March 2019 Update of 2018 AGR TRACS Competent Persons Report on the AJE Field, OML 113, Nigeria, for MX Oil PLC

The "Front Puffin" FPSO, Aje Field, OML 113, offshore Nigeria

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20th March 2019

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This report was prepared in accordance with standard geological and engineering methods generally accepted by the oil and gas industry, in particular the 2007 SPE PRMS. Estimates of hydrocarbon reserves and resources should be regarded only as estimates that may change as further production history and additional information become available. Not only are reserves and resource estimates based on the information currently available, these are also subject to uncertainties inherent in the application of judgemental factors in interpreting such information. AGR TRACS International Ltd., a wholly owned subsidiary of AGR Group (Holdings) Ltd. shall have no liability arising out of or related to the use of the report.

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Revision:

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Cover Letter

The Directors
MX OIL PLC,
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UNITED KINGDOM

20th March 2019

Gentlemen,

March 2019 Update of Competent Person's Report on the Aje field, OML 113, Nigeria, for MX OIL

In response to your request AGR TRACS International Limited ("AGR TRACS") has updated the June 2018 CPR by incorporating the production data from the two oil producers Aje-4 (Cenomanian) and Aje-5ST2 (Turonian) till end-2018. The June 2018 CPR review captured the new information from the Cenomanian oil development, and incorporated a review of the April 2017 Fast Track Gas Field Development Plan ("FDP") prepared by Folawiyo Aje Services Ltd ("FASL") for the Turonian gas-condensate field development. No additional subsurface data has become available since June 2018 apart from the production data from the two producers, hence the Geoscience and Petrophysical section from the June 2018 CPR remain unchanged, and, similarly, the Facilities and Cost reviews from the June 2018 CPR also remain unchanged.

The Reservoir Engineering sections discussing the Aje-4 and Aje-5ST2 wells has been updated with the additional production data, and revised estimates of reserves have been derived for these two wells taking into account the somewhat better than anticipated production performance recorded to end-2018.

The OML 113 Licence renewal was granted for a further 20 years in July 2018. At around the same time the Aje Turonian Gas FDP was approved by the Nigerian Department of Petroleum Resources (DPR), but the Aje JV Partners have not yet (as of March 2019) reached FID for that project, hence the reserves classification (Justified for Development) remains unchanged from the June 2018 CPR review. Due to the delay in reaching FID the notional development schedule for the Turonian gas project has been deferred by 1 year, with 1st gas now assumed by 1.1.2022 for the economic assessments presented in this CPR update. Note that there are no changes to the notional production forecasts for the Turonian gas-condensate reservoirs presented in the June 2018 CPR, except that they have been deferred by 12 months.

Key Tasks:

The main priority was to review the new production data till end-2018 and update the forward production forecasts for Aje-4 and Aje-5 ST2. The economic evaluations were also updated with the revised production forecasts and the revised schedule assumed for the Turonian gas project. The oil price scenarios (US$50-$60-$70) and gas price (US$4/Mscf) are the same as assumed for the June 2018 CPR.

Conclusions:

The key conclusion of the latest AGR TRACS review of the oil producing reservoirs is that the two wells have performed somewhat better than anticipated at the time of the previous review, but it is uncertain how long the Aje-5ST2 well can continue producing from the Turonian oil rim before water and/or gas breaks through.

The static and dynamic models used for the 2014 Cenomanian FDP were rendered invalid by the Aje-5 well results, hence these are no longer used by the Aje JV Partners. New static and dynamic models for the Cenomanian (and Turonian) are currently being constructed and be reviewed in due course as part of a future CPR update.

Reserves:

This March 2019 CPR contains updated reserves estimates for the Cenomanian and Turonian oil leg incorporating the Aje-4 and Aje-5ST2 production history from May 2016 to Year-end 2018, thus the effective date for the reserves estimates presented below is 1.1.2019. The Cenomanian and Turonian production anticipated from the Aje-4 and -5ST2 wells during 2019-2021 is classed as "Reserves – Developed Producing ("DP")", while any oil production forecast from these two wells beyond 1.1.2022 is dependent on the Turonian gas development commencing production when the condensate stream will help support the costs of the oil FPSO. The anticipated gas/condensate/LPG production from the Turonian development as well as any further oil production from Aje-4 and -5ST2 are considered as "Reserves – Justified for Development ("JD")". At present the oil production from Aje-4 and -5ST2 during 2019-2021 is forecast to be marginal to sub-economic, thus the forward L/M/H scenarios are assessed as three deterministic cases combining the Aje-4, -5ST2 and Turonian gas/condensate/LPG forecasts as follows:

- LOW: (Aje-4 & -5ST2) LOW + Tur LOW,
- MID: (Aje-4 & -5ST2) MID + Tur MID,
- HIGH: (Aje-4 & -5ST2) HIGH +Tur HIGH

As a result AGR TRACS can report that the gross (100%) 2P Reserves (DP + JD) in the Aje field, OML 113, offshore Nigeria are estimated at 138.2MMboe under the US$60/bbl oil price scenario, and the 2P Net Reserves attributable to MX OIL PLC ("MX OIL") are estimated at 8.9MMboe (see Table 0.1 below). The corresponding gross (100%) 1P Reserves and net attributable 1P Reserves are estimated at 82.4MMboe and 5.2MMboe respectively under the same oil price scenario. The overall 2P liquid volume (oil/condensate/LPG) represents about 40% of the total 2P boe estimates.

The overall increase in the reserves estimates compared to the June 2018 CPR is modest, as the bulk of the estimated reserves in the Aje field are associated with the Turonian gas/condensate project where the notional production forecasts remain unchanged. There are modest increases in the oil reserves attributable to Aje-4 and Aje-5ST2 due to the encouraging production performance recorded during the second half of 2018. The overall increase in MX OIL's net 2P reserves is estimated at 0.1MMbboe (2019: 8.9MMboe, 2018: 8.8MMboe), and for the 1P reserves there is no significant change (2019: 5.2MMboe, 2018: 5.2MMboe).

