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13th October 2023

Dear Sirs

COMPETENT PERSONS REPORT, SALTFLEETBY GAS FIELD, UK ONSHORE LICENCE, PEDL005.

In accordance with instructions received from Angus Energy plc (hereinafter "AE"), Oilfield International (hereinafter "OIL") has evaluated certain petroleum interests operated by Angus Energy Weald Basin No 3 Ltd (hereinafter "AEWB") on behalf of AE, namely AE's 100% working interest in the Saltfleetby Gas Field which is part of the UK onshore licence PEDL005.

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 2022[1]. The Effective Date of this report is 1st August 2023. AE has informed us of one material change as of 13th October 2023: the P50 date for first gas from the booster compressor has moved from 1st July 2024 to 1st October 2024. This has only a minor impact on the findings of this report.

OIL has attributed Proved Reserves (1P), Proved plus Probable Reserves (2P), and future cash flows to AE. OIL has calculated Gross Contingent Resources but has not developed production profiles or cash flows attributable to AE because it is still interpreting the recently completed depth-migrated 3D seismic data; and is building new static and dynamic simulation models based on this new geological model and the production data since production restarted in August 2022. 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 AE and AEWB.

AE is party to a £12m loan agreement dated 3rd June 2021 which includes a number of material loan costs, cash distribution restrictions, overriding royalty interests and hedging obligations. AE is bound by the terms of this loan agreement and so AE's net entitlement reserves reported here are net of the overriding royalty interest[2]. £7.35m of the loan is outstanding at the Effective Date[3].

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

OIL's estimates of pre-tax future cash flows required to assign reserves are based on datasets provided by AE. OIL conducted a site visit to PEDL005 in February 2020 before construction of

[1] Refer Petroleum Resources Management System – 2018 Update (spe.org); and Guidelines for Application of the Petroleum Resources Management System eBook (PRMS) (spe.org).

[2] 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.

[3] £0.138m and £1.050m loan repayments were made in September 2023; and circa £0.34m interest.

the surface facilities and pipeline extension commenced. The date of First Sales Gas was 30th August 2022 from two wells, B2 and A4. A third well, B7T[4], entered production in May 2023. Two further wells on the Main Westphalian reservoir, SF9 and SF10 are scheduled to enter production in January 2025 and January 2026 respectively, to extend plateau production and accelerate the extraction of gas.

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 AE (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.

> **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.
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> **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 Gross Gas and Condensate Liquids Reserves, and the Reserves attributable to AE. The Reserves are net of Gas Consumed in Operations ("CiO"). The Reserves attributable to AE are additionally net of Overriding Royalty. Table 0-4 presents the investment programme and the annual capex liability to AE. Table 0-5 presents the Net Cash Flow and NPV10 of the Reserves attributable to AE.

[4] Wells B2, A4, B7T are also referred to as SF2, SF4, SF7V, respectively by AE.

Comparing with OIL's last reserves determination of October 2021[5]:

- The Gross P90 sales gas volume has increased from the October 2021 18 BCF (at August 1st 2023, 16 BCF since 2 BCF has been produced since the October 2021 report) to 24.2 BCF. The reasons are:
  - ➢ Higher gas prices: the minimum sales gas flowrate that generates positive net cash flow is therefore lower and so more gas is produced before economic abandonment.
  - ➢ Flow from five wells rather than three wells increases the aggregate sales gas flowrate, further extending the time to economic abandonment
  - ➢ Clear evidence that the October 2021 P90 gas originally in place (GIIP) estimate of 105 BCF (less 3 BCF CiO = 102 BCF GIIP sales gas reported in October 2021) is not consistent with the pressure buildup data obtained by AEWB during the last year. The P90 value is now 112 BCF GIIP.
  - ➢ These increases are offset by an increase in CiO from 2.75% to OIL's P90 estimate of 15%, due to surface facility choices of energy supply and gas processing changes.

- The Gross P50 sales gas volume has decreased from the October 2021 31.8 BCF (at August 1st 2023, 29.8 BCF) to 27.2 BCF. The reasons are:
  - ➢ The increase in CiO from 2.75% to a P50 value of 10%[6], due to surface facility choices of energy supply and gas processing changes.
  - ➢ Clear evidence that the October 2021 P50 GIIP inc CiO of 121 BCF (less 3 BCF CiO = 118 BCF GIIP sales gas reported in October 2021) is not supported by the latest build up data. The P50 value now is 115 BCF.
  - ➢ This decrease is mitigated by higher gas prices and the additional two wells which both extend the economic field life.

- The uncertainty in the reservoir volume has reduced, causing the current P90 and P50 estimates to be closer together.

- As a reality check, a production profile was generated using the reduction in flowing wellhead pressures with cumulative production observed since August 2022. It shows a good match to the P90 recoverable volume.

Upside Recoverable Volumes

In the Main Westphalian Reservoir

- Possible Reserves

In the Southern Satellite Structure Westphalian Reservoir (a contiguous structure to the Main Reservoir)

- Recoverable hydrocarbon volumes, currently categorised as Contingent Resources; Table 0-6 and Table 0-7 refer.[7]

In the Namurian Reservoir (a deeper reservoir below the main Westphalian Reservoir)

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[5] Reserves Valuation Report Angus Energy Saltfleetby Assets Effective Date 1st October 2021 Report Date 22nd October 2021

[6] AEWB estimate, supported by OIL for the P50 category.

[7] Refer to 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

- Recoverable hydrocarbon volumes, currently categorised as Contingent Resources.

The Contingent Resources stated in Table 0-6 could be used to extend the sales gas plateau.

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

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

Table 0-2 Main Field Westphalian Reservoir: Sales Gas Reserves: Gross, and Net Attributable to AE After Royalties

Saltfleetby Field	**Gross**		**Net Attributable to AE**		**Operator**
Sales Gas Reserves	**1P**	**2P**	**1P**	**2P**	
	BCF	BCF	BCF	BCF	
Main Field Westphalian Reservoir	24.2	27.2	22.4	25.2	AEWB

Effective Date: 1st August 2023

Source: Oilfield International

Table 0-3 Main Field Westphalian Reservoir: Sales Liquids Reserves: Gross, and Net Attributable to AE After Royalties

Saltfleetby Field	**Gross**		**Net Attributable to AE**		**Operator**
Sales Liquids Reserves	**1P**	**2P**	**1P**	**2P**	
	M STB	M STB	M STB	M STB	
Main Field Westphalian Reservoir	357	447	332	415	AEWB

Effective Date: 1st August 2023
Source: Oilfield International

Table 0-4 Main Field Westphalian Reserves: Investments and Capex Attributable to AE

Investment	**P90**	**P50**	**Forecast Date Operational**
	£m 2023	£m 2023	
Accelerator String for Well A4	£0.7	£0.5	P90: 01/05/2024, P50: 01/02/2024
Booster Compressor	£2.6	£2.3	P90 & P50: 01/10/2024
Well SF9	£5.7	£5.7	P90 & P50: 01/01/2025
Well SF10	£5.7	£5.7	P90 & P50: 01/01/2026
Abandonment	£4.7	£4.7	2038
Total	**£19.3**	**£18.9**	

Year	**P90**	**P50**
	£m MOD	£m MOD
2023	£0.7	£0.7
2024	£8.5	£8.1
2025	£5.9	£5.9
2026		
2027		
2038 Abandon	£6.3	£6.3
Total	**£21.4**	**£20.9**

2023 Money; and MOD: money of the day

Effective Date: 1st August 2023

Source: Oilfield International

Table 0-5 Main Field Westphalian Reserves: NCF and NPV10 discounted to August 1st, 2023: Net Attributable to AE

	Net Cash Flow Attributable to AE		**NPV10 Attributable to AE**		**Operator**
Scenario	**1P**	**2P**	**1P**	**2P**	
Including AE's Contractual Loan terms	£m MOD	£m MOD	£m MOD	£m MOD	AEWB
Pre-Tax	£125.4	£153.5	£86.9	£104.1	
Post-Tax	£78.9	£90.6	£57.1	£64.3	

MOD: money of the day

Effective Date: 1st August 2023

Source: Oilfield International

Table 0-6 Contingent Gas Resources: Main Field Namurian Reservoir and Southern Lobe Westphalian Reservoir

Saltfleetby Field		**Gross**		**Operator**
Sales Gas Contingent Resources	**1C**	**2C**	**3C**	
	BCF	BCF	BCF	
Main Field Namurian Reservoir	0.1	1.7	3.7	AEWB
Southern Satellite Westphalian Reservoir	10.2	15.6	22.9	AEWB
Total Remaining Recoverable Gas	**10.3**	**17.2**	**26.7**	

The table has rounding errors.

The 1C Sales Gas Contingent Resources are stated net of 15% Gas Consumed in Operations (CiO). The 2C and 3C are stated net of 10% CiO. In the 2021 report, they were stated net of 2.75% CiO.

Effective Date: 1st August 2023

Source: Oilfield International

Table 0-7 Contingent Liquids Resources: Main Field Namurian Reservoir and Southern Lobe Westphalian Reservoir

Saltfleetby Field	**Gross**			**Operator**
Condensate Liquids Contingent Resources	**1C**	**2C**	**3C**	
	M STB	M STB	M STB	
Main Field Namurian Reservoir	3	26	57	AEWB
Southern Satellite Westphalian Reservoir	152	213	275	AEWB
Total Remaining Condensate Liquids	**155**	**238**	**332**	

The table has rounding errors.

Effective Date: 1st August 2023

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 1). 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 imposes 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 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 five 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 it could affect the contingent resources, and the 3P reserves.

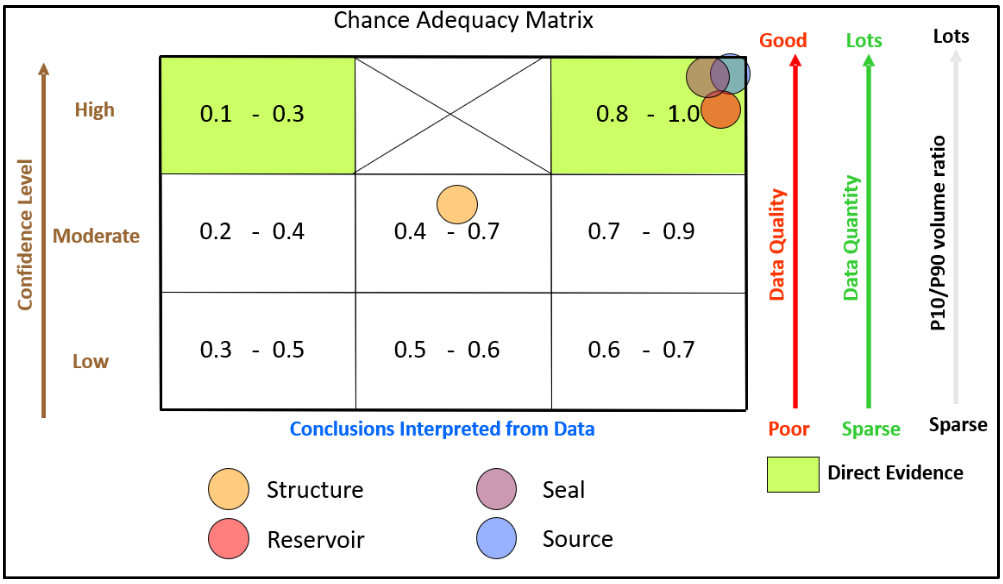

Figure 1 Chance of adequacy matrix of Saltfleetby Gas Field model

<u>Remaining uncertainty about reservoir quality and dynamic performance</u>

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 tortuosity in the near wellbore region may choke mass flowrates at high superficial velocities, reducing communication between the bulk reservoir and the wellbore, reducing the gas productivity index. The extremely rapid recovery of wellhead pressure on shut-in supports this assessment and (2) above.
4. The reservoir penetrated by the horizontal sidetrack of well B7T may be of poorer quality than expected. It is producing at lower flowrates than those forecast in the October 2021 CPR, though the reduction in horizontal length from planned 450m to actual 180m and the deployment (and subsequent acidising) of calcium carbonate for mud cake whilst drilling are also major factors in its reduced deliverability.
5. The permeability and other characteristics of the reservoir to be penetrated by wells SF9 and SF10 are uncertain.
6. 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. There is initial evidence that well A4 (aka SF4) is producing above the trend water production rate from 2012 to 2017, and this may be because it is producing at a lower wellhead pressure and higher flowrate.
7. If the water flowrate in well A4 were to increase significantly, a smaller tubing size (2 3/8") would need to be installed to enable the well to continue to flow [8]. The P50 and P90 schedules for start of well A4 operation after installation of this smaller tubing ("accelerator string") are February and May 2024, respectively. P50 and P90 Capex of £0.5m and £0.7m, respectively, are included in the cash flow calculations.
8. Each of the frequent short-term shut-ins and flowrate changes during the first year of production has sent a pressure pulse to the reservoir that follows the same evolution from early time to stabilised time (Figure 2). Hence, the flowing well head pressure on any day is the super-position of the reservoir's individual response to each flowrate change since August 30th, 2022. It is not possible to correctly interpret the reservoir's performance in the short run without sophisticated computational analysis[9] and a reliable conversion of well head pressures to bottom hole pressures. Furthermore, there is evidence of choking in the near wellbore region and so the flowing wellhead pressures may not correctly be "seeing" the gas further into the reservoir (refer (3) above). This is evident from the automated history matching of wellhead pressure undertaken by the operator's consultant for the period August 2022 to June 2023. (By contrast, the automated history match of wellhead gas flowrate for the period 2014-2017 against an almost constant separator pressure (30-32 barg) showed little deviation from actual.) There is therefore inherent uncertainty in the production forecast from the reservoir simulation, and this uncertainty increases with increasing wellbore flowrates.

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[8] Flow can be directed inside the smaller tubing, or in the annulus between it and the existing larger tubing, or both. AEWB is also investigating gas lift and surface jet pumps to lift liquids.

[9] Gringarten, A.C., "From Straight Lines to Deconvolution: the Evolution of the State of the Art in Well Test Analysis"; Gringarten, A.C. etal: "Well Test Analysis in Gas Condensate Reservoirs: Theory and Practice", paper SPE 100993.

9. AEWB's compression is currently designed to operate at 10 MMSCFD wellhead flowrate at a minimum flowing wellhead pressure constraint of 17.5 barg. When the flowing wellhead pressure declines to 17.5 barg, the flowrate will automatically reduce until booster compression is installed[10]. The P90 & P50 schedule for start of booster compressor operation is October 2024. It is likely that a 10 MMSCFD flowrate will not be sustainable until the booster compressor is operational. P50 and P90 Capex of £2.3m and £2.6m, respectively are included in the cash flow calculations for the booster compressor, and this includes investment to uprate the compressors to process 12 MMSCFD wellhead gas in time for the fourth well, SF9, to enter production in January 2025.
10. The cooling capacity of the compressors imposes an additional constraint of 9 MMSCFD at air temperatures above 23 Deg C. This will be remedied during the August 2024 planned shutdown. (At low air temperatures, the compressors can currently achieve 12 MMSCFD).

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[11], we have therefore assigned Reserves to volumes economically recoverable after 2027 for the current development plan of five 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[12].

[10] AEWB states the booster compressor will reduce the flowing wellhead pressure constraint to 4 barg.
[11] **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.
[12] Page 38 final paragraph, "Consolidated Onshore Guidance", June 2018 v 2.2, Oil & Gas Authority, UK.

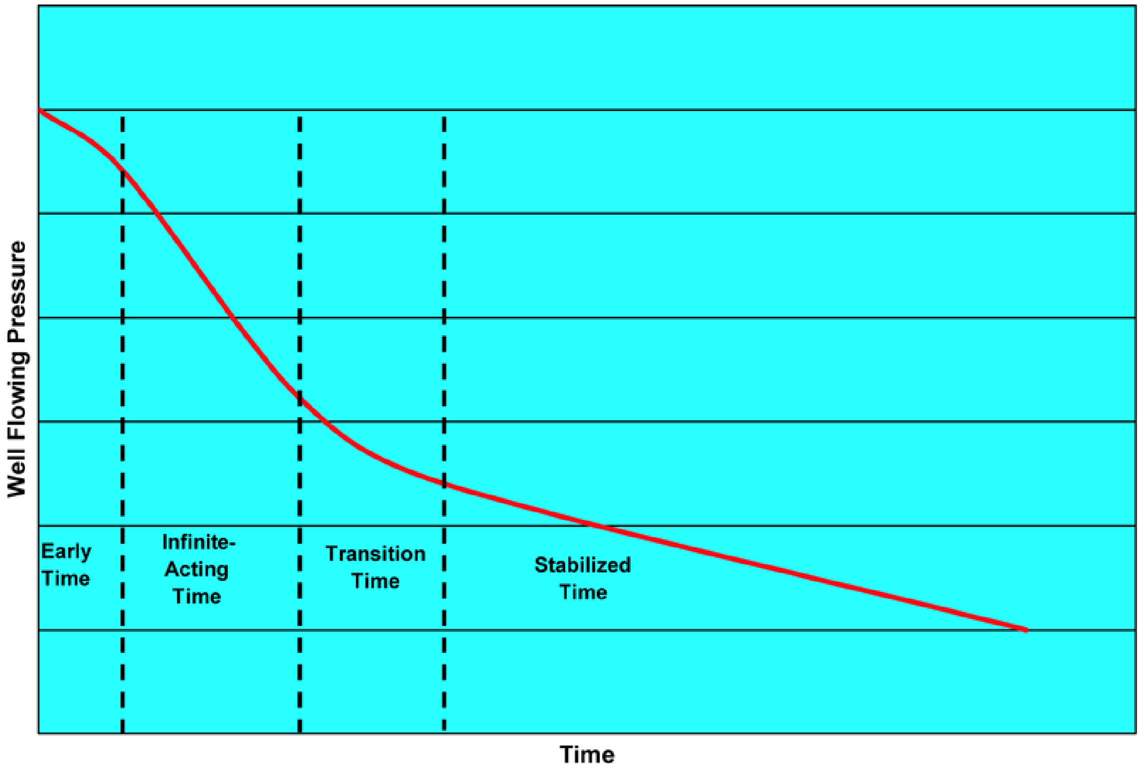

Figure 2 Schematic showing well flowing pressure vs time for a constant flowrate. Image Source: Petrowiki gas well performance

Project Execution

1. The timing of first production from the booster compressor could be delayed by:
   a. Fabrication and shipping time overruns.
   b. Potential lost time from simultaneous construction and production operations
   c. Technical difficulties during the installation and commissioning
   d. Delays in receiving Environment Agency permissions, for example the results of noise modelling.
   e. Delays in receiving HSE permissions.
2. The timing of first production from well A4 accelerator string could be delayed by:
   a. The availability of a suitable coiled tubing unit
   b. Degradation in quality of the well A4 wellbore leading to imperfect sealing of the packer and other workover risks
3. The total installed costs of the booster compressor and the accelerator string may be higher (or lower) than forecast due to inflation, market conditions and the availability of equipment and skilled personnel
4. The booster compressor and the main compressors are being designed and modified to operate at 12 MMSCFD all year round in time for the fourth well to enter service in January 2025. The compressors may not perform to specification.
5. The timing of first production from wells SF9 and SF10 could be delayed, for example by Planning Application procedures, reducing export sales gas flowrate.
6. The achieved length of the lateral section for wells SF9 and SF10 could be shorter than the design 450m, so reducing deliverability.
7. The drilling operation for wells SF9 and SF10 could damage the near wellbore region, so reducing deliverability.

Gas Consumed in Operations (CiO)

Until 2017, wellhead gas and condensate were exported to Conoco's Theddlethorpe gas processing terminal where gas shrinkage, condensate volumes and fuel gas were allocated back to operators. From August 2022 AEWB has operated its own small gas processing plant and is seeing larger wellhead gas shrinkage than previously recorded. However, in part this might be due to Theddlethorpe possibly allocating Saltfleetby's condensate therms to sales gas therms, as evidenced by the 50% ratio of {Conoco allocated CGR}/ {Separator CGR}). At present, the data are too volatile to assess wellhead gas shrinkage, but the operator is confident it will achieve around 10% CiO from next year[13]. To be cautious OIL has assumed 15% CiO for the P90 sales gas production profile, and 10% CiO for the P50 sales gas production profile.

There is material uncertainty over the current measurement of CiO which is hard to quantify because of the current data volatility. Currently, wellhead production rates are estimated from orifice plate data and allocation, with high uncertainty; once the test separator has been repaired, planned for 4Q 2023, it will be possible to measure individual wellhead flow rates accurately.

Plant Availability

AEWB has experienced unreliability challenges with its compression trains and its condensate stabilisation tower. It has achieved average plant availability around 80%-85% in the period Sept 22 to July 23. Some of the causes of this unavailability have been solved by replacing minor equipment, such as redesigned trays for the stabilisation tower and pressure/flow sensors. AEWB forecasts that future availability will be about 92.7%. This is typical and reasonable for a plant of this complexity level[14].

The key risks to production availability once troubleshooting of minor design and equipment flaws are solved, relate to rotating machinery. Although there are two 50% intermediate/export compressor trains, there is only one 100% booster compressor train and the reliability of this may be the significant contributor to long term plant availability. However, for a few years the intermediate compressors would be able to receive flow without the booster compressor: at lower flowrates: as the flowrate reduces, the flowing wellhead increases and so the intermediate compressor can accept the flow (to a limit).

Exogenous

1. Commodity prices
    a. The National Balancing Point Forward Curve (NBP) dated 1st August 2023, escalated after December 2028 by 2% pa. Realised NBP gas prices may be higher or lower.
    b. The Brent Forward Curve dated 1st August 2023, escalated after December 2028 by 2% pa. Realised Brent prices may be higher or lower.
    c. The discount to naphtha offered for AE's condensate production and the discount of naphtha to the Brent forward curve may be higher or lower than forecast.

[13] Oilfield International's 22nd October 2021 Saltfleetby Reserves Report assumed a sales gas shrinkage of 2.75% provided by AEWB from its surface facilities process simulation reports.
[14] Oilfield International's 22nd October 2021 Saltfleetby Reserves Report assumed an availability of 93.1%.

2. Cost Escalation for Oilfield services and equipment is assumed to be 2% 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 led by Mr David Curia who is independent of shareholders, management, and staff of AE and 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.

Basis of Opinion

The reserves 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 AE's Petroleum Assets. Oilfield International does not confirm AE's legal right to title of PEDL005; the detail or the enforceability of that legal title; and the absence or nature of any liens or other encumbrances that might affect AE's rights to, or value in, PEDL005.

Yours Sincerely,

David Curia
Chief Geoscientist

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TABLES

FIGURES

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. On 24th May 2022, AE acquired the remaining 49% working interest from SE, and now owns 100% working interest in the field through AEWB and SE. A £12m loan agreement dated 3rd June 2021 includes an overriding royalty interest and AE's reserves are therefore net of this royalty.

