4th March 2020

The Directors
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Dear Sirs

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

Summary: Reserves, Resources 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 is 28th February 2020, there being no material change on 4th March 2020.

OIL conducted its assessment in compliance with the SPE Petroleum 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.

OIL has attributed Reserves, Contingent Resources and future cash flows to AEWB, in compliance with SPE PRMS 2018.[2] Table 0-1 refers.

The results presented reflect OIL's judgement based on its understanding of petroleum legislation, taxation, and other regulations that currently apply to AEWB and its operating subsidiaries. However, OIL cannot attest to the certainty of property title or encumbrances related to AEWB.

Our estimates of value are based on datasets provided by AEWB and a site visit to PEDL005. We have 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

[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.

warrant that its enquiries have revealed all the matters that a more extensive examination might otherwise disclose.

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

Name of Structure	**Reservoirs**
Reserves (the Current Development Plan)	
Saltfleetby Main Gas Field	Westphalian
Contingent Resources	
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 atributable to AEWB and net of Gas Consumed in Operations. Table 0-4 and Table 0-5 present the Gas and Condensate Liquids Contingent Resources atributable to AEWB.

Table 0-6 presents the NPV10 of the Reserves and Table 0-7 the capex liability attributable to AEWB for 2020 and 2021.

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**	**3P**	**Mean**	**1P**	**2P**	**3P**	**Mean**	
	BCF	BCF	BCF	BCF	BCF	BCF	BCF	BCF	
Main Field Westphalian Reservoir	18	32	55	32	9	16	28	16	AEWB

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

Saltfleetby Field	**Gross**				**Net Attributable to AEWB**				**Operator**
Condensate Liquids Reserves	**1P**	**2P**	**3P**	**Mean**	**1P**	**2P**	**3P**	**Mean**	
	M STB	M STB	M STB	M STB	M STB	M STB	M STB	M STB	
Main Field Westphalian Reservoir	107	190	330	188	55	97	168	96	AEWB

Effective Date: 28th February 2020

Source: Oilfield International

Table 0-4 Sales Gas Contingent Resources: Gross and Net Attributable to AEWB

Saltfleetby Field	**Gross**				**Net Attributable to AEWB**				**Operator**
Sales Gas Contingent Resources	**1C**	**2C**	**3C**	**Mean**	**1C**	**2C**	**3C**	**Mean**	
	BCF	BCF	BCF	BCF	BCF	BCF	BCF	BCF	
Main Field Namurian Reservoir	0	2	4	2	0	1	2	1	AEWB
Southern Satellite Westphalian Reservoir	12	18	26	18	6	9	13	9	AEWB
Total Remaining Recoverable Gas	**12**	**20**	**30**	**20**	**6**	**10**	**15**	**10**	

Effective Date: 28th February 2020

Source: Oilfield International

Table 0-5 Condensate Liquids Contingent Resources: Gross and Net Attributable to AEWB

Saltfleetby Field	Gross				Net Attributable to AEWB				Operator
Condensate Liquids Contingent Resources	1C	2C	3C	Mean	1C	2C	3C	Mean	
	M STB	M STB	M STB	M STB	M STB	M STB	M STB	M STB	
Main Field Namurian Reservoir	5	30	64	33	3	15	33	17	AEWB
Southern Satellite Westphalian Reservoir	158	221	288	229	80	113	147	117	AEWB
Total Remaining Condensate Liquids	**163**	**251**	**351**	**263**	**83**	**128**	**179**	**134**	

Effective Date: 28th February 2020

Source: Oilfield International

Table 0-6 Post-Tax NPV10 of Reserves discounted to Jan 1st 2020: Net Attributable to AEWB

After Tax NPV10 Attributable to AEWB		
1P	**2P**	**3P**
£m MOD	£m MOD	£m MOD
£16.7	£25.2	£34.9

MOD: money of the day

Effective Date: 28th February 2020

Source: Oilfield International

Table 0-7 Capex: Net Attributable to AEWB

Year	**1P**	**2P**	**3P**
2020	£1.31	£0.29	£0.00
2021	£1.20	£1.20	£0.86

Key Risks

The volumetric analysis is intrinsically uncertain

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.

Depth migration of the seismic data could reduce the uncertainty of the depth maps.

Remaining uncertainty about structure and faults

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. If it does not, the 3P, 3C gas and condensate liquids would be too high.

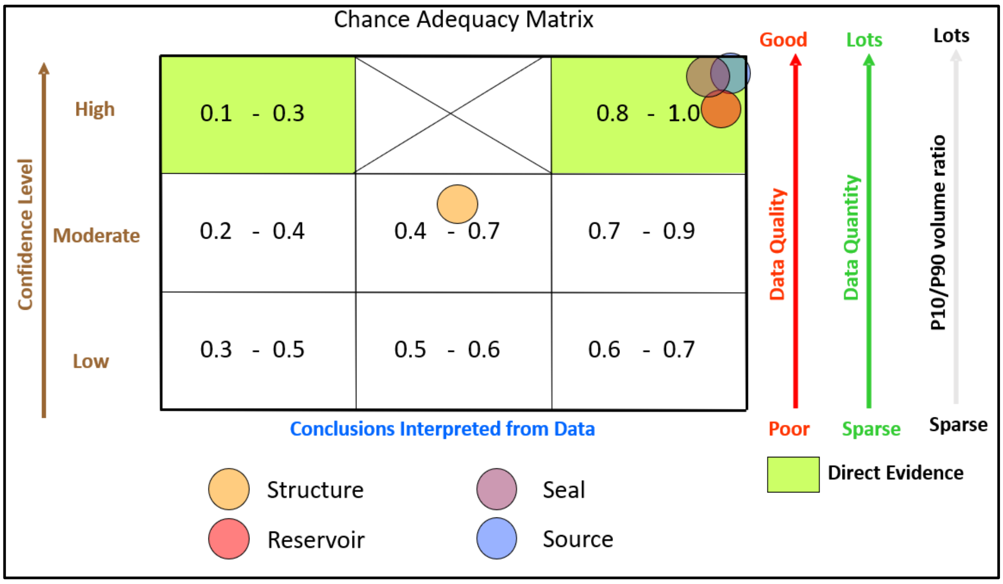

Figure 13: Chance of adequacy matrix of Saltfleetby Gas Field model

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 SF5 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[3], 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[4].

Project Execution

1. First gas is estimated to be between October 1st, 2020 and January 1st, 2021 and this range reflects amongst other the following risks:
    a. Planning Permission
    b. Approval of the Development Plan by the Oil and Gas Authority
    c. Delay in installation and commissioning of process equipment and a pipeline spur
    d. Delay in connection to the National Gas Grid
    e. Problems during start-up of the wells
    f. Offtake agreements
2. The ramp up to 10 MMSCFD in Q1/Q2 2021 could be at risk by
    a. Drilling rig and services availability
    b. Delays incurred during drilling and completing the well
    c. Lower than expected mechanical completion quality
3. The project costs may be higher (or lower) than forecast. In particular, the process plant and metering cost estimates on Site B include second-hand equipment skids which may

[3] **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.

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

or may not be available to AEWB at the time of procurement. New equipment would be more expensive.

4. The process plant may not perform to specification.

Exogenous

1. Commodity prices
    a. The National Balancing Point Forward Curve (NBP) dated 28th February 2020, escalated after December 2023 by 2% pa. Realised NBP gas prices may be higher or lower.
    b. The discount to National Balancing Point gas price offered by the off taker at the National Gas Grid connection point at Theddlethorpe is subject to firm quotation.
    c. The Brent Forward Curve dated 28th February 2020, escalated after March 2028 by 2% pa. Realised Brent oil prices may be higher or lower.
    d. The 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 2% pa. It may be higher or lower.
3. The cost of the SF5 horizontal sidetrack is subject to negotiation on hardware, rig hire and services rates and mob/demob, and rig performance.
4. Surface facilities costs are subject to firm quotations and more detailed engineering.
5. Uncertainty over the equity and debt markets.
6. 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. OIL's shareholders, management and staff are, and always have been, independent of shareholders, management and staff of Angus Energy Plc and AEWB.

This CPR was produced by three earth scientists: Mr David Curia, Dr Kanad Kulkarni and Mr Tim Lines. All hold advanced degrees in geoscience or petroleum engineering.

Mr David Curia has over 30 years' experience in geophysical interpretation and 3D modelling. 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 8 years' experience in Petrophysics and log interpretation. He holds 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 7 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.

Mr Tim Lines has over 35 years' experience in petroleum engineering and economic evaluation. He holds a B.Sc. in Chemistry from Bristol University, a M.Sc. in Petroleum Engineering from Imperial College and an MBA from Cranfield University. He is a Chartered Engineer registered with the UK Engineering Council since 1990 and he holds the Chair of the Distinguished Lecturer Committee for the Society of Petroleum Engineers Worldwide. He has been Programme Director for the Society of Petroleum Engineers London since 2000. He teaches a course on the SPE PRMS 2018. He is a member of the Institution of Gas Engineers (M. IGEM) and the Energy Institute (M. EI), the Institute of Materials, Minerals and Mining UK, and Fellow of the Geological Society of London (FGS). He has the Freedom of the City of London as a Liveryman of the Worshipful Company of Fuellers.

Basis of Opinion

The NPVs presented are based on OIL'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 OIL's opinion of the open market value of AEWB's Petroleum Assets. OIL does not confirm AEWB's legal right to title to PEDL005; the detail or the enforceability of AEWB's legal title; and the absence or nature of any liens or other encumbrances that might affect AEWB's rights to, or value in, PEDL005. However, OIL has verified that the Oil & Gas Authority has confirmed the transfer of a 51% share in the licence and Operatorship to AEWB.

Yours sincerely

Tim Lines

Tim Lines
Managing Partner, Oilfield International

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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 bblss 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) for a nominal consideration, with Salfleetby Energy contributing £2.5m to be applied by AEWB either (a) to assume 100% of the costs to be incurred during the reconnection of the Field to the National Gas Grid or (b) to satisfy all abandonment costs at the Field. Saltfleetby Energy retains liability for all abandonment costs surrounding the subsurface pipelines from the two sites to the Theddlethorpe Gas Terminal, together with certain redundancy costs. 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 AEWB's 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.