Oil & Liquids: MMbbls Gas: Bscf	Gross			Net Attributable to MX OIL			Operator
DISCOVERY	**1P Proved**	**2P Proved & Probable**	**3P Proved, Probable & Possible**	**1P Proved**	**2P Proved & Probable**	**3P Proved, Probable & Possible**	
NIGERIA:							
OML 113 Aje OIL							
DP (Cen. 2019-2021)	0.82	0.89	0.94	0.04	0.04	0.05	YFP
DP (Tur. 2019-2021)	1.23	1.36	1.49	0.06	0.07	0.07	YFP
Sub-total DP (2019-2021)	**2.05**	**2.25**	**2.43**	**0.10**	**0.11**	**0.12**	YFP
JD (Cen. 2022 onwards)	0.32	0.69	1.16	0.02	0.04	0.07	YFP
JD (Tur. 2022 onwards)	0.79	1.79	3.01	0.05	0.12	0.18	YFP
Sub-total JD (2022 onwards)	**1.11**	**2.48**	**4.17**	**0.07**	**0.16**	**0.25**	YFP
OML 113 Aje CONDENSATE							
JD (2022 onwards)	10.32	17.41	27.87	0.65	1.12	1.66	YFP
OML 113 Aje LPG							
JD (2022 onwards)	20.11	33.86	54.39	1.29	2.20	3.14	YFP
TOTAL LIQUIDS (MMbbls)							
DP OIL (2019-2021)	2.05	2.25	2.43	0.10	0.11	0.12	YFP
JD (2022 onwards, OIL + COND + LPG)	31.54	53.75	86.43	2.01	3.48	5.05	YFP
SUB-TOTAL LIQUIDS#	**33.6**	**56.0**	**88.9**	**2.1**	**3.6**	**5.2**	YFP
OML 113 Aje DRY GAS (Bscf)							
Gas Cap Gas	261.6	442.0	704.9	16.8	28.8	40.7	YFP
Solution Gas	31.1	50.9	87.0	2.0	3.3	5.0	YFP
Sub-total Gas JD (2022 onwards)	**292.7**	**492.8**	**791.9**	**18.8**	**32.1**	**45.7**	YFP
TOTAL#, MMboe	**82.4**	**138.2**	**220.8**	**5.2**	**8.9**	**12.8**	YFP

Table 0.1: Aje OML 113 - Overview of 100% gross and net attributable reserves (oil/gas/condensate/LPG) to MX OIL

(Source: 2019 AGR TRACS review)

"Total…#" – implies totals have been derived by arithmetic summation without any probabilistic addition.

Contingent Resources:

At present the Aje JV Partners are reviewing development options for a possible near-horizontal additional producer (Aje-6) in the Cenomanian targeting a NE lobe of the main reservoir as well as the Turonian oil rim (with four horizontal producers), but the respective development plans for these additional targets are not yet available. AGR TRACS was asked to provide an opinion on the technically recoverable volumes from these two targets, which are considered technically recoverable contingent resources ("development unclarified"). The Chance Of Commercial Success ("COCS") for these two targets are assessed as 50% and 40% respectively, due to the lack of any definite development or drilling plans.

Although Aje-5ST2 has performed well since the June 2018 CPR, there are no changes to the estimates of Contingent Resources for the Turonian Oil Rim presented in this CPR, as the four notional horizontal producers would penetrate a different section of the Turonian reservoir compared to the currently producing Aje-5ST2. This well is draining an interval within the deepest Turonian 4 sequence in the core of the structure immediately above a local shale baffle, and is therefore not representative of the reservoir sequence expected for the four notional oil rim producers in the more peripheral locations within the uppermost Turonian sequence (which is expected to have optimum reservoir properties). It is also unclear when the oil rim producers would be brought on stream relative to the primary gas producers targeting the Turonian gas cap, and a later development would tend to have a reduced recovery per well. However, AGR TRACS acknowledges that the production performance of Aje-5ST2 has been better than initially expected, thus it is proposed that the potential oil rim exploitation should be reviewed more thoroughly once the new static and dynamic models become available.

As a result AGR TRACS suggests that the 2C Best Estimate Unrisked Technical Contingent Resources from these two targets are 9.00MMbbls, and the corresponding Unrisked Technical Contingent Resources Net Attributable to MX OIL are estimated at 0.45MMbbls (see Table 0.2 below). The 2C Risked Technical Contingent Resources Net Attributable to MX Oil are estimated at 0.20MMbbls (Table 0.3).

Oil & Liquids: MMbbls Gas: Bscf	Gross Unrisked Technical Contingent Resources			Net Unrisked Technical Contingent Resources Attributable to MX OIL			Risk Factor	Operator
DISCOVERY	**1C Low Estimate**	**2C Best Estimate**	**3C High Estimate**	**1C Low Estimate**	**2C Best Estimate**	**3C High Estimate**	**COCS (%)**	
Oil & Liquids Contingent Resources per asset								
NIGERIA:								
OML 113 Aje OIL - Cen. Aje-6 near-horizontal well	0.00	3.00	5.50	0.00	0.15	0.28	50%	YFP
OML 113 Aje Turonian OIL rim with 4 notional producers	4.00	6.00	12.00	0.20	0.30	0.60	40%	YFP
Unrisked Totals for Oil and Liquids #, MMbbls	**4.00**	**9.00**	**17.50**	**0.20**	**0.45**	**0.88**		

Table 0.2: AGR TRACS estimates of 100% Unrisked Gross and Unrisked Net Contingent Resources attributable to MX OIL in the Aje field, OML 113

(Source: 2018 AGR TRACS review)

"Total…#" – implies totals have been derived by arithmetic summation without any probabilistic addition.

"COCS" – the Chance Of Commercial Success (COCS) ratings are explained in Section 7.3.

Oil & Liquids: MMbbls Gas: Bscf	Net Unrisked Technical Contingent Resources Attributable to MX OIL			Risk Factor	Risked Technical Contingent Resources Net Attributable to MX OIL		
DISCOVERY	**1C Low Estimate**	**2C Best Estimate**	**3C High Estimate**	**COCS (%)**	**1C Low Estimate**	**2C Best Estimate**	**3C High Estimate**
Oil & Liquids Contingent Resources per asset							
NIGERIA:							
OML 113 Aje OIL - Cen. Aje-6 near-horizontal well	0.00	0.15	0.28	50%	0.00	0.08	0.14
OML 113 Aje Turonian OIL rim with 4 notional producers	0.20	0.30	0.60	40%	0.08	0.12	0.24
Totals for Oil and Liquids #, MMbbls	**0.20**	**0.45**	**0.88**		**0.08**	**0.20**	**0.38**

Table 0.3: AGR TRACS estimates of 100% Unrisked Net and Risked Net Contingent Resources attributable to MX OIL in the Aje field, OML 113

(Source: 2018 AGR TRACS review)

"Total…#" – implies totals have been derived by arithmetic summation without any probabilistic addition.

"COCS" – the Chance Of Commercial Success (COCS) ratings are explained in Section 7.3.

Economic Results:

Following this updated evaluation AGR TRACS can report that the combined Mid Case scenario for the continued oil production from Aje-4 and -5ST2 and the Turonian gas-condensate development scenario is economically viable at $60/bbl with a NPV(10%) MOD net to MX OIL (2.6670% nominal participating interest) of US$14.4mln under the US$60/bbl oil price scenario (see Table 0.4). However, the combined Low case is currently unattractive, hence the Aje JV Partners are seeking further cost reductions; e.g. by possibly replacing the current oil FPSO ("Front Puffin") with a smaller vessel when it comes off contract in July 2019. However, at the time of writing the preferred option is to retain the current FPSO and seek a discount in the vessel dayrate.