Production restarted at the end of August 2022 from two wells, B2 (SF2) and A4 (SF4), powered by a single compressor train, and produced about 5 MMSCFD of sales gas. A third well, B7T (SF7), and a second compressor train were added in early May 2023, raising sales gas production to about 9 MMSCFD. B7T was designed to flow from a 450m horizontal section with a production potential of 12-14 MMSCFD wellhead gas flowrate but only a 180m horizontal section was achieved and with a higher "skin"[15] than anticipated, resulting in a lower flowrate potential of 4-6 MMSCFD. Two further wells with planned 450m horizontal laterals are scheduled to enter service in 2025 and 2026.

Figure 3 to Figure 6 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 summarises the licence information for PEDL005.

[15] A measure of near-wellbore damage from drilling.

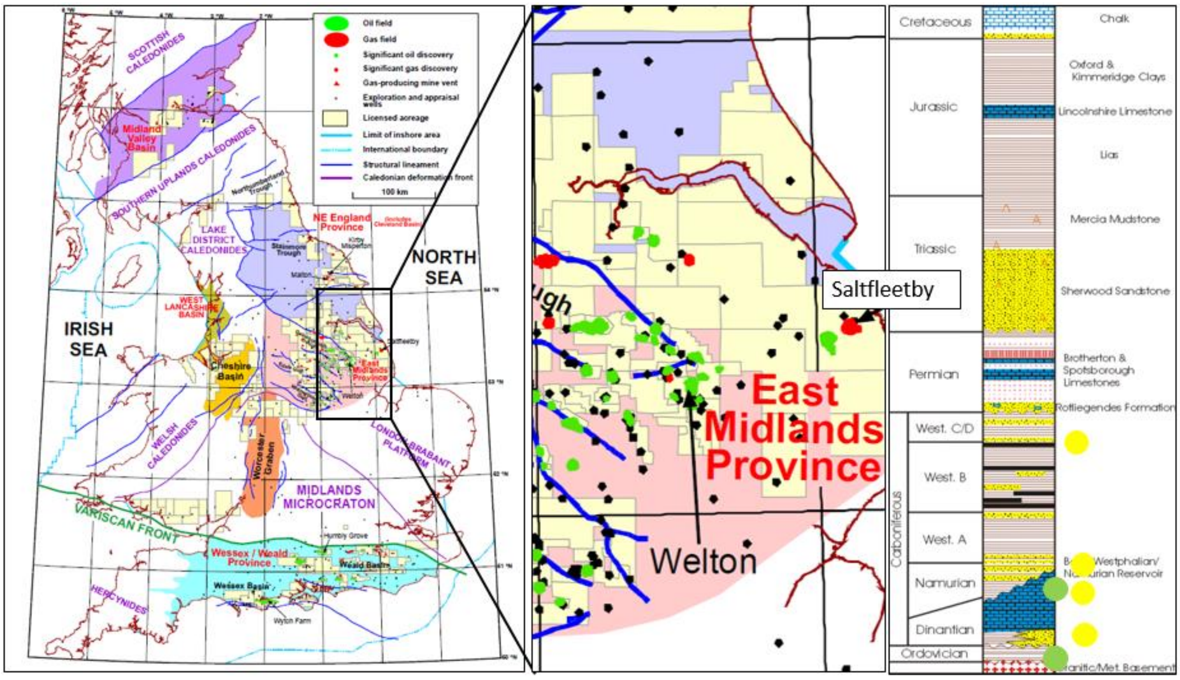

Figure 3 Geographic and Geological Setting of PEDL005; source: DECC[16]

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

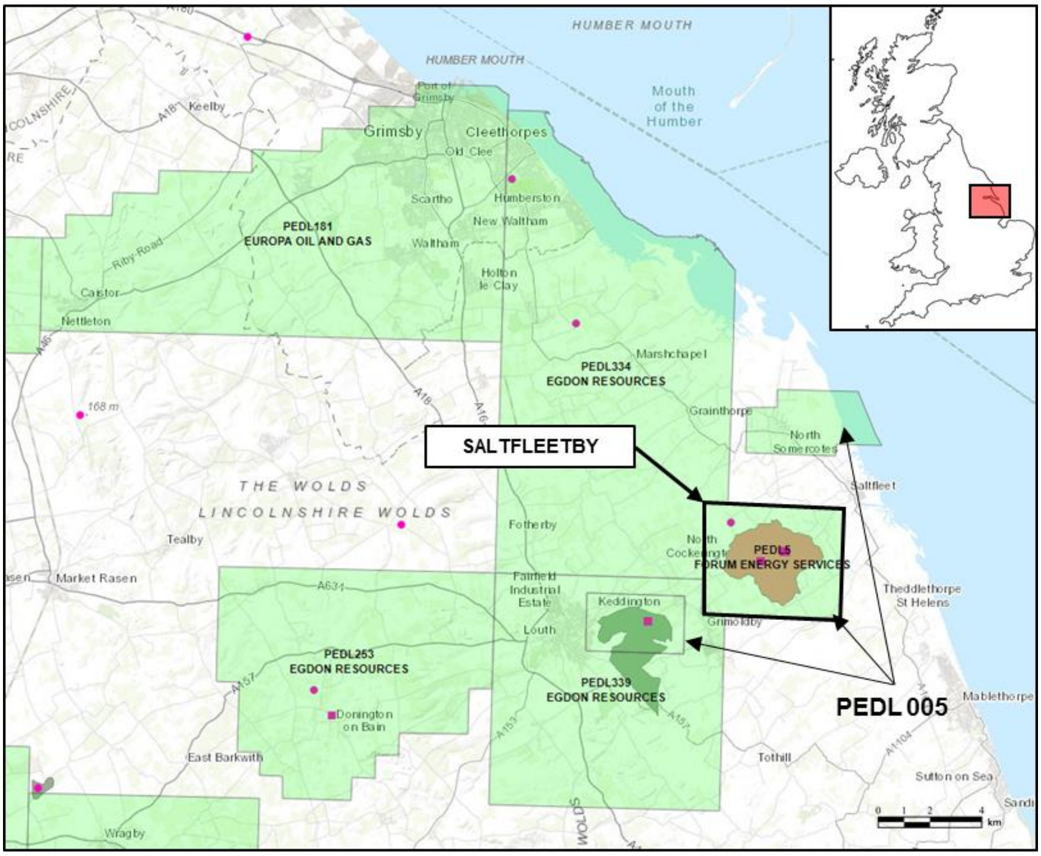

Figure 4 Location Map of PEDL005, source OGA, 2020

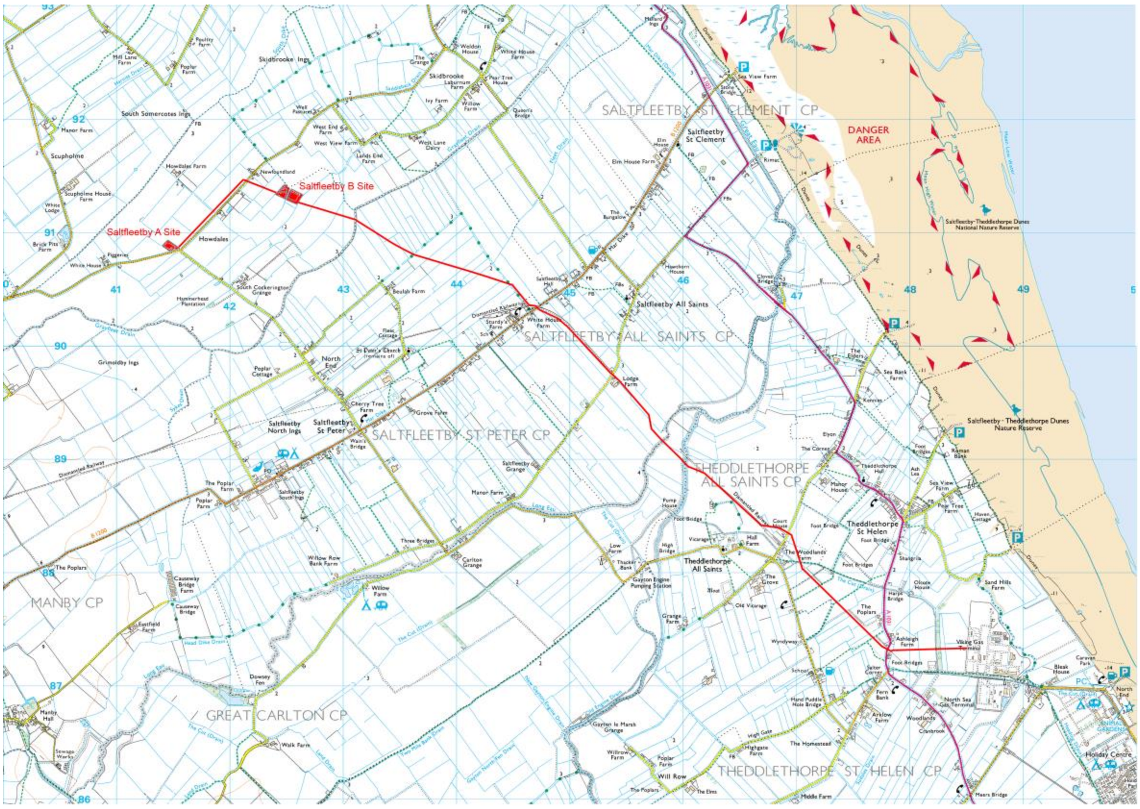

Figure 5 Saltfleetby Development Sites and Existing Gas Pipeline to (Decommissioned) Theddlethorpe Gas Terminal, Source Roc Oil

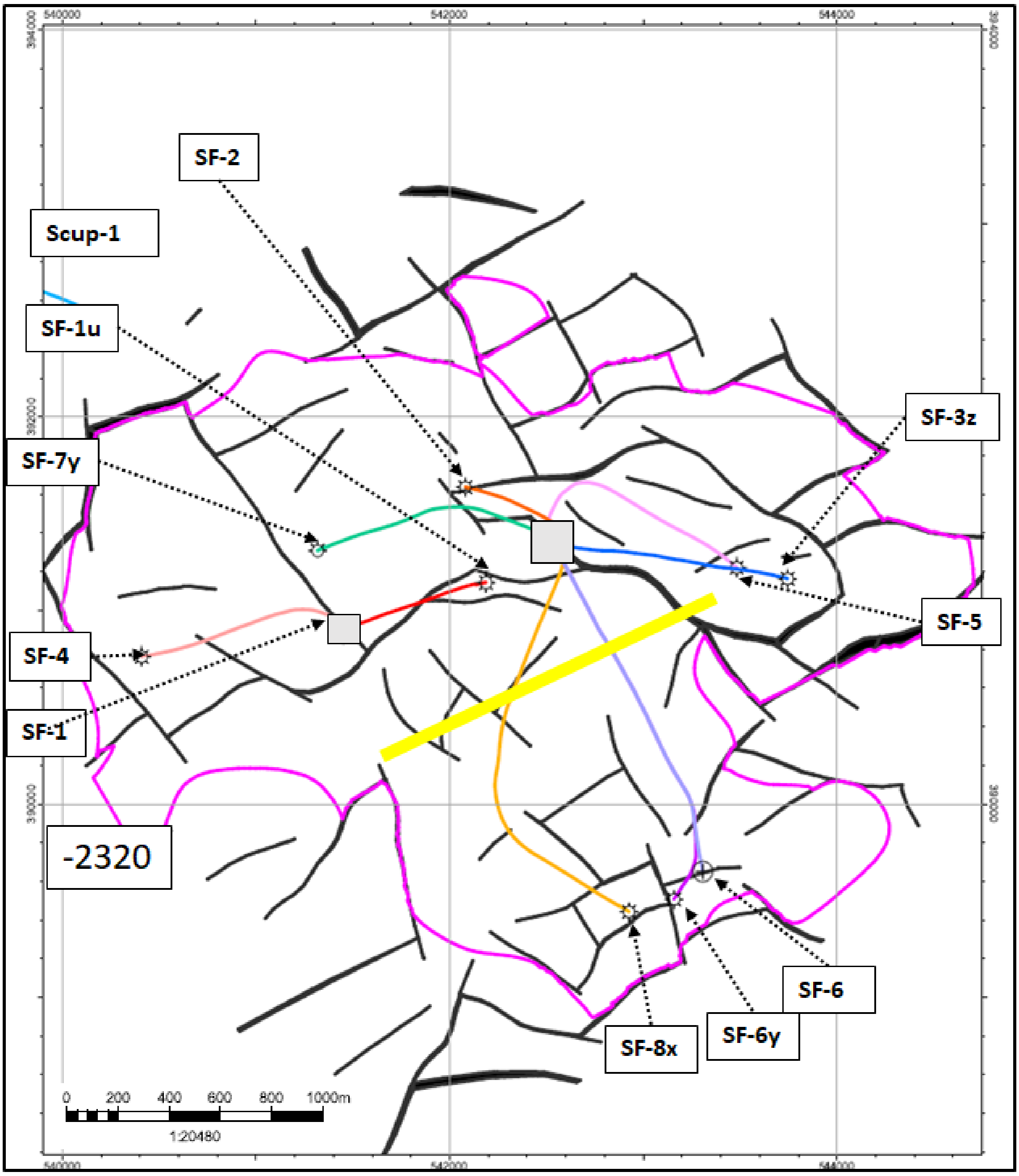

Figure 6 Surface Map of Saltfleetby Field, source OIL before B7T drilled.

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% AE acquired SE's 49% WI on 24th May 2022 and now owns 100% WI in the Saltfleetby Field through AEWB and SE.
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	Continued 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 AE, 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, now B7T.

2. Geological Description

Figure 7 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 8 - Figure 11 illustrate the elevation and relief of the principal gas-bearing Saltfleetby reservoirs. In the left hand image of Figure 9 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 most optimistic 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 11 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.

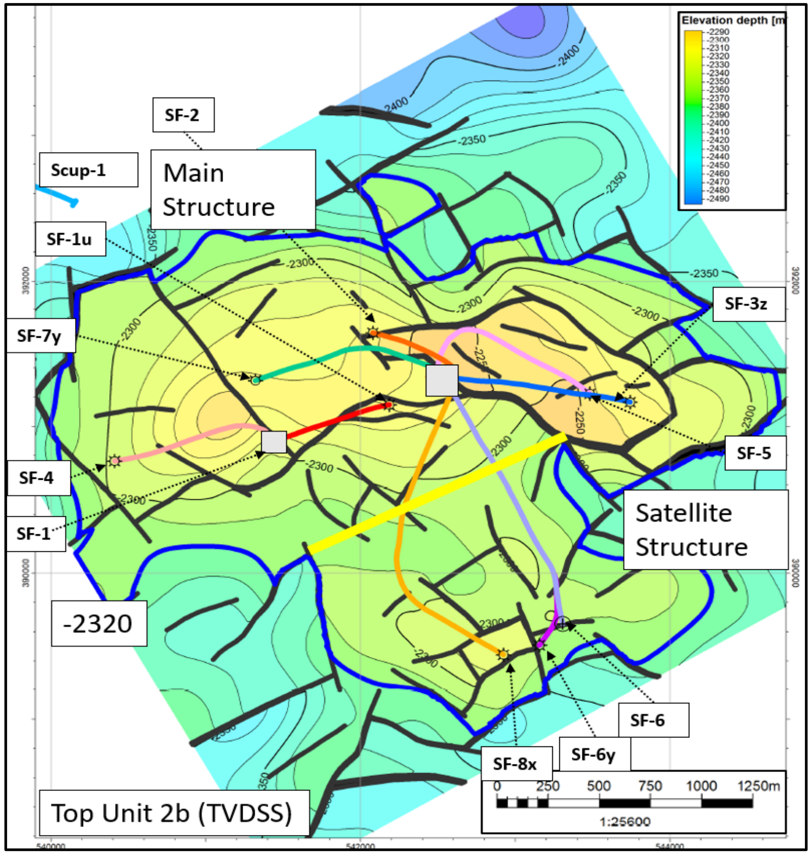

Figure 7 Structural Map of the Top of Westphalian Reservoir (Unit 2b). Source: OIL

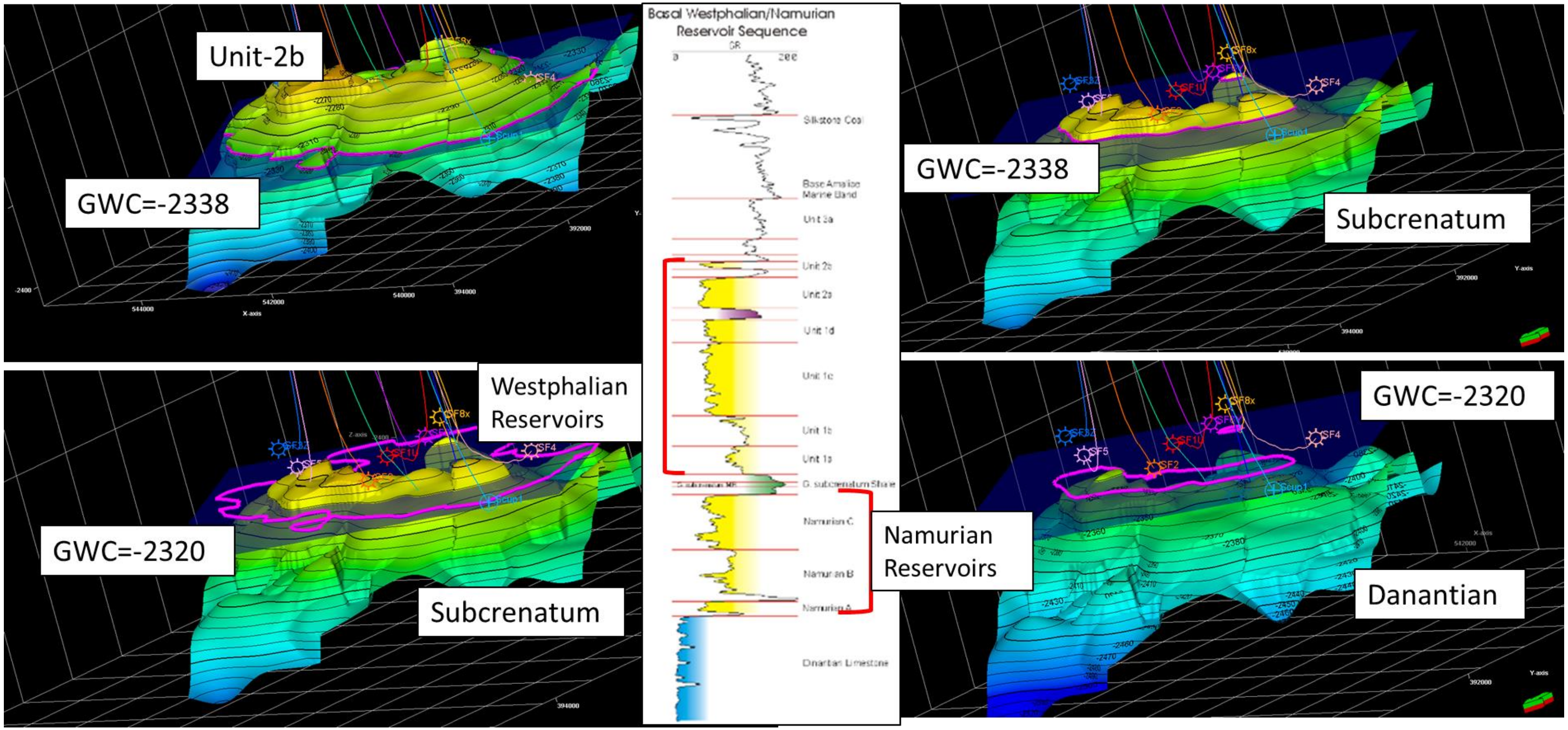

Figure 8 3D View of the stacked Westphalian and Namurian reservoirs (green arrow is north). Source: OIL

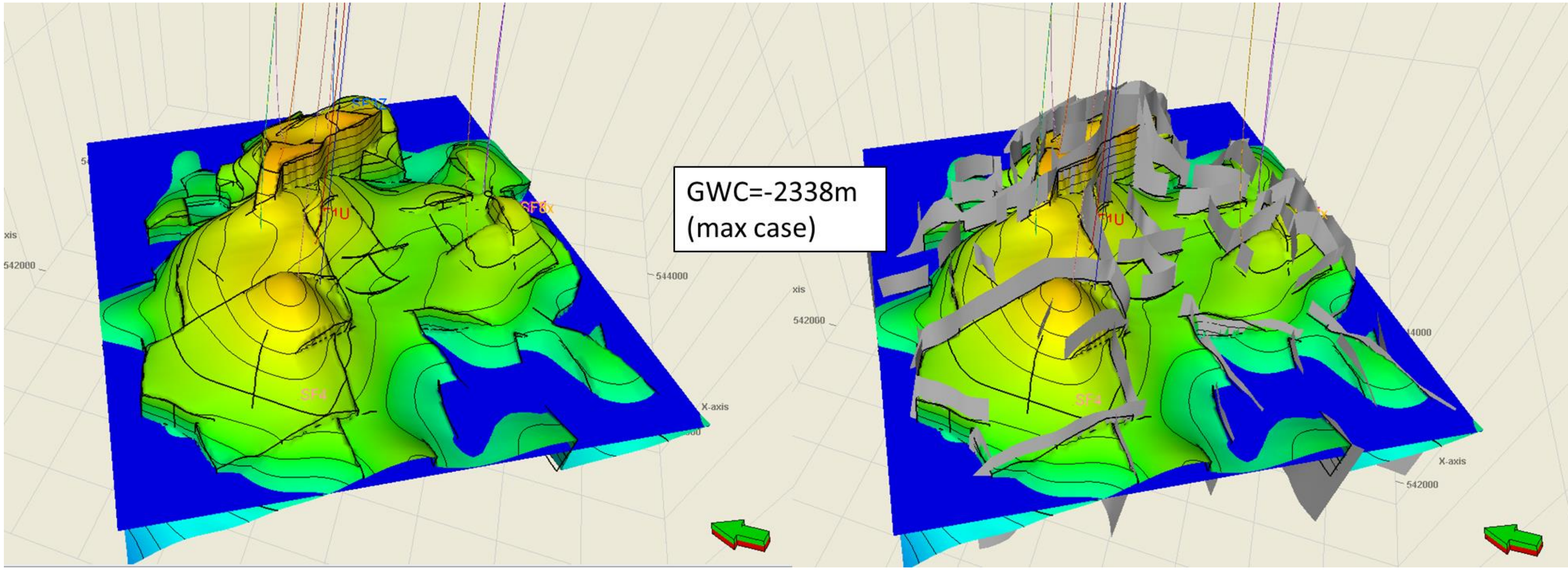

Figure 9 3D View of the Saltfleetby Gas Field structure at the top of Westphalian (Unit-2b) reservoir (green arrow is north). Source: OIL

