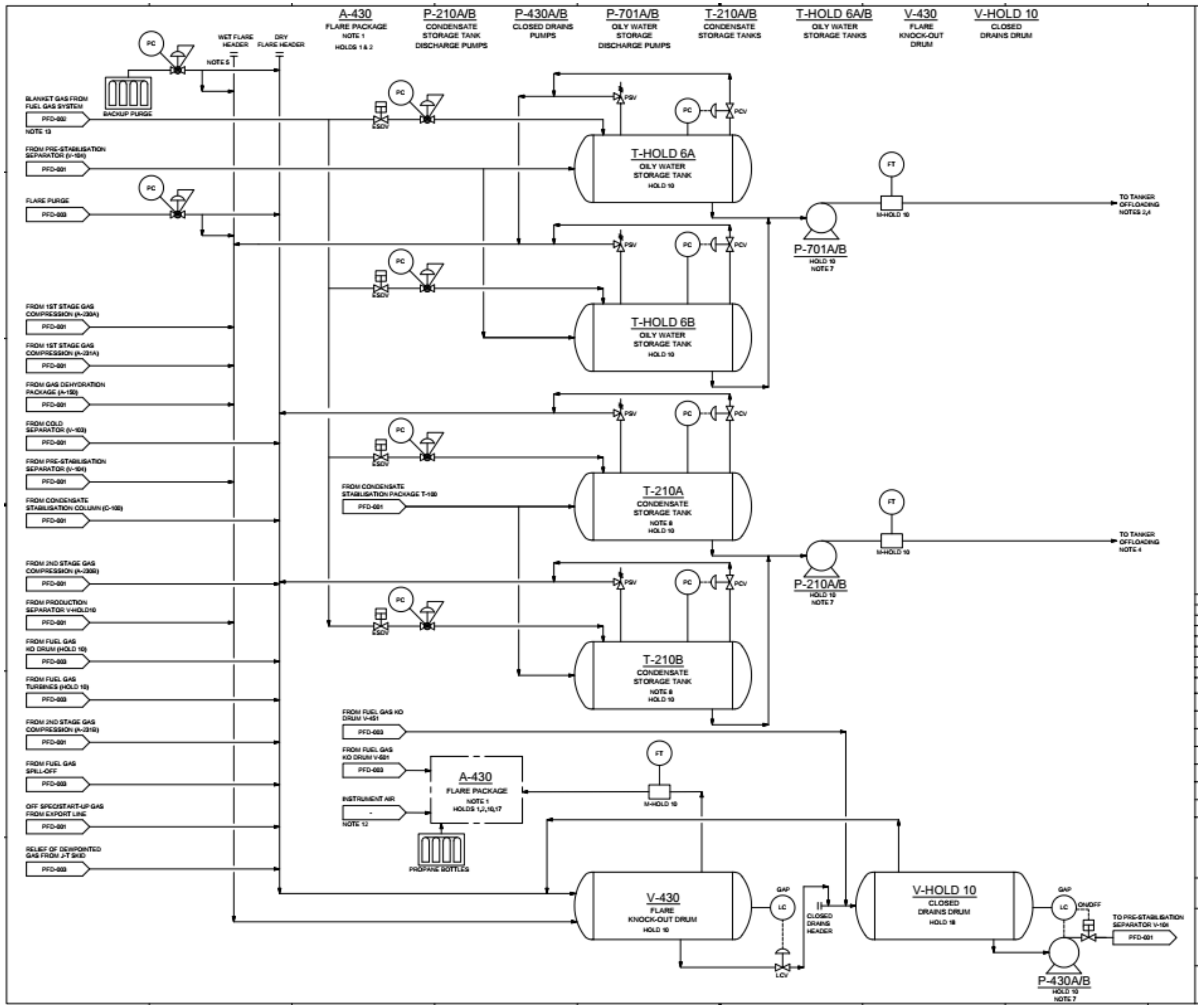

Figure 11 Condensate storage, oily water collection and flare system. Source: AEWB