OML 113 Fiscal Terms – MX OIL Net Share, 1st Gas/Cond/LPG 1.1.2022					
Aje-4 & -5ST2 Oil + Turonian Gas/Cond/LPG (Aje-6 & Tur. oil rim not included)	Reserves (DP+JD) Oil/Cond/LPG/Dry Gas (MMboe) @ $60/bbl		US $mln MOD PV(10%) 1.1.2019		
	100%	MX OIL Net Entitlement	$50	$60	$70
LOW	82.4	5.2	-23.9	-16.6	-7.0
MID	138.2	8.9	3.0	14.4	25.9
HIGH	220.8	12.8	26.3	38.3	49.8

Table 0.4: AGR TRACS PV(10%) econ. eval. MX OIL share Aje OML 113 (Aje-4 & -5ST2) Oil+Tur
(Source: 2019 AGR TRACS review)

The work was undertaken by a team of AGR TRACS professional petroleum engineers and geoscientists based on data supplied by MX OIL. The data comprised details of licence and acreage interests, all relevant exploration geological and geophysical data, interpreted data, and technical presentations. AGR TRACS have exercised due diligence on all technical information supplied by MX OIL. AGR TRACS have not independently checked title interests with Government or licence authorities.

In estimating reserves, contingent and prospective resources we have used the standard petroleum engineering techniques. These estimates are based on the joint definitions of the Society of Petroleum Engineers, the World Petroleum Congress, the American Association of Petroleum Geologists and the 2007 PRMS (Petroleum Resources Management System). AGR TRACS have not conducted a site visit to independently verify the existence of physical assets.

Qualifications

AGR TRACS International Ltd is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. Except for the provision of professional services on a fee basis, AGR TRACS International Ltd does not have a commercial arrangement with any other person or company involved in the interests that are the subject of this report.

The project was managed and signed off by Nigel Blott (M.Eng.), an AGR TRACS Manager. Mr. Blott, a petroleum engineer and SPE Member, has 30+ years' experience from the Middle East, South-East Asia, and NW Europe. AGR TRACS International Ltd has conducted valuations for many energy companies and financial institutions.

Basis of Opinion

The evaluation presented in this report reflects our informed judgement based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and subsurface reservoir data.

It should be understood that any evaluation, particularly one involving exploration and future petroleum developments, may be subject to significant variations over short periods of time as new information becomes available.

Yours faithfully,

Nigel Blott
AGR TRACS International Ltd

(from 8th April 2019: TRACS International Ltd)

Disclaimer

Competent Person's Report on MX OIL's Interest in the Aje field, OML 113, Nigeria

This report relates specifically and solely to the subject petroleum licence interests and is conditional upon the assumptions made therein. This report must therefore be read in its entirety.

This report was prepared in accordance with standard geological and engineering methods generally accepted by the oil and gas industry. Estimates of prospective hydrocarbon resources should be regarded only as estimates that may change as additional information become available. Not only are these estimates based on the information currently available, but are also subject to uncertainties inherent in the application of judgemental factors in interpreting such information. AGR TRACS International Ltd shall have no liability arising out of, or related to, the use of the report.

20th March 2019

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Executive Summary

AGR TRACS International Limited ("AGR TRACS") has updated the June 2018 CPR [Ref. 1] by incorporating the production data from the two oil producers Aje-4 (Cenomanian) and Aje-5ST2 (Turonian) till end-2018. The June 2018 CPR review captured the new information from the Cenomanian oil development, and incorporated a review of the April 2017 Fast Track Gas Field Development Plan ("FDP") prepared by Folawiyo Aje Services Ltd ("FASL") for the Turonian gas-condensate field development. The Geoscience and Petrophysical sections from the June 2018 CPR remain unchanged as no additional subsurface data has become available since June 2018 apart from the production data from the two producers. Similarly, the Facilities and Cost review from the June 2018 CPR also remain unchanged.

The Reservoir Engineering sections discussing the Aje-4 and Aje-5ST2 wells has been updated with the additional production data, and revised estimates of reserves have been developed for these two wells taking into account the somewhat better production performance recorded to end-2018.

The OML 113 Licence renewal was granted for a further 20 years in July 2018. At around the same time the Aje Turonian Gas FDP was approved by the Nigerian Department of Petroleum Resources (DPR), but the Aje JV Partners have not yet (as of March 2019) reached FID for that project, hence the reserves classification (Justified for Development) remains unchanged from the June 2018 CPR review. Due to the delay in reaching FID the notional development schedule for the Turonian gas project has been deferred by 1 year, with 1st gas now assumed by 1.1.2022 for the economic assessments presented in this CPR update. Note that there are no changes to the notional production forecasts for the Turonian gas-condensate reservoirs presented in the June 2018 CPR, except that they have been deferred by 12 months.

Scope:

The main priority was to review the new production data till end-2018 and update the forward production forecasts for Aje-4 and Aje-5 ST2. The economic evaluations were also updated with the revised production forecasts and the revised schedule assumed for the Turonian gas project. The oil price scenarios (US$50-$60-$70) and gas price (US$4/Mscf) are the same as assumed for the June 2018 CPR.

Key Conclusion:

The key conclusion of the latest AGR TRACS review of the oil producing reservoirs is that the two wells have performed somewhat better than anticipated at the time of the previous review, but it is uncertain how long the Aje-5ST2 well can continue producing from the Turonian oil rim before water and/or gas breaks through.

The static and dynamic models used for the 2014 Cenomanian FDP were rendered invalid by the Aje-5 well results, hence these are no longer used by the Aje JV Partners. New static and dynamic models for the Cenomanian (and Turonian) are currently being constructed and be reviewed as part of a future CPR update in due course.

Estimates of Reserves and Contingent Resources:

AGR TRACS have derived updated reserves estimates for the Cenomanian and Turonian incorporating the Aje-5 well results and the production history from May 2016 to Year-end 2018. The Cenomanian and Turonian oil production anticipated from the Aje-4 and -5ST2 wells during 2019-2021 is classed as "Reserves – Developed Producing ("DP")", while any oil production forecast from these two wells beyond 1.1.2022 is dependent on the Turonian gas development commencing production when the condensate stream will help support the costs of the oil FPSO. The anticipated gas/condensate/LPG production from the Turonian development as well as any further oil production from Aje-4 and -5ST2 are considered as "Reserves – Justified for Development ("JD")".