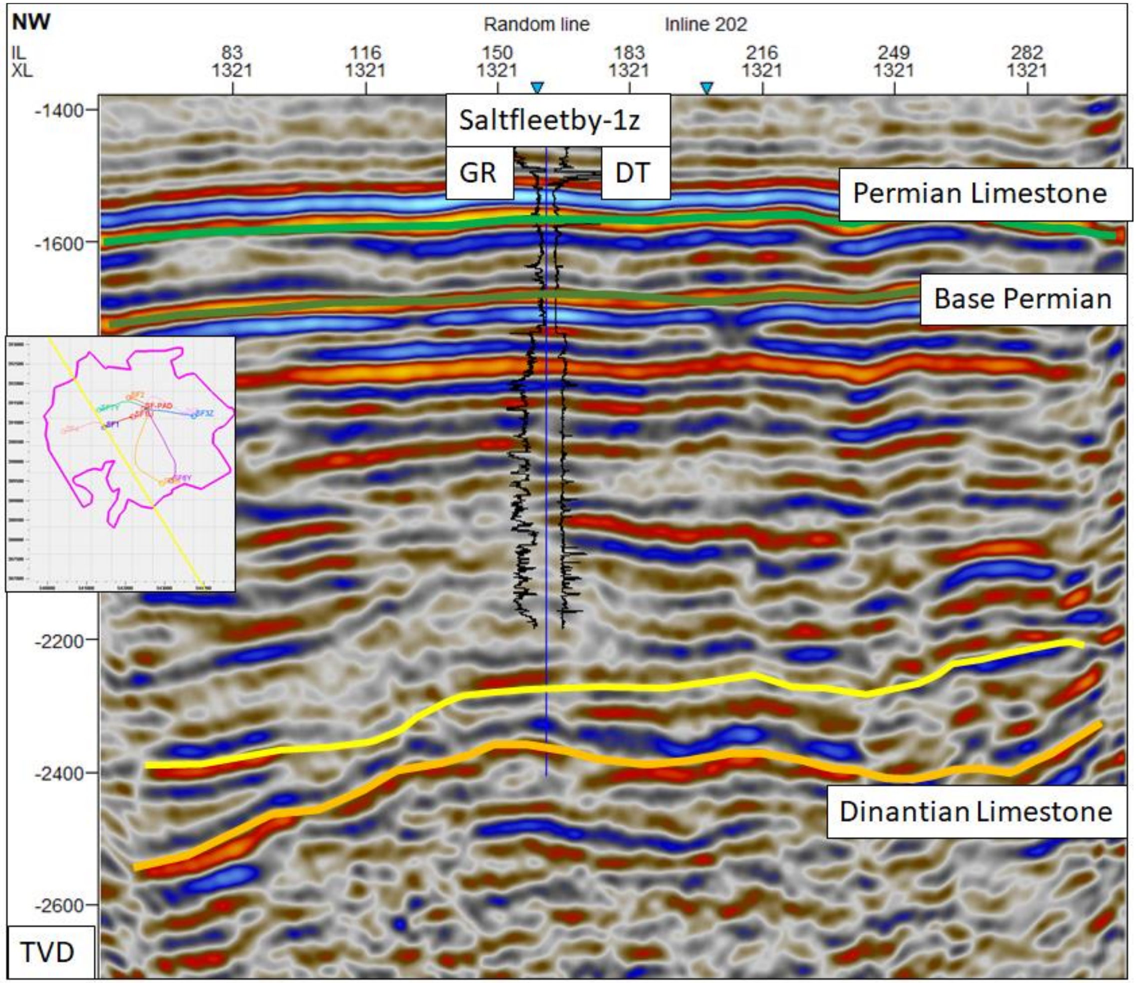

Figure 10 Well-Seismic tie. Seismic line in NS direction. Source: OIL

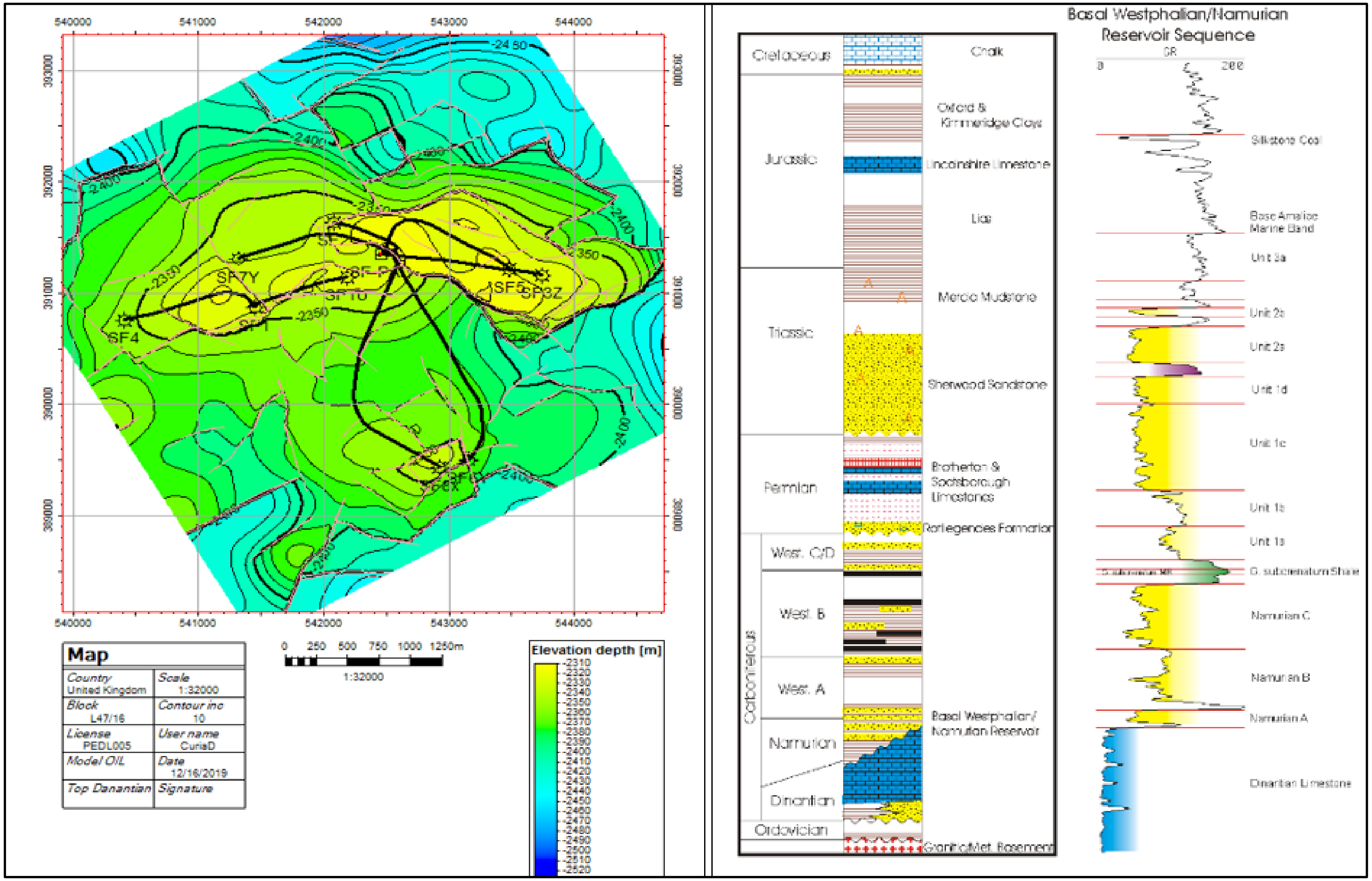

Figure 11 Structural at Top of Dinantian Limestone (Base of productive zone). Source: OIL

3. Description of the Field Development

Well fluids from well B7T are separated in a temporary separator and the gas is then comingled with the well fluids from A4 and B2 in the production separator, and thence to the intermediate stage compressor, followed by dewpoint control, export compression, metering and gas quality, and export. Condensate enters the condensate stabilisation tower and thence to storage and road tanker for sale.

Figure 12 to Figure 19 present the process schematic, aerial views of the Saltfleetby Gas Field, a plot plan, B7T completion design and well trajectory.

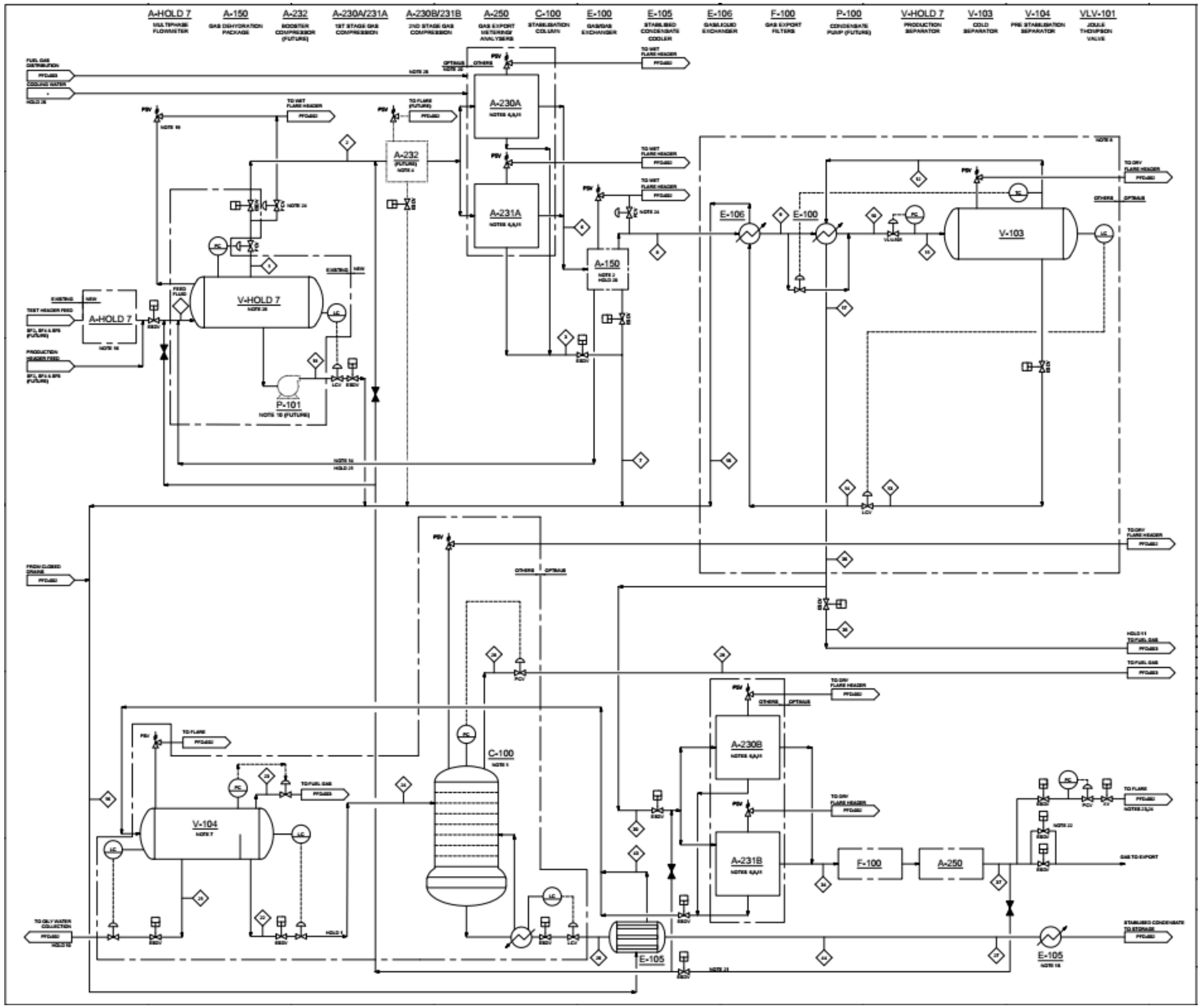

Figure 12 Gas and Liquid Processing Facility. Source: AEWB

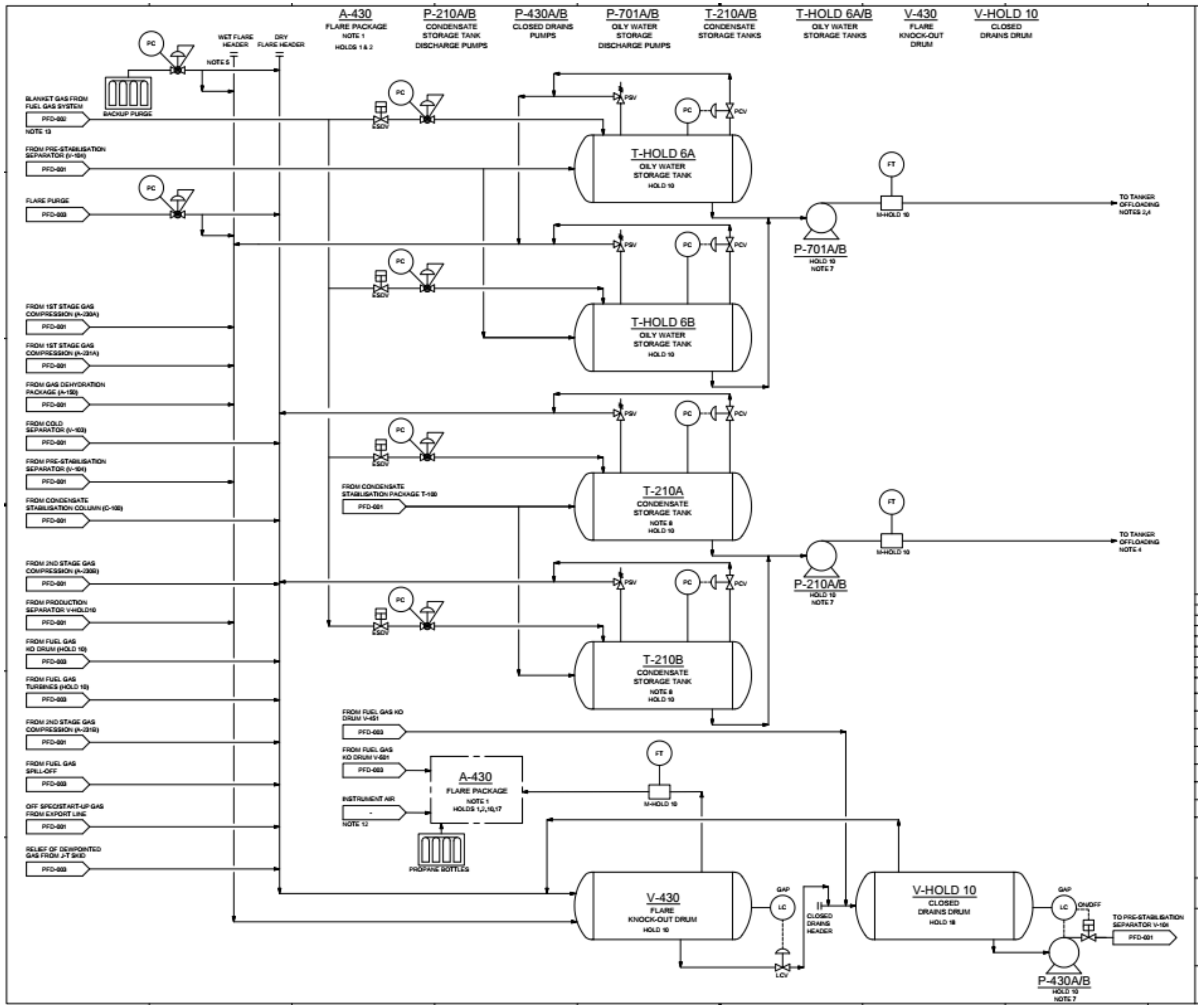

Figure 13 Condensate storage, oily water collection and flare system. Source: AEWB