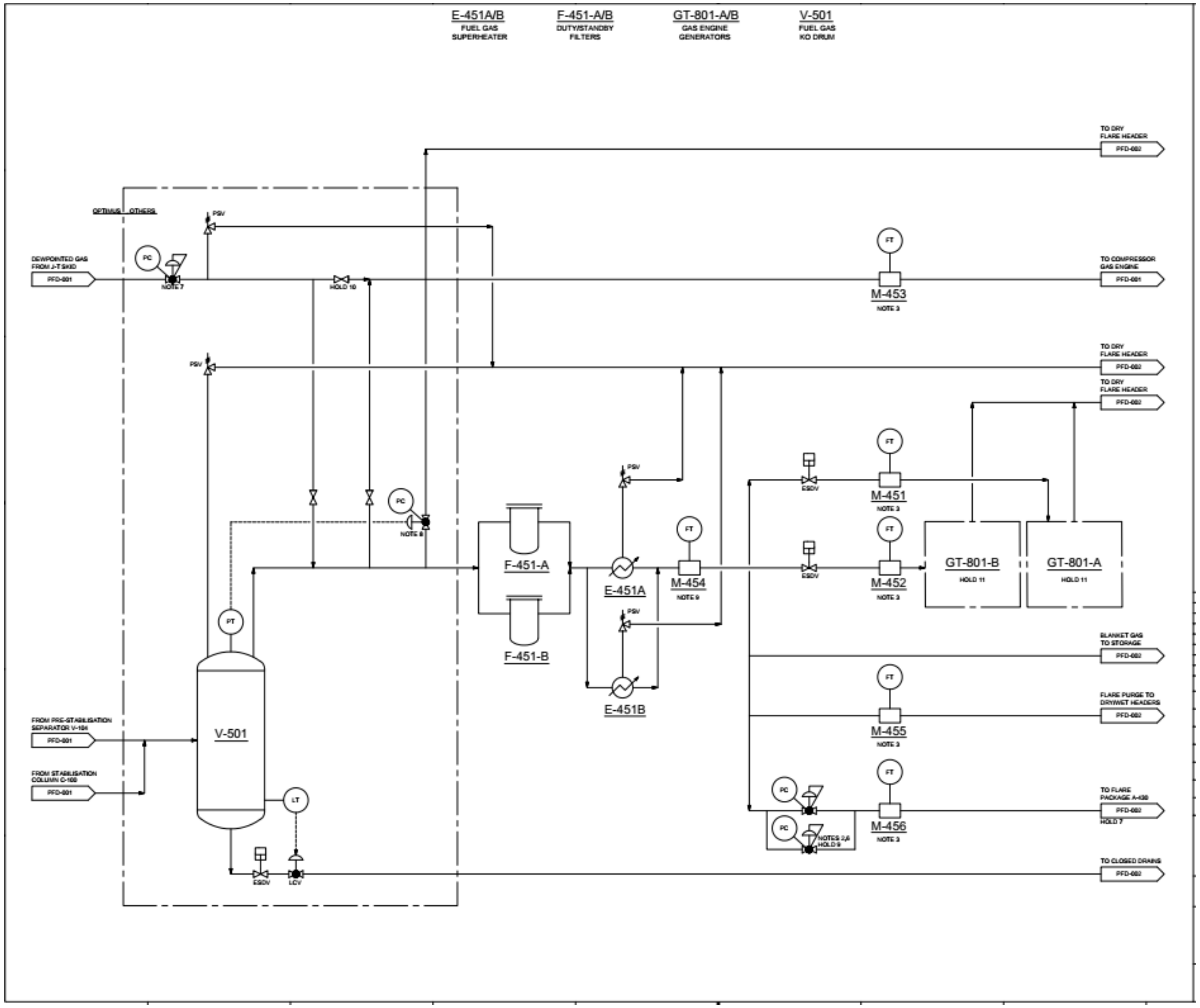

Figure 12 Fuel Gas System. Source: AEWB

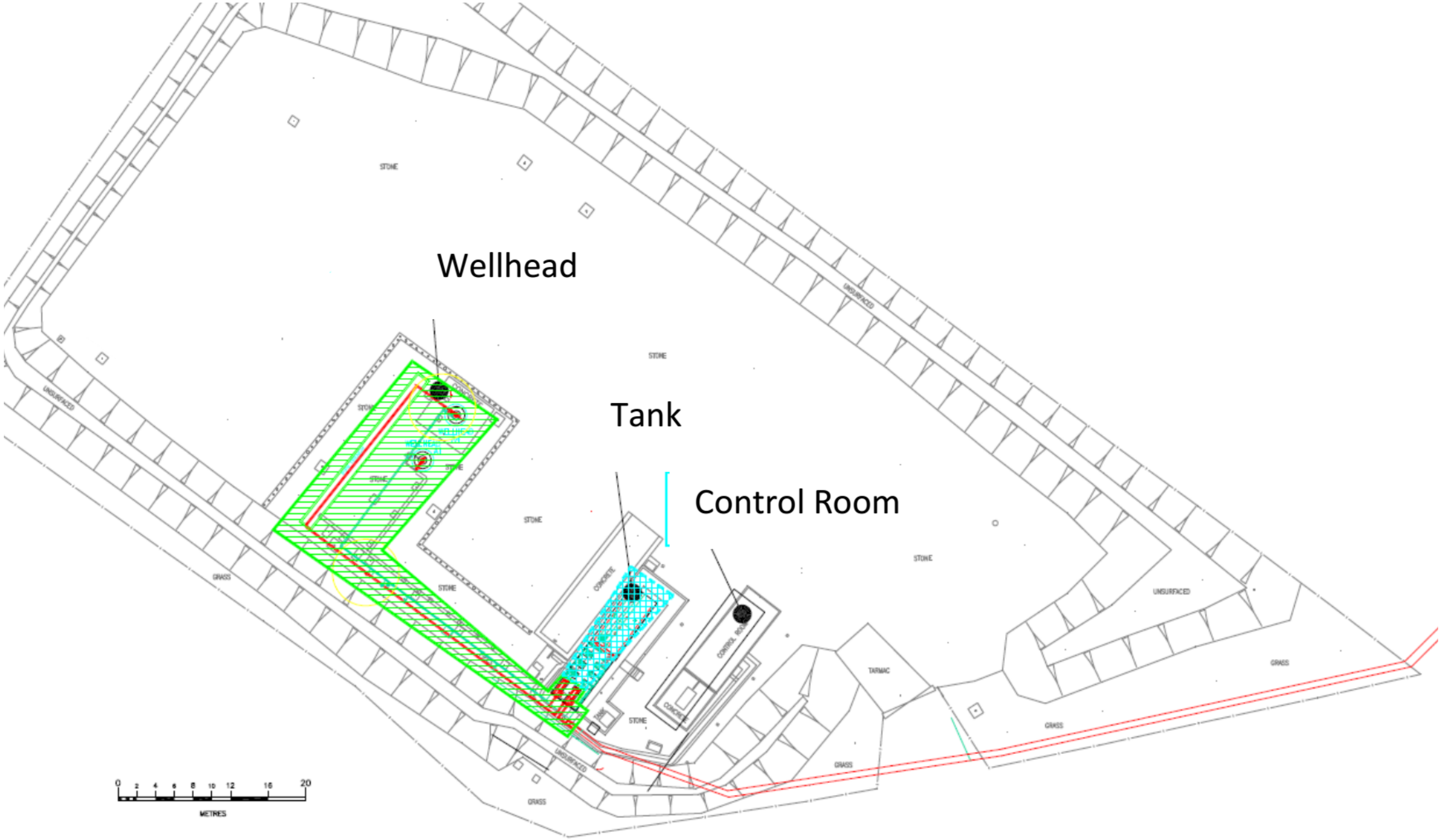

Figure 13 Site A: Existing equipment Layout including SF4 wellhead. Source: AEWB

Figure 14 Site A: Aerial photograph. Source: AEWB

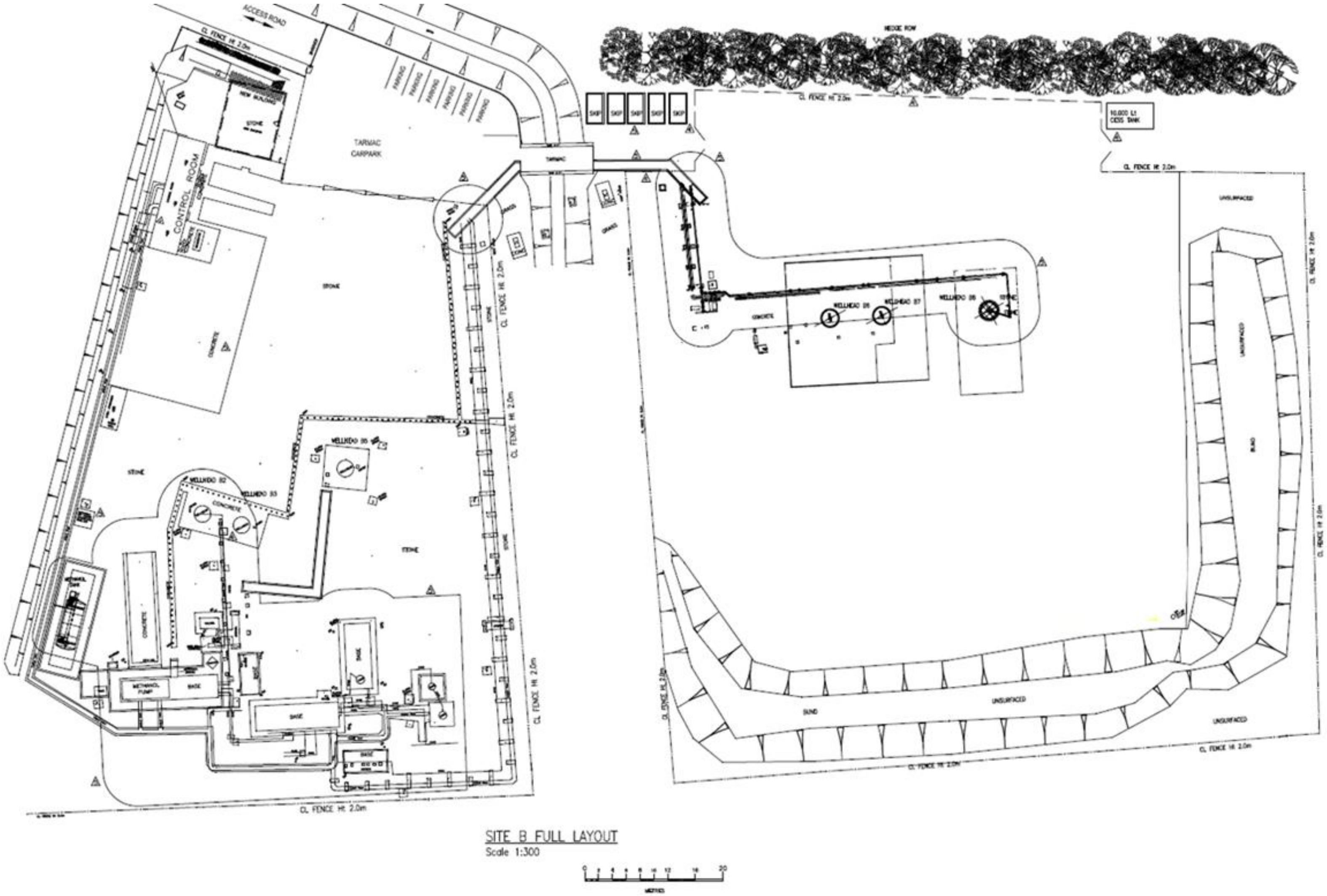

Figure 15 Site B and Site B Extension: Existing Equipment Layout. Source: AEWB

Figure 16 Aerial Photograph of Site B including SF2 Wellhead; and Site B Extension including SF6, SF7 & SF8 Wellheads. Source: AEWB