At present the oil production from Aje-4 and -5ST2 during 2019-2021 is forecast to be marginal to sub-economic, thus the forward L/M/H scenarios are assessed as three deterministic cases combining the Aje-4, -5ST2 and Turonian gas/condensate/LPG forecasts as follows (note that the same three cases were assumed for the June 2018 CPR):

- LOW: (Aje-4 & -5ST2) LOW + Tur LOW,
- MID: (Aje-4 & -5ST2) MID + Tur MID,
- HIGH: (Aje-4 & -5ST2) HIGH +Tur HIGH

Following the updated economic evaluations of the above cases, AGR TRACS can report that the gross (100%) 2P Reserves (DP + JD) in the Aje field, OML 113, offshore Nigeria are estimated at 138.2MMboe under the US$60/bbl oil price scenario. The updated 2P Net Reserves attributable to MX OIL PLC ("MX OIL") are estimated at 8.9MMboe (see Table ES.1 below). The corresponding gross (100%) 1P Reserves and net attributable 1P Reserves are estimated at 82.4MMboe and 5.2MMboe respectively under the same oil price scenario. The overall 2P liquid volume (oil/condensate/LPG) represents about 40% of the total 2P boe estimates.

The overall increase in the reserves estimates compared to the June 2018 CPR is modest, as the bulk of the estimated reserves are associated with the Turonian gas/condensate project where the notional production forecasts remain unchanged. There are modest increases in the oil reserves attributable to Aje-4 and Aje-5ST2 due to the encouraging production performance recorded during the second half of 2018. The overall increase in MX OIL's net 2P reserves is estimated at 0.1MMbboe (2019: 8.9MMboe, 2018: 8.8MMboe), and for the 1P reserves there is no significant change (2019: 5.2MMboe, 2018: 5.2MMboe).

The Aje JV Partners are reviewing development options for a possible near-horizontal additional producer (Aje-6) in the Cenomanian targeting a NE lobe of the main reservoir as well as the Turonian oil rim (with four horizontal producers), but the respective development plans for these additional targets are still in progress. AGR TRACS was therefore requested to provide an opinion on the technically recoverable volumes from these two targets, which are considered technically recoverable contingent resources ("development unclarified"). The Chance Of Commercial Success ("COCS") for these two targets are assessed as 50% and 40% respectively, due to the lack of any definite development or drilling plans.

Although Aje-5ST2 has performed well since the June 2018 CPR [Ref. 1], there are no changes to the estimates of Contingent Resources for the Turonian Oil Rim presented in this CPR, as the four notional horizontal producers would penetrate a different section of the Turonian reservoir compared to the currently producing Aje-5ST2. This well is draining an interval within the deepest Turonian 4 sequence in the core of the structure immediately above a local shale baffle, and is therefore not representative of the reservoir sequence expected for the four notional oil rim producers in the more peripheral locations within the uppermost Turonian sequence (which is expected to have optimum reservoir properties). It is also unclear when the oil rim producers would be brought on stream relative to the primary gas producers targeting the Turonian gas cap, and a later development would tend to have a reduced recovery per well. However, AGR TRACS acknowledges that the production performance of Aje-5ST2 has been better than initially expected, thus it is proposed that the potential oil rim exploitation should be reviewed more thoroughly once the new static and dynamic models become available.

Following a brief assessment of these two additional development targets AGR TRACS suggests that the 2C Unrisked Technical Contingent Resources Net Attributable to MX OIL are estimated at 0.45MMbbls (see Table ES.2 below), and the corresponding 2C Risked Technical Contingent Resources Net Attributable to MX OIL are estimated at 0.20MMbbls.

Oil & Liquids: MMbbls Gas: Bscf	Gross			Net Attributable to MX OIL			Operator
DISCOVERY	**1P Proved**	**2P Proved & Probable**	**3P Proved, Probable & Possible**	**1P Proved**	**2P Proved & Probable**	**3P Proved, Probable & Possible**	
NIGERIA:							
OML 113 Aje OIL							
DP (Cen. 2019-2021)	0.82	0.89	0.94	0.04	0.04	0.05	YFP
DP (Tur. 2019-2021)	1.23	1.36	1.49	0.06	0.07	0.07	YFP
Sub-total DP (2019-2021)	**2.05**	**2.25**	**2.43**	**0.10**	**0.11**	**0.12**	YFP
JD (Cen. 2022 onwards)	0.32	0.69	1.16	0.02	0.04	0.07	YFP
JD (Tur. 2022 onwards)	0.79	1.79	3.01	0.05	0.12	0.18	YFP
Sub-total JD (2022 onwards)	**1.11**	**2.48**	**4.17**	**0.07**	**0.16**	**0.25**	YFP
OML 113 Aje CONDENSATE							
JD (2022 onwards)	10.32	17.41	27.87	0.65	1.12	1.66	YFP
OML 113 Aje LPG							
JD (2022 onwards)	20.11	33.86	54.39	1.29	2.20	3.14	YFP
TOTAL LIQUIDS (MMbbls)							
DP OIL (2019-2021)	2.05	2.25	2.43	0.10	0.11	0.12	YFP
JD (2022 onwards, OIL + COND + LPG)	31.54	53.75	86.43	2.01	3.48	5.05	YFP
SUB-TOTAL LIQUIDS#	**33.6**	**56.0**	**88.9**	**2.1**	**3.6**	**5.2**	YFP
OML 113 Aje DRY GAS (Bscf)							
Gas Cap Gas	261.6	442.0	704.9	16.8	28.8	40.7	YFP
Solution Gas	31.1	50.9	87.0	2.0	3.3	5.0	YFP
Sub-total Gas JD (2022 onwards)	**292.7**	**492.8**	**791.9**	**18.8**	**32.1**	**45.7**	YFP
TOTAL#, MMboe	**82.4**	**138.2**	**220.8**	**5.2**	**8.9**	**12.8**	YFP

Table ES.1: AGR TRACS estimates of 100% Gross and Net Attributable Reserves attributable to MX OIL in the Aje field, OML 113

(Source: 2019 AGR TRACS review)

"Total…#" – implies totals have been derived by arithmetic summation without any probabilistic addition.

Oil & Liquids: MMbbls Gas: Bscf	Net Unrisked Technical Contingent Resources Attributable to MX OIL			Risk Factor	Risked Technical Contingent Resources Net Attributable to MX OIL		
DISCOVERY	**1C Low Estimate**	**2C Best Estimate**	**3C High Estimate**	**COCS (%)**	**1C Low Estimate**	**2C Best Estimate**	**3C High Estimate**
Oil & Liquids Contingent Resources per asset							
NIGERIA:							
OML 113 Aje OIL - Cen. Aje-6 near-horizontal well	0.00	0.15	0.28	50%	0.00	0.08	0.14
OML 113 Aje Turonian OIL rim with 4 notional producers	0.20	0.30	0.60	40%	0.08	0.12	0.24
Totals for Oil and Liquids #, MMbbls	**0.20**	**0.45**	**0.88**		**0.08**	**0.20**	**0.38**

Table ES.2: AGR TRACS estimates of 100% Unrisked Net and Risked Net Contingent Resources attributable to MX OIL in the Aje field, OML 113
(Source: 2018 AGR TRACS review)

"Total…#" – implies totals have been derived by arithmetic summation without any probabilistic addition.