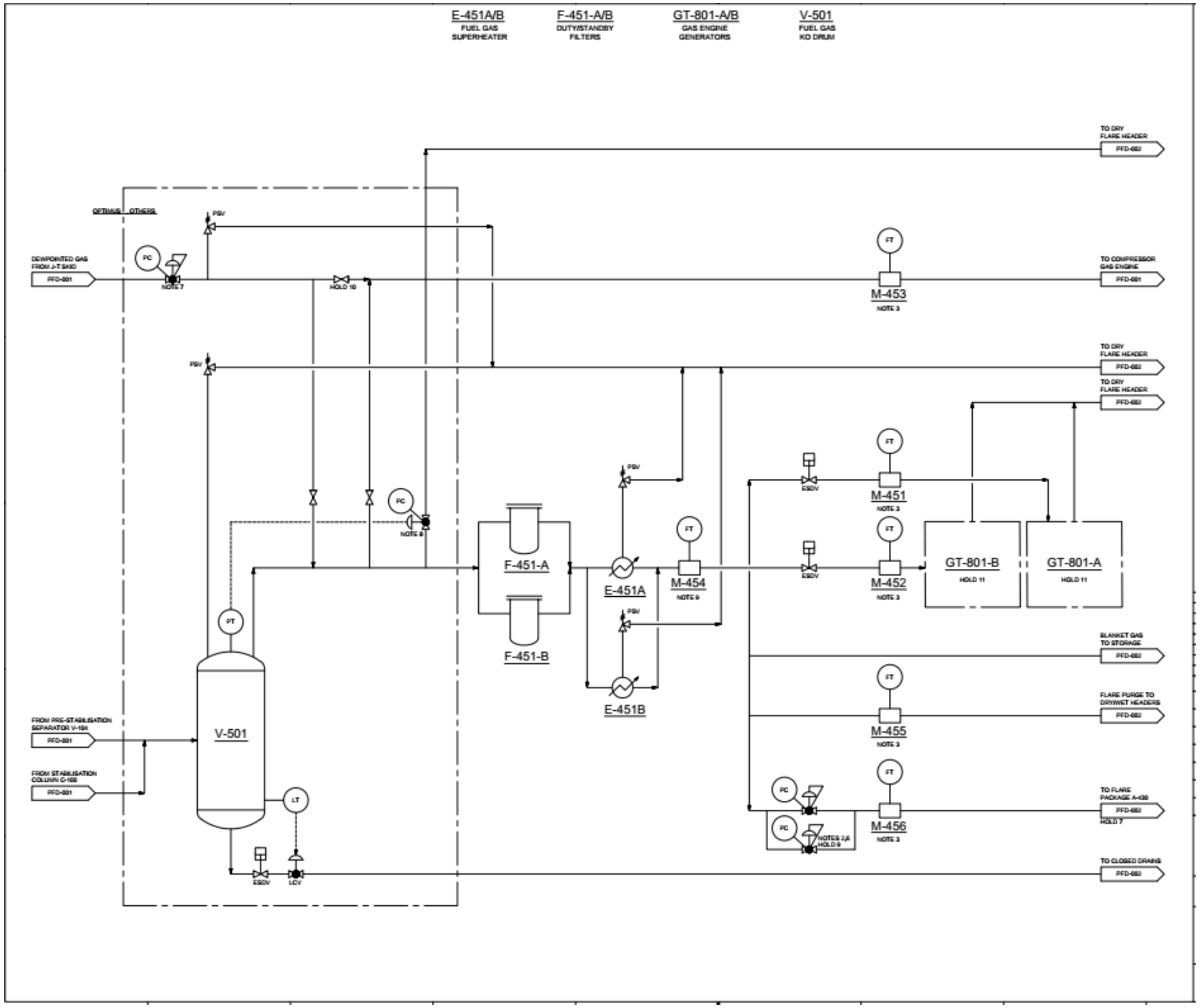

Figure 14 Fuel Gas System. Source: AEWB

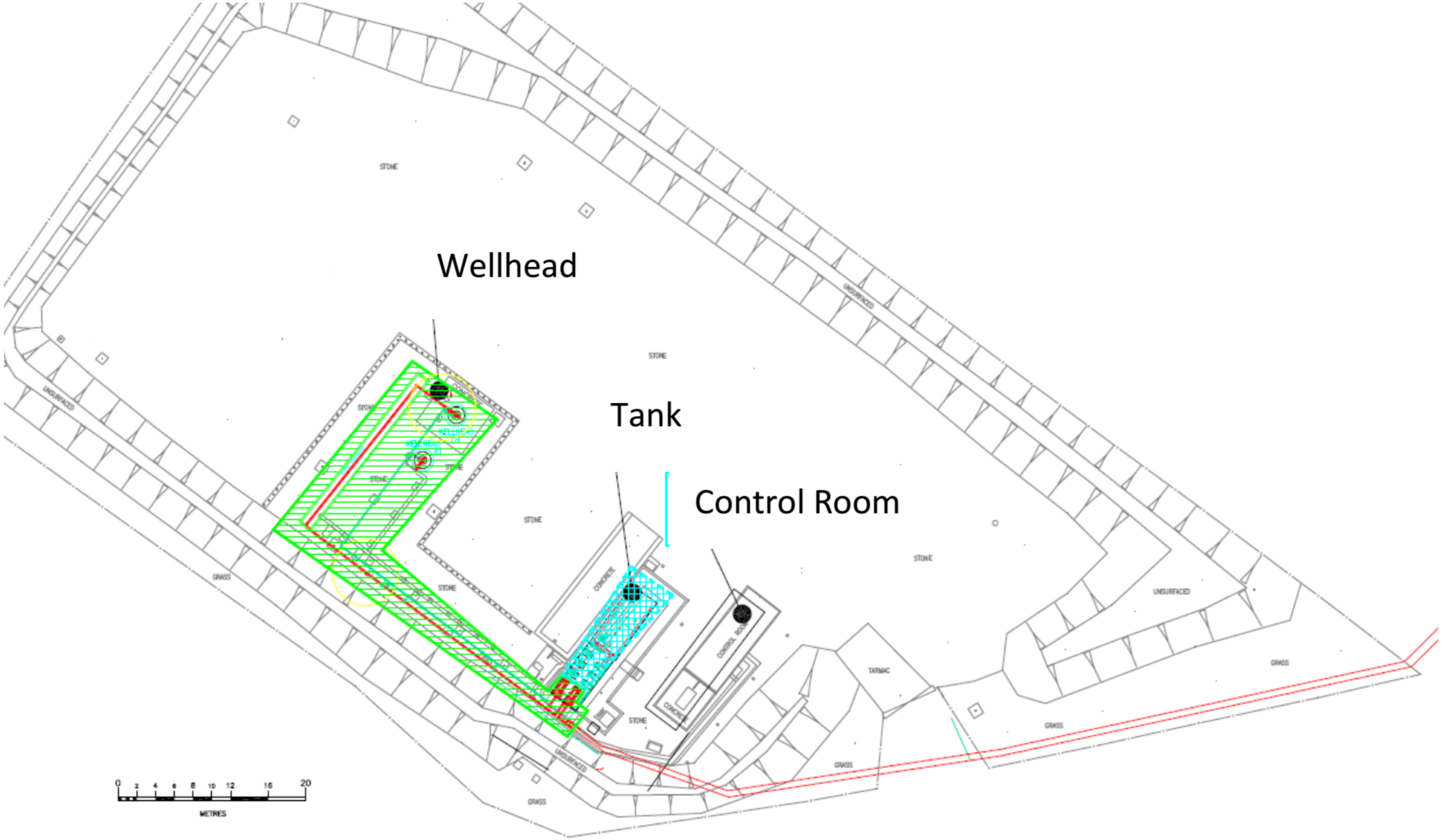

Figure 15 Site A: Existing equipment Layout including SF4 wellhead. Source: AEWB

Figure 16 Site A: Aerial photograph. Source: AEWB

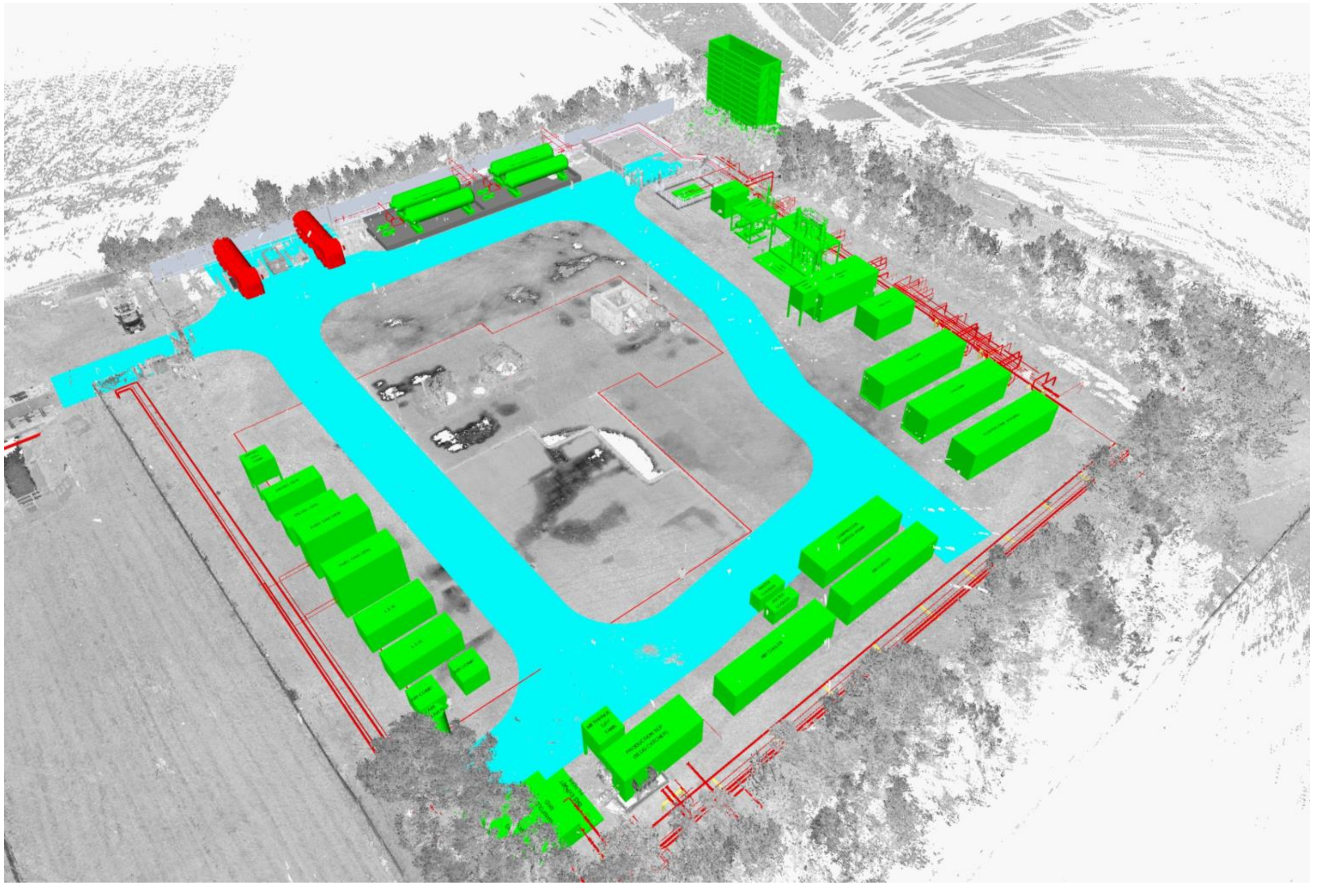

Figure 17 Location of New Processing Equipment on Site B Extension. Source AEWB

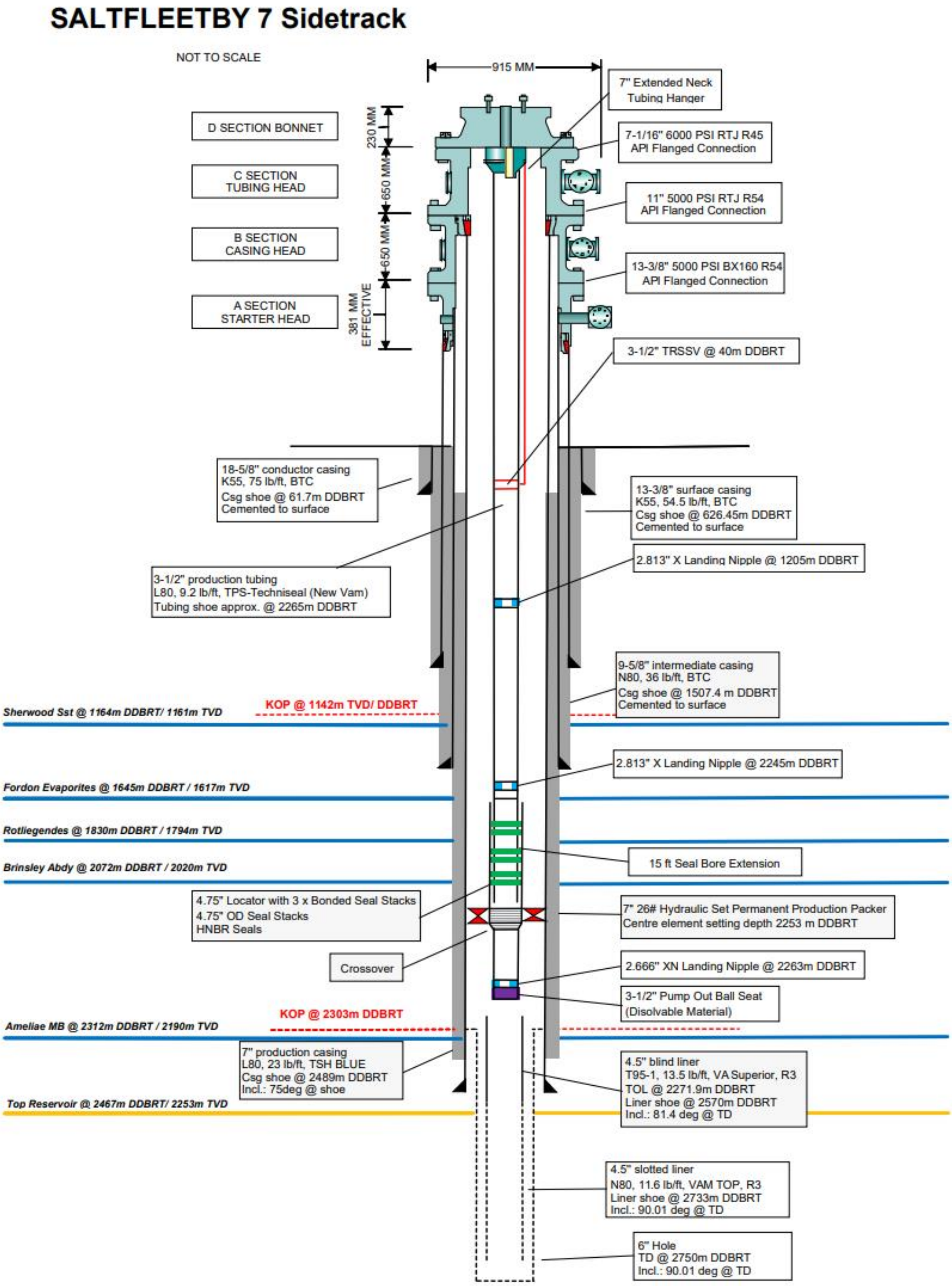

Figure 18 B7T Completion Design - the 180m lateral is open hole. Source AEWB

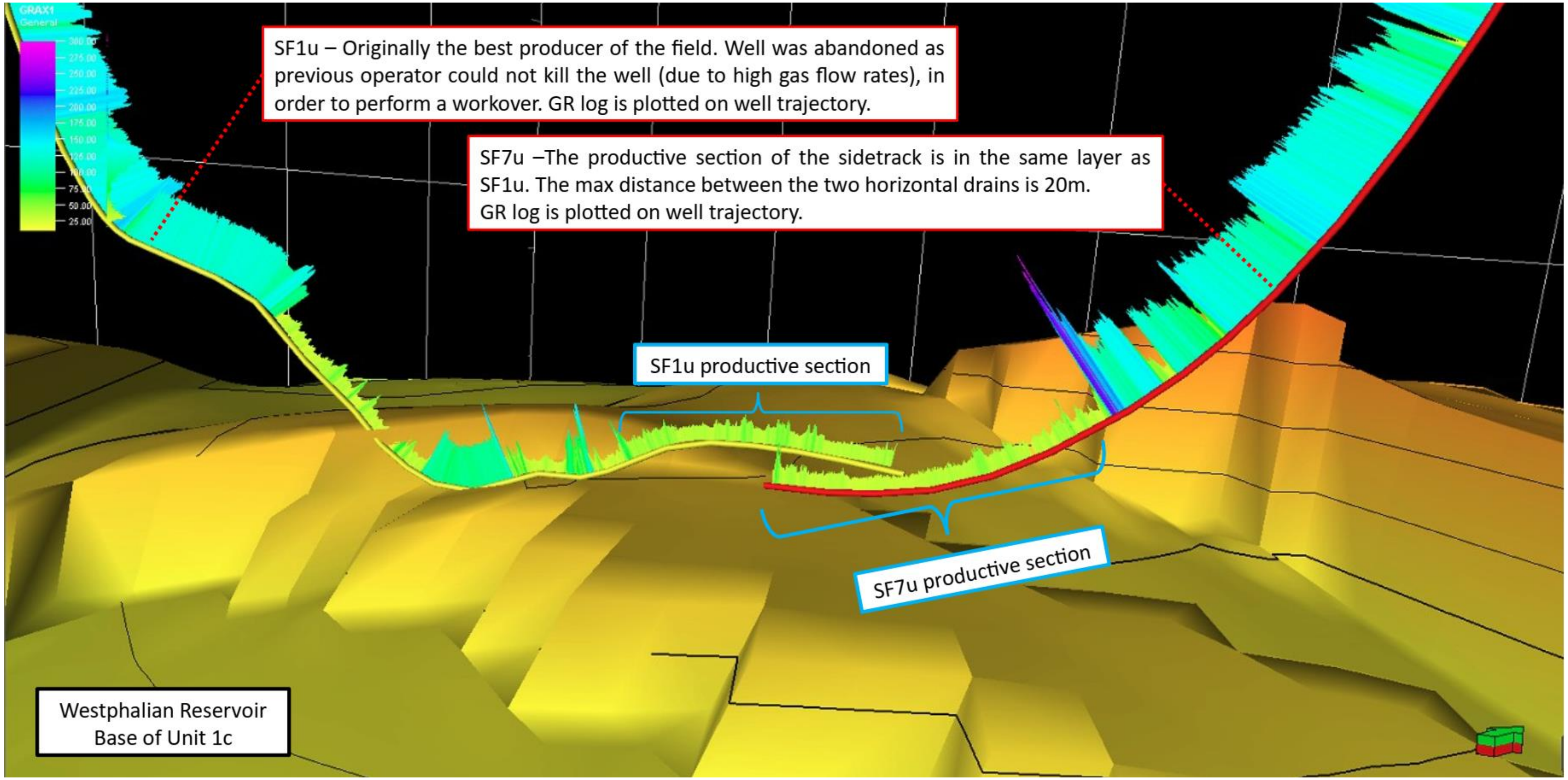

Figure 19 B7T (SF7U, later SF7T) Side-track runs parallel with the abandoned SF1U well, but approaches from Site B rather than Site A. The 180m lateral is open hole. Source: AEWB.

4. Determination of Remaining Recoverable Sales Gas and Liquids

Table 4-1 and Table 4-2 present respectively the probability distribution of Sales Gas[17] initially in place ("GIIP") and Condensate Liquids initially in place ("CIIP") for the Main Field, Westphalian Reservoir (the only target for the Development Plan). Figure 20 shows the material balance from the Main Field Westphalian reservoir, updated by a long shut-in in June 2023 which shows there is little uncertainty in the original gas in place: P90: 112 BCF; P50: 115 BCF.

4.1. Update to 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.

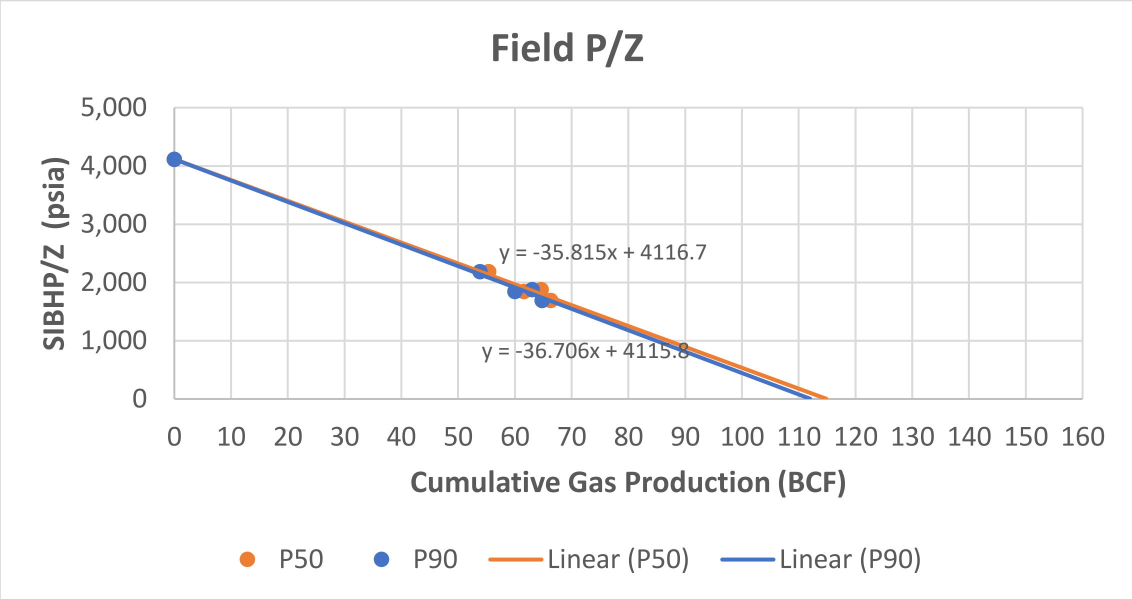

Figure 20 Extrapolation of historical pressure response (psia) to cumulative production (BCF): Main Westphalian Reservoir, Source: AEWB

[17] 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 the integrity of 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. AEWB reports that the export pressure typically has been 59 bara.

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

Saltfleetby Field	**Gross**		**Operator**
Sales Gas inc. CiO	**P90**	**P50**	
	BCF	BCF	
Main Field Westphalian Reservoir	112	115	AEWB

Effective Date: 1st August 2023
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	3,739	3,842	AEWB

Comma Separator is Thousands

Effective Date: 1st August 2023
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	64.75	1,062
Main Field Namurian Reservoir	1.53	29
Southern Satellite Westphalian Reservoir	2.05	34
Total Produced	**68.34**	**1,126**

Comma Separator is Thousands

Effective Date: 1st August 2023
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 (%) ("EUR") for Gas and Condensate Liquids. The EUR refers to technically recoverable gas and condensate liquids, potentially over many decades. **It is not a measure of potential economic recovery.**

Table 4-8 and Table 4-9 present respectively the remaining technically recoverable gas and condensate liquids.

Table 4-4 : Saltfleetby Gas Field: Remaining Sales Gas in Place including Consumed in Operations ("CiO"): Gross

Saltfleetby Field	**Gross**		**Operator**
Sales Gas including CiO	**P90**	**P50**	
	BCF	BCF	
Main Field Westphalian Reservoir	47.3	50.1	AEWB

Effective Date: 1st August 2023
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	2,677	2,780	AEWB

Comma Separator is Thousands

Effective Date: 1st August 2023
Source: Oilfield International

Table 4-6 Saltfleetby Gas Field: Sales Gas and Condensate Liquids Percentage Recovery to 31st July 2023

Saltfleetby Field	Sales Gas			Condensate Liquids	
	P90	P50		P90	P50
	%	%		%	%
Main Field Westphalian Reservoir	57.8%	56.4%		28.4%	27.6%

Effective Date: 1st August 2023
Source: Oilfield International

Table 4-7 Saltfleetby Gas Field: Sales Gas and Condensate Liquids Estimated Ultimate % Recovery Factor (a technical not an economic measure)

Saltfleetby Field	Sales Gas			Condensate Liquids	
	P90	P50		P90	P50
	%	%		%	%
Main Field Westphalian Reservoir	85%	87.5%		45%	47.5%

Effective Date: 1st August 2023
Source: Oilfield International

Table 4-8 Saltfleetby Gas Field: Remaining Technically Recoverable Sales Gas after subtracting 15% CiO P90 and 10% CiO P50: Gross.

Saltfleetby Field	**Expected Ultimate Recovery**	
Remaining Technically Recoverable Sales Gas	**P90**	**P50**
	BCF	BCF
Main Field Westphalian Reservoir	26.0	32.2

Effective Date: 1st August 2023

Source: Oilfield International

Table 4-9 Saltfleetby Gas Field: Remaining Technically Recoverable Condensate Liquids: Gross

Saltfleetby Field	**Expected Ultimate Recovery**	
Remaining Technically Recoverable Condensate Liquids	**P90**	**P50**
	M STB	M STB
Main Field Westphalian Reservoir	620.3	762.9

Effective Date: 1st August 2023

Source: Oilfield International

5. Sales Gas Flowrates and Flowing Wellhead Pressures since August 2022

The October 2021 development plan of 10 MMSCFD from three wells assumed the existing two wells, B2 and A4[18] would together produce approximately 5 MMSCFD sales gas, supplemented by another 5 MMSCFD from the new well, B7T. Table 5-1 presents the production from B2 and A4 from 30th August 2022 until 30th April 2023. The average flowrate from these two wells over the 244-day period was 5.2 MMSCFD sales gas.

The delayed third well, B7T, commenced production on 2nd May 2023 and Well A4 was shut-in to enable maintenance work and the connection and commissioning of the second compressor in early May. From 1st May to 28th July 2023, the average sales gas was 7.7 MMSCFD. The highest day average sales gas flowrate was 9.6 MMSCFD.

1.9775 BCF of sales gas was produced from 30th August 2022 to 31st July 2023 inclusive, compared with the CPR 2021 forecast of 3.113 BCF for the same number of calendar days. The reasons are the third well started production 8 months after first gas instead of at first gas; and its maximum flowrate capability is about 5.7 MMSCFD (average 4.1 MMSCFD) compared with a forecast 12-14 MMSCFD (planned 5 MMSCFD).

Figure 21 to Figure 24 present the flowrates and wellhead pressures for the three wells since August 2022 and a comparison of the aggregate wellhead gas flowrates vs sales gas flowrate.

[18] Wells B2 and A4 are also referred to as SF2 and SF4 in the October 2021 CPR.