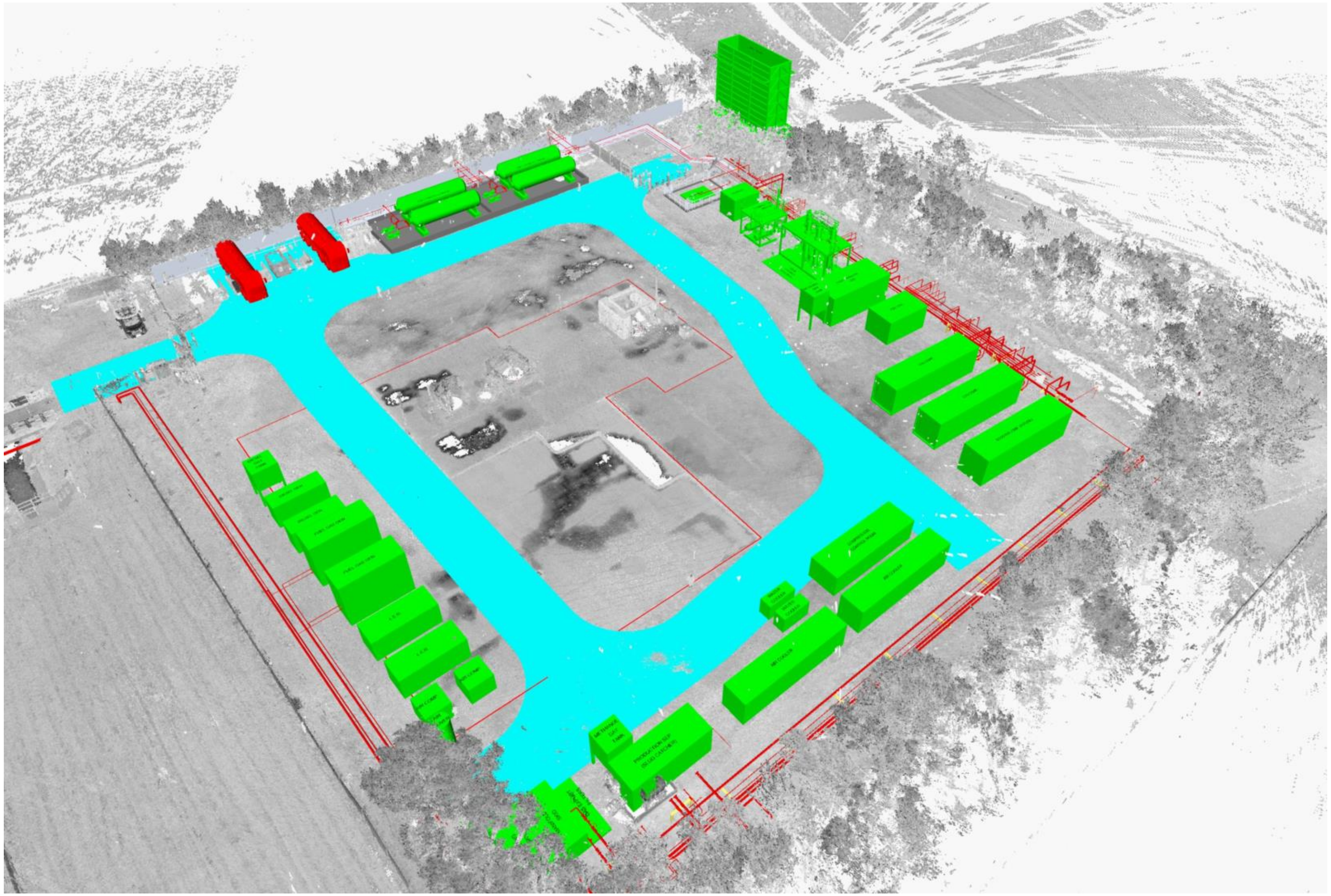

Figure 17 Location of New Processing Equipment on Site B Extension. Source AEWB

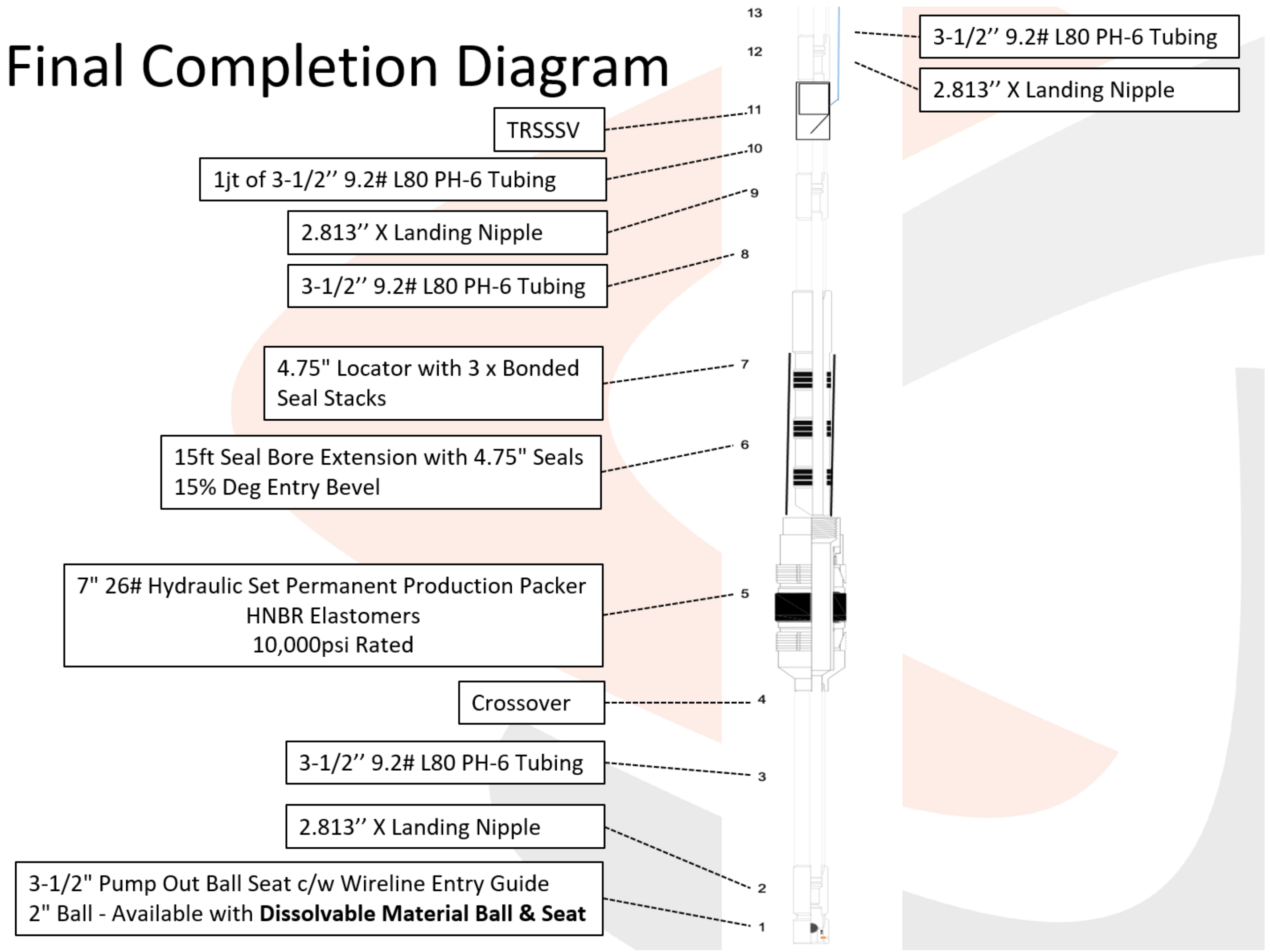

Figure 18 SF7V Completion Design - the 450m lateral is open hole. Source AEWB

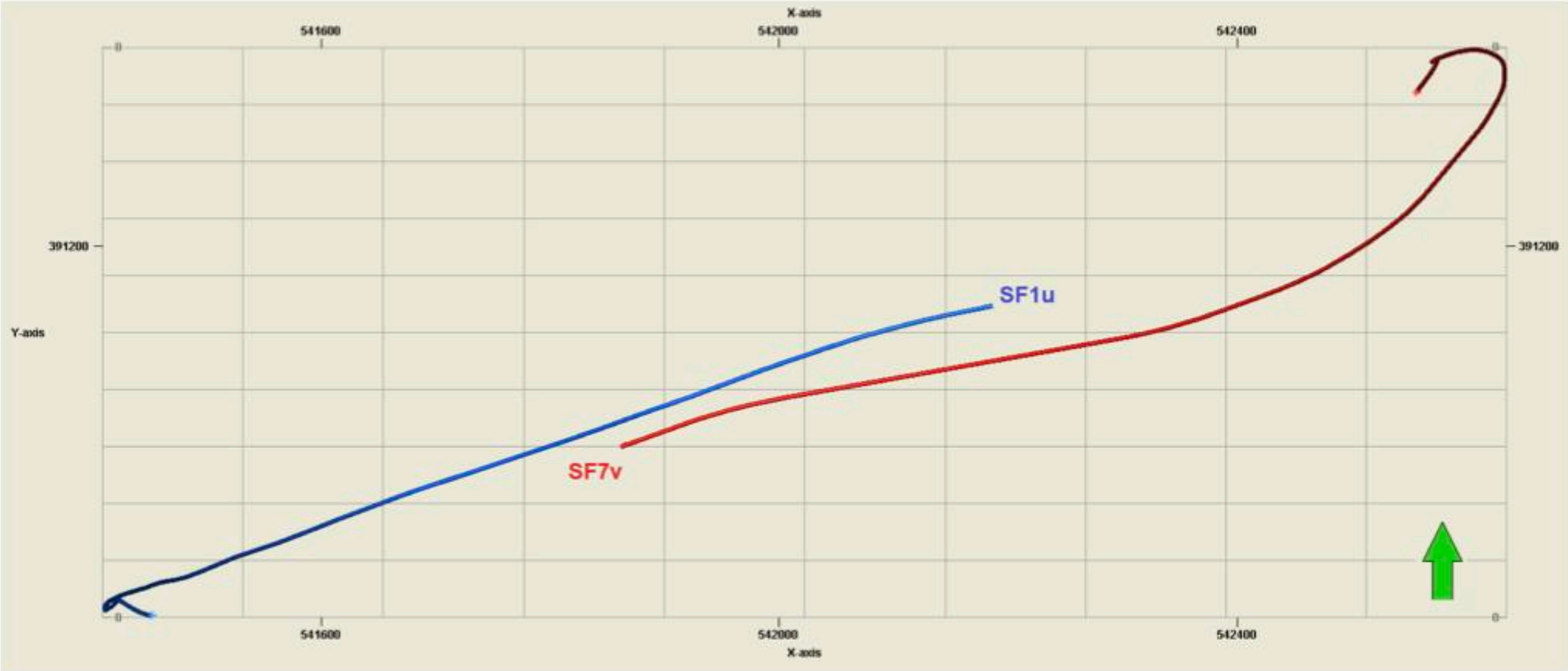

Figure 19 SF7V Side-track to run parallel with the abandoned SF1U well, but approaching from Site B rather than Site A. The 450m lateral is open hole. Source: AEWB.

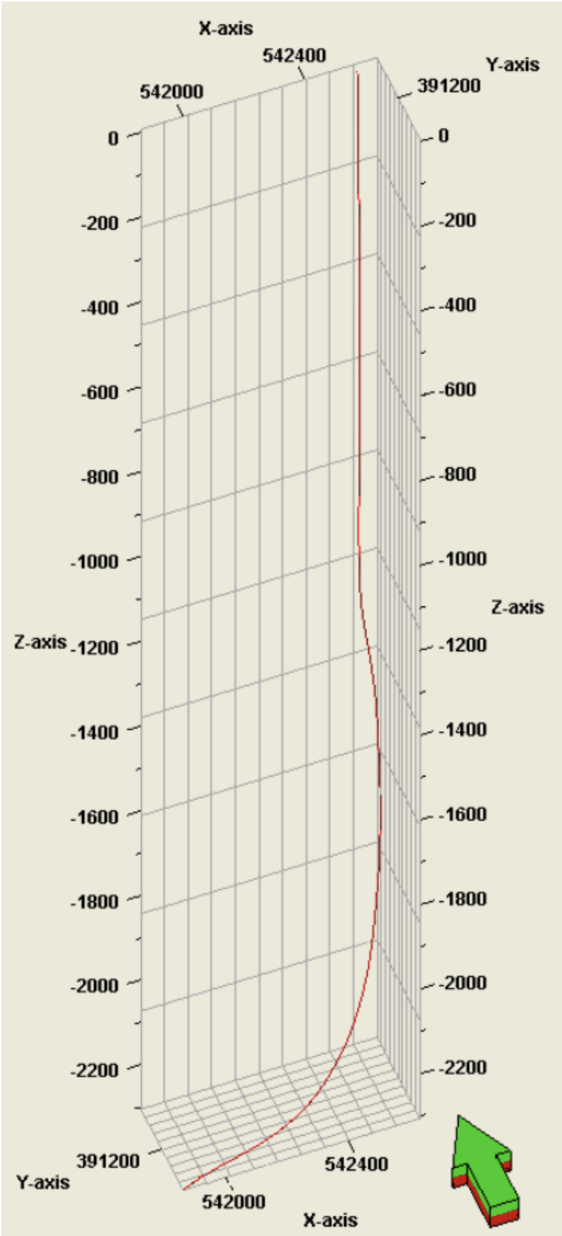

Figure 20 3D Dimensional Trajectory of well SF7V Sidetrack - Source AEWB

4. Determination of Remaining Recoverable Sales Gas and Liquids

Table 4-1 and Table 4-2 present respectively the probability distribution of Sales Gas[10] initially in place ("GIIP") and Condensate Liquids initially in place ("CIIP") for the Main Field, Westphalian Reservoir (the only target for the Development Plan). A description of how the GIIP, CIIP and recoverable hydrocarbons, follows:

4.1. Monte Carlo simulation

A Monte Carlo simulation to determine the probability distribution of GIIP and CIIP, and recoverable hydrocarbons was conducted for each Westphalian reservoir subunit (Units 2b, 2a, 1d, 1c, 1b, 1a. The inputs to the simulation were the probability density functions of:-

- The gross rock volume (from the area and geometry of the reservoir subunit associated with a range of Gas Water Contacts)
    - The Operator is currently interpreting a depth migrated seismic cube which will increase the resolution and accuracy of the GRV
- The fraction of the gross rock volume that was viable reservoir rock (from log analysis)
- The porosity of the rock (from log analysis)
- The initial water saturation in the pores (from log analysis)
- The expansion coefficient of the gas from reservoir to standard conditions (from PVT reports)
- The quantity of condensate liquids yielded by the raw gas (from PVT reports)
- The 2.75% shrinkage of raw gas to sales gas due to gas consumed in operation, and condensate yield (sales gas/raw gas = 0.9725 -from surface facilities process simulation reports).
- The recovery factors for the gas and the condensate

4.2. Material balance calculations

The substantial reservoir production history provided excellent data on the relationship between historical pressure response and cumulative production from the Westphalian Reservoir: Figure 21 shows the Best Estimate of GIIP from the material balance is 121 BCF, and the Low Estimate is 105 BCF, by extrapolating the relationship to abandonment pressures. Note these figures are Raw gas, not Sales gas. Since this analysis is based on 17 years' production, it is more accurate than the Monte Carlo analysis which is based on log data from eight wells and the seismic survey before the 2021 time-depth migration. Therefore the material balance Low and Best estimates were preferred to the Monte Carlo estimates. Figure 22 shows the material balance without the production from wells SF6 and SF8, in case flow communication is partially baffled across the saddle; the results are similar and provide no reason to adjust the Low and Best Estimates.