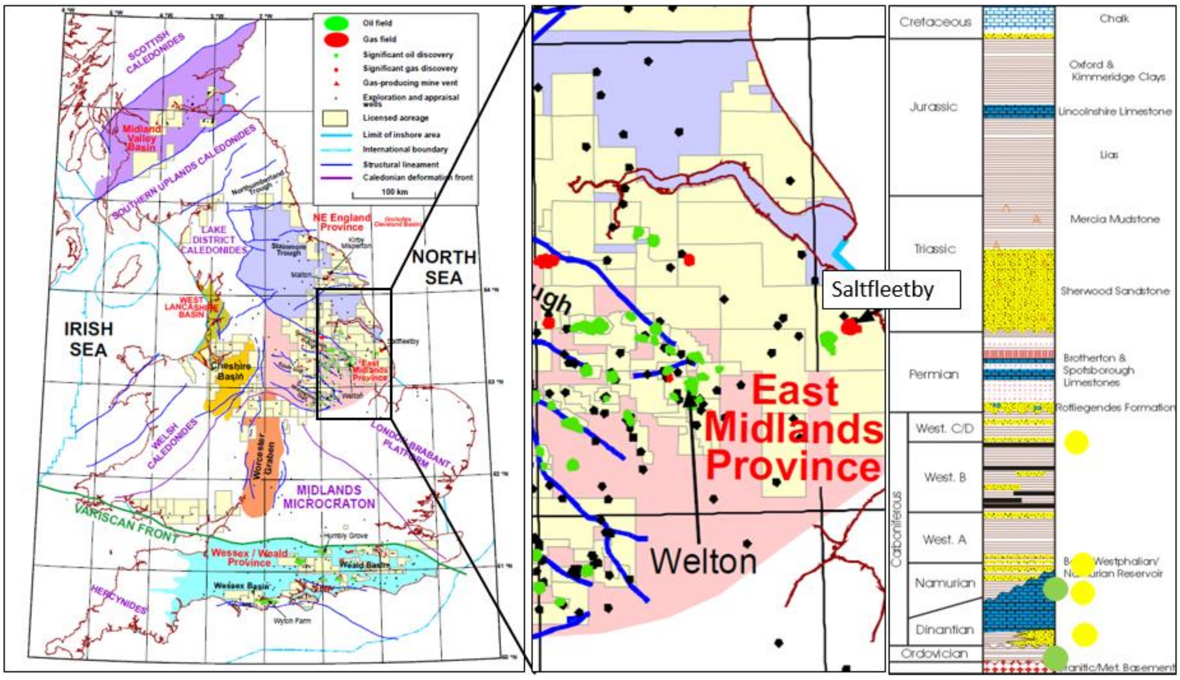

Figure 1 Geographic and Geological Setting of PEDL005; source: DECC[5]

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

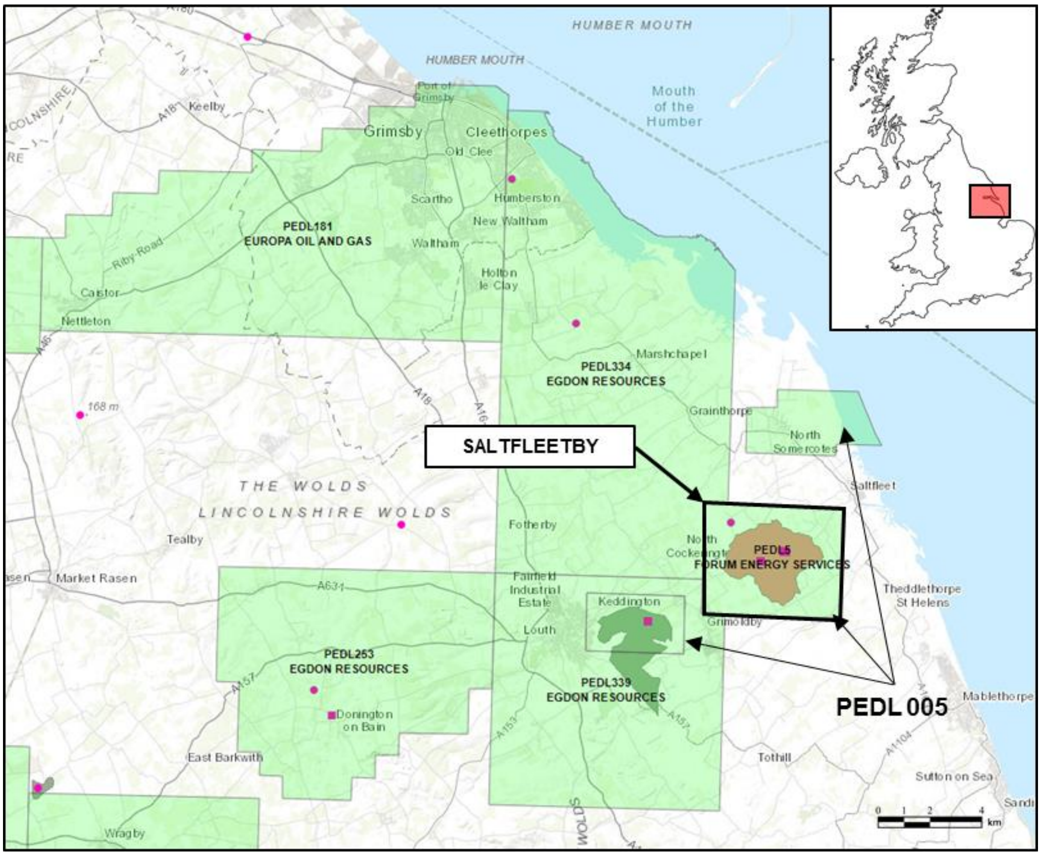

Figure 2 Location Map of PEDL005, source OGA, 2020

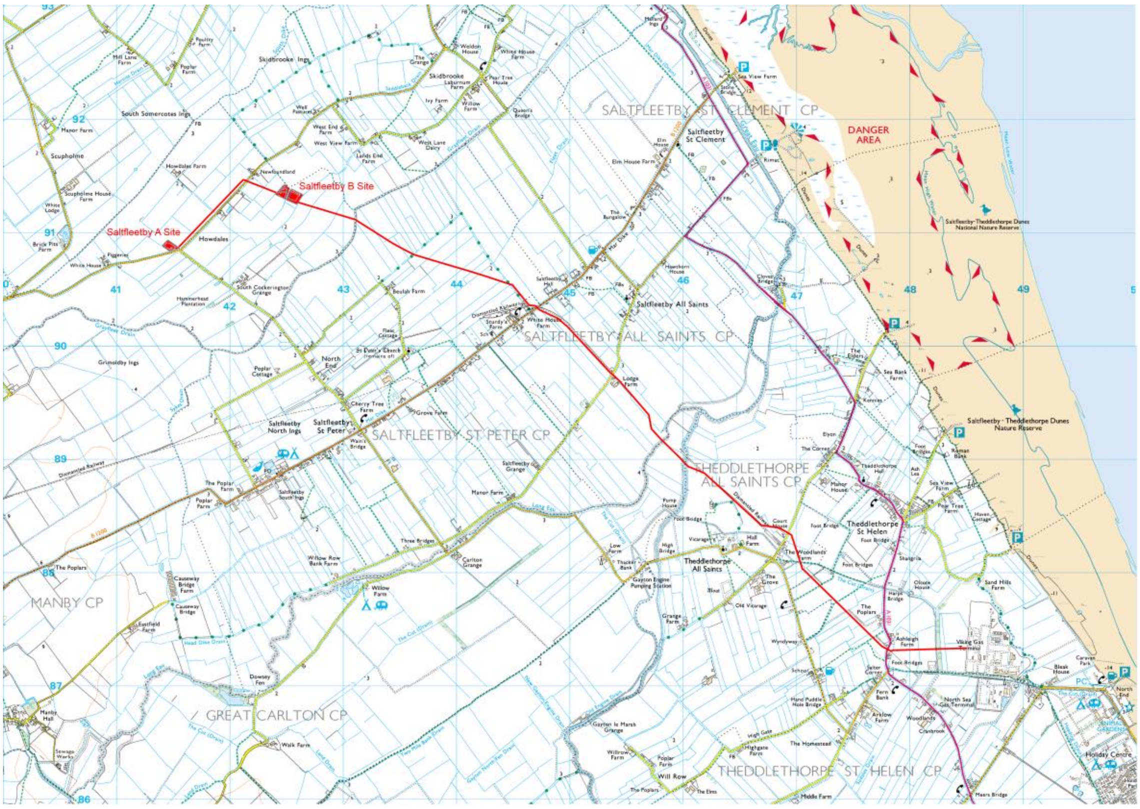

Figure 3 Saltfleetby Development Sites and Existing Gas Pipeline to (Decommissioned) Theddlethorpe Gas Terminal, Source Roc Oil

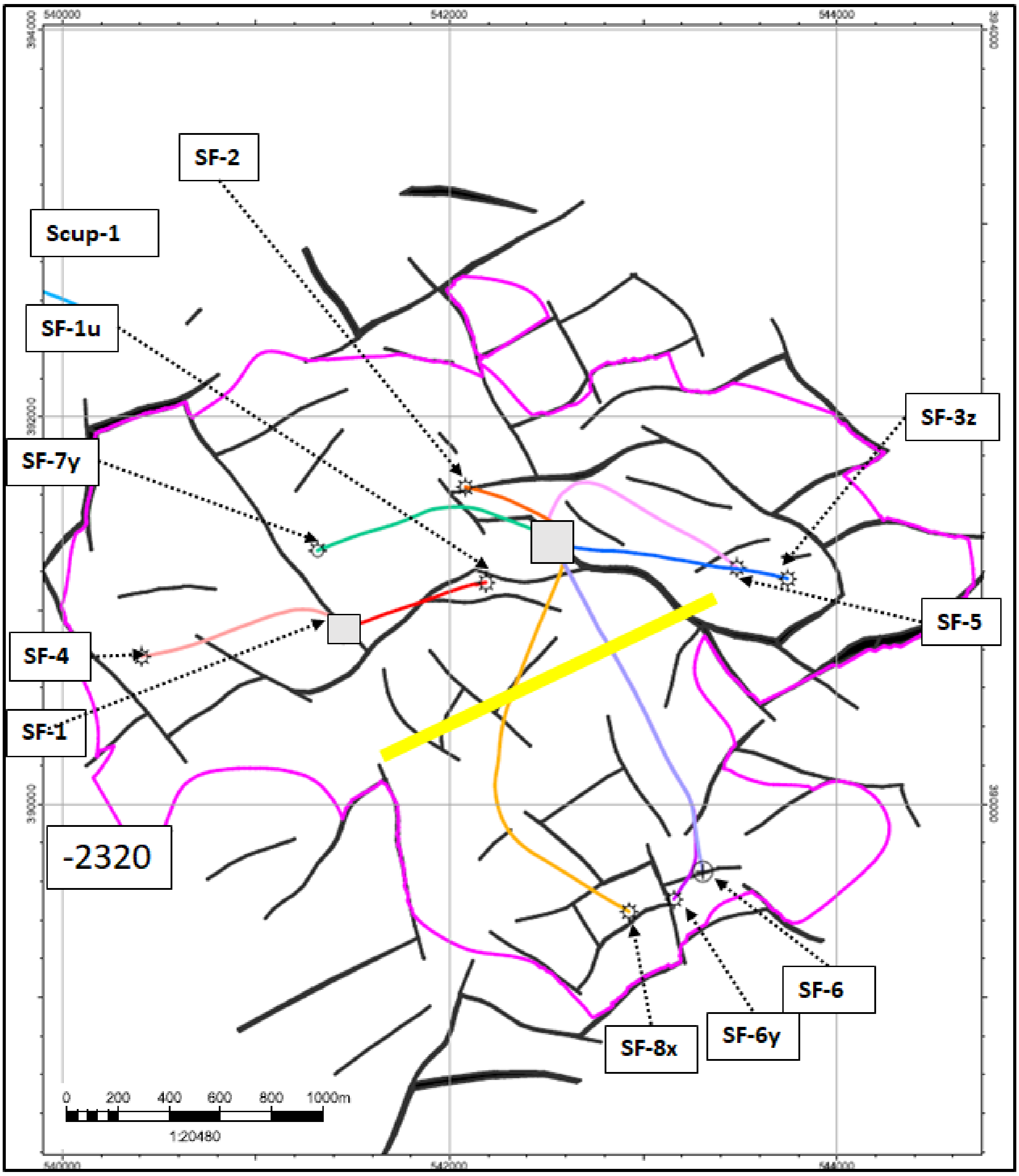

Figure 4 Surface Map of Saltfleetby Field, source OIL

Table 1-1 Summary of PEDL005 Licence and Extant Planning Permissions

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.
<u>Extant Planning permissions (AEWB/Saltfleetby Energy)</u>	
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.

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 but there is no evidence of pressure communication between the structures.

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 AEWB and verified by OIL.

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.