"COCS" – the Chance Of Commercial Success (COCS) ratings are explained in Section 7.3.

Economic Results:

As a result of this updated evaluation AGR TRACS can report that the combined Mid Case scenario for the continued oil production from Aje-4 and -5ST2 and the Turonian gas-condensate development scenario is economically viable at $60/bbl with a NPV(10%) MOD net to MX OIL (2.6670% nominal participating interest) of US$14.4mln under the US$60/bbl oil price scenario (see Table ES.3 and Table ES.4). However, the combined Low case is currently NPV –ve under a PV(10%) discount rate, hence the Aje JV Partners are seeking further cost reductions.

OML 113 Fiscal Terms – MX OIL Net Share, 1st Gas/Cond/LPG 1.1.2022					
Aje-4 & -5ST2 Oil + Turonian Gas/Cond/LPG (Aje-6 & Tur. oil rim not included)	**Reserves (DP+JD) Oil/Cond/LPG/Dry Gas (MMboe) @ $60/bbl**		**US $mln MOD PV(10%) 1.1.2019**		
	100%	**MX OIL Net Entitlement**	**$50**	**$60**	**$70**
LOW	82.4	5.2	-23.9	-16.6	-7.0
MID	138.2	8.9	3.0	14.4	25.9
HIGH	220.8	12.8	26.3	38.3	49.8

Table ES.3: AGR TRACS PV(10%) econ. eval. MX OIL share Aje OML 113 (Aje-4 & -5ST2) Oil+Tur
(Source: 2019 AGR TRACS review)

OML 113 Fiscal Terms – MX OIL Net Share, 1st Gas/Cond/LPG 1.1.2022					
Aje-4 & -5ST2 Oil + Turonian Gas/Cond/LPG (Aje-6 & Tur. oil rim not included)	Reserves (DP+JD) Oil/Cond/LPG/Dry Gas (MMboe) @ $60/bbl		IRR for MX OIL net share (from MOD cashflows)		
	100%	MX OIL Net Entitlement	$50	$60	$70
LOW	82.4	5.2	-11.2%	-5.4%	3.3%
MID	138.2	8.9	11.7%	18.0%	24.4%
HIGH	220.8	12.8	19.7%	24.6%	29.7%

Table ES.4: AGR TRACS IRR summary MX OIL share Aje OML 113 (Aje-4 & -5ST2) Oil+Tur
(Source: 2019 AGR TRACS review)

The Undiscounted Maximum Exposure net to MX OIL for the combined Cenomanian + Turonian Mid case is estimated at US$58.1mln under US$60/bbl.

Recommendations:

Cenomanian structure: It is recommended that a new interpretation is carried out fully integrating the new seismic and well data in order to provide a more accurate interpretation of the Aje Cenomanian structure. This should include rebuilding the static and dynamic models to improve the understanding of the field, and ought to be carried out prior to any further development drilling (e.g. the Aje-6 well in the "NE Lobe"). AGR TRACS understand that updated static and dynamic models for both the Turonian and Cenomanian reservoirs are being developed at the time of writing (March 2019), and that once these are completed they will be made available for a future CPR review.

Reservoir Engineering – Cenomanian: The production allocation from May 2017 to year end 2018 (YE2018) is highly uncertain for the Aje-4 well, and it is therefore recommended that both wells (Aje-4 and Aje-5 ST2) be tested on a regular basis in the future to check production allocation and adjust production forecasts.

Reservoir Engineering – Turonian Gas Cap: There is still some uncertainty in the depth to the GOC and hence in the in place estimates in the gas cap and oil rim. There is also some uncertainty in the likely wet gas to sales gas shrinkage factor (gas shrinkage plus fuel gas requirement), but this has less impact on the overall estimated technically recoverable volumes than the GOC uncertainty. Further data should be therefore be gathered in order resolve both of these uncertainties.

Reservoir Engineering – Turonian Oil Rim: The encouraging production performance for the Aje-5ST2 well so far provides a strong incentive for further studies, and the Turonian oil rim remains a potentially valuable additional resource within the Aje field complex. It is therefore recommended that static and dynamic modelling of the oil rim should be carried out in order to derive more reliable estimates of recoverable volumes.

Facilities Engineering - Risk Register: It is recommended that the Aje JV Partners compile a Risk Register for the surface and subsurface risks, their potential impact and possible mitigations as part of the next phase of detailed development studies.

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1 Introduction

This March 2019 CPR is a brief update of the June 2018 CPR [Ref. 1], and incorporates the production data from the Aje-4 and Aje-5ST2 oil wells until Year-end 2018. The previous CPR was a comprehensive update based on the "OML 113 – Aje Field Fast Track Field Development Plan" (FDP, [Ref. 2]) issued by Folawiyo Aje Services Limited ("FASL") in April 2017 for the proposed Aje Turonian gas-condensate development. Since the June 2018 CPR the Aje licence has been renewed for a further 20 years, but the Aje partnership have not yet reached FID for the Turonian gas-condensate development. AGR TRACS have therefore delayed the anticipated 1st gas date by 12 months till 1.1.2022 in the latest economic evaluations.

MX OIL holds a nominal participation interest of 2.6670% in OML 113, which corresponds to a 6.6750% cost bearing interest and a 5.0006% revenue interest, see Table 1.1 below.

OML 113	Costs for YFP payout (as of 1.1.2018)	Nominal Interest	Pre-YFP Payout	Post-YFP Payout & Pre-Project Payout#	Post-Project Payout	Throughout
	Net US$mln		Cost Rec & Profit Share	Cost Rec & Profit Share	Opex & Profit Share	Capex share and Opex prior to Proj. Payout
YFP*	18.5	60.0000%	25.0000%	0.0000%	25.0000%	0.0000%
EER		9.0000%	16.8750%	22.5000%	16.8750%	22.5000%
YFP-DW**		9.0000%	16.8750%	22.5000%	16.8750%	22.5000%
New Age		12.8310%	24.0581%	32.0780%	24.0581%	32.0780%
MX Oil		2.6670%	5.0006%	6.6750%	5.0006%	6.6750%
Panoro		6.5020%	12.1913%	16.2550%	12.1913%	16.2550%
Farminees		40.0000%	75.0000%	100.0000%	75.0000%	100.0000%
TOTAL		**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**

Table 1.1: Aje equity interests April 2018

* YFP (= Yinka Folawiyo Petroleum) is the operator and was carried through the appraisal and development programme for the Aje field, but after start-up YFP has a 25% Net Revenue interest and a 25% Paying Interest until their past costs of US$30mln have been recovered (that is until "pre-YFP payout" is achieved). As of 1.1.2019 the unrecovered past costs due to YFP amounted to US$18.5mln from an original balance of US$30.0mln.