There being no high estimate from the material balance, the Monte Carlo result would normally be used but until the new depth migrated seismic has been fully interpreted, there is no revised

[10] The principal sales gas specifications for delivery to the National Gas Grid at Theddlethorpe are: delivery pressure 70 bara; Wobbe Number between 47.2 and 51.41 MJ/m3; and hydrocarbon dew point to not interfere with integrity op operation of pipes and gas appliances. Source: https://www.nationalgridgas.com/data-and-operations/quality. The delivery pressure may be reduced to 40 bara at a later date.

estimate of the gross rock volume and fine structure of the reservoir and so the high estimate is not reported.

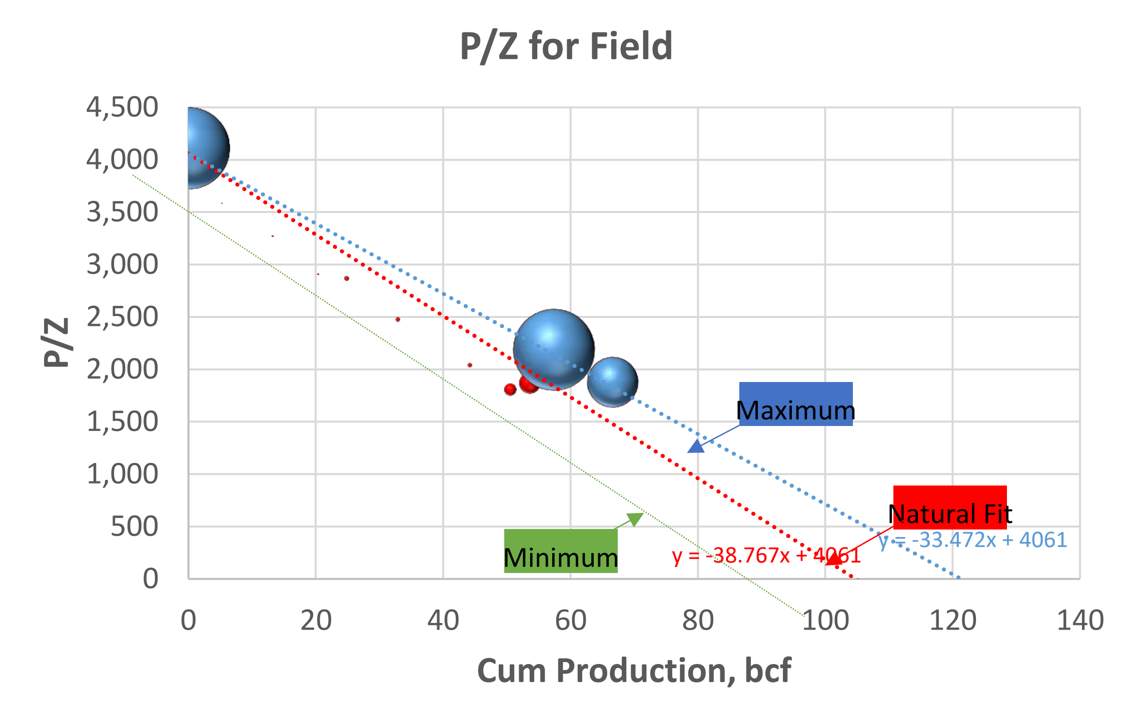

Figure 21 Extrapolation of historical pressure response (psia) to cumulative production (BCF): Westphalian Reservoir all wells, Source: AEWB

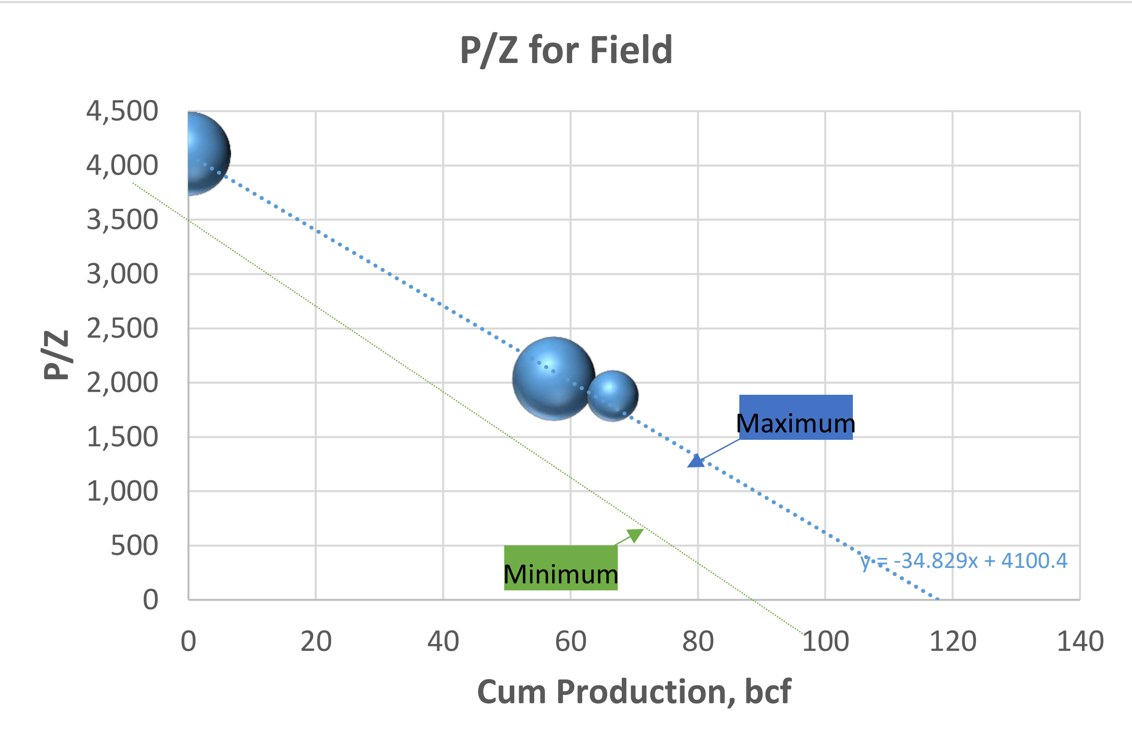

Figure 22 Extrapolation of historical pressure response (psia) to cumulative production (BCF): Westphalian Reservoir excluding SF6 & SF8, Source: AEWB

Table 4-1 : Saltfleetby Gas Field: Sales Gas Initially in Place: Gross

Saltfleetby Field	**Gross**		**Operator**
Sales Gas	**P90**	**P50**	
	BCF	BCF	
Main Field Westphalian Reservoir	102	118	AEWB

Effective Date: 1st October 2021
Source: Oilfield International

Table 4-2 Saltfleetby Gas Field: Condensate Liquids Initially in Place: Gross

Saltfleetby Field	**Gross**		**Operator**
Condensate Liquids	**P90**	**P50**	
	M STB	M STB	
Main Field Westphalian Reservoir	3,502	4,046	AEWB

Comma Separator is Thousands

Effective Date: 1st October 2021
Source: Oilfield International

Table 4-3 presents the total sales gas and condensate liquids produced from the field to date.

Table 4-3 Saltfleetby Gas Field: Sales Gas and Condensate Liquids Produced

Saltfleetby Field	**Cumulative Production to Date**	
	Sales Gas	**Condensate Liquids**
	BCF	M STB
Main Field Westphalian Reservoir	63	1,031
Main Field Namurian Reservoir	2	29
Southern Satellite Westphalian Reservoir	2	34
Total Produced	**66**	**1,094**

Comma Separator is Thousands

Effective Date: 1st October 2021
Source: Oilfield International

By subtraction Table 4-4 and Table 4-5 present the probability distribution of the remaining sales gas and condensate liquids in place, and hence Table 4-6 presents the probability distribution of sales gas and condensate liquids recovery (%) to date.

Table 4-7 presents OIL's estimate of the Estimated Ultimate Recovery Factor (%) for Gas and Condensate Liquids, and hence Table 4-8 and Table 4-9 present respectively the remaining recoverable gas and condensate liquids.