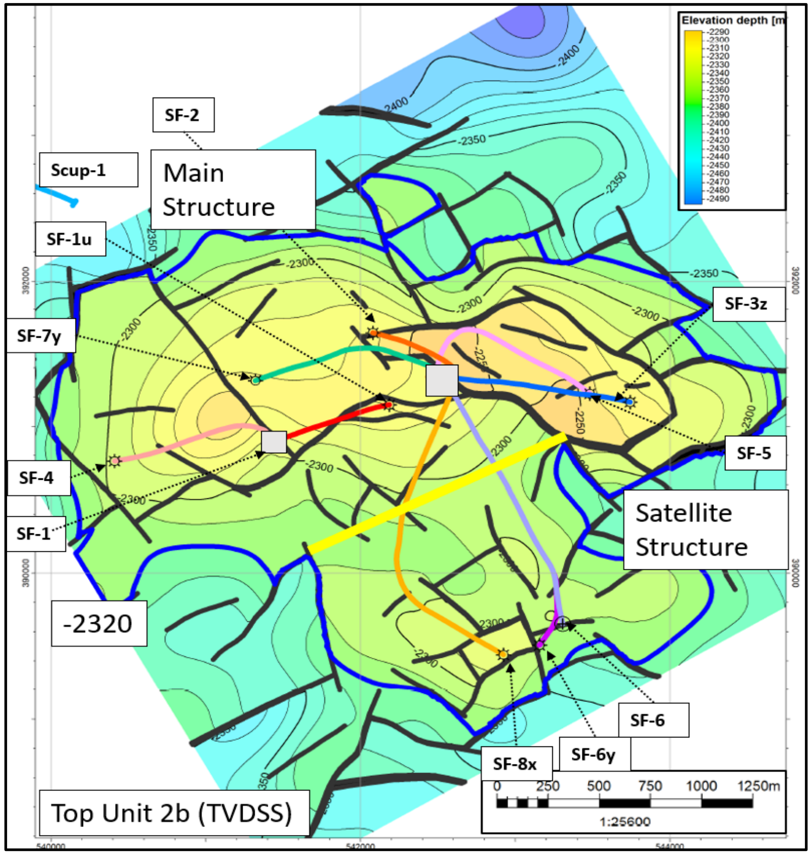

Figure 5 Structural Map of the Top of Westphalian Reservoir (Unit 2b).

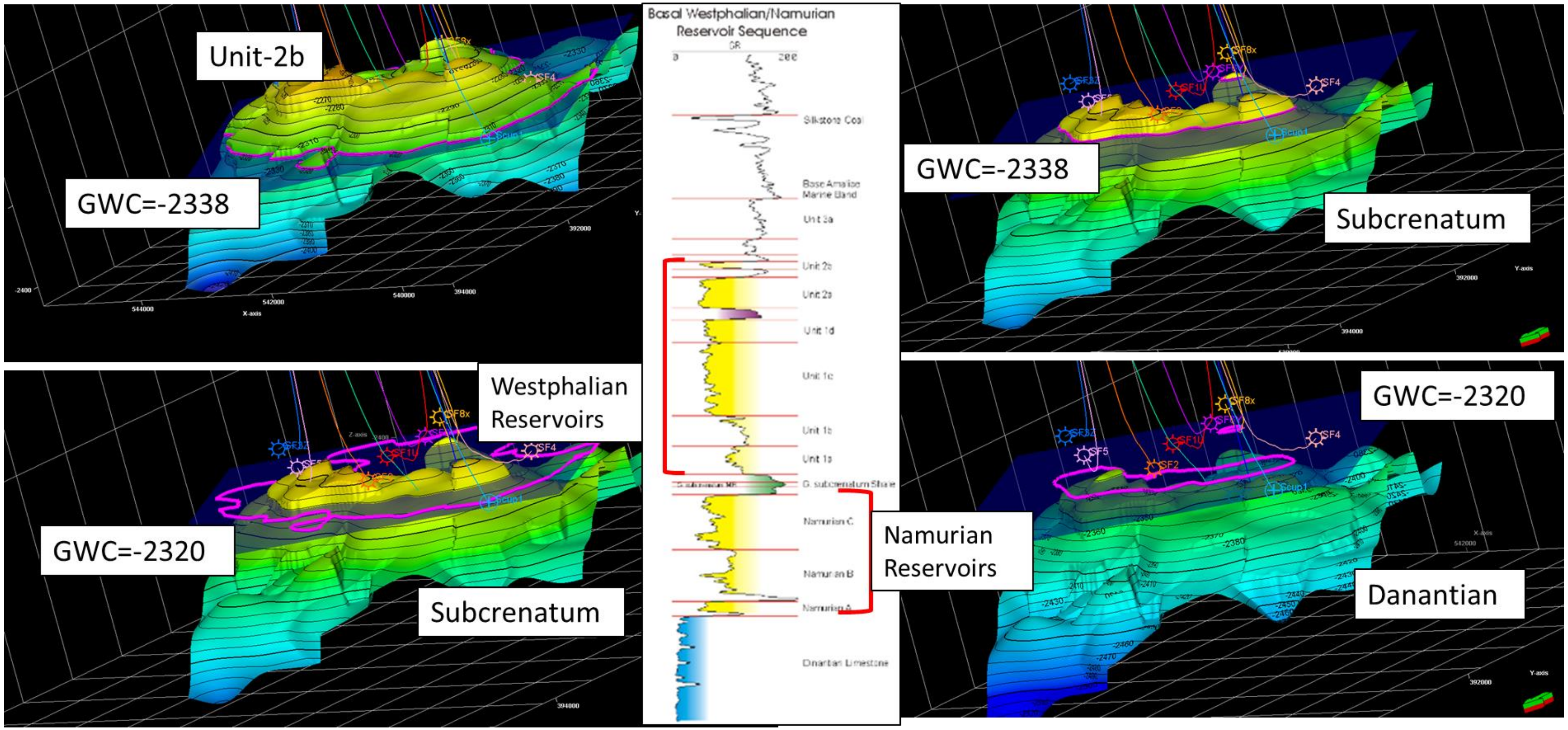

Figure 6 3D View of the stacked Westphalian and Namurian reservoirs (green arrow is north).

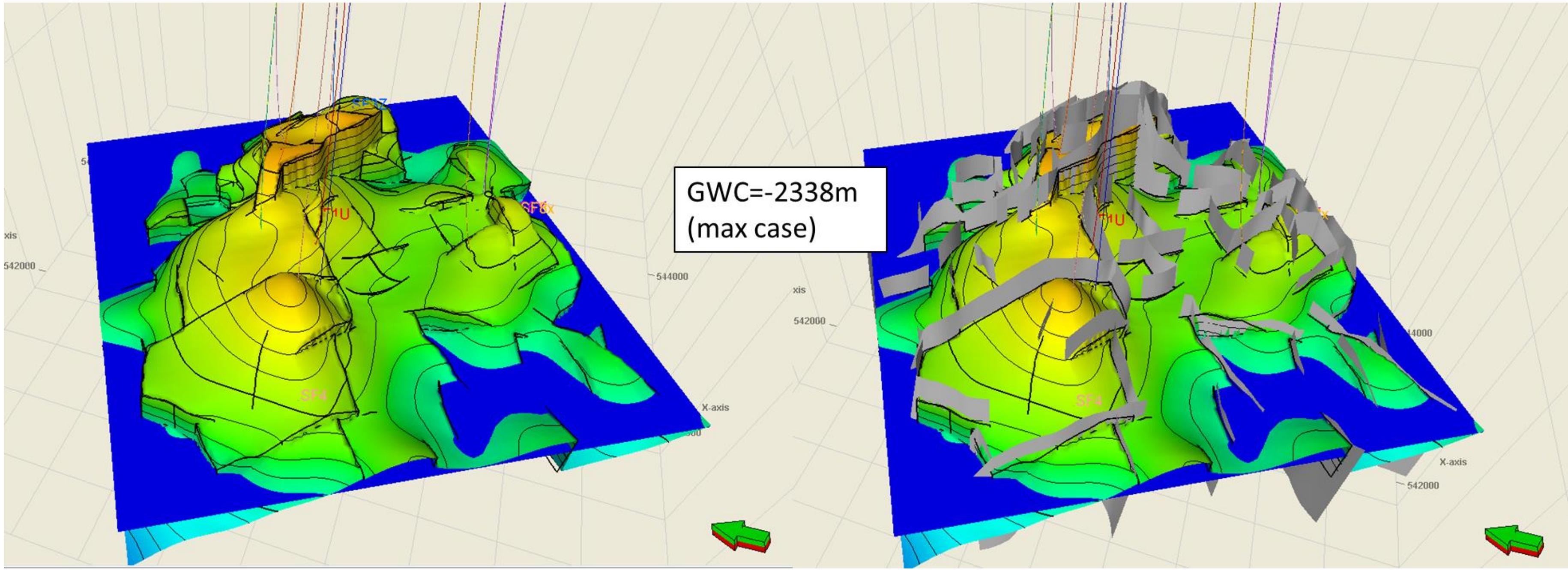

Figure 7 3D View of the Saltfleetby Gas Field structure at the top of Westphalian (Unit-2b) reservoir (green arrow is north).