Table 5-1 Sales Gas Production August 30th, 2022, to July 31st, 2023 (two wells until May 1st, 2023, then three wells)

Month	Avg Sales Gas Flowrate	Recorded Gas Sales for first 336 days		CV
	MMSCFD	MM Th	MMSCF	BTU/SCF
2 Wells on production during period to 30th April 23				
Aug 30-31 2022	0.6	0.01	1	1107
Sep-22	3.8	1.26	115	1099
Oct-22	5.4	1.86	168	1104
Nov-22	6.0	1.99	180	1107
Dec-22	5.3	1.80	163	1106
Jan-23	5.5	1.90	171	1107
Feb-23	5.4	1.67	150	1108
Mar-23	5.3	1.83	166	1106
Apr-23	5.3	1.75	158	1106
Total 244 days	5.21	14.07	1272	1106
B7T on production from 2nd May but A4 shut in for part of May, June, July				
May-23	7.4	2.54	230	1107
Jun-23	7.3	2.44	220	1107
Jul-23	9.1	2.83	255	1107
Total 92 days	7.67	7.81	705	1107
Grand Total Aug 30 22 to 31 July 23 (336 days)	**5.89**	**21.87**	**1977.5**	**1106**
CPR Oct 2021	Forecast Average Sales Gas Flowrate	Forecast Gas sales for first 336 days		Forecast CV
	MMSCFD	MM Th	MMSCF	BTU/SCF
3 Wells on production from first gas (95% availability plus 7 day shutdown)				
15 Mar 22 to 13 Feb 23 (336 days)	**10.0**	**34.24**	**3113**	**1100**

Oilfield International

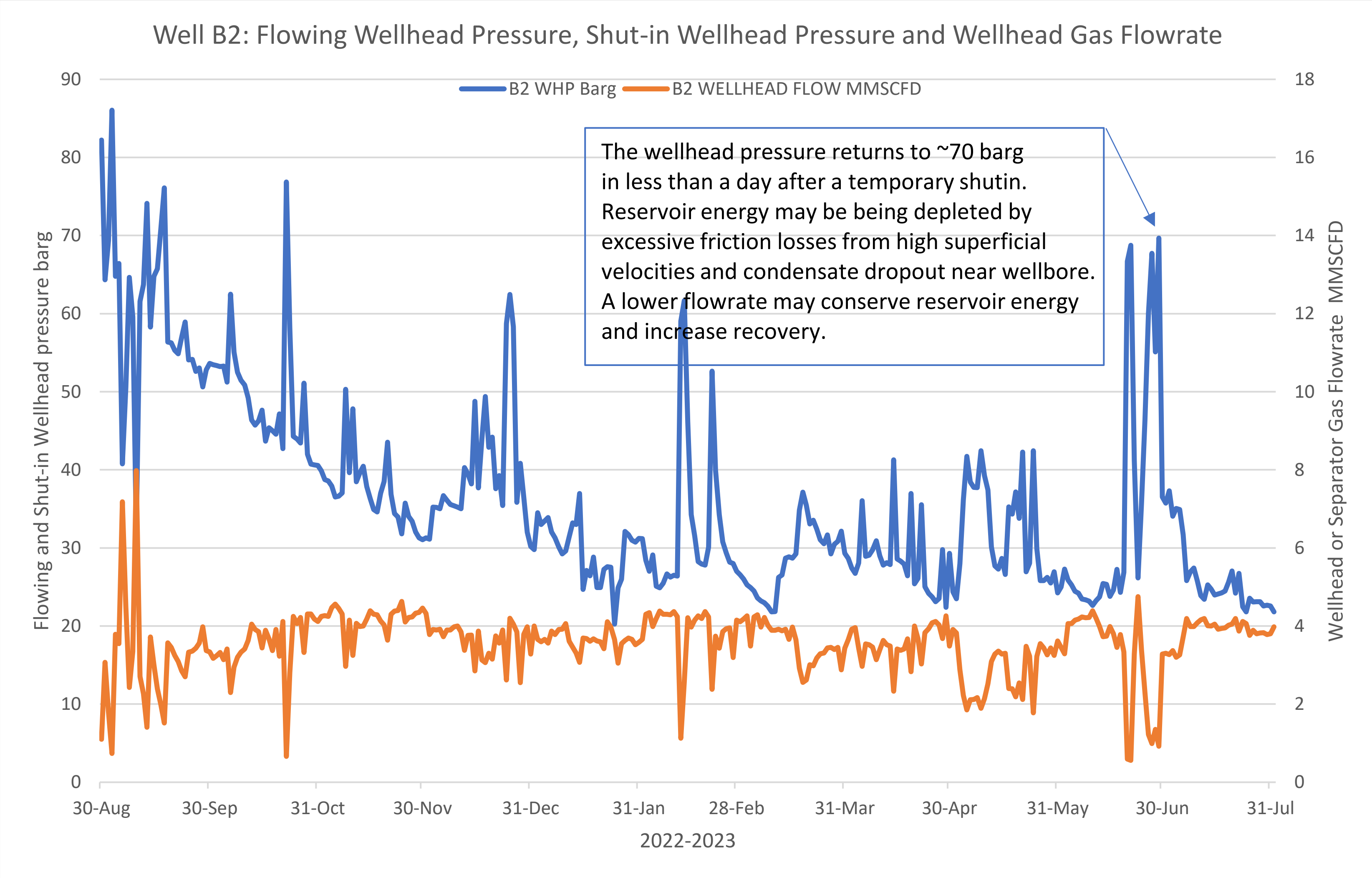

Figure 21 Well B2: Flowrates and Wellhead pressures since August 2022

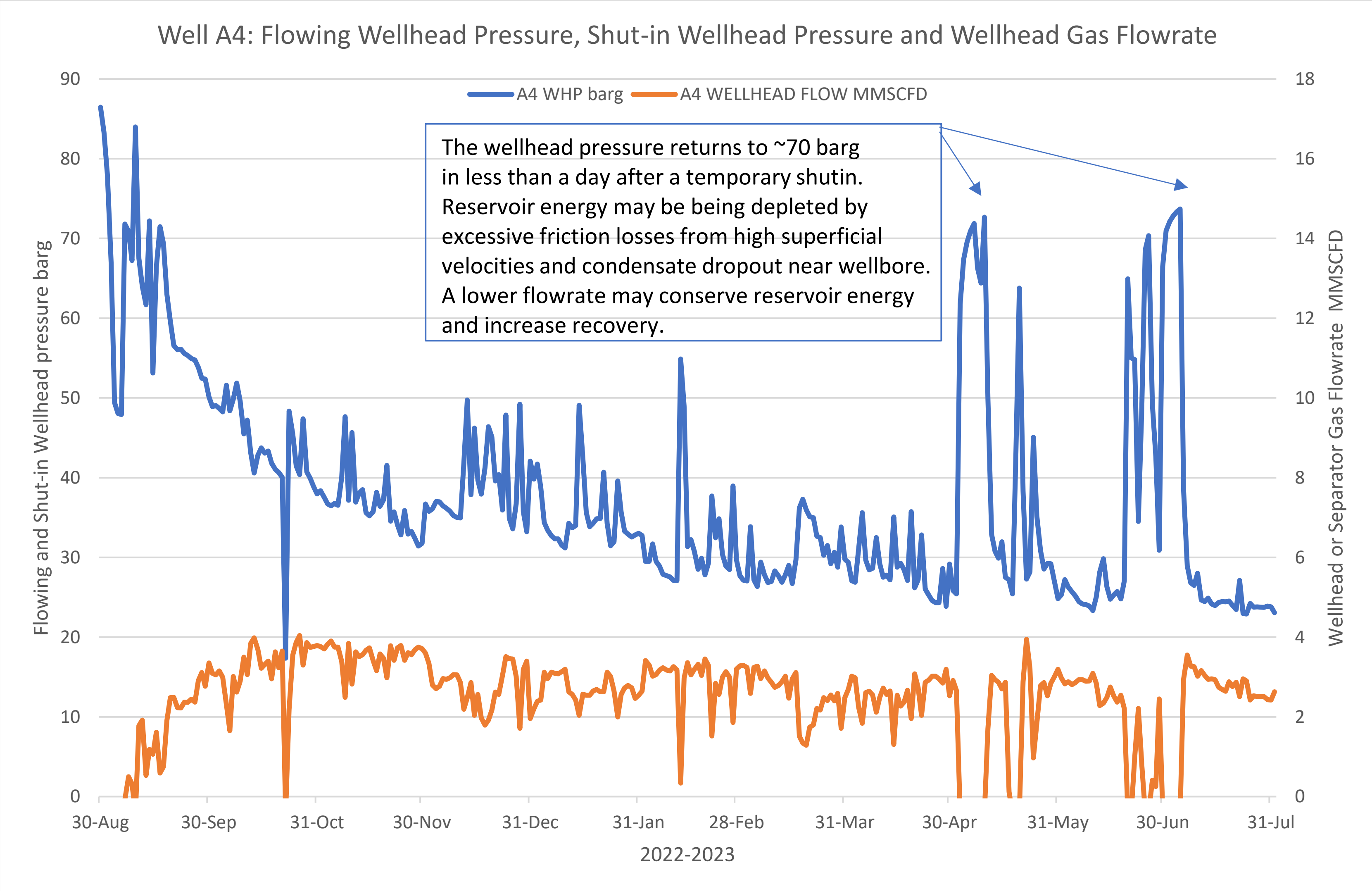

Figure 22 Well A4: Flowrates and Wellhead pressures since August 2022

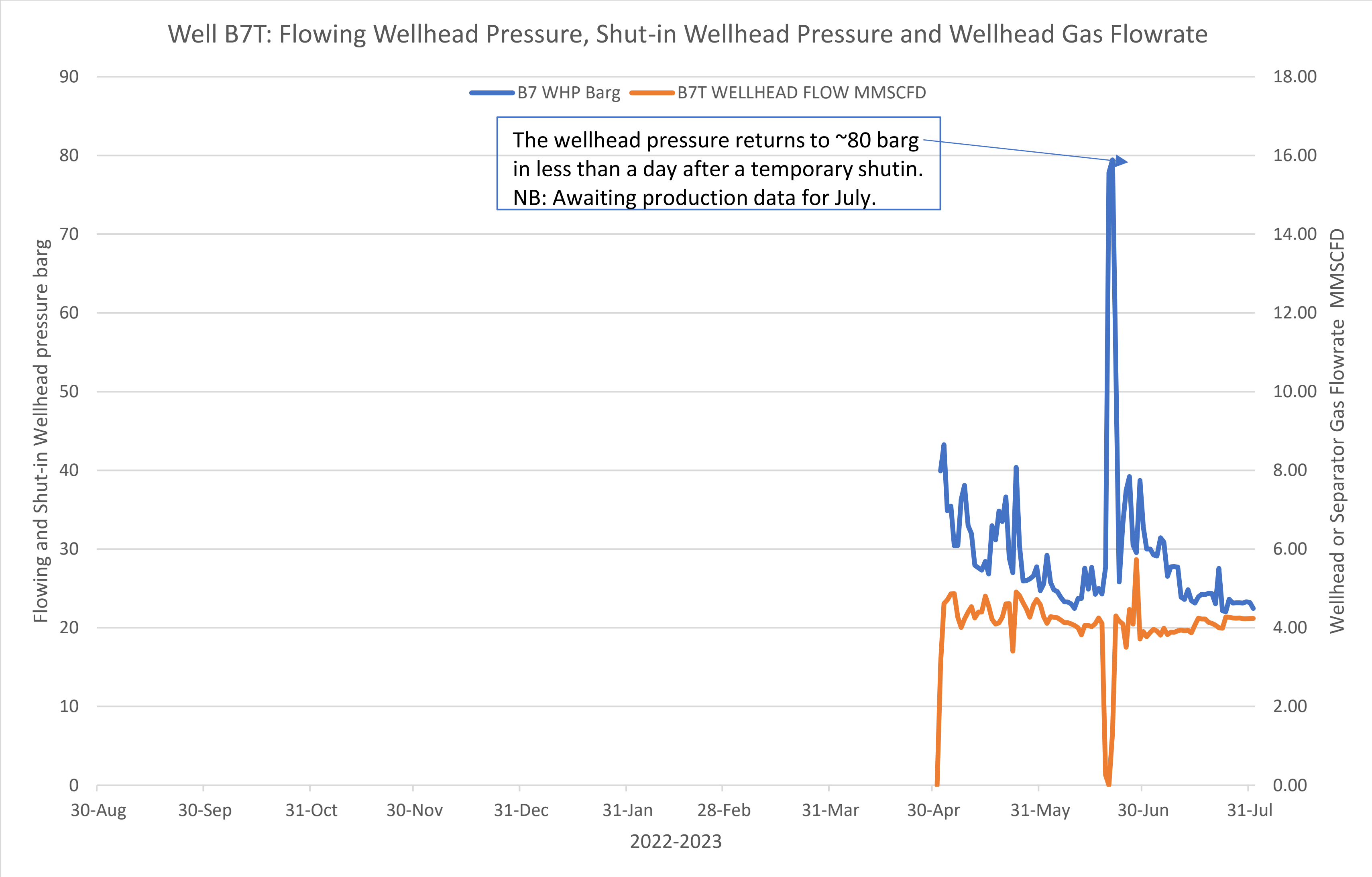

Figure 23 Well B7T: Wellhead pressures May to July 2023. Flowrates May-July 2023

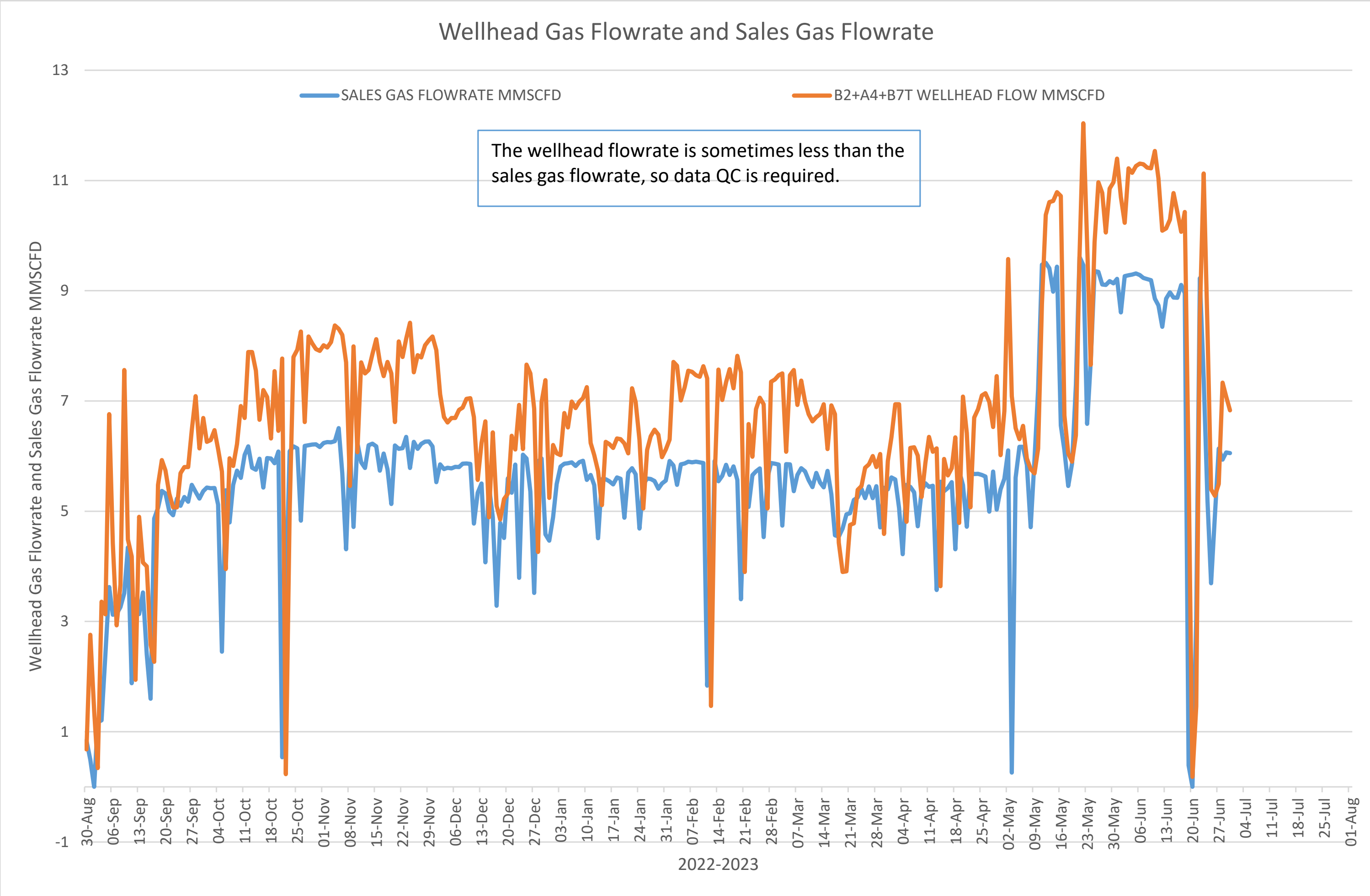

Figure 24 Comparison of Wellhead Gas Flowrate and Sales Gas Flowrate from August 2022

6. <u>Sales Condensate Production since August 2022</u>

AEWB reports that 31,271 bbls of condensate have been sold from wells A4 and B2 from August 30th, 2022, to August 1st, 2023. This implies a <u>sales</u> condensate flowrate of about 94 bbls/d. However, roughly 40 bbl/d condensate from well B7T is not included in these sales figures because it has been out of sales specification since the well started production. Wells B2 and A4 produce about 21-23 bbls condensate / MMSCF of sales gas. Interestingly, since it started production in May 2023, well B7T is producing at a lower CGR, 14 - 16 bbl/MMSCF. Table 6-1 refers. The combined CGR at the Effective Date is 18.8 bbl/MMSCF.

Table 6-1 2023 Condensate / Sales Gas Ratios (bbl/MMSCF)

Well	March	April	May	June	July
B2	23	21	22	21	-
A4	23	21	22	21	-
B7T	-	-	14	16	15

AEWB's reservoir simulation calculates an August 2023 CGR of 10 bbl/MMSCF which is a poor match which may partly be due to B7T condensate not being recorded as sales condensate. The simulation also forecasts the CGR rises by end of life to 15 bbl/MMSCF, which is not typical of a retrograde condensate reservoir, but the PVT properties of the reservoir fluid have been matched and so a certain credence is due to the simulation.

To balance this contradictory information, this report assumes:

- P90: 18.8 bbl/MMSCF until the end of 2024, then decline linearly to 5 bbl/MMSCF in 2038. A constant CGR of 15 bbl/MMSCF produces similar recovered volumes.
- P50: 18.8 bbl/MMSCF until the end of 2024, then decline linearly to 11 bbl/MMSCF in 2038. A constant CGR of 17 bbl/MMSCF produces similar recovered volumes.

7. Water Production since August 2022

Well B2 produces almost no water and there are insufficient data on Well B7T since it is still cleaning up. Well A4 produced water between 2012 and 2017 and Table 7-1 indicates that it continues to do so - the WGR has increased since October 2022. AEWB has planned to install an "accelerator string" in this well when the WGR becomes too high to lift.

Table 7-1 Water production from Well A4 (SF4)

Month	Water Production	Gas production	WGR
	bbl pcm	MMSCF pcm	bbl/MMSCF
Oct-22	358	90	4
Nov-22	626	106	6
Dec-22	624	76	8
Jan-23	938	76	12
Feb-23	718	69	10
Mar-23	1019	75	14
Apr-23	1117	72	15
May-23	588	44	13
Jun-23	541	41	13

AEWB is also investigating surface jet pumps and down-hole gas-lift to lift condensate and water from the wells if necessary.

8. Development Plan Production Profiles

The Development Plan targets the remaining hydrocarbons in the Westphalian reservoir of the Main Field by producing from five wells. The wells on production are SF2, SF4 and a new B7T (SF7T) 180m horizontal side-track. Two new wells, SF9 and SF10 will be drilled on the eastern high where there are no wells at the moment. SF9 is scheduled to come on stream in January 2025; and SF10 in January 2026. The wells have the same completion design as the B7T well but have 450m laterals (which was the original intention for the B7T well). The location of the new wells is shown in Figure 25.

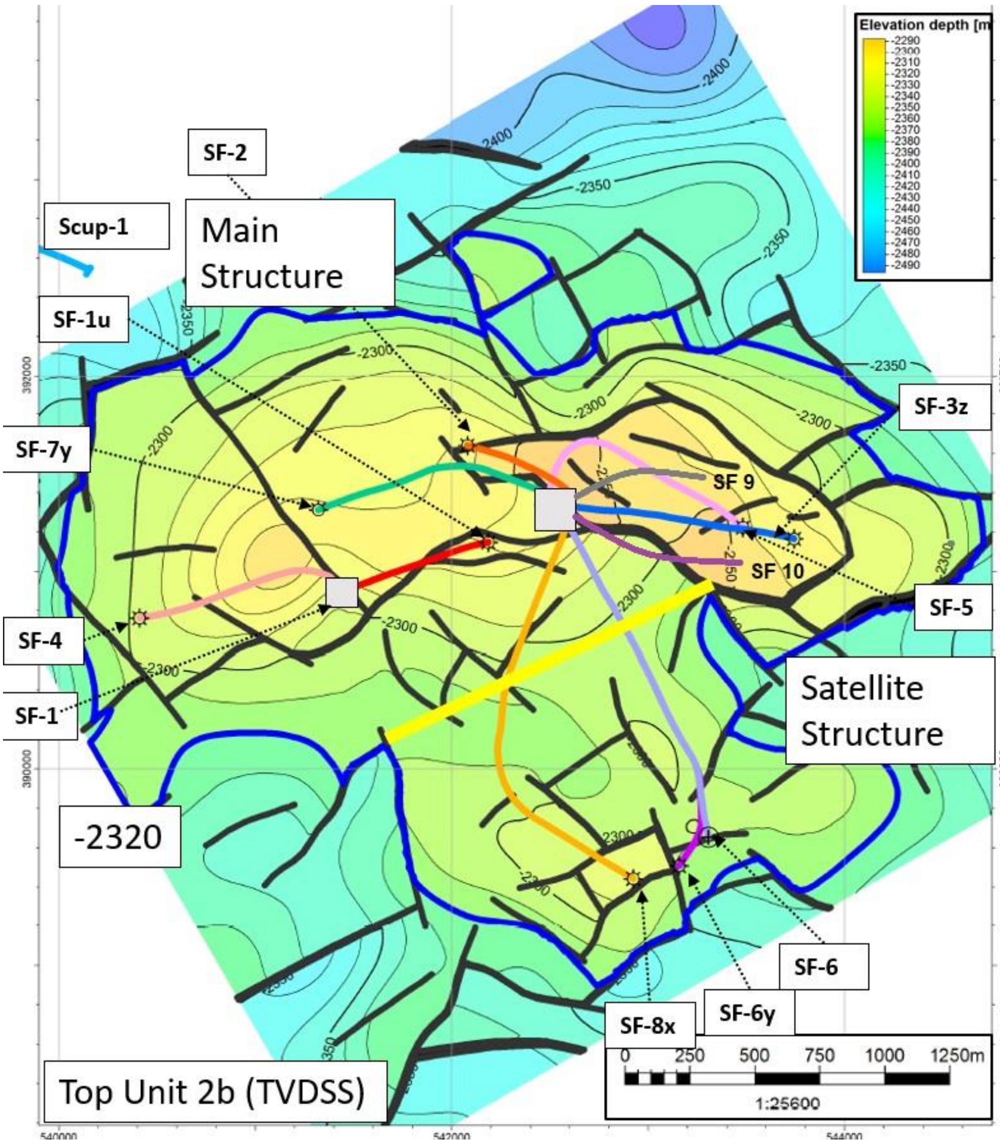

Figure 25 Location of two new wells, SF9 (grey) and SF10 (mauve)

Table 8-1 and Figure 26 present the P90 development plan and production profiles. These have been generated by AEWB using Rock Flow Dynamics' tNavigator[19] reservoir simulation software and verified by OIL. The wellhead gas flowrates have been adjusted for an uptime of 92.65%. The profiles have been cut off by the software at an aggregate field flowrate of 1 MMSCFD. For the economic analysis, OIL has applied a further cutoff of 0.5 MMSCFD per well[20] and Table 8-2 presents these production profiles as sales gas by applying a gas CiO of 15%. AE has requested that future cash flows be calculated for the 9 MMSCFD sales gas plateau from January 2025 for the reserves determination.

Table 8-3 and Figure 27 present the tNavigator-generated P50 development plan and production profiles, again cut-off by the software at 1 MMSCFD. These have been generated by AEWB and verified by OIL. The wellhead gas flowrates have been adjusted for an uptime of 92.65%. Again, for the economic analysis, OIL has applied a further cutoff of 0.5 MMSCFD per well and Table 8-4 presents these production profiles as sales gas by applying a gas CiO of 10%. AE has requested that future cash flows be calculated for the 9 MMSCFD sales gas plateau from January 2025 for the reserves determination.