Table 4-4 : Saltfleetby Gas Field: Remaining Sales Gas in Place: Gross

Saltfleetby Field	Gross		Operator
Sales Gas	**P90**	**P50**	
	BCF	BCF	
Main Field Westphalian Reservoir	39	55	AEWB

Effective Date: 1st October 2021
Source: Oilfield International

Table 4-5 Saltfleetby Gas Field: Remaining Condensate Liquids in Place: Gross

Saltfleetby Field	Gross		Operator
Condensate Liquids	**P90**	**P50**	
	M STB	M STB	
Main Field Westphalian Reservoir	2,471	3,015	AEWB

Comma Separator is Thousands

Effective Date: 1st October 2021
Source: Oilfield International

Table 4-6 Saltfleetby Gas Field: Sales Gas and Condensate Liquids Percentage Recovery to Date

Saltfleetby Field	Sales Gas			Condensate Liquids	
	P90	P50		P90	P50
	%	%		%	%
Main Field Westphalian Reservoir	61%	53%		29%	25%

Effective Date: 1st October 2021
Source: Oilfield International

Table 4-7 Saltfleetby Gas Field: Sales Gas and Condensate Liquids Estimated Ultimate % Recovery Factor

Saltfleetby Field	Sales Gas			Condensate Liquids	
	P90	P50		P90	P50
	%	%		%	%
Main Field Westphalian Reservoir	79%	80%		32%	30%

Effective Date: 1st October 2021

Source: Oilfield International

Table 4-8 Saltfleetby Gas Field: Remaining Recoverable Sales Gas: Gross, and Net Attributable to AEWB

Saltfleetby Field	**Gross**		**Net Attributable to AEWB**		**Operator**
Sales Gas Reserves	**1P**	**2P**	**1P**	**2P**	
	BCF	BCF	BCF	BCF	
Main Field Westphalian Reservoir	18.0	31.8	8.5	15.0	AEWB

Effective Date: 1st October 2021
Source: Oilfield International

Table 4-9 Saltfleetby Gas Field: Remaining Recoverable Condensate Liquids: Gross, and Net Attributable to AEWB

Saltfleetby Field	**Gross**		**Net Attributable to AEWB**		**Operator**
Condensate Liquids Reserves	**1P**	**2P**	**1P**	**2P**	
	M STB	M STB	M STB	M STB	
Main Field Westphalian Reservoir	107.2	189.8	50.8	89.5	AEWB

Effective Date: 1st October 2021
Source: Oilfield International

5. Development Plan Production Profiles

The Development Plan targets the remaining hydrocarbons in the Westphalian reservoir of the Main Field by producing from three wells: SF2, SF4 and a new SF7V 450m horizontal side-track. Table 5-1 and Figure 1 present the P90 and P50 production profiles for the Development Plan. These have been generated by the operator and verified by OIL. The profiles assume a minimum flowing well head pressure of 90 psia, consistent with a future third stage of compression.

Table 5-1 Gas, Condensate and Water Production Profiles

Production Profiles						
	P(90)	P(50)	P(90)	P(50)	P(90)	P(50)
Draining, bcf	55	121	55	121	55	121
Wells, #	3	3	3	3	3	3
Reserves, bcf	17.99	31.78				
C/W, mmbbls			0.107	0.190	0.036	0.063
2021	0.00	0.00	0.00	0.00	0.00	0.00
2022	7.71	7.71	69.07	70.76	15.88	15.77
2023	9.81	9.81	75.57	83.13	20.02	19.98
2024	9.81	9.81	61.69	75.34	19.47	19.89
2025	8.42	9.81	41.82	67.56	16.35	19.32
2026	4.94	9.53	19.68	58.18	11.01	18.52
2027	3.39	8.17	11.45	44.00	6.43	15.87
2028	2.59	6.11	7.63	29.33	4.53	12.92
2029	2.11	4.94	5.48	21.50	3.68	11.03
2030	0.47	4.36	1.14	17.32	0.83	9.73
2031	0.00	3.33	0.00	12.19	0.00	5.99
2032	0.00	2.96	0.00	10.08	0.00	5.18
2033	0.00	2.68	0.00	8.50	0.00	4.69
2034	0.00	2.43	0.00	7.21	0.00	4.25
2035	0.00	2.21	0.00	6.13	0.00	3.86
2036	0.00	2.01	0.00	5.24	0.00	3.51
2037	0.00	1.11	0.00	2.75	0.00	1.94
2038	0.00	0.00	0.00	0.00	0.00	0.00

Source: AEWB, verified by OIL.

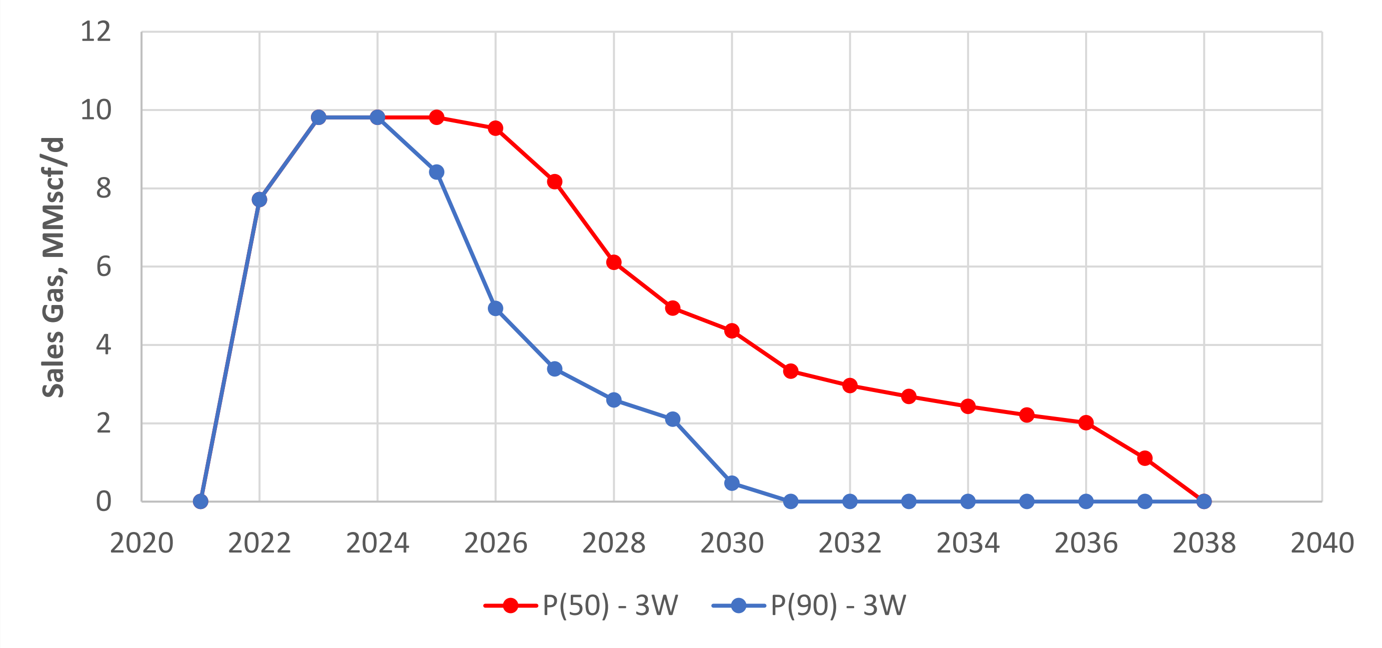

Figure 23 P90, P50 Production Profiles for Sales Gas. Source: AEWB, verified by OIL

6. Discounted Cash Flow Valuation

OIL has estimated discounted net present values at 10% discount factor for the two production profiles in Table 5-1. Table 6-1 to Table 6-6 present the summary inputs to the economic model for the Development Plan. Table 6-7 to Table 6-14 present annual cash flow calculations and the post-tax NPV10 for the P90 and P50 development plan production profiles. Cash flow calculations and NPVs are presented both on a project basis (ie with no reference to the means of financing except the 10% discount factor); and including the loan terms. Since the loan terms are binding on AEWB and SE, the reserves and NPVs quoted in this report include the loan terms.

The commodity prices used were from October 1st, 2021 and the cash flows were discounted to October 1st, 2021, using mid-year discounting. The cash flows were calculated on a monthly basis and aggregated to yearly for ease of display. Table 6-1 presents the operator's capital cost AFE to achieve First Gas, and to install booster compression and install a smaller tubing in well SF4 when required.

Table 6-1 Remaining Capex Assumptions for Cash Flow Forecasts, Saltfleetby Field

Cost Centre	**P90**	**P50**
	GB£ m	GB£ m
AFE Process Plant	£6.57	£6.57
AFE Pipeline Spur	£0.86	£0.86
AFE National Grid Connection	£0.99	£0.99
AFE Well SF07V Side-track	£2.84	£2.84
Contingency (facilities and well)	£1.41	£1.41
Total Capex to First Gas	**£12.67**	**£12.67**
Paid to 30 Sept 2021	**-£5.74**	**-£5.74**
Remaining Capex to First Gas, of which:	**£6.93**	**£6.93**
Oct -Dec 21	**£3.47**	**£3.47**
Jan-Mar 22	**£3.47**	**£3.47**
Booster Compression (Required: P90: Feb 24; P50: Jan 26)		
Second Gas Engine (Oct 23)	£0.32	£0.32
Variable drive electric motor (Feb24 (P90) or Jan 26 (P50)	£0.36	£0.36
Overruns, say 10% for P90	£0.07	£0.00
Total Capex Booster Compression	**£0.75**	**£0.68**
Install 2 7/8 tubing string in well SF04 (P90: June 24, P50: Apr 25)	£0.12	£0.12
Abandonment Capex (end of life)	**£1.50**	**£1.50**
Grand Total Capex Future Cash Flow Analysis	**£9.31**	**£9.24**

Effective Date: 1st October 2021
Source: AEWB

OIL is not able to verify the accuracy of the operator's AFE but given the advanced stage of the design, construction and procurement phases (£5.7m of £12.7m has already been disbursed and nearly all contracted), it is likely the contingency included will cover any overruns.

Opex and economics assumptions are presented in Table 6-2.

Table 6-2 Opex and Economics assumptions for Cash Flow Forecasts

Item Description	Units	Value
Operating Expenses		
Fixed Opex	GB£ m pa	£1.55
G&A (Field, and Head Office allocation) 2022 unescalated	GB£ m pa	£0.58
G&A (Field, and Head Office allocation) 2023 onwards, unescalated	GB£ m pa	£0.69
National Grid Fixed Metering fee (>8.4 MMSCFD)	GB£ m pa	£0.02
Condensate Haulage tariff	£/bbl	£4
Produced Water Haulage and Disposal tariff	£/bbl	£20
Non Transmission Services Entry Charges (NTSEC)	£/Therm	£0.00386
Theddlethorpe Monthly System Entry Capacity (MSCE)	£/MMSCFD	£166
Commodity Pricing		
Gas price	NBP Forward Curve	
Calorific value of gas	Therms / MMSCF	10873
Sales Gas Price Discount to (NBP -NTSEC)	%	1.50%
Oil Price	Brent Forward Curve	
Condensate Discount to Brent	£/bbl	£5.00
Exogenous		
Inflation	% pa	1.5%
Commodity Price Inflation (after end of FWD curves)	% pa	1.5%
Taxation		
Ring Fence Corporation Tax (RFCT)	% of taxable base	30%
Supplementary Charge (SC)	% of taxable base	10%
SC Uplift of First Year Allowances	%	175%
Interest and ORRI disallowed for SC		
Tax relief for abandonment costs credited to abandonment year cash flow; reference Decommissioning Relief Deeds, FA 2013		
AEWB Ring Fenced Losses Carried Forward 30/9/2021	GB £m	£16.92

6.1. Terms of Licensees' Loan

Table 6-3 summarises the loan terms used to model AEWB's cash flows.