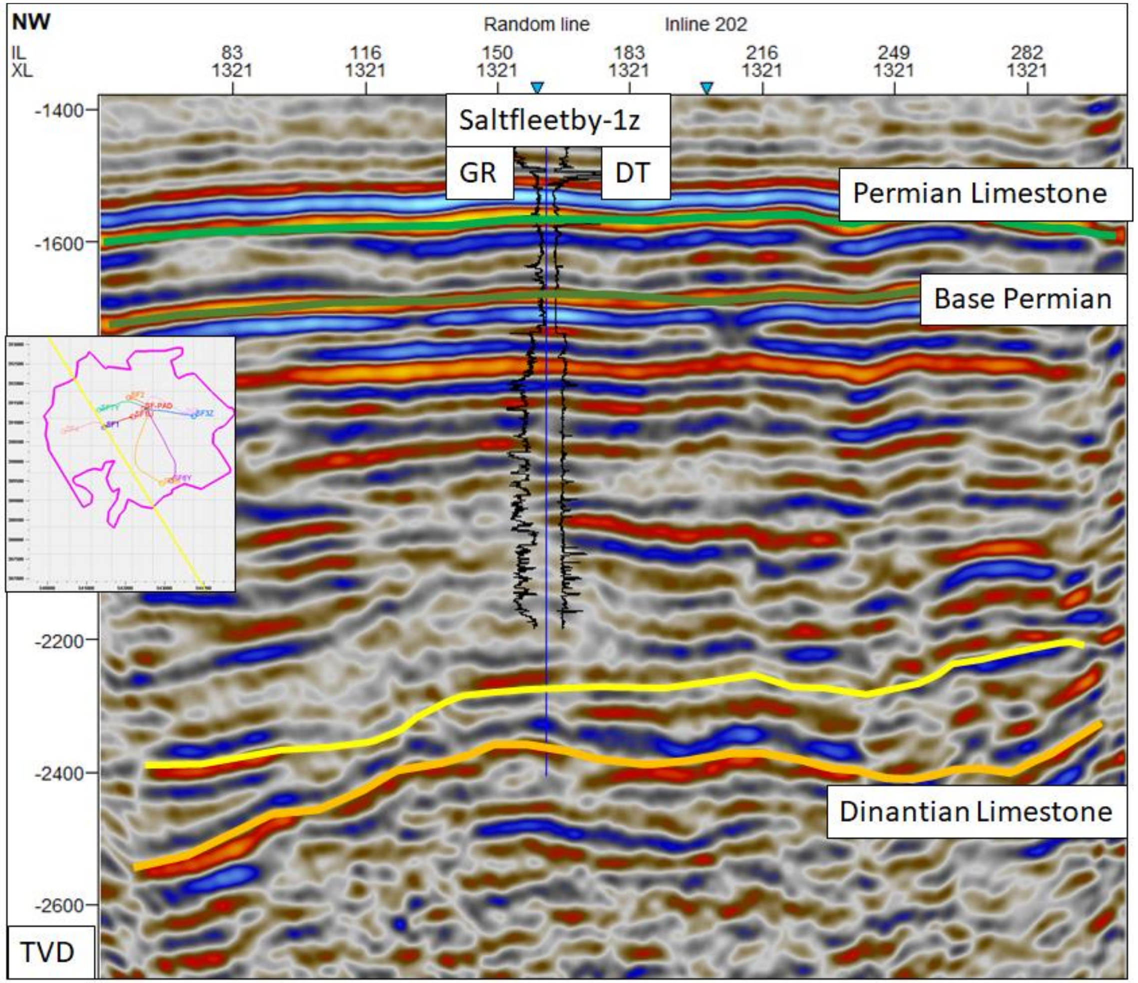

Figure 8 Well-Seismic tie. Seismic line in NS direction

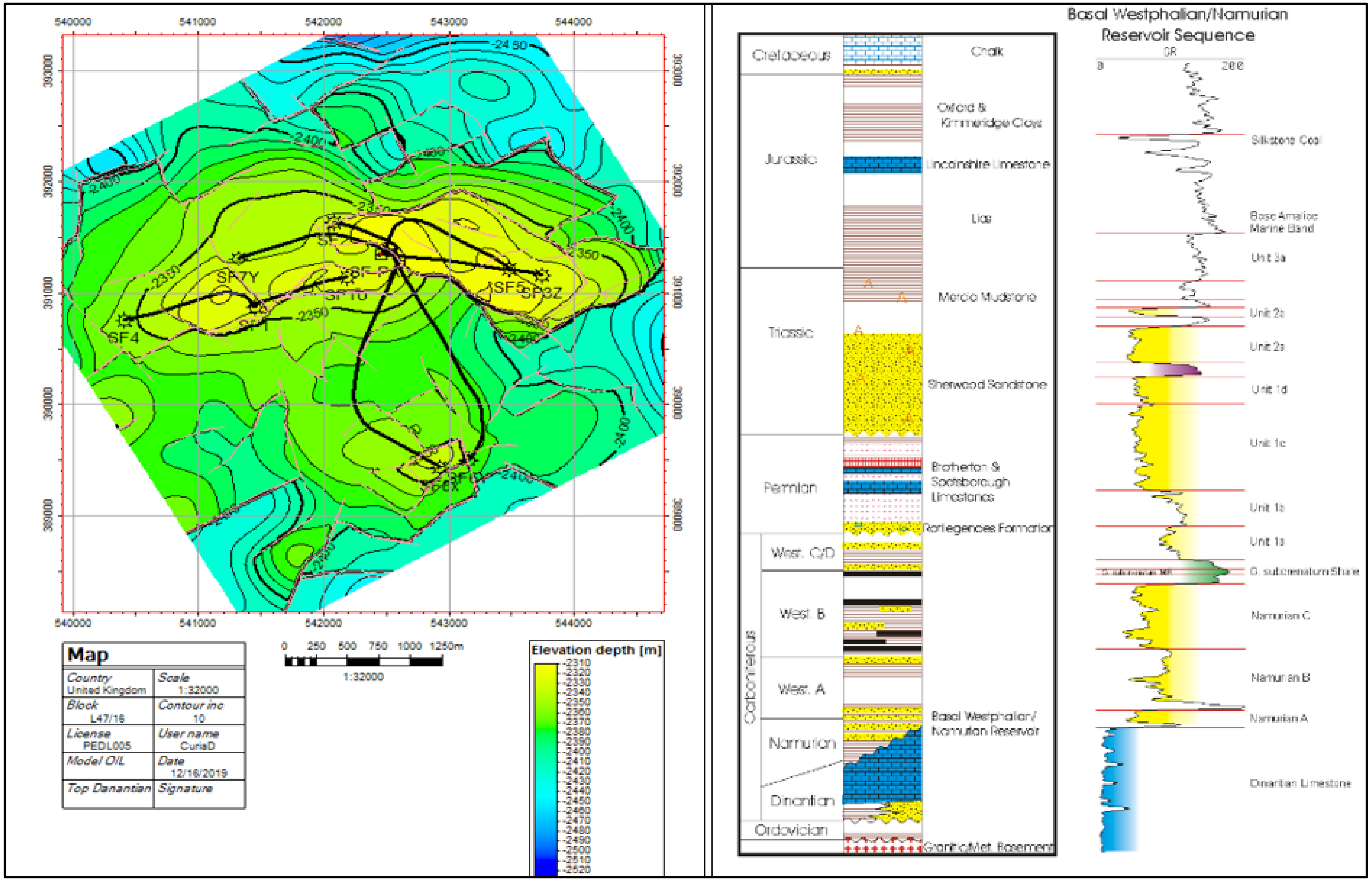

Figure 9 Structural at Top of Dinantian Limestone (Base of productive zone)

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

AEWB 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 between October 1st, 2020 and January 1st, 2021. The Board of AEWB has also resolved to drill a horizontal side-track from the existing SF5 well, and this is scheduled to increase total production from the field to about 10 MMSCFD about six months after First Gas.

Table 3-1 summarises the scope of the planning applications that will be submitted to Lincolnshire County Council required to restart, then ramp-up, production to 10 MMSCFD. Initially 4 to 5 MMSCFD of gas and liquids produced from two existing wells (SF2, SF4) will be processed at a new plant on site 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. AEWB has finalised its selection of the gas process design and is issuing tender documents for detailed engineering, procurement and construction of the plant and equipment. National Grid Gas plc ("NG") has committed to produce a Full Connection Offer by 4th May 2020 to connect AEWB's gas pipeline spur to the National Transmission System at Theddlethorpe Gas Terminal. AEWB and NG are finalising the detailed design for the connection.

Table 3-1 Planning Applications in Preparation, and Field Development Plan Submitted to OGA for Approval

Planning Application 1	An application for prior approval of development ancillary to mining operations for the installation of processing facilities at the Saltfleetby 'B' Site, together with metering, a refrigeration unit manifold, glycol dehydration unit and compressor, and some associated pipework and manifolding.
Planning Application 2	A planning application for the installation of an underground gas pipeline approximately 530m in length from a point on the existing Saltfleetby to Theddlethorpe pipeline at a location to the west of the Chrysaor Gas Terminal to the National Transmission System (NTS) connection point at Theddlethorpe operated by the National Grid.
Planning Application 3	Build and operate a horizontal side-track to well SF5, including drilling, testing and production phases.
OGA Approval.	Field Development Plan Submitted 18th February 2020.

Figure 10 to *Figure 15* present the proposed process schematic, plot plans and aerial views of the AEWB development plan.