** YFP-DW (= Yinka Folawiyo Petroleum Deep Water) acquired the 9% stake previously held by FHN following the collapse of FHN's parent company Afren in Q2/2015. YFP-DW is not carried through the field development phase, and has no preferential cost recovery, thus this interest is shown separately in the table.

Post YFP Payout and until Project Payout the partners will have Cost Recovery and Profit Sharing Interests equal to their Cost Bearing Participation Paying Interests, thus for Panoro this represents 16.255% Cost Recovery and 16.255% Profit Sharing Interest until Project Payout.

Aje background

The Aje field lies 24 km from the coast and entirely within OML 113, close to the West Africa Gas Pipeline (WAGP, 12 km away) and only 64 km from Lagos (see Fig. 1.1 below). Water depth across the field ranges from 99 metres to over 1,500 metres. The field was discovered by well Aje-1, drilled in 1996 and was further appraised in 1997 by well Aje-2 located approximately 1 km to the east of Aje-1. A third well Aje-3, drilled to the south as a step out from the first two locations, confirmed the structural interpretation and resolved fluid distribution, but penetrated rather poorer quality reservoir. The 2008 appraisal well Aje-4 confirmed the Turonian and Cenomanian reservoirs, and encountered a gas-condensate bearing interval in the deeper Albian interval.

As part of the initial phase of the Cenomanian oil development a new well Aje-5 was drilled in Q2/2016 as a twin to the early appraisal well Aje-2, and completed as a Cenomanian producer. However, the reservoir performance was disappointing, and the well watered out within a few months and was shut in. Two side-tracks were drilled (Aje-5-ST1 and -5ST2) to test the western and northern extent of the Cenomanian reservoir, but both side-tracks came in deep to prognosis and only encountered limited oil columns at the top of the Cenomanian section. Aje-5ST2 was therefore plugged back, and recompleted as a producer in the Turonian oil rim in May 2017.

The licence renewal for OML 113 for a further 20 years was granted in August 2018, on condition of the Aje JV Partners committing to developing the Turonian gas potential.

There are no outstanding work commitments on OML 113.

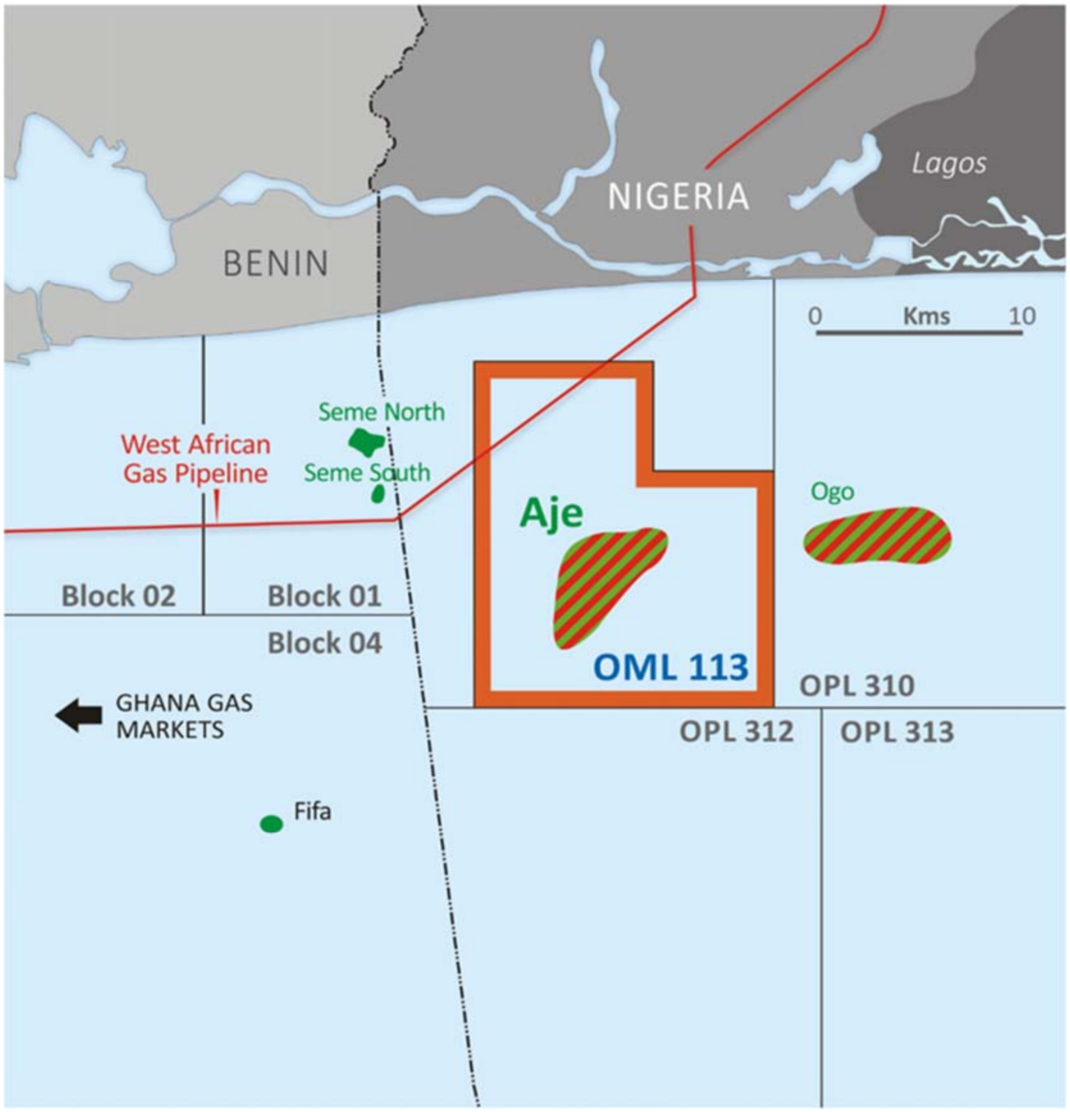

Figure 1.1: Aje OML 113 location map
(Source: MX OIL)

2 AJE Discovery, OML 113

Aje is primarily a gas-condensate discovery, but also contains a thin oil leg below the main Turonian gas reservoirs, an oil leg in the deeper Cenomanian reservoir, and a gas condensate interval in the Albian.

The primary development scheme reviewed in this report is the project described in the recent fast track FDP issued in April 2017 [Ref. 2], which focuses on the Turonian gas-condensate discovery overlying the deeper Cenomanian oil reservoir brought on stream in May 2016. At present the development of the oil leg below the Turonian gas cap is not included in Phase 1 of the Fast Track Gas FDP, but is being studied as a development target to be addressed in Phase 2 as there is a potentially significant resource (P50 STOIIP about 138MMbbl assuming the deeper GOC and OWC).