Table 6-3 Licensees' Loan Terms

Item Description	Units	Value
Debt Terms		
Loan amount agreed May 2021	GB£ m	12.00
Expiry of Loan		31/12/2024
Interest rate over "Sonia"	%	12%
Sonia (Sterling Overnight Index Average)	%	0.05%
Overriding Royalty Interest (after repayment of >85% of loan until end of production)	%	8%
Minimum distribution to licensees if profit > £600k pcm	GB£ m pcm	£0.20
[1] Minimum bank balance to exceed rolling three months of interest payment plus minimum loan repayment		
[2] Proceeds over minimum bank balance distributed 60% to accelerated loan repayment and 40% to licensees		

6.2. Calculation of Gas Price forecast at the Theddlethorpe Sales Point

The Licensees have fixed (hedged) the monthly gas price for part of forecast production between July 2022 and June 2025 (ranging from 3.3 MMSCFD to 5.4 MMSCFD). Table 6-4 presents the hedged prices, hedged therms/MMSCF and forecast revenues. The calorific value from Table 6-2 was used to convert therms to MMSCF. The total gross revenue for Saltfleetby Field forecast from hedged production is £21.809m.

The cash flow calculation assumes the balance of production will be sold at the NBP forward price. Table 6-5 presents a forecast of the annual net Sales Gas price received by AEWB from the off taker at the Theddlethorpe entry point. The basis of the forecast is the National Balancing Point Monthly Forward Curve for October 1st, 2021 until December 2026. After 2026, the NBP price is escalated by 1.5% pa.

The NTS Theddlethorpe Non-Transmission Services Entry Charges (NTSEC), £0.386 pence/Therm in 2022, is subtracted from the NBP price. The NTSEC is escalated by 1.5% pa.

The off-taker's proposed charge of 1.5% is applied to the NBP price net of the NTSEC.
The resulting sales price to AEWB is converted from pence/Therm to £/MMSCF again using gas calorific value of 10872.5 Therms / MMSCF.

In the cash flow model, the monthly NBP prices are used rather than the annual averages presented in Table 6-5.

Table 6-4 Hedged Prices, Hedged Volumes

MONTH	HEDGE PRICE p/Th	HEDGE VOLUME MM Th	HEDGE MONTH VOLUME MMSCF	HEDGE DAY VOLUME MMSCFD	£/MMSCF at Sales Point (10872.5 Th/MMSCF	REVENUE FROM HEDGED SALES £M
Jul-22	41.4	1.125	103.47	3.34	£4,392	£0.45
Aug-22	41.4	1.125	103.47	3.34	£4,392	£0.45
Sep-22	41.4	1.125	103.47	3.45	£4,392	£0.45
Oct-22	52.05	1.75	160.96	5.19	£5,533	£0.89
Nov-22	52.05	1.75	160.96	5.37	£5,533	£0.89
Dec-22	52.05	1.75	160.96	5.19	£5,533	£0.89
Jan-23	52.05	1.75	160.96	5.19	£5,532	£0.89
Feb-23	52.05	1.75	160.96	5.75	£5,532	£0.89
Mar-23	52.05	1.75	160.96	5.19	£5,532	£0.89
Apr-23	37.55	1.75	160.96	5.37	£3,979	£0.64
May-23	37.55	1.75	160.96	5.19	£3,979	£0.64
Jun-23	37.55	1.75	160.96	5.37	£3,979	£0.64
Jul-23	37.55	1.5	137.96	4.45	£3,979	£0.55
Aug-23	37.55	1.5	137.96	4.45	£3,979	£0.55
Sep-23	37.55	1.5	137.96	4.60	£3,979	£0.55
Oct-23	46.55	1.5	137.96	4.45	£4,943	£0.68
Nov-23	46.55	1.5	137.96	4.60	£4,943	£0.68
Dec-23	46.55	1.5	137.96	4.45	£4,943	£0.68
Jan-24	46.55	1.5	137.96	4.45	£4,943	£0.68
Feb-24	46.55	1.5	137.96	4.76	£4,943	£0.68
Mar-24	46.55	1.5	137.96	4.45	£4,943	£0.68
Apr-24	35.6	1.5	137.96	4.60	£3,770	£0.52
May-24	35.6	1.5	137.96	4.45	£3,770	£0.52
Jun-24	35.6	1.5	137.96	4.60	£3,770	£0.52
Jul-24	35.6	1.25	114.97	3.71	£3,770	£0.43
Aug-24	35.6	1.25	114.97	3.71	£3,770	£0.43
Sep-24	35.6	1.25	114.97	3.83	£3,770	£0.43
Oct-24	45	1.25	114.97	3.71	£4,777	£0.55
Nov-24	45	1.25	114.97	3.83	£4,777	£0.55
Dec-24	45	1.25	114.97	3.71	£4,777	£0.55
Jan-25	45	1.25	114.97	3.71	£4,776	£0.55
Feb-25	45	1.25	114.97	4.11	£4,776	£0.55
Mar-25	45	1.25	114.97	3.71	£4,776	£0.55
Apr-25	35.25	1.25	114.97	3.83	£3,732	£0.43
May-25	35.25	1.25	114.97	3.71	£3,732	£0.43
Jun-25	35.25	1.25	114.97	3.83	£3,732	£0.43

Source: AEWB.

Table 6-5 NBP Forward Prices: Calculation of Net Gas price at Sales Point £/MMSCF

Year	NBP FWD Pence/Therm (01 Oct 21)	Non Transportation Services Entry Charges	Off-taker's charge (1.5% of NBP-MSCE)	NBP FWD Pence/Th at Sales Point	£/MMSCF at Sales Point (10872.5 Th/MMSCF	Gas price Escalation Assumption from 2027	MSCE Cost Escalation
	Pence/Therm	Pence/Therm	Pence/Therm	Pence/Therm	10872.5	% pa	% pa
					£0	1.5%	1.5%
2021	254.01p	0.38p	3.80p	249.82p	£27,162		1.5%
2022	150.32p	0.39p	2.25p	147.68p	£16,057		1.5%
2023	85.65p	0.39p	1.28p	83.98p	£9,130		1.5%
2024	66.39p	0.40p	0.99p	65.00p	£7,068		1.5%
2025	61.13p	0.40p	0.91p	59.81p	£6,503		1.5%
2026	60.05p	0.41p	0.89p	58.74p	£6,387		1.5%
2027	60.95p	0.42p	0.91p	59.62p	£6,482	1.5%	1.5%
2028	61.86p	0.42p	0.92p	60.52p	£6,580	1.5%	1.5%
2029	62.79p	0.43p	0.94p	61.42p	£6,678	1.5%	1.5%
2030	63.73p	0.44p	0.95p	62.35p	£6,779	1.5%	1.5%
2031	64.69p	0.44p	0.96p	63.28p	£6,880	1.5%	1.5%
2032	65.66p	0.45p	0.98p	64.23p	£6,983	1.5%	1.5%
2033	66.64p	0.46p	0.99p	65.19p	£7,088	1.5%	1.5%
2034	67.64p	0.46p	1.01p	66.17p	£7,194	1.5%	1.5%
2035	68.66p	0.47p	1.02p	67.16p	£7,302	1.5%	1.5%
2036	69.69p	0.48p	1.04p	68.17p	£7,412	1.5%	1.5%
2037	70.73p	0.48p	1.05p	69.19p	£7,523	1.5%	1.5%

6.3. Calculation of Condensate Sales Price forecast at Immingham Refinery

The condensate price forecast was based on the Brent Forward Curve minus a £5/bbl discount; Table 6-6 refers. A haulage charge of £4/bbl is accounted for separately in the cash flow model.

Table 6-6 Calculation of Condensate Price £/bbl

	Brent FWD Curve 01 Oct 21				
Year	Forward Curve $/bbl	Brent Escalation Assumption % pa	Condy Discount to Brent $/bbl	Exchange rate $/£ (1/7/21)	Condensate £/bbl
			£5.00		
2021	$75.76		-$6.90	$1.38	£49.91
2022	$74.87		-$6.89	$1.38	£49.32
2023	$68.91		-$6.86	$1.37	£45.19
2024	$64.90		-$6.89	$1.38	£42.13
2025	$62.05		-$6.92	$1.38	£39.82
2026	$60.18		-$6.95	$1.39	£38.30
2027	$59.16		-$6.95	$1.39	£37.57
2028	$58.93		-$6.95	$1.39	£37.40
2029	$59.00		-$6.95	$1.39	£37.46
2030	$59.89	1.5%	-$7.05	$1.39	£38.02
2031	$60.78	1.5%	-$7.16	$1.39	£38.59
2032	$61.70	1.5%	-$7.27	$1.39	£39.17
2033	$62.62	1.5%	-$7.37	$1.39	£39.75
2034	$63.56	1.5%	-$7.49	$1.39	£40.35
2035	$64.51	1.5%	-$7.60	$1.39	£40.96
2036	$65.48	1.5%	-$7.71	$1.39	£41.57
2037	$66.46	1.5%	-$7.83	$1.39	£42.19
2038	$67.46	1.5%	-$7.94	$1.39	£42.83
2039	$68.47	1.5%	-$8.06	$1.39	£43.47
2040	$69.50	1.5%	-$8.18	$1.39	£44.12
2041	$70.54	1.5%	-$8.31	$1.39	£44.78
2042	$71.60	1.5%	-$8.43	$1.39	£45.45
2043	$72.67	1.5%	-$8.56	$1.39	£46.14
2044	$73.76	1.5%	-$8.69	$1.39	£46.83
2045	$74.87	1.5%	-$8.82	$1.39	£47.53

Table 6-7 P90 Cash Flow Forecast £m on a project basis; effective date October 1st, 2021