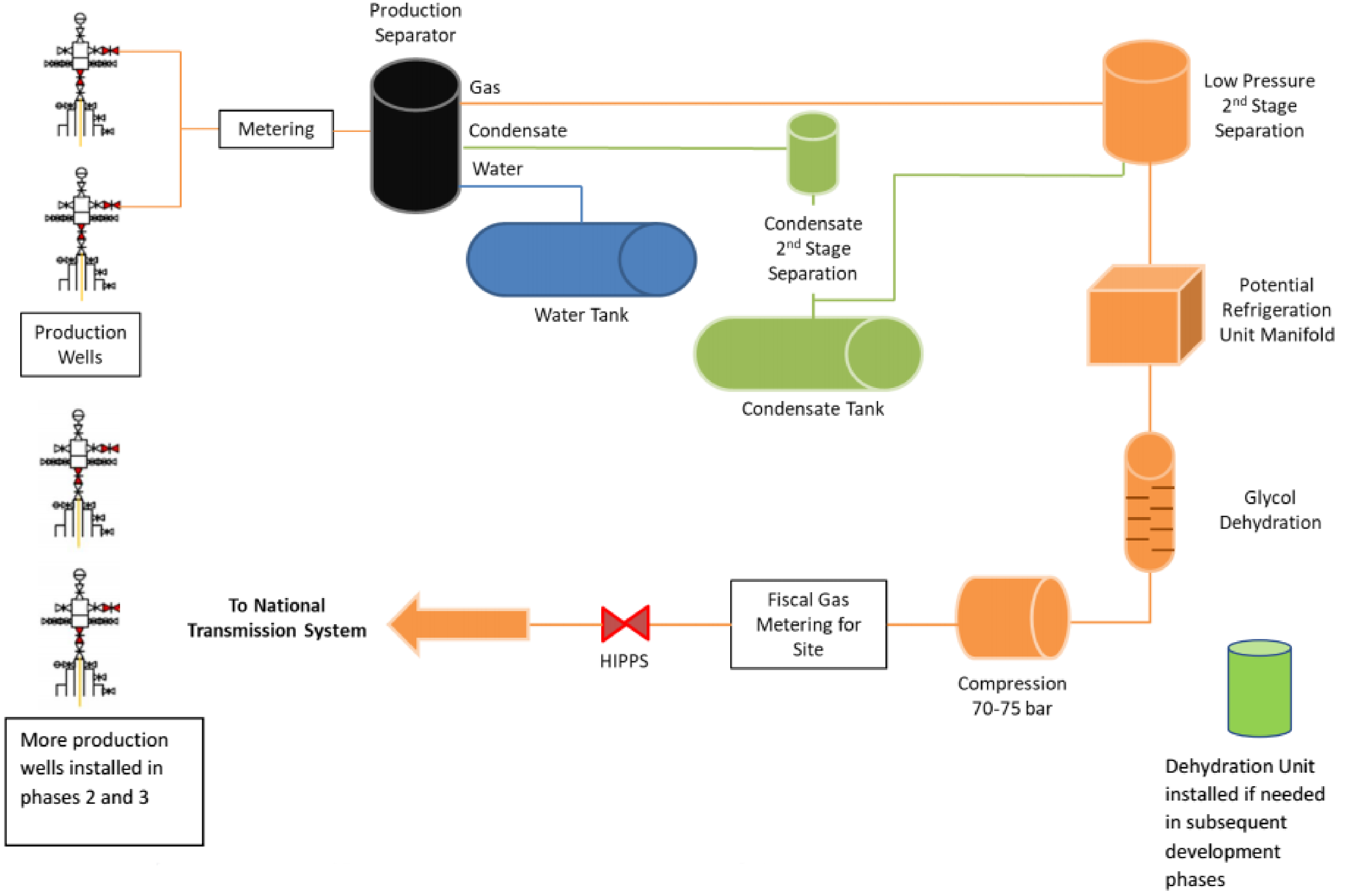

Figure 10 Proposed Gas and Liquid Processing Schematic. Source AEWB

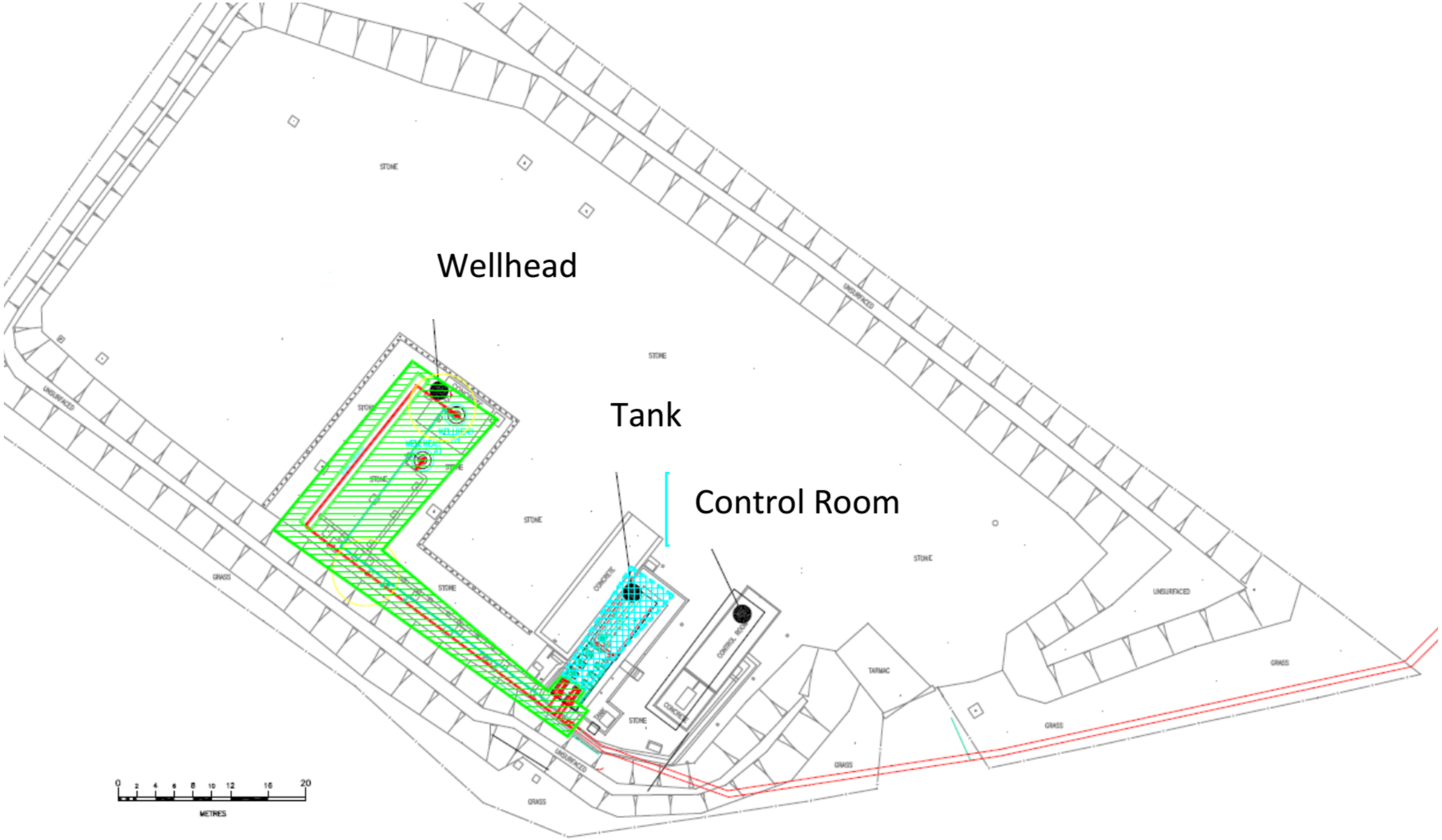

Figure 11 Site A: Existing equipment Layout. Source AEWB

Figure 12 Site A: Aerial photograph. Source AEWB

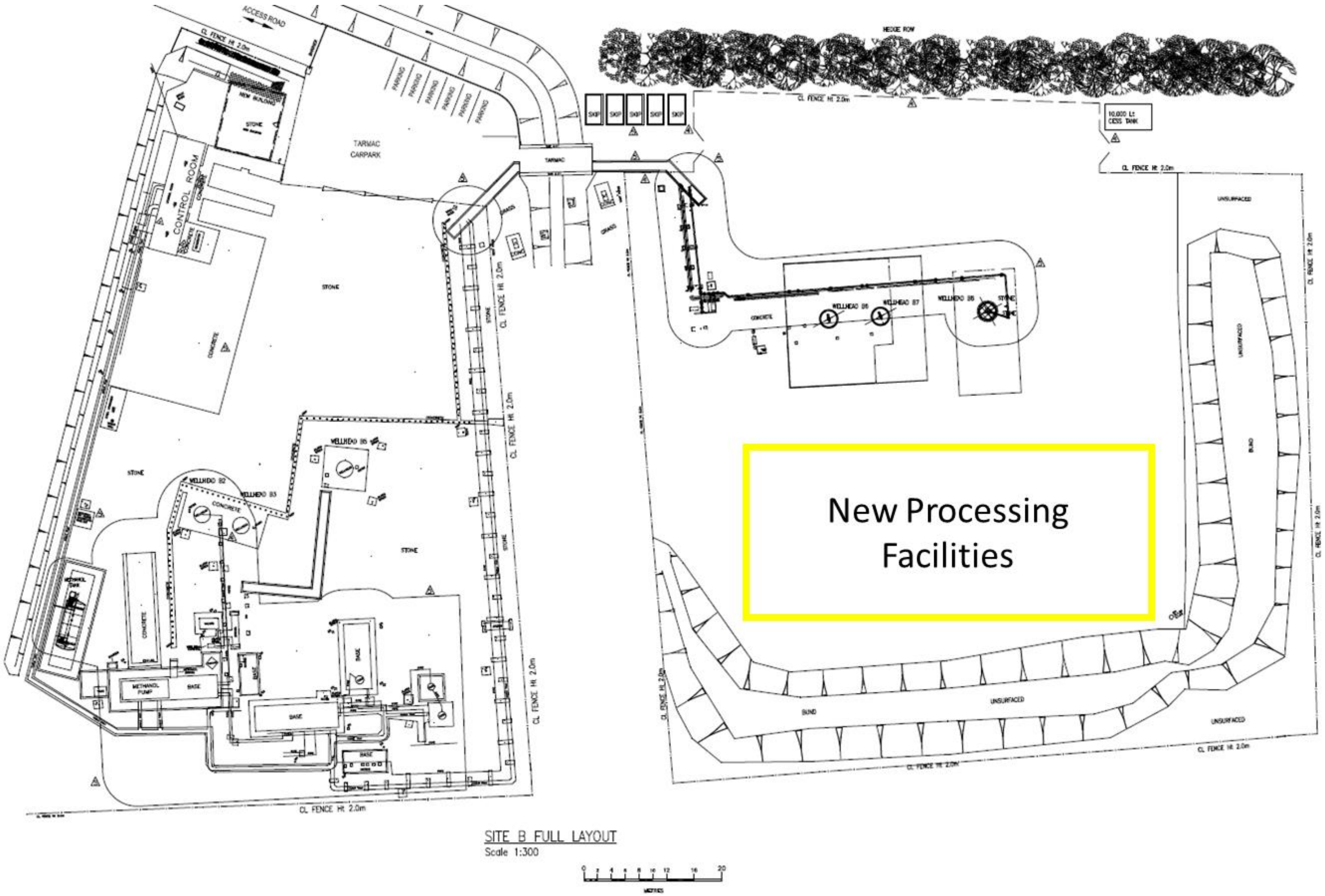

Figure 13 Site B: Existing and Proposed Equipment Layout. Source AEWB

Figure 14 Site B: Aerial Photograph. Source AEWB

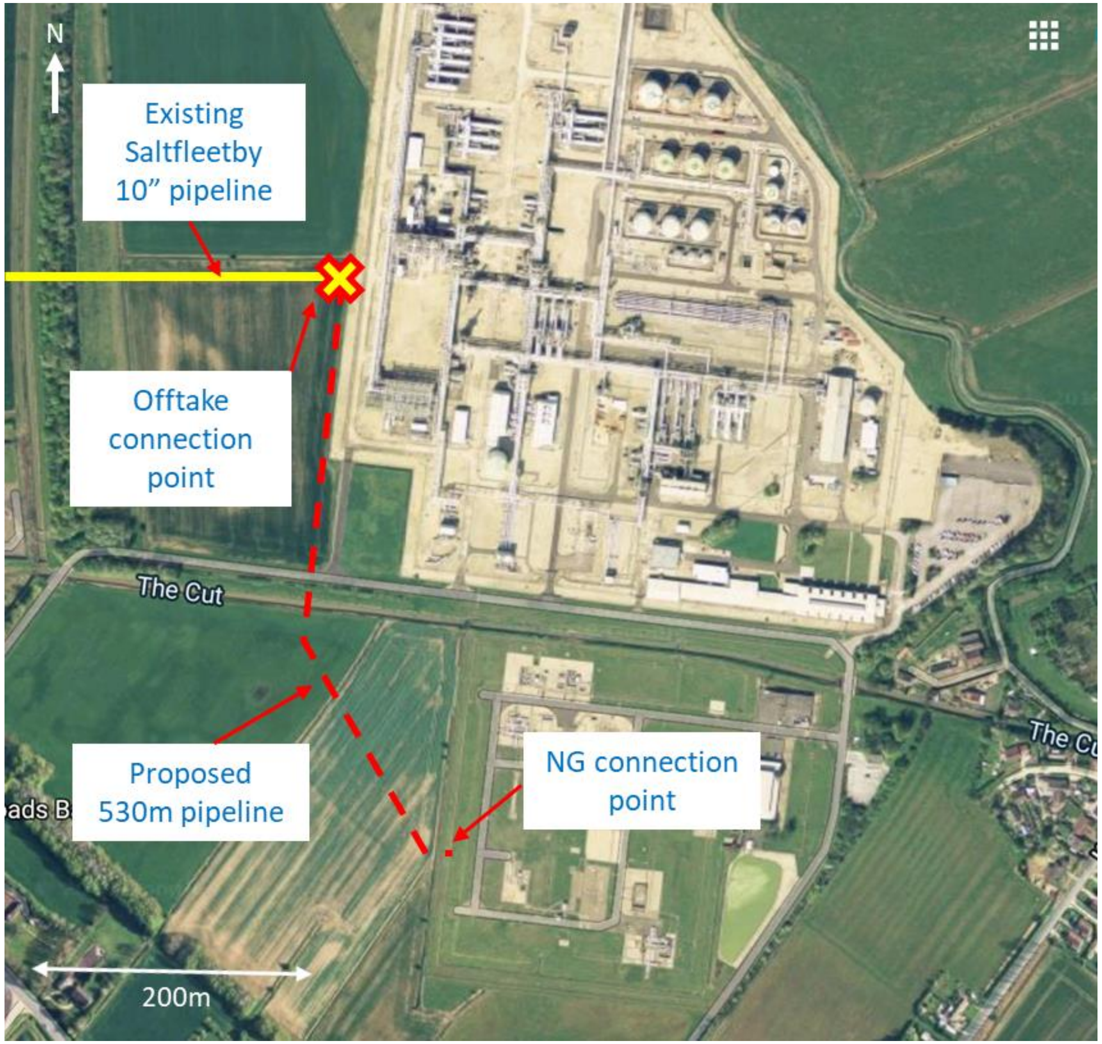

Figure 15 Proposed AEWB Pipeline Route from Conoco-Phillips Decommissioned Terminal to National Grid Connection Point. Source AEWB

4. Determination of Remaining Recoverable Sales Gas and Liquids

Table 4-1 & Table 4-2 present respectively the probability distribution of sales gas[6] initially in place ("GIIP") and condensate liquids initially in place ("CIIP") for

a. Main Field, Westphalian Reservoir (the only target for the Development Plan)
b. Main Field Namurian Reservoir
c. Southern Satellite, Westphalian Reservoir

GIIP and CIIP, and recoverable hydrocarbons were calculated as 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), and The Namurian C, B, A reservoir subunits. 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 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 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 of the Main Field: Figure 16 shows that 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 of production, it is more accurate than the Monte Carlo analysis which is based on log data from eight wells and a seismic survey. Therefore the material balance Low and Best estimates were preferred to the Monte carlo estimates.

There being no high estimate from the material balance, the Monte Carlo result was used: 150 BCF.

[6] 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.