The accuracy of the history match of the AEWB simulation for the period 2012-2017 is presented in Figure 28 and Figure 29. Consistent with this being the P90 case, the forecast is biased slightly below the actuals. The P50 history match is presented in Figure 30 and Figure 31. The period 2022 to 2023 was volatile for the reasons discussed earlier and a good match was not possible.

A mass balance simulation using the wellhead P/Z vs Gp relationship for the aggregate production of the three wells was undertaken by AEWB. It forecasts a sales gas recovery of 24 BCF to 2039 for a 10% CiO, refer to Figure 32 and Figure 33. The theoretical basis for the plot is robust.

[19] https://rfdyn.com/tnavigator-22-2-available-now/

[20] This may require a jet pump or gas lift if liquid loading constrains the well.

Table 8-1 Description of P90 Flowrate Scenarios for tNavigator Simulations

Description of Scenario	Wellhead Gas Plateau Flowrate exc. Unavailability	Annual Average Wellhead Gas Plateau Flowrate, inc. Unavailability		Sales Gas Plateau Flowrate, exc. Unavailability	Annual Average Sales Gas Plateau Flowrate inc. Unavailability
	MMSCFD	MMSCFD		MMSCFD	MMSCFD
(I) P90 Reservoir model from P90 Automated History Match					
From 1st August 2023 to 31st December 2024					
Flow at 9 MMSCFD wellhead gas (excluding 92.65% availability	9	8.34		7.65	7.09
From January 1st 2025					
Scenario 1: Plateau: 3285 MMSCF of sales gas per year.	11.43	10.59		9.71	9
Scenario 2: Plateau: 3650 MMSCF of sales gas per year.	12.70	11.76		10.79	10
Scenario 3: Plateau: 4015 MMSCF of sales gas per year.	13.97	12.94		11.87	11
Scenario 4: Plateau: 3285 MMSCF of sales gas per year. 300m laterals instead of 450m for the two new wells.	12.70	10.59		10.79	10

Availability	92.65%	
P90 Gas Consumed in Operations	15%	of wellhead gas

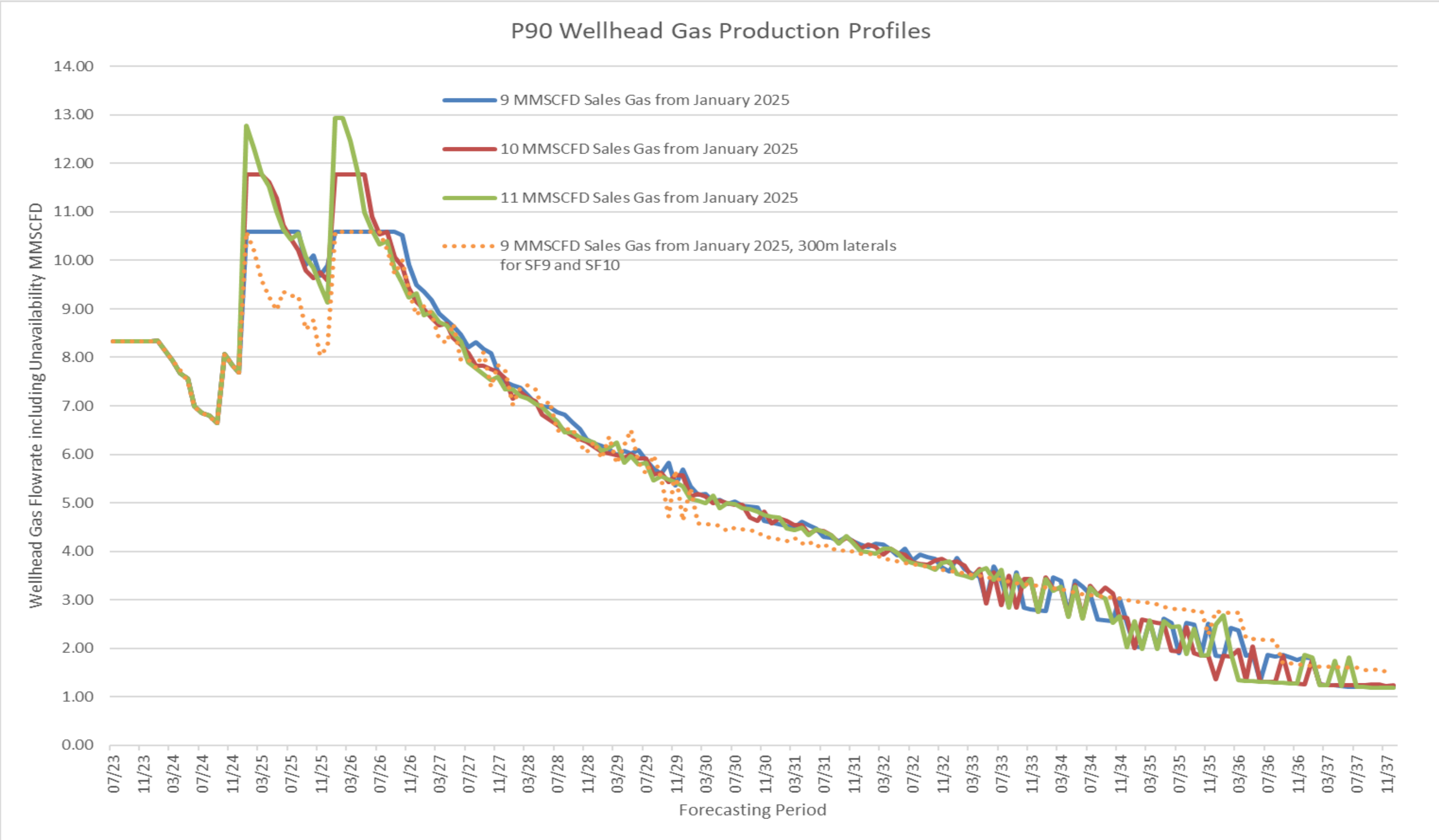

Figure 26 P90 Wellhead Gas Production Profiles including 92.65% availability. Source: AEWB/tNavigator, verified by OIL

Table 8-2 P90 Sales Gas and Sales Condensate Production Profiles; 92.65% availability, 15% Gas CiO, 0.5 MMSCFD/well cutoff

Year	Sales Gas Plateau: 9 MMSCFD				Sales Gas Plateau: 10 MMSCFD				Sales Gas Plateau: 11 MMSCFD				Sales Gas Plateau: 9 MMSCFD - 300m laterals for SF9 & SF10			
	Sales Gas		Condensate		Sales Gas		Condensate		Sales Gas		Condensate		Sales Gas		Condensate	
	MMSCFD	BCF	bbl/d	M bbl	MMSCFD	BCF	bbl/d	M bbl	MMSCFD	BCF	bbl/d	M bbl	MMSCFD	BCF	bbl/d	M bbl
5M 2023	7.1	1.08	133	20	7.1	1.08	133	20	7.1	1.08	133	20	7.1	1.08	133	20
2024	6.4	2.35	121	44	6.4	2.35	121	44	6.4	2.35	121	44	6.4	2.35	120	44
2025	8.8	3.21	161	59	9.1	3.32	166	61	9.2	3.35	167	61	7.8	2.85	142	52
2026	8.9	3.24	152	56	9.2	3.34	157	57	9.2	3.37	159	58	8.7	3.16	149	54
2027	7.2	2.62	116	42	7.0	2.55	113	41	6.9	2.53	112	41	6.9	2.53	112	41
2028	5.8	2.14	88	32	5.7	2.08	86	31	5.7	2.10	86	32	5.8	2.11	87	32
2029	5.0	1.82	70	25	4.9	1.80	69	25	4.9	1.79	68	25	4.9	1.78	68	25
2030	4.2	1.55	55	20	4.2	1.53	54	20	4.2	1.53	54	20	3.8	1.40	50	18
2031	3.7	1.36	44	16	3.7	1.36	44	16	3.7	1.35	44	16	3.5	1.28	41	15
2032	3.3	1.22	36	13	3.3	1.21	36	13	3.3	1.20	35	13	3.2	1.17	35	13
2033	2.8	1.02	27	10	2.8	1.03	28	10	2.9	1.05	28	10	2.9	1.06	28	10
2034	2.5	0.91	22	8	2.6	0.95	23	8	2.5	0.91	22	8	2.7	0.97	23	8
2035	1.9	0.70	15	5	1.8	0.66	14	5	1.9	0.70	15	5	2.4	0.87	18	7
2036	1.6	0.59	11	4	1.3	0.48	9	3	1.3	0.47	9	3	1.8	0.67	12	4
2037	1.1	0.39	6	2	1.1	0.40	6	2	1.1	0.42	6	2	1.3	0.49	7	3
Total		**24.2**		**357.1**		**24.1**		**357.8**		**24.2**		**358.4**		**23.8**		**346.6**

Source: AEWB, verified by OIL.

Table 8-3 Description of P50 Flowrate Scenarios for tNavigator Simulations

Description of Scenario	Wellhead Gas Plateau Flowrate exc. Unavailability	Annual Average Wellhead Gas Plateau Flowrate, inc. Unavailability		Sales Gas Plateau Flowrate, exc. Unavailability	Annual Average Sales Gas Plateau Flowrate inc. Unavailability
	MMSCFD	MMSCFD		MMSCFD	MMSCFD
(I) P50 Reservoir model from P50 Automated History Match					
From 1st August 2023 to 31st December 2024					
Flow at 9 MMSCFD wellhead gas (excluding 92.65% availability	9	8.34		8.10	7.50
From January 1st 2025					
Scenario 1: Plateau: 3285 MMSCF of sales gas per year.	10.79	10.00		9.71	9
Scenario 2: Plateau: 3650 MMSCF of sales gas per year.	11.99	11.11		10.79	10
Scenario 3: Plateau: 4015 MMSCF of sales gas per year.	13.19	12.22		11.87	11
Scenario 4: Plateau: 3285 MMSCF of sales gas per year. 300m laterals instead of 450m for the two new wells.	11.99	10.00		10.79	10

Availability	92.65%	
P50 Gas Consumed in operations	10%	of wellhead gas

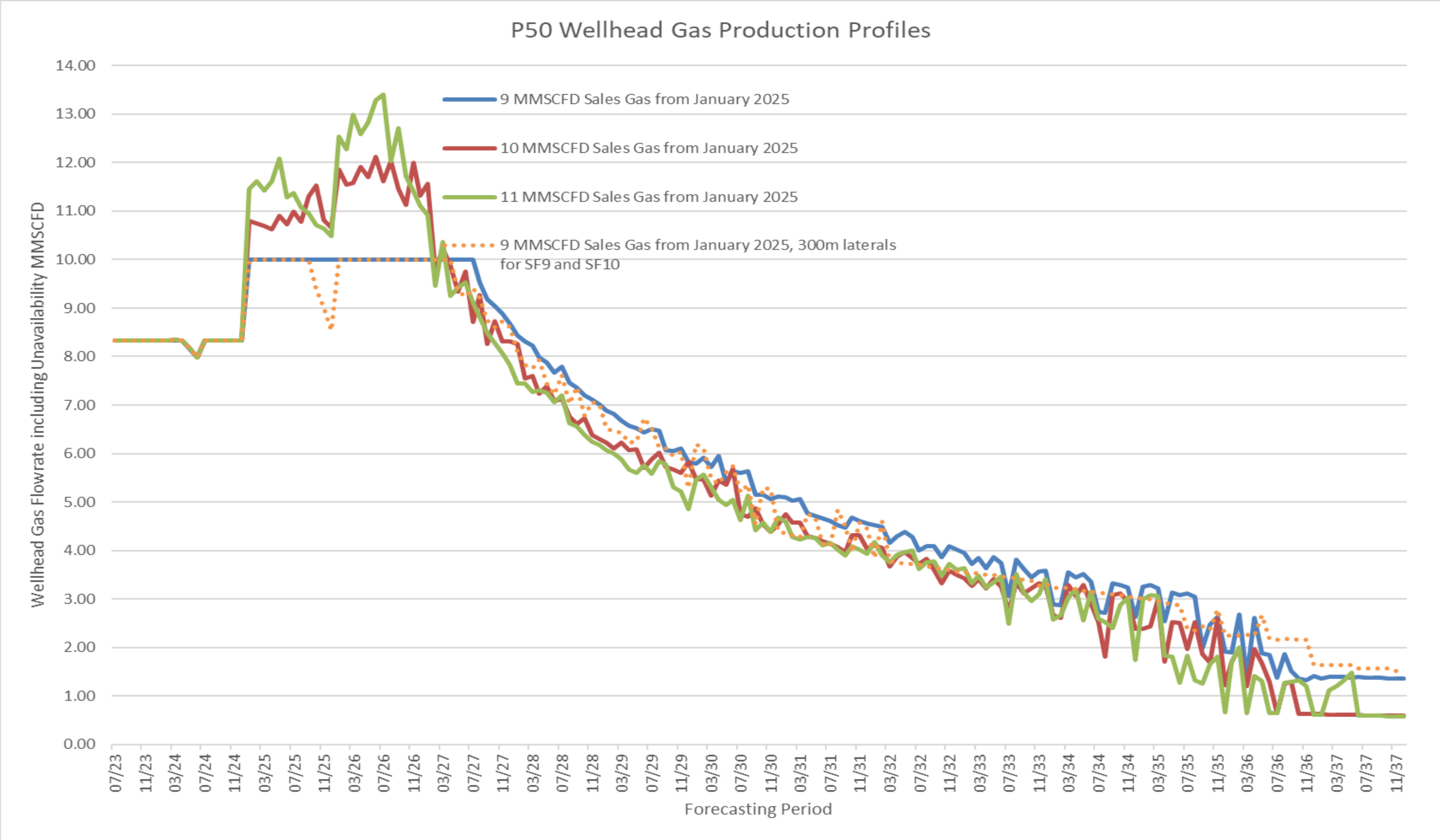

Figure 27 P50 Wellhead Gas Production Profiles including 92.65% availability. Source: AEWB/tNavigator, verified by OIL.

Table 8-4 P50 Sales Gas and Sales Condensate Production Profiles; 92.65% availability, 10% Gas CiO, 0.5 MMSCFD/well cutoff

Year	Sales Gas Plateau: 9 MMSCFD				Sales Gas Plateau: 10 MMSCFD				Sales Gas Plateau: 11 MMSCFD				Sales Gas Plateau: 9 MMSCFD - 300m laterals for SF9 & SF10			
	Sales Gas		Condensate		Sales Gas		Condensate		Sales Gas		Condensate		Sales Gas		Condensate	
	MMSCFD	BCF	bbl/d	M bbl	MMSCFD	BCF	bbl/d	M bbl	MMSCFD	BCF	bbl/d	M bbl	MMSCFD	BCF	bbl/d	M bbl
5M 2023	7.5	1.15	141	21.6	7.5	1.15	141	22	7.5	1.15	141	22	7.5	1.15	141	22
2024	7.5	2.73	140	51.4	7.5	2.73	140	51	7.5	2.73	140	51	7.5	2.73	140	51
2025	9.0	3.28	166	60.7	9.8	3.57	181	66	10.1	3.69	187	68	8.8	3.20	162	59
2026	9.0	3.28	161	58.7	10.5	3.84	188	69	11.2	4.08	200	73	9.0	3.28	161	59
2027	8.6	3.16	149	54.5	8.4	3.07	145	53	8.2	3.00	142	52	8.4	3.06	145	53
2028	6.9	2.54	116	42.3	6.4	2.33	106	39	6.2	2.28	104	38	6.7	2.45	112	41
2029	5.8	2.11	93	33.9	5.3	1.95	86	31	5.1	1.85	81	30	5.6	2.04	90	33
2030	5.0	1.81	77	28.0	4.5	1.65	70	26	4.4	1.62	69	25	4.8	1.77	75	27
2031	4.3	1.55	63	23.1	3.9	1.41	57	21	3.7	1.37	56	20	4.0	1.45	59	22
2032	3.8	1.38	54	19.7	3.4	1.24	48	18	3.4	1.25	49	18	3.4	1.24	48	18
2033	3.3	1.20	45	16.4	2.9	1.07	40	15	2.9	1.07	40	15	3.1	1.13	42	15
2034	2.8	1.03	37	13.5	2.5	0.92	33	12	2.4	0.89	32	12	2.8	1.03	37	14
2035	2.5	0.92	32	11.5	2.0	0.72	25	9	1.7	0.62	21	8	2.4	0.88	30	11
2036	1.6	0.58	19	6.9	1.1	0.41	13	5	1.1	0.39	13	5	2.0	0.72	24	9
2037	1.2	0.45	14	5.1	0.5	0.20	6	2	0.7	0.27	8	3	1.4	0.52	16	6
Total		**27.2**		**447.3**		**26.3**		**438.0**		**26.2**		**438.4**		**26.7**		**438.5**

Source: AEWB, verified by OIL.

9. Discounted Cash Flow Valuation

OIL has estimated net present values at 10% discount factor for the 9 MMSCFD sales gas plateau production scenario in Table 8-2 and Table 8-4.

Table 9-1 to Table 9-7 present the summary inputs to the economic model for the Development Plan. Table 9-8 to Table 9-11 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 AE, the reserves and NPVs quoted in this report include the loan terms.

Table 9-12 presents the sensitivity of the post tax NCF and NPV10 attributable to AE for higher sales gas flowrates and a 300m lateral (instead of the planned 450m).

The commodity prices used were from August 1st, 2023 and the cash flows were discounted to August 1st, 2023, using mid-year discounting. The cash flows were calculated on a monthly basis and aggregated to yearly for ease of display.

Table 9-1 presents the operator's capital cost estimates to extend plateau with a booster compressor and accelerator string for well A4 (SF4), and the addition of two wells: SF9 and SF10.

AE's 2023/24 opex budget is presented in Table 9-2. Some of the expenses are temporary, and AE forecasts a minimum 20% reduction in real terms opex for 24/25 onwards. OIL has escalated from 2025 by 2% pa. From 2035, opex is reduced by 3.5% pa (1.5% Real Terms) reflecting normal practice to extend field life. OIL has included a further £50,000 pa for field G&A, escalated by 2% pa from 2025.

Table 9-1 Remaining Capex Assumptions for Cash Flow Forecasts, Saltfleetby Field

Investment	**P90**	**P50**	**Forecast Date Operational**
	£m 2023	£m 2023	
Accelerator String for Well A4	£0.7	£0.5	P90: 01/05/2024, P50: 01/02/2024
Booster Compressor	£2.6	£2.3	P90 & P50: 01/10/2024
Well SF9	£5.7	£5.7	P90 & P50: 01/01/2025
Well SF10	£5.7	£5.7	P90 & P50: 01/01/2026
Abandonment	£4.7	£4.7	2038
Total	**£19.3**	**£18.9**	
Year	**P90**	**P50**	
	£m MOD	£m MOD	
2023	£0.7	£0.7	
2024	£8.5	£8.1	
2025	£5.9	£5.9	
2026			
2027			
2038 Abandon	£6.3	£6.3	
Total	**£21.4**	**£20.9**	

2023 money; and Money-of-the-day

Effective Date: 1st August 2023
Source: AEWB. OIL is not able to verify the accuracy of AEWB's above cost estimates and schedules.

Table 9-2 2023/24 Opex Budget for Cash Flow Forecasts

Assumptions			Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24
CPI (UK)	5.00	%	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	0.17%
	Production		Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24
OPEX			Budget	Budget	Budget	Budget	Budget	Budget	Budget	Budget	Budget	Budget	Budget	Budget	Budget
Fixed costs															
Direct employment costs	975,300	pa	81,275	81,275	81,275	81,275	81,275	81,275	81,275	81,275	81,275	81,275	81,275	81,275	
Security costs	133,200	pa	11,100	11,100	11,100	11,100	11,100	11,100	11,100	11,100	11,100	11,100	11,100	11,100	
NSTA (OGA)	64,000	pa										64,000			
Site lease costs A lease	7,800	pa			3,700			4,100							
Site lease costs B lease	27,000	pa	1,250		17,750			8,000							
Louth office	49,000	pa	1,167	9,917	1,167	1,167	9,917	1,167	1,167	9,917	1,167	1,167	9,917	1,167	
G&A recharges	-	pa	-	-	-	-	-	-	-	-	-	-	-	-	
Variable costs															
Site/Well Maintenance	1,230,728	pa	102,561	102,561	102,561	102,561	102,561	102,561	102,561	102,561	102,561	102,561	102,561	102,561	
Environment Agency	25,000	pa	25,000												
HSE advisor	24,000	pa	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	
HSE training costs	69,000	pa	5,750	5,750	5,750	5,750	5,750	5,750	5,750	5,750	5,750	5,750	5,750	5,750	
Planning	24,000	pa	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	
Environment consultancy	24,000	pa	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	
Fuel/electricity	240,000	pa	40,000	40,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	
Waste water disposal	500,000	pa	41,667	41,667	41,667	41,667	41,667	41,667	41,667	41,667	41,667	41,667	41,667	41,667	
General Expenses	38,850	pa	3,238	3,238	3,238	3,238	3,238	3,238	3,238	3,238	3,238	3,238	3,238	3,238	
Transport of Condensate	264,000	pa	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	
Miscellaneous (contingency)	50,000	pa	4,167	4,167	4,167	4,167	4,167	4,167	4,167	4,167	4,167	4,167	4,167	4,167	
Business rates	300,000	pa	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	
Other disposal costs	-	pa	-	-	-	-	-	-	-	-	-	-	-	-	
Temp. flow line	250,000	pa	250,000	-	-	-	-	-	-	-	-	-	-	-	
Total	4,295,878		620,174	352,674	345,373	323,923	332,674	336,023	323,923	332,674	323,923	387,923	332,674	323,923	270,382
VEHICLES			Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24
Fixed costs															
Leasing costs	7,000	pa	583	583	583	583	583	583	583	583	583	583	583	583	584
Insurance	1,000	pa										1,000			
Variable costs															
Fuel	4,800	pa	400	400	400	400	400	400	400	400	400	400	400	400	401
Total	12,800		983	983	983	983	983	983	983	983	983	1,983	983	983	985
PROFESSIONAL FEES			Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24
Fixed costs															
Insurance	71,000	pa	750	750	750	750	750	750	750	750	750	750	750	750	751
Accounts/Taxation	1,000	pa		62,000			1,000								
Variable costs															
Legal	5,000	pa					5,000								
Total	77,000		750	62,750	750	750	6,750	750	750	750	750	750	750	750	751
Total	4,385,678		Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24
	4,385,678		**621,907**	**416,407**	**347,106**	**325,656**	**340,407**	**337,756**	**325,656**	**334,407**	**325,656**	**390,656**	**334,407**	**325,656**	**272,118**

Tax assumptions are presented in Table 9-3.