	Gross								AEWB Net			
Year	Sales Gas	Condensate Liquids	Gross Revenue	Operating Expenses	Abandon Costs	Capital Costs	Wells on production	Pre Tax Future Net Revenue	Pre Tax Future Net Revenue	Corporate Taxes	Post Tax Future Net Revenue	Post tax NPV at 10% Mid-Year
	BCF	MSTB	£m	£m	£m	£m	No.	£m	£m	£m	£m	£m
31/5/21-30/9/21				-£0.3		-£4.7		-£5.0	-£2.5		-£2.5	-£2.5
Q4 2021				-£0.3		-£3.5		-£3.7	-£1.9		-£1.9	-£1.8
2022	2.8	25.4	£32.7	-£2.8		-£3.5	3	£26.4	£13.5		£13.5	£12.1
2023	3.6	27.6	£25.7	-£3.4		-£0.3	3	£22.0	£11.2	-£0.9	£10.3	£8.6
2024	3.6	22.6	£22.1	-£3.3		-£0.6	3	£18.3	£9.3	-£2.8	£6.6	£4.9
2025	3.1	15.2	£19.0	-£3.2			3	£15.8	£8.1	-£2.9	£5.2	£3.5
2026	1.8	7.2	£11.8	-£2.9			2	£8.9	£4.5	-£2.4	£2.1	£1.3
2027	1.2	4.2	£8.2	-£2.8			2	£5.4	£2.8	-£1.4	£1.3	£0.8
2028	0.9	2.8	£6.4	-£2.8			1	£3.6	£1.8	-£0.8	£1.0	£0.5
2029	0.8	2.0	£5.2	-£2.8			1	£2.4	£1.2	-£0.6	£0.7	£0.3
2030	0.2	0.4	£1.3	-£1.3	-£1.3		1	-£1.3	-£0.7	-£0.1	-£0.8	-£0.3
2031				-£0.2	-£0.4			-£0.6	-£0.3	£0.3	£0.0	£0.0
Total	**18**	**107**	**£132.5**	**-£25.8**	**-£1.7**	**-£7.8**		**£97.1**	**£49.5**	**-£11.6**	**£38.0**	**£29.8**

Table 6-8 P90 Cash Flow Forecast £m including loan terms; effective date October 1st, 2021

	Gross				**Net to Licensees after Financing**						**AEWB Net**			
Year	Sales Gas	Liquids	Gross Revenue	Pre-Tax NCF before Financing	Gas Net of Royalty	Liquids Net of Royalty	Royalty Value	Interest	Draw Down Loan & Repay	Pre Tax NCF after Financing	Pre Tax NCF after Financing	Corporate Taxes	Post Tax Future Net Revenue	Post tax NPV at 10% Mid-Year
	BCF	MSTB	£m	£m	BCF	MSTB	£m	£m	£m	£m	£m	£m	£m	£m
31/5/21-30/9/21				*-£5.0*				*£0.5*	*-£5.5*					
Q4 2021				-£3.7				£0.4	-£4.1					
2022	2.8	25.4	£32.7	£26.4	2.7	24.3	£1.1	£0.7	£9.0	£15.6	£7.9		£7.9	£7.3
2023	3.6	27.6	£25.7	£22.0	3.3	25.4	£2.1			£20.0	£10.2	-£0.7	£9.5	£8.1
2024	3.6	22.6	£22.1	£18.3	3.3	20.8	£1.8		£0.1	£16.4	£8.4	-£2.3	£6.1	£4.7
2025	3.1	15.2	£19.0	£15.8	2.8	14.0	£1.5			£14.3	£7.3	-£2.6	£4.7	£3.2
2026	1.8	7.2	£11.8	£8.9	1.7	6.6	£0.9			£7.9	£4.0	-£2.2	£1.8	£1.1
2027	1.2	4.2	£8.2	£5.4	1.1	3.8	£0.7			£4.7	£2.4	-£1.3	£1.1	£0.6
2028	0.9	2.8	£6.4	£3.6	0.9	2.6	£0.5			£3.1	£1.6	-£0.8	£0.8	£0.4
2029	0.8	2.0	£5.2	£2.4	0.7	1.8	£0.4			£2.0	£1.0	-£0.5	£0.5	£0.2
2030	0.2	0.4	£1.3	-£1.3	0.2	0.4	£0.1			-£1.4	-£0.7	-£0.1	-£0.8	-£0.3
2031				-£0.6						-£0.6	-£0.3	£0.3	£0.0	£0.0
Total	**18.0**	**107.3**	**£132.5**	**£97.1**	**16.7**	**99.7**	**£9.1**	**£1.1**	**-£0.48**	**£82.0**	**£41.8**	**-£10.1**	**£31.7**	**£25.4**

Table 6-8 suggests about £0.5m addition capital is required.

Table 6-9 P50 Cash Flow Forecast £m on a project basis; effective date October 1st, 2021

	Gross								AEWB Net			
Year	Sales Gas	Condensate Liquids	Gross Revenue	Operating Expenses	Abandon Costs	Capital Costs	Wells on production	Pre Tax Future Net Revenue	Pre Tax Future Net Revenue	Corporate Taxes	Post Tax Future Net Revenue	Post tax NPV at 10% Mid-Year
	BCF	MSTB	£m	£m	£m	£m	No.	£m	£m	£m	£m	£m
31/5/21-30/9/21				*-£0.3*		*-£4.7*		*-£5.0*	*-£2.5*		*-£2.5*	*-£2.5*
Q4 2021				-£0.3		-£3.5		-£3.7	-£1.9	£0.0	-£1.9	-£1.8
2022	2.8	26.0	£32.7	-£2.9		-£3.5	3	£26.4	£13.5	-£0.6	£12.8	£11.5
2023	3.6	30.3	£25.8	-£3.4		-£0.3	3	£22.2	£11.3	-£1.5	£9.8	£8.1
2024	3.6	27.6	£22.4	-£3.3			3	£19.0	£9.7	-£1.9	£7.8	£5.9
2025	3.6	24.6	£22.6	-£3.3		-£0.1	3	£19.2	£9.8	-£3.8	£6.0	£4.1
2026	3.5	21.2	£23.0	-£3.3		-£0.4	3	£19.4	£9.9	-£3.9	£6.0	£3.7
2027	3.0	16.0	£20.0	-£3.2			3	£16.8	£8.6	-£3.7	£4.9	£2.7
2028	2.2	10.7	£15.2	-£3.1			3	£12.2	£6.2	-£2.9	£3.3	£1.7
2029	1.8	7.8	£12.4	-£3.0			2	£9.3	£4.8	-£2.1	£2.7	£1.2
2030	1.6	6.3	£11.0	-£3.0			2	£8.1	£4.1	-£1.7	£2.4	£1.0
2031	1.2	4.4	£8.6	-£3.0			1	£5.6	£2.9	-£1.4	£1.5	£0.6
2032	1.1	3.7	£7.7	-£3.0			1	£4.8	£2.4	-£1.0	£1.4	£0.5
2033	1.0	3.1	£7.1	-£3.0			1	£4.1	£2.1	-£0.9	£1.2	£0.4
2034	0.9	2.6	£6.5	-£3.0			1	£3.5	£1.8	-£0.8	£1.0	£0.3
2035	0.8	2.2	£6.0	-£3.1			1	£2.9	£1.5	-£0.6	£0.9	£0.2
2036	0.7	1.9	£5.5	-£3.1			1	£2.5	£1.3	-£0.5	£0.7	£0.2
2037	0.4	1.0	£3.1	-£2.2	-£0.8		1	£0.1	£0.1	-£0.2	-£0.2	£0.0
2038				-£0.5	-£1.1			-£1.6	-£0.8	£0.2	-£0.6	-£0.1
Total	**32**	**190**	**£229.7**	**-£49.4**	**-£1.9**	**-£7.8**		**£170.6**	**£87.0**	**-£27.2**	**£59.8**	**£40.0**

Table 6-10 P50 Cash Flow Forecast £m including loan terms; effective date October 1st, 2021

	Gross				Net to Licensees after Financing						AEWB Net			
Year	Sales Gas	Liquids	Gross Revenue	Pre-Tax NCF before Financing	Gas Net of Royalty	Liquids Net of Royalty	Royalty Value	Interest	Draw Down Loan & Repay	Pre Tax NCF after Financing	Pre Tax NCF after Financing	Corporate Taxes	Post Tax Future Net Revenue	Post tax NPV at 10% Mid-Year
	BCF	MSTB	£m	£m	BCF	MSTB	£m	£m	£m	£m	£m	£m	£m	£m
31/5/21-30/9/21				*-£5.0*				*£0.5*	*-£5.5*					
Q4 2021				-£3.7				£0.4	-£4.1					
2022	2.8	26.0	£32.7	£26.4	2.7	24.9	£1.1	£0.7	£9.0	£15.6	£8.0		£8.0	£7.3
2023	3.6	30.3	£25.8	£22.2	3.3	27.9	£2.1			£20.1	£10.2		£10.2	£8.7
2024	3.6	27.6	£22.4	£19.0	3.3	25.4	£1.8		£0.1	£17.2	£8.8	-£0.6	£8.2	£6.3
2025	3.6	24.6	£22.6	£19.2	3.3	22.7	£1.8			£17.4	£8.9	-£2.1	£6.8	£4.7
2026	3.5	21.2	£23.0	£19.4	3.2	19.5	£1.8			£17.5	£9.0	-£2.9	£6.1	£3.8
2027	3.0	16.0	£20.0	£16.8	2.7	14.8	£1.6			£15.2	£7.7	-£3.2	£4.6	£2.6
2028	2.2	10.7	£15.2	£12.2	2.1	9.9	£1.2			£10.9	£5.6	-£2.7	£2.9	£1.5
2029	1.8	7.8	£12.4	£9.3	1.7	7.2	£1.0			£8.4	£4.3	-£1.9	£2.4	£1.1
2030	1.6	6.3	£11.0	£8.1	1.5	5.8	£0.9			£7.2	£3.7	-£1.6	£2.1	£0.9
2031	1.2	4.4	£8.6	£5.6	1.1	4.1	£0.7			£4.9	£2.5	-£1.3	£1.3	£0.5
2032	1.1	3.7	£7.7	£4.8	1.0	3.4	£0.6			£4.1	£2.1	-£0.9	£1.2	£0.4
2033	1.0	3.1	£7.1	£4.1	0.9	2.9	£0.6			£3.5	£1.8	-£0.8	£1.0	£0.3
2034	0.9	2.6	£6.5	£3.5	0.8	2.4	£0.5			£3.0	£1.5	-£0.7	£0.8	£0.2
2035	0.8	2.2	£6.0	£2.9	0.7	2.1	£0.5			£2.5	£1.3	-£0.6	£0.7	£0.2
2036	0.7	1.9	£5.5	£2.5	0.7	1.8	£0.4			£2.0	£1.0	-£0.5	£0.6	£0.1
2037	0.4	1.0	£3.1	£0.1	0.4	0.9	£0.2			-£0.1	-£0.1	-£0.2	-£0.2	-£0.1
2038				-£1.6						-£1.6	-£0.8	£0.2	-£0.6	-£0.1
Total	**31.8**	**189.7**	**£229.7**	**£170.6**	**29.3**	**175.5**	**£16.9**	**£1.1**	**-£0.48**	**£147.7**	**£75.3**	**-£19.4**	**£55.9**	**£38.5**

Table 6-10 suggests about £0.5m addition capital is required.