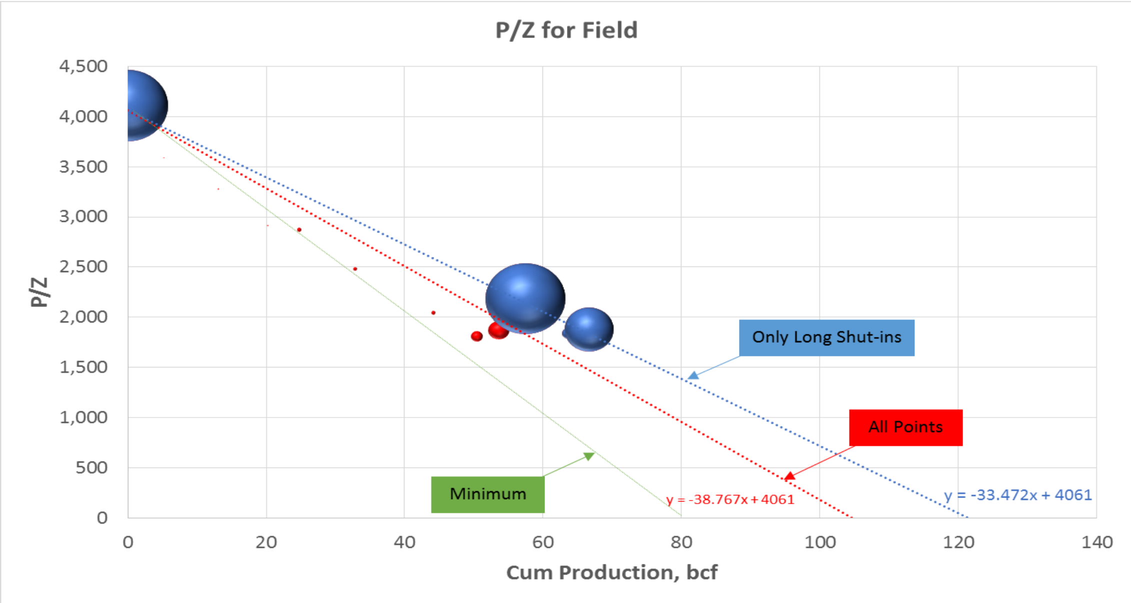

Figure 16 Extrapolation of historical pressure response (psia) to cumulative production (BCF): Main Field, Westphalian Reservoir only, source: AEWB

Table 4-1 : Saltfleetby Gas Field: Sales Gas Initially in Place: Gross, and Net Attributable to AEWB (51% WI)

Saltfleetby Field	**Gross**				**Net Attributable to AEWB**				**Operator**
Sales Gas	**P90**	**P50**	**P10**	**Mean**	**P90**	**P50**	**P10**	**Mean**	
	BCF	BCF	BCF	BCF	BCF	BCF	BCF	BCF	
Main Field Westphalian Reservoir	102	118	146	118	52	60	74	60	AEWB
Main Field Namurian Reservoir	3	5	8	5	1	3	4	3	AEWB
Southern Satellite Westphalian Reservoir	18	25	34	25	9	13	18	13	AEWB
Total Gas Initially in Place	**123**	**147**	**189**	**148**	**63**	**75**	**96**	**76**	

Effective Date: 28th February 2020
Source: Oilfield International

Table 4-2 Saltfleetby Gas Field: Condensate Liquids Initially in Place: Gross, and Net Attributable to AEWB (51% WI)

Saltfleetby Field	Gross				Net Attributable to AEWB				Operator
Condensate Liquids	**P90**	**P50**	**P10**	**Mean**	**P90**	**P50**	**P10**	**Mean**	
	M STB	M STB	M STB	M STB	M STB	M STB	M STB	M STB	
Main Field Westphalian Reservoir	3,502	4,046	5,025	4,041	1786	2064	2563	2061	AEWB
Main Field Namurian Reservoir	93	173	286	184	47	88	146	94	AEWB
Southern Satellite Westphalian Reservoir	591	847	1,188	874	301	432	606	446	AEWB
Total Condensate Initially in Place	**4,185**	**5,067**	**6,498**	**5,099**	**2,135**	**2,584**	**3,314**	**2,600**	

Comma Separator is Thousands

Effective Date: 28th February 2020
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: 28th February 2020
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, and Net Attributable to AEWB (51% WI)

Saltfleetby Field	Gross				Net Attributable to AEWB				Operator
Sales Gas	**P90**	**P50**	**P10**	**Mean**	**P90**	**P50**	**P10**	**Mean**	
	BCF	BCF	BCF	BCF	BCF	BCF	BCF	BCF	
Main Field Westphalian Reservoir	39	55	83	55	20	28	42	28	AEWB
Main Field Namurian Reservoir	1	4	7	4	1	2	3	2	AEWB
Southern Satellite Westphalian Reservoir	16	23	32	23	8	12	16	12	AEWB
Total Remaining Gas in Place	**56**	**81**	**122**	**82**	**29**	**41**	**62**	**42**	

Effective Date: 28th February 2020
Source: Oilfield International

Table 4-5 Saltfleetby Gas Field: Remaining Condensate Liquids in Place: Gross, and Net Attributable to AEWB (51% WI)

Saltfleetby Field	**Gross**				**Net Attributable to AEWB**				**Operator**
Condensate Liquids	**P90**	**P50**	**P10**	**Mean**	**P90**	**P50**	**P10**	**Mean**	
	M STB	M STB	M STB	M STB	M STB	M STB	M STB	M STB	
Main Field Westphalian Reservoir	2,471	3,015	3,994	3,010	1260	1538	2037	1535	AEWB
Main Field Namurian Reservoir	64	144	256	155	32	73	131	79	AEWB
Southern Satellite Westphalian Reservoir	556	813	1,154	840	284	415	588	428	AEWB
Total Remaining Condensate Liquids in Place	**3,091**	**3,972**	**5,404**	**4,005**	**1,577**	**2,026**	**2,756**	**2,042**	

Comma Separator is Thousands

Effective Date: 28th February 2020
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	P10	Mean		P90	P50	P10	Mean
	%	%	%	%		%	%	%	%
Main Field Westphalian Reservoir	61%	53%	43%	53%		29%	25%	21%	26%
Main Field Namurian Reservoir	56%	30%	19%	29%		31%	17%	10%	16%
Southern Satellite Westphalian Reservoir	12%	8%	6%	8%		6%	4%	3%	4%

Effective Date: 28th February 2020
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**	**P10**	**Mean**	**P90**	**P50**	**P10**	**Mean**
	%	%	%	%	%	%	%	%
Main Field Westphalian Reservoir	79%	80%	81%	80%	33%	30%	27%	30%
Main Field Namurian Reservoir	68%	68%	69%	69%	37%	34%	33%	34%
Southern Satellite Westphalian Reservoir	79%	80%	81%	80%	33%	30%	27%	30%

Effective Date: 28th February 2020

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	**P90**	**P50**	**P10**	**Mean**	**P90**	**P50**	**P10**	**Mean**	
	BCF	BCF	BCF	BCF	BCF	BCF	BCF	BCF	
Main Field Westphalian Reservoir	18	32	55	32	9	16	28	16	AEWB
Main Field Namurian Reservoir	0	2	4	2	0	1	2	1	AEWB
Southern Satellite Westphalian Reservoir	12	18	26	18	6	9	13	9	AEWB
Total Remaining Recoverable Gas	**30**	**51**	**85**	**52**	**15**	**26**	**43**	**27**	

Effective Date: 28th February 2020
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	**P90**	**P50**	**P10**	**Mean**	**P90**	**P50**	**P10**	**Mean**	
	M STB	M STB	M STB	M STB	M STB	M STB	M STB	M STB	
Main Field Westphalian Reservoir	107	190	330	188	55	97	168	96	AEWB
Main Field Namurian Reservoir	5	30	64	33	3	15	33	17	AEWB
Southern Satellite Westphalian Reservoir	158	221	288	229	80	113	147	117	AEWB
Total Remaining Condensate Liquids in Place	**270**	**441**	**681**	**451**	**138**	**225**	**347**	**230**	

Effective Date: 28th February 2020
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 SF5 horizontal side-track. Table 5-1 and Figure 1 present the P90, P50, and P10 production profiles for the Development Plan. These have been generated by AEWB and verified by OIL.

Table 5-1 Gas, Condensate and Water Production Profiles

Production Profiles									
	Gas, MMscf/d sales			Condensate, bbl/d			Water, bbl/d		
	P(90)	P(50)	P(10)	P(90)	P(50)	P(10)	P(90)	P(50)	P(10)
Draining, BCF	55	121	150	55	121	150	150	121	150
Wells, #	3	3	3	3	3	3	3	3	3
Reserves, BCF	18.02	31.80	55.20						
C/W, MMbbls				0.107	0.190	0.330	0.037	0.065	0.113
2020	0.00	1.24	1.24	0.00	11.64	11.66	0.00	3.19	3.21
2021	6.08	6.08	6.08	55.11	55.55	56.38	14.55	14.37	14.48
2022	9.69	9.69	9.69	77.08	82.51	86.43	19.92	19.81	20.00
2023	9.69	9.69	9.69	63.59	74.92	82.07	19.20	19.68	19.91
2024	8.84	9.69	9.69	46.14	67.32	77.71	17.67	19.09	19.83
2025	5.34	9.50	9.69	22.34	58.61	73.36	12.04	19.02	19.75
2026	3.85	8.20	9.69	13.53	44.71	69.00	8.36	16.38	19.66
2027	2.67	6.14	9.69	8.10	29.88	64.65	4.66	13.33	18.81
2028	2.19	4.98	9.69	5.89	21.96	60.29	3.84	11.38	19.45
2029	0.97	4.40	9.60	2.38	17.73	55.40	1.69	10.03	19.22
2030	0.00	3.85	8.78	0.00	14.21	46.93	0.00	8.61	17.55
2031	0.00	2.91	7.91	0.00	9.95	39.22	0.00	5.09	15.79
2032	0.00	2.65	6.50	0.00	8.46	30.04	0.00	4.63	13.79
2033	0.00	2.42	5.33	0.00	7.22	23.15	0.00	4.22	12.20
2034	0.00	2.21	4.93	0.00	6.18	20.23	0.00	3.86	11.26
2035	0.00	2.02	4.56	0.00	5.31	17.73	0.00	3.53	10.41
2036	0.00	1.40	4.23	0.00	3.48	15.57	0.00	2.44	9.64
2037	0.00	0.00	3.93	0.00	0.00	13.71	0.00	0.00	8.94
2038	0.00	0.00	3.20	0.00	0.00	10.64	0.00	0.00	6.10
2039	0.00	0.00	2.86	0.00	0.00	9.11	0.00	0.00	5.00
2040	0.00	0.00	2.70	0.00	0.00	8.24	0.00	0.00	4.72
2041	0.00	0.00	2.55	0.00	0.00	7.46	0.00	0.00	4.45
2042	0.00	0.00	2.41	0.00	0.00	6.78	0.00	0.00	4.21
2043	0.00	0.00	2.27	0.00	0.00	6.16	0.00	0.00	3.98
2044	0.00	0.00	2.15	0.00	0.00	5.60	0.00	0.00	3.76
2045	0.00	0.00	2.04	0.00	0.00	5.11	0.00	0.00	3.56