Table 9-3 Economics and Tax assumptions for Cash Flow Forecasts

Corporation tax	30%	Taxable base includes debt interest
Supplementary Charge	10%	Taxable base excludes debt interest
Intangibles portion of capex	100%	100% depreciated in year 1
Depreciation	7	Years. No capex allocated
Supplementary Charge Capital Uplift allowance (onshore)	175%	75% uplift from 1st production
Discount rate, yearly	10%	
AE Working interest, %	100%	
Energy Profits Levy (until 31/3/2028)	35%	Taxable base excludes debt interest. Investment allowance uplift is 80% for capex incurred between 26/5/22 to 31/12/22 and 29% thereafter.
Energy Levy Capital Uplift Allowance	129%	
AE Tax Loss Carryforward May 23 £m	£62.92	AE notification
AE Energy Profits Levy Allowances May 23 £m	£20.00	AE notification

Table 9-4 summarises the loan terms used to model AE's cash flows.

Table 9-4 Licensees' Loan Terms

Item Description	**Units**	**Value**
Debt Terms		
Loan amount agreed May 2021	GB£ m	12.00
Loan Outstanding 1st August 2023	GB£ m	7.35
Expiry of Loan		31/12/2024
Interest rate over "Sonia"	%	12%
Sonia (Sterling Overnight Index Average)	%	4.00%
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 + minimum loan repayment		

9.1. 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 August 2023 and June 2025 (ranging from 1.87 MMSCFD to 4.6 MMSCFD). Table 9-5 presents the hedged prices, hedged therms/MMSCF and forecast revenues. The calorific value was used to convert therms to MMSCF. The total gross revenue for Saltfleetby Field forecast from hedged production from August 2023 to June 2025 is £10.0153m.

The cash flow calculation assumes the balance of production will be sold at the NBP forward price. Table 9-6 presents a forecast of the annual net Sales Gas price received by AE from the off taker at the Theddlethorpe entry point. The basis of the forecast is the National Balancing Point Monthly Forward Curve for August 1st, 2023, until December 2028. After 2028, the NBP price is escalated by 2% pa.

The off-taker's charge of 1.25% is applied to the NBP price. The NTS Theddlethorpe Non-Transmission Services Entry (NTSEC), 2.4940 pence/Therm, and the General Non-Transmission Service Charge, 1.0052 pence/Therm (in both 2022 & 2023), are subtracted from the NBP price. After 2024, the NTS charges are escalated by 2% pa.

The resulting sales price to AE is converted from pence/Therm to £/MMSCF again using a gas calorific value of 11060 Therms / MMSCF.

In the cash flow model, the monthly NBP prices are used rather than the annual averages presented in Table 9-6.

Table 9-5 Hedged Prices, Hedged Volumes

MONTH	HEDGE PRICE p/Th	HEDGE VOLUME MM Th	HEDGE MONTH VOLUME MMSCF	HEDGE DAY VOLUME MMSCFD	£/MMSCF Gross Revenue (11060 Th/MMSCF	GROSS REVENUE FROM HEDGED SALES £M
Aug-23	37.55	1.5	135.62	4.37	£4,153	£0.56
Sep-23	37.55	1.5	135.62	4.52	£4,153	£0.56
Oct-23	46.55	1.5	135.62	4.37	£5,148	£0.70
Nov-23	46.55	1.5	135.62	4.52	£5,148	£0.70
Dec-23	46.55	1.5	135.62	4.37	£5,148	£0.70
Jan-24	46.55	1.5	135.62	4.37	£5,148	£0.70
Feb-24	46.55	1.5	135.62	4.68	£5,148	£0.70
Mar-24	46.55	1.5	135.62	4.37	£5,148	£0.70
Apr-24	35.6	1.5	135.62	4.52	£3,937	£0.53
May-24	35.6	1.5	135.62	4.37	£3,937	£0.53
Jun-24	35.6	1.5	135.62	4.52	£3,937	£0.53
Jul-24	35.6	0.63	56.96	1.84	£3,937	£0.22
Aug-24	35.6	0.63	56.96	1.84	£3,937	£0.22
Sep-24	35.6	0.65	58.77	1.96	£3,937	£0.23
Oct-24	45	0.63	56.96	1.84	£4,977	£0.28
Nov-24	45	0.65	58.77	1.96	£4,977	£0.29
Dec-24	45	0.63	56.96	1.84	£4,977	£0.28
Jan-25	45	0.63	56.96	1.84	£4,977	£0.28
Feb-25	45	0.69	62.39	2.23	£4,977	£0.31
Mar-25	45	0.63	56.96	1.84	£4,977	£0.28
Apr-25	35.25	0.65	58.77	1.96	£3,899	£0.23
May-25	35.25	0.63	56.96	1.84	£3,899	£0.22
Jun-25	35.25	0.65	58.77	1.96	£3,899	£0.23

Source: AEWB.

Table 9-6 NBP Forward Prices £/MMSCF

Year	NBP FWD Pence/Therm (01 Aug 23)	NTS Entry Capacity Charge (NETSEC) & General Non-Transmission Service Charge (p/therm)	Off-taker's charge (1.25% of NBP)	NBP FWD Pence/Th at Sales Point	£/MMSCF at Sales Point (11060 Th/MMSCF
2023	91.9p	3.5p	1.1p	87.2p	£9,646
2024	128.3p	3.6p	1.6p	123.1p	£13,613
2025	119.0p	3.6p	1.5p	113.9p	£12,592
2026	98.1p	3.7p	1.2p	93.2p	£10,306
2027	84.5p	3.8p	1.1p	79.6p	£8,807
2028	81.3p	3.9p	1.0p	76.5p	£8,457
2029	83.0p	3.9p	1.0p	78.0p	£8,626
2030	84.6p	4.0p	1.1p	79.6p	£8,799
2031	86.3p	4.1p	1.1p	81.1p	£8,975
2032	88.1p	4.2p	1.1p	82.8p	£9,154
2033	89.8p	4.3p	1.1p	84.4p	£9,337
2034	91.6p	4.4p	1.1p	86.1p	£9,524
2035	93.4p	4.4p	1.2p	87.8p	£9,714
2036	95.3p	4.5p	1.2p	89.6p	£9,909
2037	97.2p	4.6p	1.2p	91.4p	£10,107

9.2. Condensate Sales Price forecast at Harwich Refinery

The condensate price forecast was based on the naphtha forward price; Table 9-7 refers. The price was escalated by 2% pa after 2028.

Table 9-7 Forecast Condensate Price £/bbl

Year	Condensate price £/bbl
2023	£31.8
2024	£29.9
2025	£27.0
2026	£24.8
2027	£20.1
2028	£20.1

Table 9-8 P90 Cash Flow Forecast £m on a project basis; effective date August 1st, 2023

	Gross								AE 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
5M 2023	1.1	20.4	£7.9	-£2.8		-£0.7	3	£4.5	£4.5	£0.0	£4.5	£4.4
2024	2.3	44.1	£23.5	-£5.7		-£8.5	3	£9.4	£9.4	£0.0	£9.4	£8.5
2025	3.2	58.6	£40.6	-£5.7		-£5.9	4	£28.9	£28.9	-£2.5	£26.4	£22.0
2026	3.2	55.6	£36.5	-£5.8			5	£30.7	£30.7	-£9.8	£20.9	£15.8
2027	2.6	42.2	£25.4	-£5.5			5	£19.9	£19.9	-£13.6	£6.3	£4.3
2028	2.1	32.2	£19.9	-£5.3			5	£14.6	£14.6	-£9.1	£5.5	£3.3
2029	1.8	25.5	£17.2	-£5.2			5	£12.0	£12.0	-£3.9	£8.1	£4.6
2030	1.5	20.0	£14.9	-£5.2			5	£9.7	£9.7	-£3.5	£6.2	£3.2
2031	1.4	16.1	£13.3	-£5.2			5	£8.1	£8.1	-£3.5	£4.6	£2.2
2032	1.2	13.2	£12.2	-£5.2			5	£7.0	£7.0	-£3.0	£4.0	£1.7
2033	1.0	9.9	£10.4	-£5.2			5	£5.2	£5.2	-£2.4	£2.8	£1.1
2034	0.9	7.9	£9.5	-£5.2			5	£4.2	£4.2	-£1.7	£2.5	£0.9
2035	0.7	5.3	£7.3	-£5.1			5	£2.2	£2.2	-£1.2	£1.0	£0.3
2036	0.6	3.9	£6.3	-£5.0			5	£1.3	£1.3	-£0.7	£0.6	£0.2
2037	0.4	2.2	£4.3	-£4.9			5	-£0.6	-£0.6	£0.1	-£0.5	-£0.1
2038				-£0.8	-£6.3			-£7.1	-£7.1	£1.2	-£5.9	-£1.4
2039										£1.4	£1.4	£0.3
Total	**24.2**	**357**	**£249.2**	**-£77.9**	**-£6.3**	**-£15.1**		**£150.0**	**£150.0**	**-£52.3**	**£97.7**	**£71.1**

Mid-Year Nominal Net Present Values			
as at 01-Aug-23 (GB£ m)			
Disc Rate	**Gross Pre-Tax**	**AE Pre-Tax**	**AE Post-Tax**
0%	£150.0	£150.0	£97.7
5%	£124.0	£124.0	£82.7
10%	£104.4	£104.4	£71.1
12.5%	£96.4	£96.4	£66.4
15%	£89.3	£89.3	£62.1
20%	£77.6	£77.6	£55.0
MIRR	26%	26%	18%

Table 9-9 P90 Cash Flow Forecast £m including loan terms; effective date August 1st, 2023.

	Gross				Net to Licensees after Financing						AE Net			
Year	Sales Gas	Liquids	Gross Revenue	Pre-Tax NCF before Financing	Gas Net of Royalty	Liquids Net of Royalty	Royalty Value	Interest	Loan Repay	Pre Tax NCF after Financing [1]	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
5M 2023[1]	1.1	20.4	£7.9	£4.5	1.1	20.4		£0.4	£2.6	**£1.0**	£1.0	£0.0	£1.0	£1.0
2024 [1]	2.3	44.1	£23.5	£9.4	2.3	42.4	£1.1	£0.32	£4.7	**£5.7**	£5.7	£0.0	£5.7	£5.1
2025	3.2	58.6	£40.6	£28.9	3.0	53.9	£3.2			£25.7	£25.7	-£2.5	£23.2	£19.3
2026	3.2	55.6	£36.5	£30.7	3.0	51.1	£2.9			£27.8	£27.8	-£8.9	£18.9	£14.3
2027	2.6	42.2	£25.4	£19.9	2.4	38.8	£2.0			£17.9	£17.9	-£11.6	£6.3	£4.3
2028	2.1	32.2	£19.9	£14.6	2.0	29.6	£1.6			£13.0	£13.0	-£8.6	£4.4	£2.7
2029	1.8	25.5	£17.2	£12.0	1.7	23.4	£1.4			£10.6	£10.6	-£3.5	£7.2	£4.1
2030	1.5	20.0	£14.9	£9.7	1.4	18.4	£1.2			£8.5	£8.5	-£3.2	£5.3	£2.7
2031	1.4	16.1	£13.3	£8.1	1.3	14.9	£1.1			£7.1	£7.1	-£3.2	£3.9	£1.8
2032	1.2	13.2	£12.2	£7.0	1.1	12.1	£1.0			£6.0	£6.0	-£2.7	£3.3	£1.4
2033	1.0	9.9	£10.4	£5.2	0.9	9.1	£0.8			£4.3	£4.3	-£2.1	£2.2	£0.9
2034	0.9	7.9	£9.5	£4.2	0.8	7.3	£0.8			£3.5	£3.5	-£1.5	£2.0	£0.7
2035	0.7	5.3	£7.3	£2.2	0.6	4.9	£0.6			£1.6	£1.6	-£1.0	£0.6	£0.2
2036	0.6	3.9	£6.3	£1.3	0.5	3.5	£0.5			£0.8	£0.8	-£0.5	£0.3	£0.1
2037	0.4	2.2	£4.3	-£0.6	0.4	2.0	£0.3			-£0.9	-£0.9	£0.1	-£0.8	-£0.2
2038				-£7.1						-£7.1	-£7.1	£1.2	-£5.9	-£1.4
2039												£1.4	£1.4	£0.3
Total	**24.2**	**357**	**£249.2**	**£150.0**	**22.4**	**331.9**	**£18.5**	**£0.8**	**£7.4**	**£125.4**	**£125.4**	**-£46.5**	**£78.9**	**£57.1**
Note [1]: The Opening Cash Float RA+DSRA is £2.0m and this is not included in the Future NCF, hence the apparent inconsistency in the Pre-Tax NCF After Financing.														

Mid-Year Nominal Net Present Values			
as at 01-Aug-23 (GB£ m)			
Disc Rate	**Gross Pre-Tax**	**AE Pre-Tax**	**AE Post-Tax**
0%	£150.0	£125.4	£78.9
5%	£124.0	£103.6	£66.7
10%	£104.4	£86.9	£57.1
12.5%	£96.4	£80.0	£53.1
15%	£89.3	£73.9	£49.5
20%	£77.6	£63.7	£43.4
MIRR		29%	18%

Table 9-10 P50 Cash Flow Forecast £m on a project basis; effective date August 1st, 2023

	Gross								AE 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
5M 2023	1.1	21.6	£8.6	-£2.8		-£0.7	3	£5.1	£5.1	£0.0	£5.1	£5.0
2024	2.7	51.4	£29.2	-£5.9		-£8.1	3	£15.2	£15.2	-£0.1	£15.1	£13.8
2025	3.3	60.7	£41.5	-£5.8		-£5.9	4	£29.8	£29.8	-£3.4	£26.4	£22.0
2026	3.3	58.7	£37.1	-£5.8			5	£31.3	£31.3	-£12.5	£18.7	£14.2
2027	3.2	54.5	£30.6	-£5.8			5	£24.8	£24.8	-£16.9	£7.9	£5.3
2028	2.5	42.3	£23.7	-£5.5			5	£18.2	£18.2	-£11.8	£6.4	£3.9
2029	2.1	33.9	£20.0	-£5.4			5	£14.6	£14.6	-£5.7	£8.9	£5.0
2030	1.8	28.0	£17.5	-£5.3			5	£12.2	£12.2	-£5.3	£6.9	£3.6
2031	1.6	23.1	£15.4	-£5.3			5	£10.1	£10.1	-£4.4	£5.7	£2.7
2032	1.4	19.7	£13.9	-£5.3			5	£8.6	£8.6	-£3.6	£4.9	£2.1
2033	1.2	16.4	£12.3	-£5.3			5	£7.0	£7.0	-£3.0	£4.0	£1.5
2034	1.0	13.5	£10.7	-£5.3			5	£5.4	£5.4	-£2.4	£3.0	£1.0
2035	0.9	11.5	£9.8	-£5.3			5	£4.5	£4.5	-£1.9	£2.6	£0.8
2036	0.6	6.9	£6.3	-£5.0			5	£1.3	£1.3	-£1.0	£0.3	£0.1
2037	0.5	5.1	£5.0	-£4.9			5	£0.1	£0.1	£0.0	£0.1	£0.0
2038				-£0.8	-£6.3			-£7.1	-£7.1	£1.2	-£5.9	-£1.4
2039										£1.4	£1.4	£0.3
Total	**27.2**	**447**	**£281.6**	**-£79.6**	**-£6.3**	**-£14.7**		**£181.1**	**£181.1**	**-£69.5**	**£111.7**	**£79.9**

Mid-Year Nominal Net Present Values			
as at 01-Aug-23 (GB£ m)			
Disc Rate	**Gross Pre-Tax**	**AE Pre-Tax**	**AE Post-Tax**
0%	£181.1	£181.1	£111.7
5%	£148.0	£148.0	£93.4
10%	£123.5	£123.5	£79.9
12.5%	£113.7	£113.7	£74.4
15%	£105.1	£105.1	£69.6
20%	£91.0	£91.0	£61.6
MIRR	31%	31%	17%

Table 9-11 P50 Cash Flow Forecast £m including loan terms; effective date August 1st, 2023.

	Gross				**Net to Licensees after Financing**						**AE Net**			
Year	Sales Gas	Liquids	Gross Revenue	Pre-Tax NCF before Financing	Gas Net of Royalty	Liquids Net of Royalty	Royalty Value	Interest	Loan Repay	Pre Tax NCF after Financing [1]	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
5M 2023[1]	1.1	21.6	£8.6	£5.1	1.1	21.6		£0.4	£2.7	**£1.1**	£1.1	£0.0	£1.1	£1.1
2024 [1]	2.7	51.4	£29.2	£15.2	2.6	48.6	£1.7	£0.26	£4.6	**£11.1**	£11.1	-£0.1	£11.1	£10.0
2025	3.3	60.7	£41.5	£29.8	3.0	55.8	£3.3			£26.5	£26.5	-£3.4	£23.1	£19.2
2026	3.3	58.7	£37.1	£31.3	3.0	54.0	£3.0			£28.3	£28.3	-£11.6	£16.7	£12.6
2027	3.2	54.5	£30.6	£24.8	2.9	50.2	£2.4			£22.4	£22.4	-£14.7	£7.6	£5.2
2028	2.5	42.3	£23.7	£18.2	2.3	38.9	£1.9			£16.3	£16.3	-£11.1	£5.2	£3.1
2029	2.1	33.9	£20.0	£14.6	1.9	31.2	£1.6			£13.0	£13.0	-£5.2	£7.8	£4.4
2030	1.8	28.0	£17.5	£12.2	1.7	25.8	£1.4			£10.8	£10.8	-£4.8	£6.0	£3.1
2031	1.6	23.1	£15.4	£10.1	1.4	21.3	£1.2			£8.8	£8.8	-£4.0	£4.9	£2.3
2032	1.4	19.7	£13.9	£8.6	1.3	18.1	£1.1			£7.5	£7.5	-£3.3	£4.2	£1.8
2033	1.2	16.4	£12.3	£7.0	1.1	15.1	£1.0			£6.0	£6.0	-£2.7	£3.3	£1.3
2034	1.0	13.5	£10.7	£5.4	0.9	12.4	£0.9			£4.5	£4.5	-£2.2	£2.4	£0.8
2035	0.9	11.5	£9.8	£4.5	0.8	10.6	£0.8			£3.7	£3.7	-£1.7	£2.0	£0.7
2036	0.6	6.9	£6.3	£1.3	0.5	6.4	£0.5			£0.8	£0.8	-£0.8	-£0.1	£0.0
2037	0.5	5.1	£5.0	£0.1	0.4	4.7	£0.4			-£0.3	-£0.3	£0.1	-£0.2	-£0.1
2038				-£7.1						-£7.1	-£7.1	£1.2	-£5.9	-£1.4
2039												£1.4	£1.4	£0.3
Total	**27.2**	**447**	**£281.6**	**£181.1**	**25.2**	**414.6**	**£21.2**	**£0.7**	**£7.4**	**£153.5**	**£153.5**	**-£62.9**	**£90.6**	**£64.3**
Note [1]: The Opening Cash Float RA+DSRA is £1.60m and this is not included in the Future NCF, hence the apparent inconsistency in the Pre-Tax NCF After Financing.														

Mid-Year Nominal Net Present Values			
as at 01-Aug-23 (GB£ m)			
Disc Rate	**Gross Pre-Tax**	**AE Pre-Tax**	**AE Post-Tax**
0%	£181.1	£153.5	£90.6
5%	£148.0	£125.2	£75.6
10%	£123.5	£104.1	£64.3
12.5%	£113.7	£95.5	£59.7
15%	£105.1	£88.0	£55.6
20%	£91.0	£75.7	£48.8
MIRR		30%	17%

Table 9-12 Sensitivity of NCF and NPV10 to Sales Gas Plateau Flowrate from 2025 £m including loan terms; effective date August 1st, 2023.

	Post Tax Net Cash Flow Attributable to AE		Post tax NPV10 Attributable to AE		Operator
Sales gas Flowrate from January 2025	**1P**	**2P**	**1P**	**2P**	
Including AE's Contractual Loan terms	£m MOD	£m MOD	£m MOD	£m MOD	AEWB
9 MMSCFD	£78.9	£90.6	£57.1	£64.3	
10 MMSCFD	£78.2	£82.5	£57.2	£62.2	
11 MMSCFD	£78.5	£82.0	£57.4	£62.3	
9 MMSCFD: 300m lateral instead of 450m	£78.8	£88.9	£55.7	£63.1	

10. 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 AE 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 AE must be positive. The cash flow shall **not** include ADR for this test. This test will be met if the the above NPV test is met

"Reasonable Expectation" (according to PRMS 2018)[21] indicates a high degree of confidence (low risk of failure) that …. the referenced event will occur.

Table 9-8 and Table 9-9 demonstrate that the P90 production case profile has a net cash flow that is positive without the ADR cost (and indeed with ADR included). Table 9-10 and Table 9-11 demonstrate that the P50 production case profile has a NPV10 that is positive with the ADR cost.

Therefore, the Development Plan meets the Commercial criteria for Reserves.

Table 10-1 and Table 10-2 quantify the remaining recoverable gas and condensate liquids that satisfy the Reserves category.