Table 6-11 P90 Pre- and Post-Tax NPV £m on a project basis; effective date and discounting date October 1st, 2021

Mid-Year Nominal Net Present Values as at 01-Oct-21 (GB£ m)			
Disc Rate	**Gross Pre-Tax**	**AEWB Pre-Tax**	**AEWB Post-Tax**
0%	£97.1	£49.5	£38.0
5%	£84.0	£42.9	£33.4
10%	£73.5	£37.5	£29.8
12.5%	£69.1	£35.2	£28.2
15%	£65.0	£33.2	£26.7
20%	£58.1	£29.6	£24.2
IRR	1517%	1517%	1509%
MIRR	21%	21%	18%

Note: MIRR is the modified internal rate of return, which assumes reinvestment of positive cash flows at (in this case) 10% and financing of negative cash flows at 10%. When IRRs are very high, MIRR is a more useful measure of profitability to the asset owner.

Table 6-12 P90 Pre- and Post-Tax NPV £m including loan terms; effective date and discounting date October 1st, 2021

Mid-Year Nominal Net Present Values as at 01-Oct-21 (GB£ m)			
Disc Rate	**Gross Pre-Tax**	**AEWB Pre-Tax**	**AEWB Post-Tax**
0%	£82.0	£41.8	£31.7
5%	£71.7	£36.5	£28.2
10%	£63.3	£32.3	£25.4
12.5%	£59.7	£30.5	£24.1
15%	£56.5	£28.8	£23.0
20%	£50.9	£25.9	£21.0
MIRR		30%	21%

Table 6-13 P50 Pre- and Post-Tax NPV £m on a project basis; effective date and discounting date October 1st, 2021

Mid-Year Nominal Net Present Values as at 01-Oct-21 (GB£ m)			
Disc Rate	**Gross Pre-Tax**	**AEWB Pre-Tax**	**AEWB Post-Tax**
0%	£170.6	£87.0	£59.8
5%	£133.8	£68.2	£48.2
10%	£108.4	£55.3	£40.0
12.5%	£98.6	£50.3	£36.8
15%	£90.2	£46.0	£34.0
20%	£76.7	£39.1	£29.5
IRR	1519%	1519%	1386%
MIRR	24%	24%	18%

Table 6-14 P50 Pre- and Post-Tax NPV £m including loan terms; effective date and discounting date October 1st, 2021

Mid-Year Nominal Net Present Values as at 01-Oct-21 (GB£ m)			
Disc Rate	**Gross Pre-Tax**	**AEWB Pre-Tax**	**AEWB Post-Tax**
0%	£147.7	£75.3	£55.9
5%	£117.0	£59.6	£45.8
10%	£95.6	£48.7	£38.5
12.5%	£87.3	£44.5	£35.7
15%	£80.1	£40.9	£33.2
20%	£68.6	£35.0	£29.0
MIRR		36%	23%

7. Determination of Reserves of Sales Gas and Liquids

The Westphalian Main reservoir satisfies three of the four criteria for Reserves, i.e., Discovered, Recoverable and Remaining. The decision whether to categorise the volumes as reserves or contingent resources depends on whether they also satisfy the "Commercial" sub-criteria for Reserves, i.e., for volumes to be Commercial, there needs to be a "Reasonable Expectation" of:

- Firm intention to proceed with development within five years
- A market and the production & transportation facilities needed to access it
- Legal, contractual, HSE requirements can be satisfied
- The net present value of the post-tax cash flow of the median production profile attributable to AEWB must be positive. The cash flow must include abandonment, decommissioning and restoration costs (ADR) and G&A directly associated with the field. The discount factor applied must be appropriate and in our opinion 10% is appropriate.
- The post-tax cash flow of the low case production profile attributable to AEWB must be positive. The cash flow shall **not** include ADR for this test.

"Reasonable Expectation" (according to PRMS 2018)[11] indicates a high degree of confidence (low risk of failure) that …. the referenced event will occur.

Table 6-7 and Table 6-11 demonstrate that the low production case profile has a net cash flow that is positive without the ADR cost (and indeed with ADR included). Table 6-9 and Table 6-13 demonstrate that the median production profile has a positive net present value.

Therefore, the Development Plan meets the Commercial criteria for Reserves. Table 7-1 and Table 7-2 quantify the remaining recoverable gas and condensate liquids that satisfy the Reserves category.

[11] PRMS 2018 Definitions, page 48

Table 7-1 Sales Gas Reserves: Gross and Net Attributable to AEWB

Saltfleetby Field	Gross		Net Attributable to AEWB		Operator
Sales Gas Reserves	**1P**	**2P**	**1P**	**2P**	
	BCF	BCF	BCF	BCF	
Main Field Westphalian Reservoir	18.0	31.8	8.5	15.0	AEWB

Table 7-2 Condensate Liquids Reserves: Gross and Net Attributable to AEWB

Saltfleetby Field	Gross		Net Attributable to AEWB		Operator
Condensate Liquids Reserves	**1P**	**2P**	**1P**	**2P**	
	M STB	M STB	M STB	M STB	
Main Field Westphalian Reservoir	107.2	189.8	50.8	89.5	AEWB

Effective Date: 1st October 2021

Source: Oilfield International

8. Glossary

ADR	Abandonment, Decommissioning and Reclamation Expenditure
bbl	Barrels
/bbl	per barrel
Bscf or Bcf	Billion standard cubic feet
bcpd	Barrels of condensate per day
bbl/d	Barrels of Oil per day
blpd	Barrels of liquid per day
bpd	Barrels per day
boe	Barrels of Oil equivalent @ xxx MCF/bbl
boepd	Barrels of Oil equivalent per day @ xxx MCF/bbl
bopd	Barrels Oil per day
bwpd	Barrels of water per day
bwpd	Barrels water per day
C$,CAD$, CDN$	Canadian Dollar
CAPEX	Capital Expenditure
E&A	Exploration & Appraisal
E&P	Exploration and Production
EBIT	Earnings before Interest and Tax
EBITDA	Earnings before interest, tax, depreciation, and amortisation
EI	Entitlement Interest
EIA	Environmental Impact Assessment
EMV	Expected Monetary Value
EOR	Enhanced Oil Recovery
EUR	Estimated Ultimate Recovery
FDP	Field Development Plan
G&A	General and Administrative costs
GIIP	Gas initially in place
GOR	Gas Oil Ratio
HSE	Health, Safety and Environment
HSSE-SR	Health, Safety, Security, Environment and Social Responsibility
IRR	Internal Rate of Return
km	Kilometres
km^2	Square kilometres
LoF	Life of Field
m	Metres
$m	Million US dollars
M	Thousand, especially of volume
m^3	Cubic metres

Mcf or Mscf	Thousand standard cubic feet
MMcf or MMscf	Million standard cubic feet
m^3d	Cubic metres per day
Mean	Arithmetic average of a set of numbers
Median	Middle value in a set of values
Mm^3	Thousand Cubic metres
Mm^3d	Thousand Cubic metres per day
MM	Million (especially of volume and energy)
MMbbl	Millions of barrels
MMBTU	Millions of British Thermal Units
Mode	Value that exists most frequently in a set of values = most likely
Mscfd	Thousand standard cubic feet per day
MMscfd	Million standard cubic feet per day
NGL	Natural Gas Liquids
NPV	Net Present Value
IRR	Internal Rate of Return
MIRR	Modified Rate of Return (Reinvestment of CF at market rate)
OCM	Operating Committee Meeting
OPEX	Operating Expenditure
p.a.	Per annum
P&A	Plugged and abandoned
PDP	Proved Developed Producing
PUD	Proved Undeveloped
PVT	Pressure volume temperature
P10	10% Probability
P50	50% Probability
P90	90% Probability
Rf	Recovery factor
Sales Gas	Gas that satisfies all National Grid plc's quality and safety specifications and so can be transported through the National Gas Grid to domestic and industrial consumers. Refer also note 6.
scf or cf	Standard Cubic Feet
scfd or cfd	Standard Cubic Feet per day
scf/ton	Standard cubic foot per ton
SEC	Securities and Exchange Commission
SPE	Society of Petroleum Engineers
SPE PRMS 2018	Guidelines for categorising and valuing petroleum resources
SPEE	Society of Petroleum Evaluation Engineers
STB or stb	Stock tank barrel
STOIIP	Stock tank Oil initially in place

T	Tonnes
TD	Total Depth
Te	Tonnes equivalent
Tscf or Tcf	Trillion standard cubic feet
TCM	Technical Committee Meeting
Tpd	Tonnes per day
US$	United States Dollar
WI	Working Interest
1H20	First half (6 months) of 2020 (example of date)
2Q20	Second quarter (3 months) of 2020 (example of date)
2D	Two dimensional
3D	Three dimensional
4D	Four dimensional
1P	Proved Reserves
2P	Proved plus Probable Reserves
3P	Proved plus Probable plus Possible Reserves
Contingent Resources	Those quantities of gas and liquids estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies.
1C	Denotes a low estimate of contingent resources.
2C	Denotes the most likely estimate of contingent resources.
3C	Denotes a high estimate of contingent resources.
%	Percentage