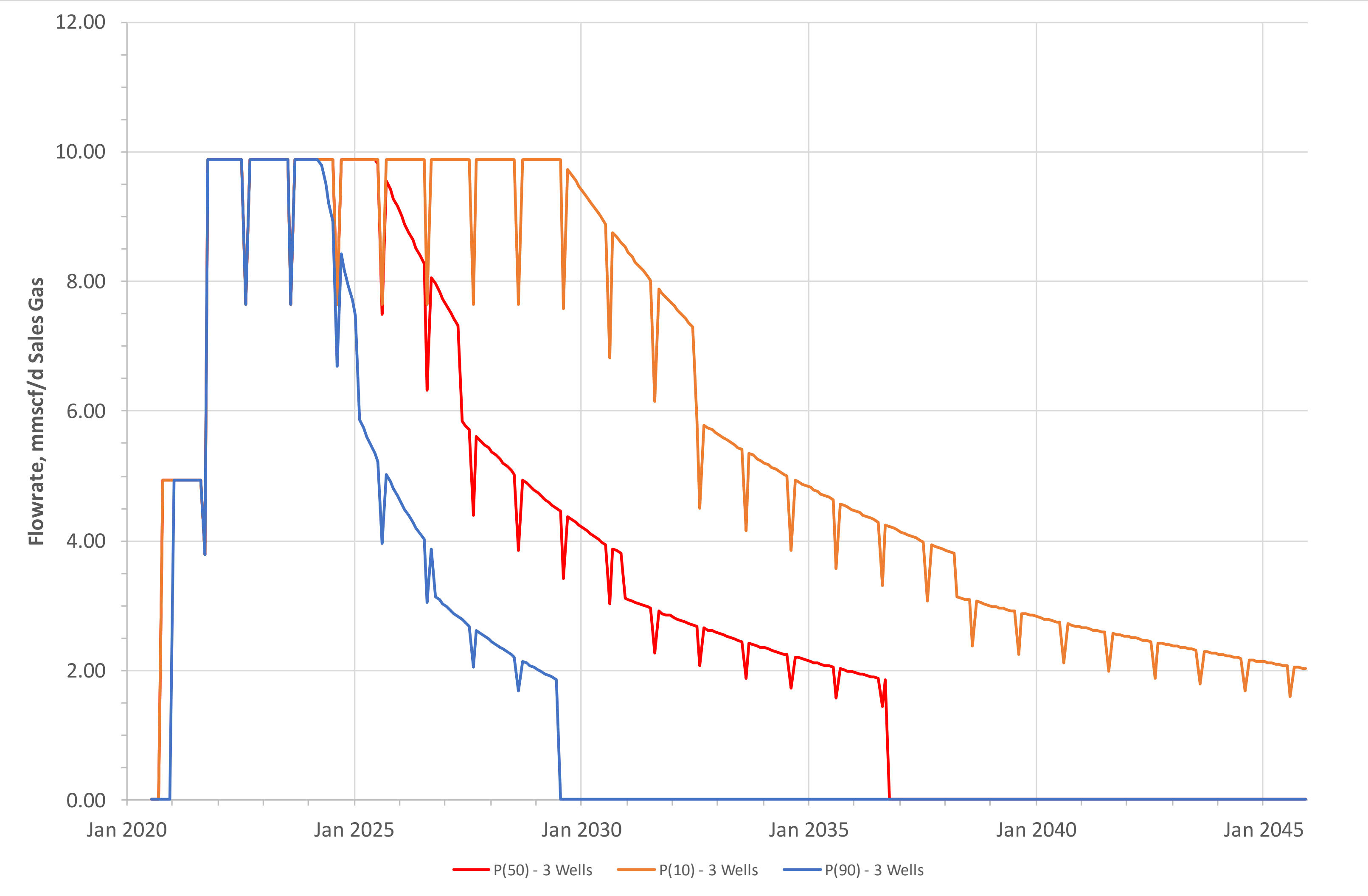

Figure 17 P90, P50, P10 Production Profiles for Sales Gas. Source AEWB, verified by OIL

6. Discounted Cash Flow Valuation

Oil has estimated discounted net present values at 10% discount factor for the three 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 6-12 present annual cash flow calculations and the post-tax NPV10 for the P90, P50, P10 development plan production profiles. The commodity prices used were from 28th February 2020 and the cash flows were discounted to January 1st 2020, using mid-year discounting.

AEWB is carrying a range of capital cost estimates to achieve First Gas before January 1st, 2021. Table 6-1 refers: Low: £1.83m, Most Likely: £2.79m; High: £3.81m, of which £2.5m is payable by Saltfleetby Energy (or £1.83m for Low case, leaving a balance of £0.67m for 2021 capex). AEWB estimates the cost of a horizontal sidetrack to well SF5 in 2021 to be £2.36m, which will be split 51%/49% AEWB/Saltfleetby Energy, except in the Low case where AEWB would contribute £0.86m: £2.36m-£0.67m = £1.69m of which 51%= £0.86m.

Table 6-1 Capex assumptions for Cash Flow Forecasts

Cost Centre	**Units**	**Low**	**Most Likely**	**High**
Capex				
Process Plant Q3 2020	GB£ m	£0.93	£1.30	£1.73
Pipeline Spur Q3 2020	GB£ m	£0.40	£0.50	£0.88
NationalGrid Connection 2020	GB£ m	£0.50	£0.99	£1.20
Saltfleetby Energy Share of Costs 2020	GB£ m	£2.50	£2.50	£2.50
Well SF5 Sidetrack Q1 2021	GB£ m	£2.36	£2.36	£2.36
Abandonment Capex (end of life)	GB£ m	£2.00	£2.00	£2.00

Note that the High-Cost estimate is used in the Proved (1P) Cash flow forecast; the Most Likely in the Proved + Probable (2P) forecast and the Low-Cost Estimate in the Proved + Probable + Possible (3P) forecast; Table 6-2 refers.

Table 6-2 Capex liability attributable to AEWB

Year	1P	2P	3P
2020	£1.31	£0.29	£0.00
2021	£1.20	£1.20	£0.86

The Process Plant costs were supplied by AEWB based on confidential negotiations that it is holding with a supplier of second-hand process and metering skids; and a hookup and commissioning contractor. OIL is not able to verify the accuracy of AEWB's range of costs for the Process Plant. However, OIL has reviewed the firm quotes from CNG and nationalgrid.

Opex and economics assumptions are presented in Table 6-3.

Table 6-3 Opex and Economics assumptions for Cash Flow Forecasts

Opex		Single Estimate
Fixed Opex inc Equipment Lease Costs	GB£ m pa	£1.39
G&A (Field, and Head Office allocation)	GB£ m pa	£0.52
Condensate Haulage tariff	£/bbl	£4.00
Produced Water Disposal tariff	£/bbl	£20.00
Commodity		
Sales Gas Discount to NBP	%	1.50%
Condensate Discount to Brent	£/bbl	£10.00
National Gas Grid Capacity Charges	Refer Section 6.1	
National Gas Grid Monthly Charges	Refer Section 6.2	
Exogenous		
Inflation	% pa	2%
Commodity Price Inflation	% pa after end of forward curve	2%
Taxation		
Corporation Tax Rate	% of taxable base	30%
Supplementary Charge	% of taxable base	10%
Tax Loss Carry Forward Sept 30 2019	GB £m	£15.64

6.1. Annual entry capacity and high-pressure metering charges at the Theddlethorpe Sales Point

Table 6-4 presents the entry capacity and metering charges published in The Notice of Gas Transmission Transportation charges, National Grid, effective 1st October 2019.

Table 6-4 Annual Capacity Charges for Entry to NTS at Theddlethorpe

Theddlethorpe Monthly System Entry Capacity (MSCE)	**Theddlethorpe Monthly System Entry Capacity (MSCE)**	**High pressure Metering Installation <8.6 MMSCFD**	**High pressure Metering Installation 8.6 -12.6 MMSCFD**
p/kWh/day	£/MMSCFD pa	£ pa	£ pa
0.0134	15768	15382	16320

The MSCE charge was converted from pence/kWh/d to £/MMSCFD pa using the calculated gas calorific value of 1100 BTU/SCF and the conversion constant: 1Th = 29.30711 kWh.

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

Table 6-5 presents a forecast of the 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 10th February 2020 until 2026. After 2026, the price is escalated by 2% pa thereafter.

The NTS Theddlethorpe Transportation Owner and System Owner (TO+SO) entry charge, currently 1.668 pence/Therm, is subtracted from the NBP price. The entry charge is escalated by 2% pa.

The off-taker's proposed charge of 1.5% is applied to the NBP price net of the TS & OS charge. The resulting sales price to AEWB is converted from pence/Therm to £/MMSCF again using gas calorific value of 1100 BTU/SCF.

6.3. Calculation of Condensate Sales Price forecast at Immingham Refinery

The condensate price forecast was based on the Brent Forward Curve minus a £10/bbl discount; Table 6-6 refers. A haulage charge of £4/bbl is accounted for separately in the economic model.

Table 6-5 Calculation of Gas price at Sales Point £/MMSCF

Year	NBP FWD Pence/Therm (Feb 28, 2020)	Transportation and System Owner entry charges	Off-taker's charge (1.5% of NBP-MSCE)	NBP FWD Pence/Th at Sales Point	£/MMSCF at Sales Point (11000 Th/MMSCF)	Gas price Escalation Assumption	MSCE Cost Escalation
	Pence/Therm	Pence/Therm	Pence/Therm	Pence/Therm	11000	% pa	% pa
2020 Oct-Dec	32.49p	1.67p	0.46p	30.36p	£3,339	FWD Curve	2%
2021	34.92p	1.70p	0.50p	32.72p	£3,599	FWD Curve	2%
2022	39.33p	1.73p	0.56p	37.03p	£4,073	FWD Curve	2%
2023	42.08p	1.77p	0.60p	39.70p	£4,368	FWD Curve	2%
2024	41.41p	1.81p	0.59p	39.01p	£4,291	FWD Curve	2%
2025	42.24p	1.84p	0.61p	39.79p	£4,377	FWD Curve	2%
2026	38.90p	1.88p	0.56p	36.46p	£4,011	FWD Curve	2%
2027					£4,091	2%	
2028					£4,173	2%	
2029					£4,256	2%	
2030					£4,341	2%	
2031					£4,428	2%	
2032					£4,517	2%	
2033					£4,607	2%	
2034					£4,699	2%	
2035					£4,793	2%	
2036					£4,889	2%	
2037					£4,987	2%	
2038					£5,087	2%	

Table 6-6 Calculation of Condensate Price £/bbl

	Nymex Brent FWD Curve 28/02/20				
Year	Forward Curve $/bbl	Brent Escalation Assumption % pa	Condy Premium / Discount to Brent $/bbl	Exchange rate $/£ (28/02/20)	Condensate £/bbl
			£10.00		
2020 Oct-Dec	$50.13		-$12.76	$1.28	£29.30
2021	$51.05		-$12.76	$1.28	£30.02
2022	$52.12		-$12.76	$1.28	£30.86
2023	$52.98		-$12.76	$1.28	£31.54
2024	$53.76		-$12.76	$1.28	£32.15
2025	$54.55		-$12.76	$1.28	£32.77
2026	$55.00		-$12.76	$1.28	£33.12
2027	$55.47		-$12.76	$1.28	£33.49
2028	$55.87		-$12.76	$1.28	£33.80
2029	$56.02		-$12.76	$1.28	£33.92
2030	$57.14	2%	-$13.01	$1.28	£34.60
2031	$58.28	2%	-$13.27	$1.28	£35.29
2032	$59.45	2%	-$13.54	$1.28	£36.00
2033	$60.64	2%	-$13.81	$1.28	£36.72
2034	$61.85	2%	-$14.08	$1.28	£37.45
2035	$63.09	2%	-$14.36	$1.28	£38.20
2036	$64.35	2%	-$14.65	$1.28	£38.96
2037	$65.64	2%	-$14.94	$1.28	£39.74
2038	$66.95	2%	-$15.24	$1.28	£40.54
2039	$68.29	2%	-$15.55	$1.28	£41.35
2040	$69.65	2%	-$15.86	$1.28	£42.17
2041	$71.05	2%	-$16.18	$1.28	£43.02
2042	$72.47	2%	-$16.50	$1.28	£43.88
2043	$73.92	2%	-$16.83	$1.28	£44.76
2044	$75.40	2%	-$17.17	$1.28	£45.65
2045	$76.90	2%	-$17.51	$1.28	£46.56

Table 6-7 P90 Cash Flow Forecast £m; effective date 28th February 2020

	Gross									**AEWB Net**			
Year	Sales Gas	Condensate Liquids	Future Gross Revenue	Operating Expenses	Equipment Lease Costs	Abandon Costs	Capital Costs	Production wells to be drilled	Pre-Tax Future Net Revenue	Pre-Tax Future Net Revenue	Corporate Taxes	Post Tax Future Net Revenue	Post tax Net Present Value at 10% Mid-Year
	BCF	MSTB	£m	£m	£m	£m	£m	No.	£m	£m	£m	£m	£m
2020				£1.6			£3.8		-£5.4	-£2.1		-£2.1	-£2.1
2021	2.22	20.1	£8.6	£2.2			£2.4	1	£4.0	£2.1		£2.1	£2.0
2022	3.54	28.2	£15.3	£2.3					£13.0	£6.6		£6.6	£5.7
2023	3.54	23.2	£16.2	£2.1					£14.1	£7.2		£7.2	£5.7
2024	3.23	16.9	£14.4	£1.9					£12.5	£6.4	£1.5	£4.9	£3.5
2025	1.95	8.2	£8.8	£1.9					£6.9	£3.5	£1.4	£2.1	£1.4
2026	1.41	4.9	£5.8	£1.8					£4.0	£2.0	£0.8	£1.2	£0.7
2027	0.97	3.0	£4.1	£1.8					£2.3	£1.2	£0.5	£0.7	£0.4
2028	0.80	2.2	£3.4	£1.8					£1.6	£0.8	£0.3	£0.5	£0.2
2029				£0.6		£2.4			-£3.1	-£1.6		-£1.6	-£0.7
Total	18	107	£76.6	£18.2	£0.0	£2.4	£6.2	£1.0	£49.8	£26.0	£4.5	£21.5	£16.7