Following a number of previous evaluations in the period 2006-2014 additional data from the Aje-5, -5ST1 and -5ST2 wells was provided to AGR TRACS in Q1/2018. Due to the disappointing well results from the 2016-2017 drilling campaign the static and dynamic reservoir models from NewAge that were the basis for the volumetric estimates and production forecasts underpinning the 2014 Cenomanian oil development FDP [Ref. 4] have now been discarded, thus for the current CPR update no updated static or dynamic models were available. Those models were reviewed by AGR TRACS for the July 2014 CPR [Ref. 3].

2.1 Aje Seismic Mapping and Volumetric Review

2.1.1 Database

The Aje database is comprehensive and has been updated following the acquisition of new 3D data in 2014, and the drilling of the Aje-5 well and two sidetracks.

The geophysical database available for this review consisted primarily of a Kingdom project containing two 3D seismic volumes; the 1997 data, reprocessed in 2009 and the new 2014 data. The Aje-5 well and data from the two sidetracks was also provided and this included log data, deviation surveys and formation tops. This was added to the well data already in the project, which included interpreted horizons, grids, a full set of formation tops as well as culture data and volumetric polygons. Figure 2.1, Figure 2.2 and Figure 2.3 show the extent and orientation of the two 3D seismic volumes and the location of the Aje wells.