[21] PRMS 2018 Definitions, page 48

Table 10-1 Sales Gas Reserves: Gross and Net Attributable to AE

Saltfleetby Field	**Gross**		**Net Attributable to AE**		**Operator**
Sales Gas Reserves	**1P**	**2P**	**1P**	**2P**	
	BCF	BCF	BCF	BCF	
Main Field Westphalian Reservoir	24.2	27.2	22.4	25.2	AEWB

Effective Date: 1st August 2023
Source: Oilfield International

Table 10-2 Condensate Liquids Reserves: Gross and Net Attributable to AE

Saltfleetby Field	Gross		Net Attributable to AE		Operator
Sales Liquids Reserves	**1P**	**2P**	**1P**	**2P**	
	M STB	M STB	M STB	M STB	
Main Field Westphalian Reservoir	357	447	332	415	AEWB

Effective Date: 1st August 2023
Source: Oilfield International

11. Simulation History Match

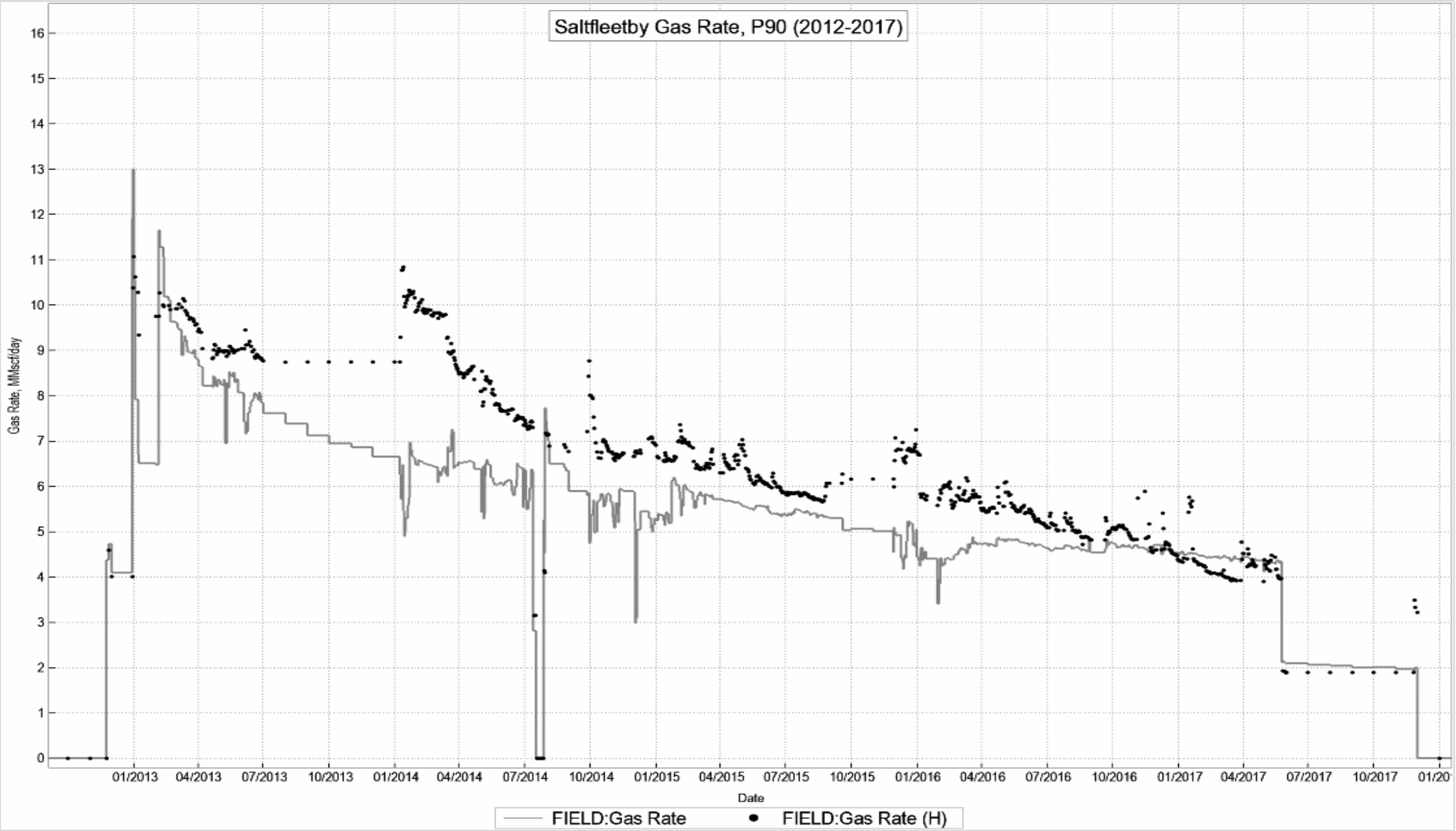

Figure 28 P90 History Match: Forecast (grey line) vs Actual (black points)

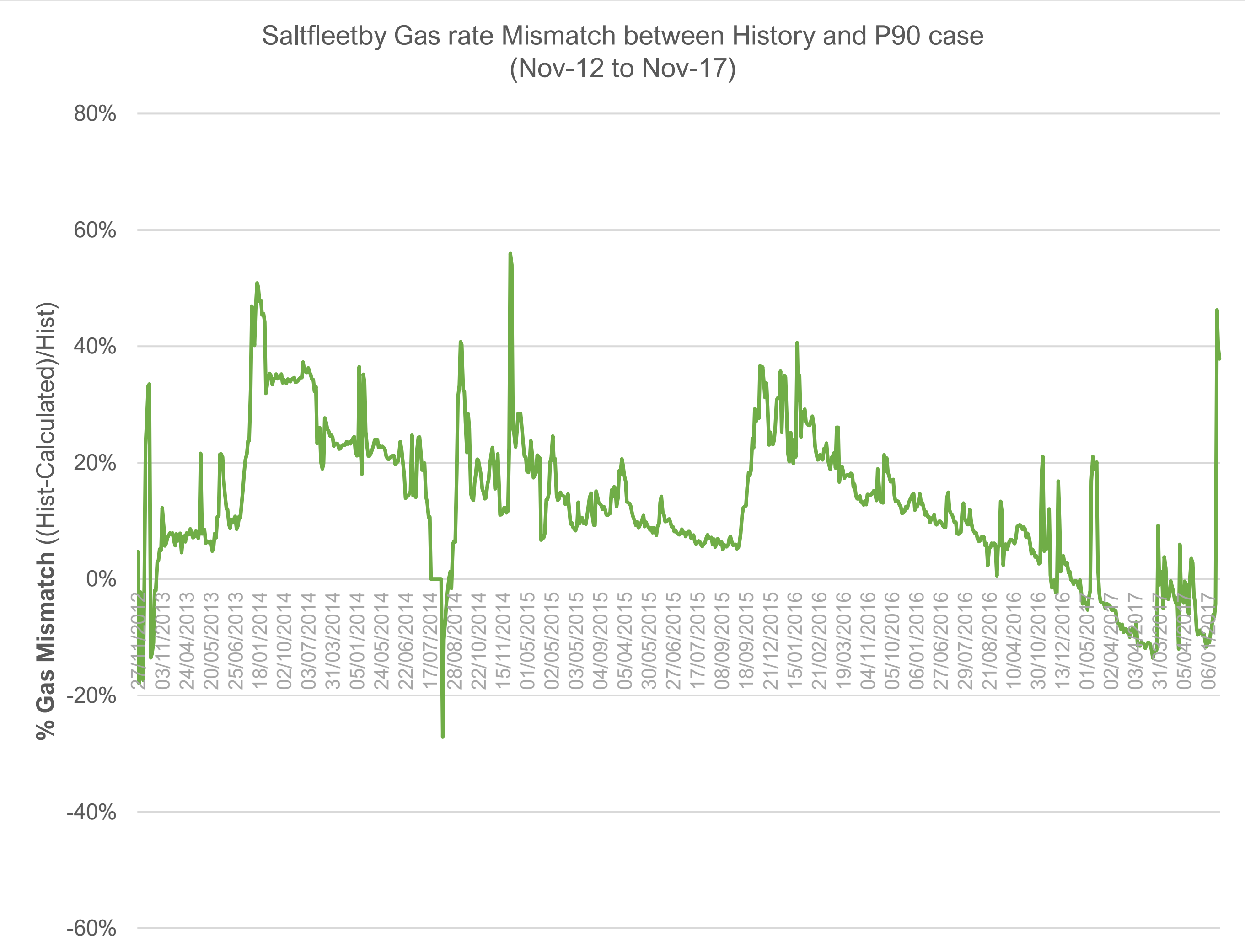

Figure 29 P90: Percentage Gas Flow Mismatch (positive means actual is higher than forecast)

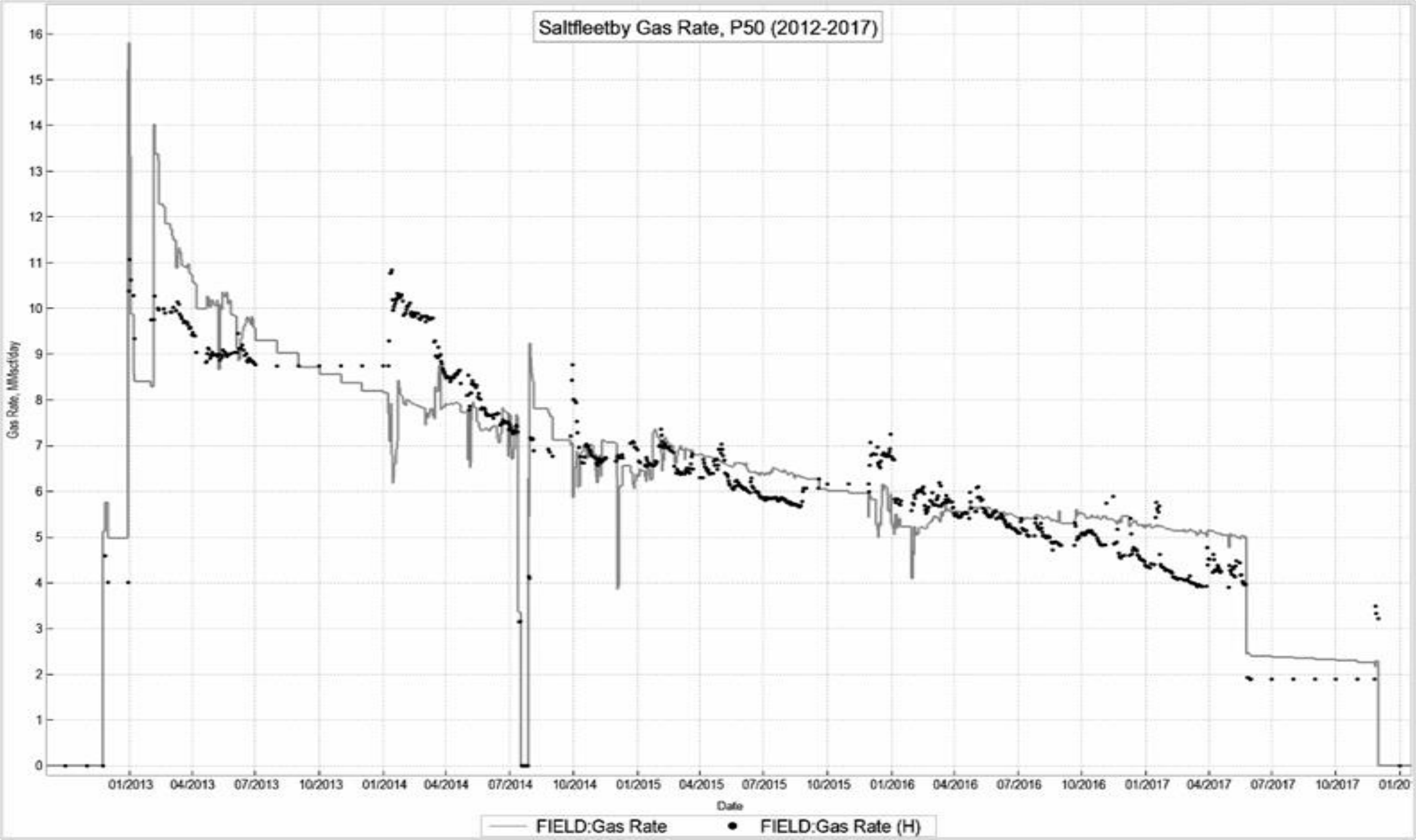

Figure 30 P50 History Match: Forecast (grey line) vs Actual (black points)

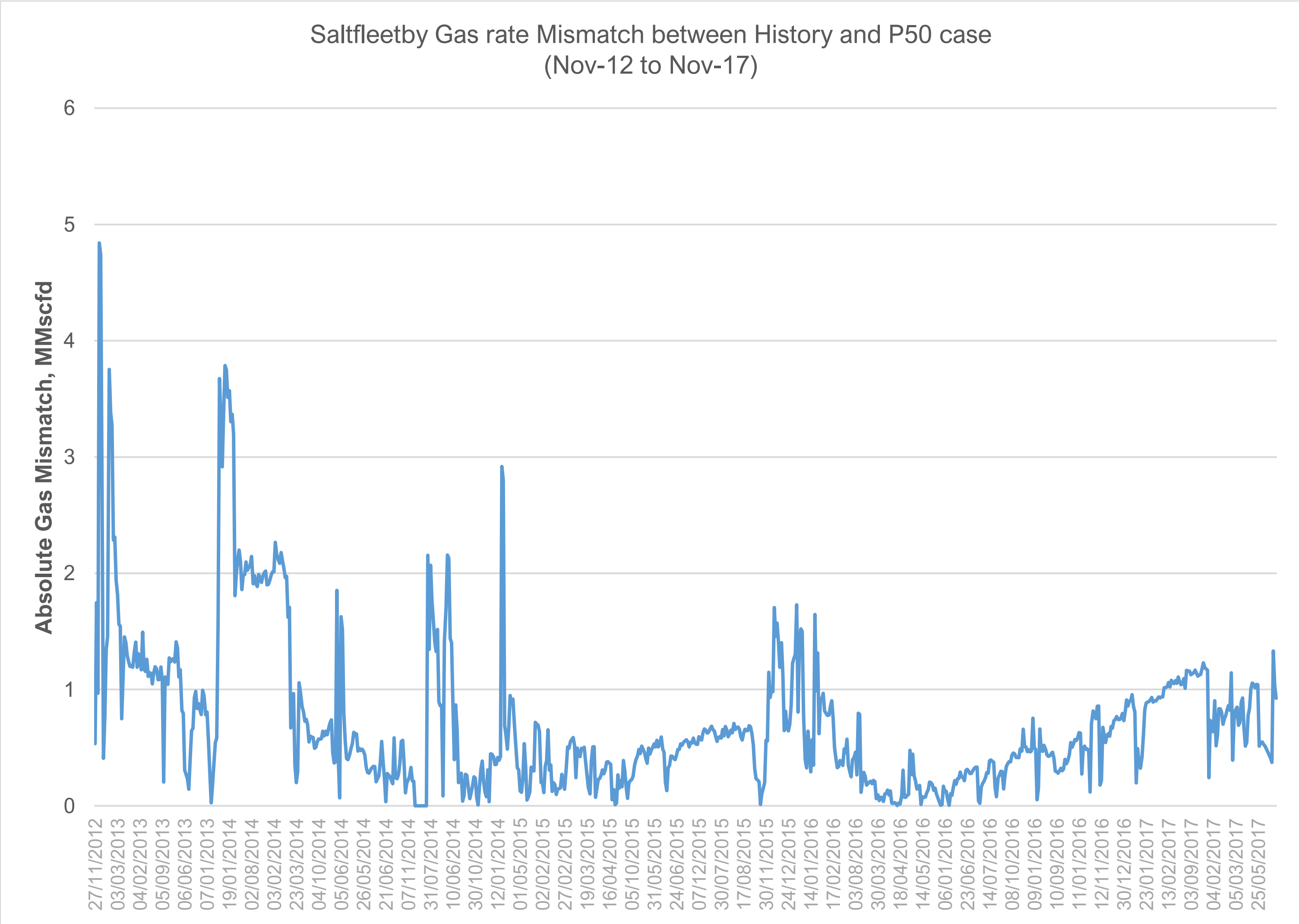

Figure 31 P50: Percentage Gas Flow Mismatch (positive means actual is higher than forecast)

12. “Reality Check” Simulation based on extrapolation of the aggregate P/Z vs Cum production for the three wells

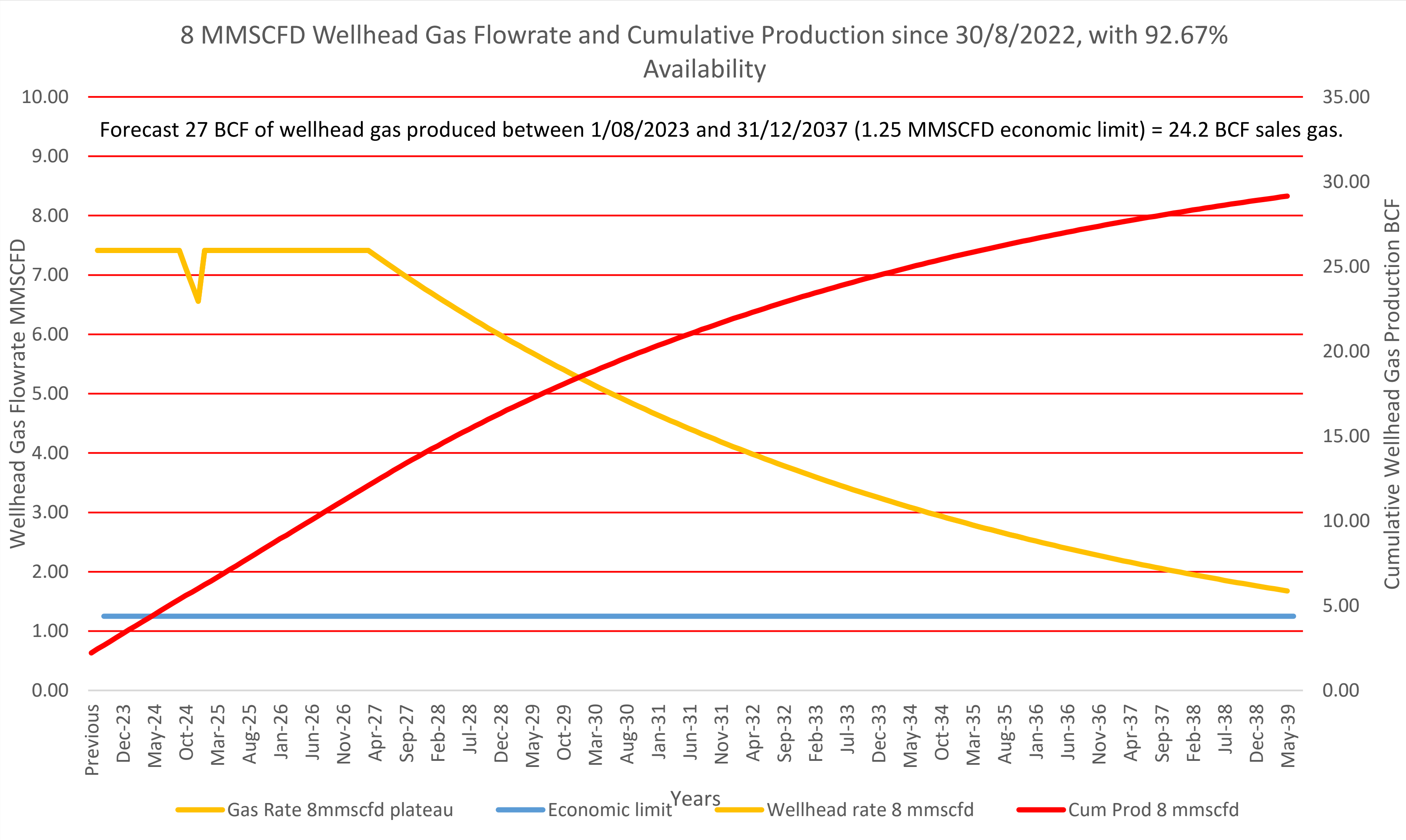

Figure 32 Production Forecast based on the aggregated P/Z vs Gp plot for the three wells on production, 10% CiO

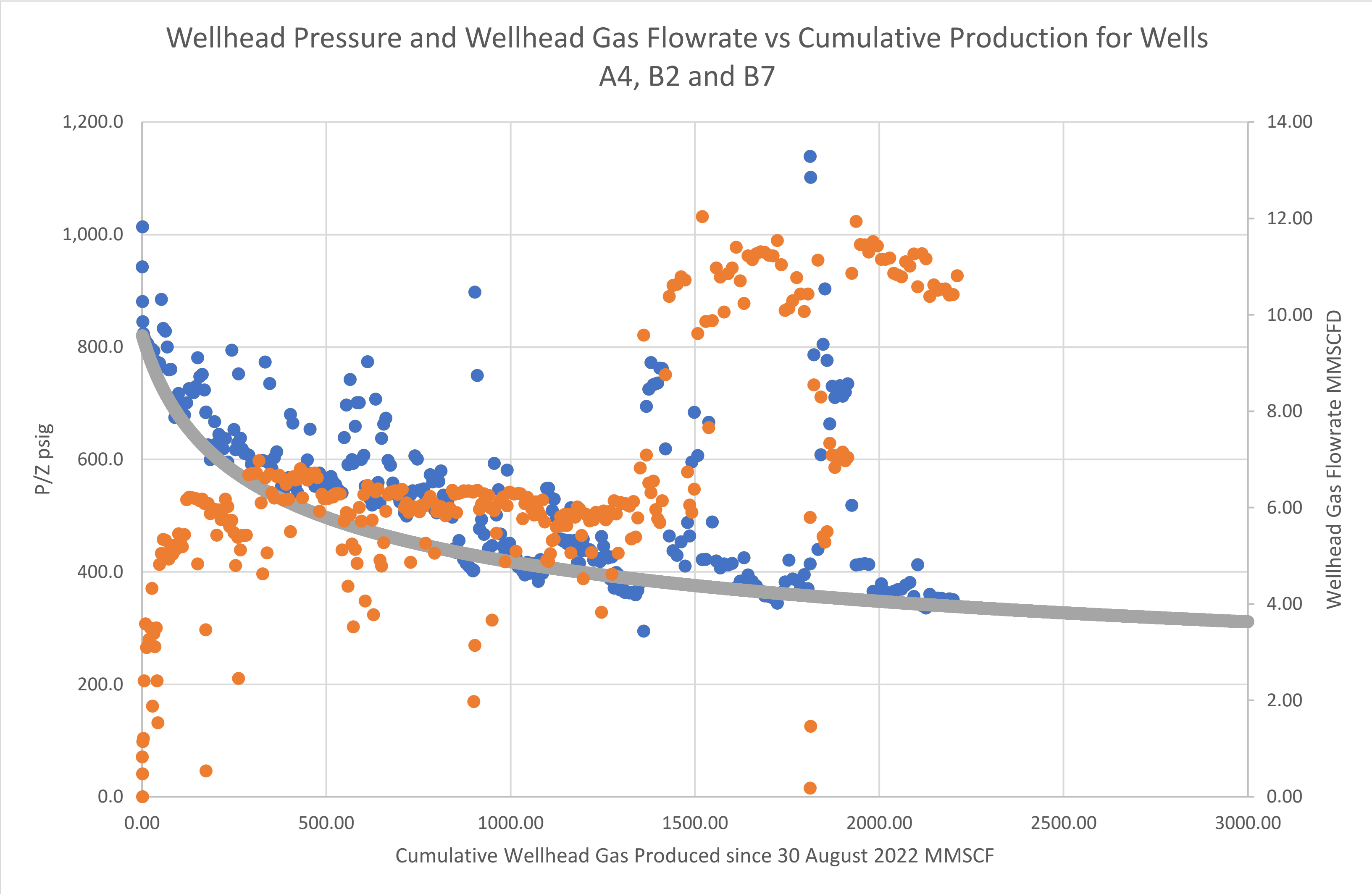

Figure 33 Flowing Wellhead pressure and Gas Flowrate vs Cumulative Production, and curve fit.

13.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 of being exceeded
P50	50% Probability of being exceeded
P90	90% Probability of being exceeded
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
1H23	First half (6 months) of 2023 (example of date)
2Q23	Second quarter (3 months) of 2023 (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