Table 6-8 P50 Cash Flow Forecast £m; effective date 28th February 2020

	Gross									**AEWB Net**			
Year	Sales Gas	Condensate Liquids	Future Gross Revenue	Operating Expenses	Equipment Lease Costs	Abandon Costs	Capital Costs	Production wells to be drilled	Pre-Tax Future Net Revenue	Pre-Tax Future Net Revenue	Corporate Taxes	Post Tax Future Net Revenue	Post tax Net Present Value at 10% Mid-Year
	BCF	MSTB	£m	£m	£m	£m	£m	No.	£m	£m	£m	£m	£m
2020	0.45	4.3	£1.6	£1.7			£2.8		-£2.9	-£0.3		-£0.3	-£0.3
2021	2.22	20.3	£8.6	£2.2			£2.4	1	£4.0	£2.1		£2.1	£2.0
2022	3.54	30.1	£15.4	£2.3					£13.0	£6.6		£6.6	£5.8
2023	3.54	27.4	£16.3	£2.1					£14.2	£7.2		£7.2	£5.7
2024	3.54	24.6	£16.0	£2.0					£13.9	£7.1	£2.3	£4.8	£3.4
2025	3.47	21.4	£15.9	£2.1					£13.8	£7.1	£2.8	£4.2	£2.8
2026	3.00	16.3	£12.6	£2.0					£10.5	£5.4	£2.2	£3.2	£1.9
2027	3.54	10.9	£9.5	£2.0					£7.6	£3.9	£1.5	£2.3	£1.2
2028	1.82	8.0	£7.9	£2.0					£5.9	£3.0	£1.2	£1.8	£0.9
2029	1.61	6.5	£7.1	£2.0					£5.1	£2.6	£1.0	£1.6	£0.7
2030	1.40	5.2	£6.3	£2.0					£4.3	£2.2	£0.9	£1.3	£0.5
2031	1.06	3.6	£4.8	£2.0					£2.8	£1.5	£0.6	£0.9	£0.3
2032	0.97	3.1	£4.5	£2.0					£2.5	£1.3	£0.5	£0.8	£0.3
2033	0.88	2.6	£4.2	£2.1					£2.0	£1.0	£0.4	£0.6	£0.2
2034	0.81	2.3	£3.9	£2.2					£1.7	£0.9	£0.3	£0.5	£0.1

2035	0.74	1.9	£3.6	£2.2					£1.4	£0.7	£0.3	£0.4	£0.1
2036	0.51	1.3	£2.5	£2.2					£0.4	£0.2	£0.1	£0.1	£0.0
2037				£0.7		£2.9			-£3.6	-£1.8		-£1.8	-£0.4
Total	33	190	£140.6	£35.8	£0.0	£2.9	£5.2	£1.0	£96.7	£50.5	£14.2	£36.3	£25.2

Table 6-9 P10 Cash Flow Forecast £m; effective date 28th February 2020

	Gross									AEWB Net			
Year	Sales Gas	Condensate Liquids	Future Gross Revenue	Operating Expenses	Equipment Lease Costs	Abandon Costs	Capital Costs	Production wells to be drilled	Pre-Tax Future Net Revenue	Pre-Tax Future Net Revenue	Corporate Taxes	Post Tax Future Net Revenue	Post tax Net Present Value at 10% Mid-Year
	BCF	MSTB	£m	£m	£m	£m	£m	No.	£m	£m	£m	£m	£m
2020	0.45	4.3	£1.6	£1.7			£1.8		-£1.9	-£0.03		£0.0	£0.0
2021	2.22	20.6	£8.6	£2.2			£2.4	1	£4.1	£2.4		£2.4	£2.3
2022	3.54	31.6	£15.4	£2.3					£13.1	£6.7		£6.7	£5.8
2023	3.54	30.0	£16.4	£2.2					£14.3	£7.3		£7.3	£5.7
2024	3.54	28.4	£16.1	£2.1					£14.0	£7.2	£2.6	£4.6	£3.3
2025	3.54	26.8	£16.4	£2.1					£14.3	£7.3	£2.9	£4.4	£2.8
2026	3.54	25.2	£15.0	£2.1					£12.9	£6.6	£2.6	£3.9	£2.3
2027	3.54	23.6	£15.3	£2.2					£13.1	£6.7	£2.7	£4.0	£2.2
2028	3.54	22.0	£15.5	£2.2					£13.3	£6.8	£2.7	£4.1	£2.0
2029	3.51	20.2	£15.6	£2.2					£13.4	£6.8	£2.7	£4.1	£1.8
2030	3.21	17.1	£14.5	£2.2					£12.3	£6.3	£2.5	£3.8	£1.5
2031	2.89	14.3	£13.3	£2.2					£11.1	£5.6	£2.3	£3.4	£1.2
2032	2.38	11.0	£11.1	£2.2					£8.9	£4.5	£1.8	£2.7	£0.9
2033	1.95	8.5	£9.3	£2.3					£7.0	£3.6	£1.4	£2.1	£0.6
2034	1.80	7.4	£8.7	£2.3					£6.4	£3.3	£1.3	£2.0	£0.5
2035	1.67	6.5	£8.2	£2.3					£5.9	£3.0	£1.2	£1.8	£0.5

2036	1.55	5.7	£7.8	£2.4					£5.4	£2.8	£1.1	£1.7	£0.4
2037	1.43	5.0	£7.4	£2.4					£4.9	£2.5	£1.0	£1.5	£0.3
2038	1.17	3.9	£6.1	£2.4					£3.7	£1.9	£0.8	£1.1	£0.2
2039	1.05	3.3	£5.6	£2.4					£3.1	£1.6	£0.6	£1.0	£0.2
2040	0.99	3.0	£5.3	£2.5					£2.9	£1.5	£0.6	£0.9	£0.1
2041	0.93	2.7	£5.1	£2.5					£2.6	£1.3	£0.5	£0.8	£0.1
2042	0.88	2.5	£5.0	£2.5					£2.4	£1.2	£0.5	£0.7	£0.1
2043	0.83	2.2	£4.8	£2.6					£2.2	£1.1	£0.4	£0.7	£0.1
2044	0.79	2.0	£4.6	£2.6					£2.0	£1.0	£0.4	£0.6	£0.1
2045	0.74	1.9	£4.4	£2.7					£1.8	£0.9	£0.4	£0.5	£0.1
2046				£0.9		£3.4			-£4.3	-£2.2		-£2.2	-£0.2
Total	55	330	£257.2	£60.9	£0.0	£3.4	£4.2	£1.0	£188.7	£97.5	£33.1	£64.4	£34.9

Table 6-10 P90 Post-Tax NPV discounted to Jan 1st 2020 £m; effective date 28th February 2020

Mid-Year Nominal Net Present Values as at 01-Jan-20 (GB£ m)			
Disc Rate	**Gross Pre-Tax**	**AEWB Pre-Tax**	**AEWB Post-Tax**
0%	£49.8	£26.0	£21.5
5%	£42.9	£22.5	£18.9
10%	£37.2	£19.6	£16.7
12.5%	£34.7	£18.3	£15.8
15%	£32.5	£17.2	£14.9
20%	£28.6	£15.2	£13.3

Table 6-11 P50 Post-Tax NPV discounted to Jan 1st 2020 £m; effective date 28th February 2020

Mid-Year Nominal Net Present Values as at 01-Jan-20 (GB£ m)			
Disc Rate	**Gross Pre-Tax**	**AEWB Pre-Tax**	**AEWB Post-Tax**
0%	£96.7	£50.5	£36.3
5%	£76.6	£40.2	£29.9
10%	£62.3	£32.9	£25.2
12.5%	£56.6	£30.0	£23.3
15%	£51.7	£27.5	£21.6
20%	£43.7	£23.4	£18.8

Table 6-12 P10 Post-Tax NPV discounted to Jan 1st 2020 £m; effective date 28th February 2020

Mid-Year Nominal Net Present Values as at 01-Jan-20 (GB£ m)			
Disc Rate	**Gross Pre-Tax**	**AEWB Pre-Tax**	**AEWB Post-Tax**
0%	£188.7	£97.5	£64.4
5%	£128.2	£66.6	£45.9
10%	£93.3	£48.8	£34.9
12.5%	£81.2	£42.7	£31.0
15%	£71.5	£37.7	£27.9
20%	£57.1	£30.4	£23.1

7. Determination of Reserves of Sales Gas and Liquids

The Westphalian reservoir in the Main Field and the Southern Satellite Structure, and the Namurian Reservoir in the Main Field, satisfy 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)[7] indicates a high degree of confidence (low risk of failure) that …. the referenced event will occur.

Table 6-7 and Table 6-10 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 6-8 and Table 6-11 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.

The remaining hydrocarbons in the Namurian Reservoir of the Main Reservoir, and the Westphalian Reservoir of the Southern Satellite, are Contingent Resources. These are presented in Table 7-3 and Table 7-4. These recoverable volumes have the potential to be recategorised as Reserves if AEWB commits to a subsequent development plan that meets the Commercial criteria.

[7] 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**	**3P**	**Mean**	**1P**	**2P**	**3P**	**Mean**	
	BCF	BCF	BCF	BCF	BCF	BCF	BCF	BCF	
Main Field Westphalian Reservoir	18	32	55	32	9	16	28	16	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**	**3P**	**Mean**	**1P**	**2P**	**3P**	**Mean**	
	M STB	M STB	M STB	M STB	M STB	M STB	M STB	M STB	
Main Field Westphalian Reservoir	107	190	330	188	55	97	168	96	AEWB

Effective Date: 28th February 2020

Source: Oilfield International

Table 7-3 Sales Gas Contingent Resources: Gross and Net Attributable to AEWB

Saltfleetby Field	Gross				Net Attributable to AEWB				Operator
Sales Gas Contingent Resources	**1C**	**2C**	**3C**	**Mean**	**1C**	**2C**	**3C**	**Mean**	
	BCF	BCF	BCF	BCF	BCF	BCF	BCF	BCF	
Main Field Namurian Reservoir	0	2	4	2	0	1	2	1	AEWB
Southern Satellite Westphalian Reservoir	12	18	26	18	6	9	13	9	AEWB
Total Remaining Recoverable Gas	**12**	**20**	**30**	**20**	**6**	**10**	**15**	**10**	

Effective Date: 28th February 2020

Source: Oilfield International

Table 7-4 Condensate Liquids Contingent Resources: Gross and Net Attributable to AEWB

Saltfleetby Field	**Gross**				**Net Attributable to AEWB**				**Operator**
Condensate Liquids Contingent Resources	**1C**	**2C**	**3C**	**Mean**	**1C**	**2C**	**3C**	**Mean**	
	M STB	M STB	M STB	M STB	M STB	M STB	M STB	M STB	
Main Field Namurian Reservoir	5	30	64	33	3	15	33	17	AEWB
Southern Satellite Westphalian Reservoir	158	221	288	229	80	113	147	117	AEWB
Total Remaining Condensate Liquids	**163**	**251**	**351**	**263**	**83**	**128**	**179**	**134**	

Effective Date: 28th February 2020

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
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 NationalGrid 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