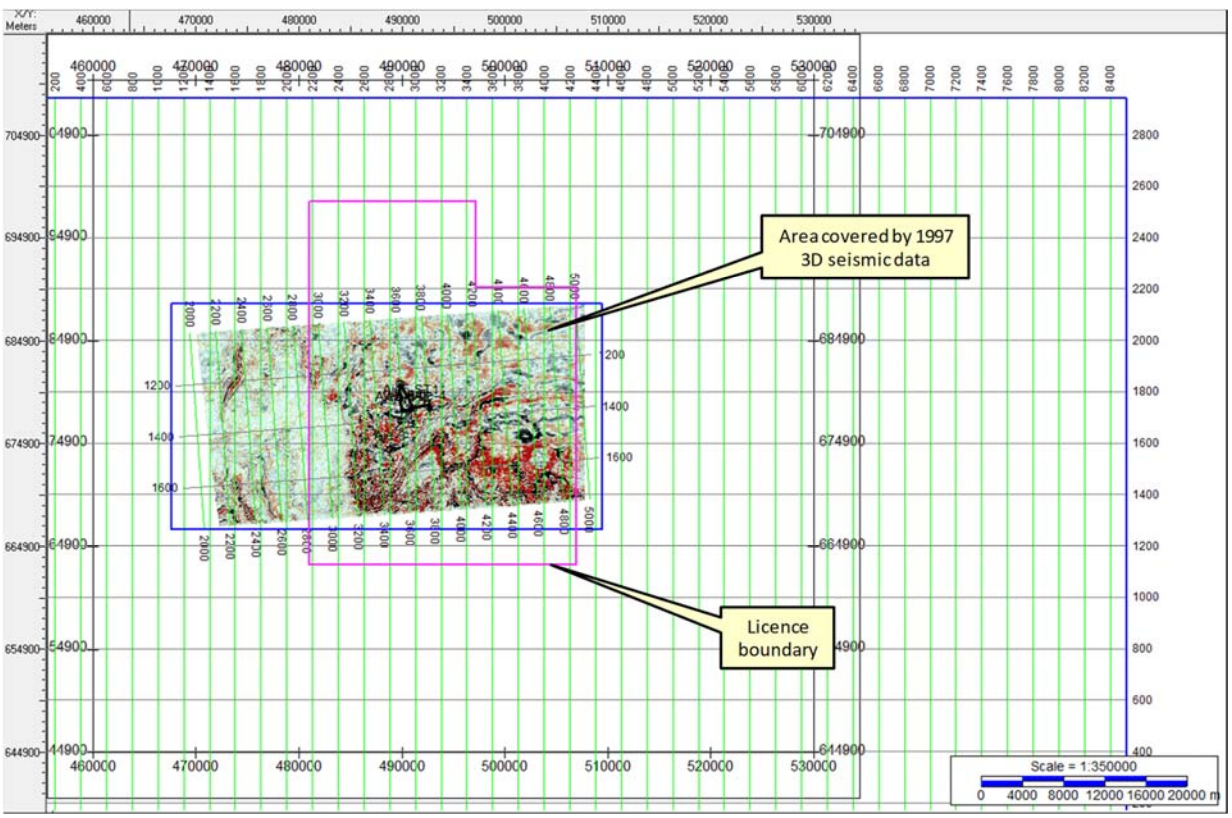

Figure 2.1: Map showing the extent of the 1997 3D seismic data

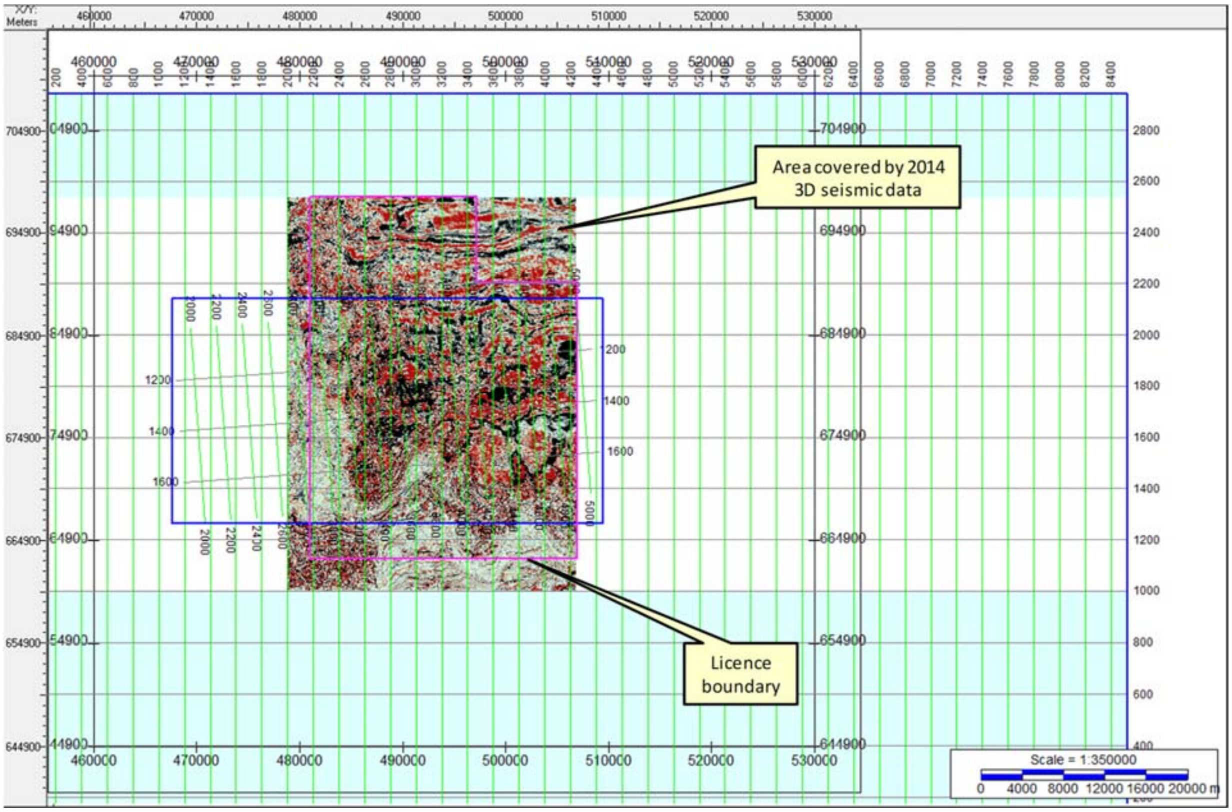

Figure 2.2: Map showing the extent of the 2014 3D seismic data

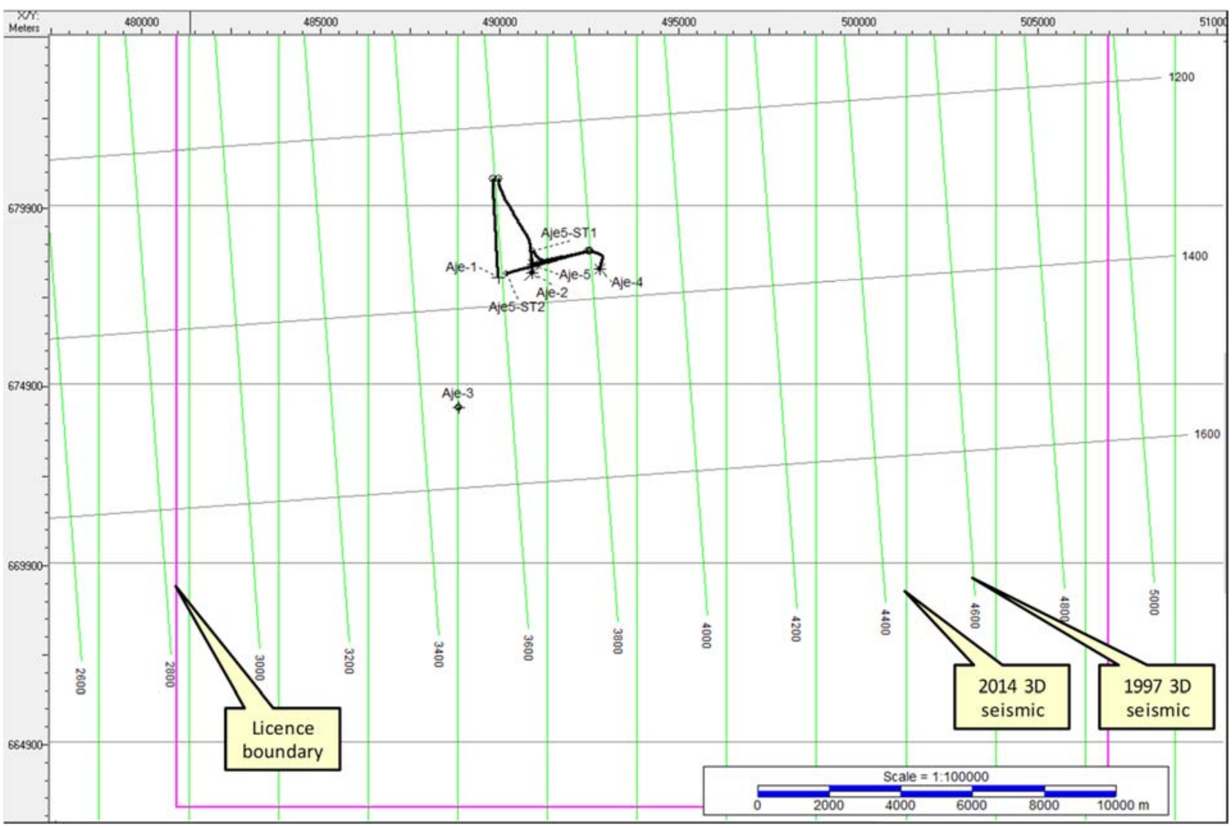

Figure 2.3: Map showing Aje well locations and 3D seismic orientations

The 1997 data covers most of the Aje licence and has a NNW-SSE orientation (Figure 2.1). The data was acquired and processed by PGS, but since then the data has been reprocessed a number of times. The data covers approximately 700 km^2.

The 2014 survey is part of a larger dataset acquired by Polarcus and processed by PGS, which extends to the east to cover the Ogo discovery in OPL 310. Both Pre-Stack Time Migrated (PSTM) and Pre-Stack Depth Migrated (PSDM) volumes were generated. Only the data covering the Aje licence was available amounting to approximately 1,000 km^2 (Figure 2.2). The data covers the whole block and has a N-S orientation.

In addition to the data in the Kingdom project, various presentations were included that summarised the results of the Aje-5 well together with the FDP for the Turonian gas development.

These were all analysed in this review and the following sections provide a summary of the results.

2.1.2 Aje discovery

The Aje discovery is a simple structural trap that lies at the western limit of the Nigerian offshore sector close to the border with Benin (Figure 1.1). The discovery Aje-1 well was drilled in 1996 and followed up with the first appraisal well Aje-2 completed in 1997. Both wells were drilled as highly deviated wells from the shallow shelf and encountered gas above a thin oil rim in the Turonian, and Aje-2 also penetrated an oil leg in the deeper Cenomanian. A third appraisal well Aje-3 was drilled as a south-westerly step-out in 2005, but this was a disappointing well encountering non-reservoir rock in the Turonian and water in the Cenomanian. The Aje-4 well was drilled in 2008 due east of the Aje-2 down-hole location, and confirmed the Turonian and Cenomanian reservoirs. It also encountered an additional, deeper reservoir in the Albian sands.

The Aje discovery lies beneath the steep shelf-break, thus time-depth conversion is critical in assessing the likely structural extent (Figure 2.4). The Aje appraisal was based on the interpretation of a 1997 3D survey which is considered to be of good quality. Both the TWT and Pre-Stack Depth Migrated (PSDM) versions of the 3D processed by Chevron were reviewed as part of the earlier reviews.

A new 3D survey was acquired in 2014 resulting in a new PSDM 3D volume. This formed the basis of the interpretation for the Aje development. There have been some reservations about the accuracy of the depth migration, which may have some basis. However, the overall form of the structure appears to have been captured reasonably well in the latest depth volume.

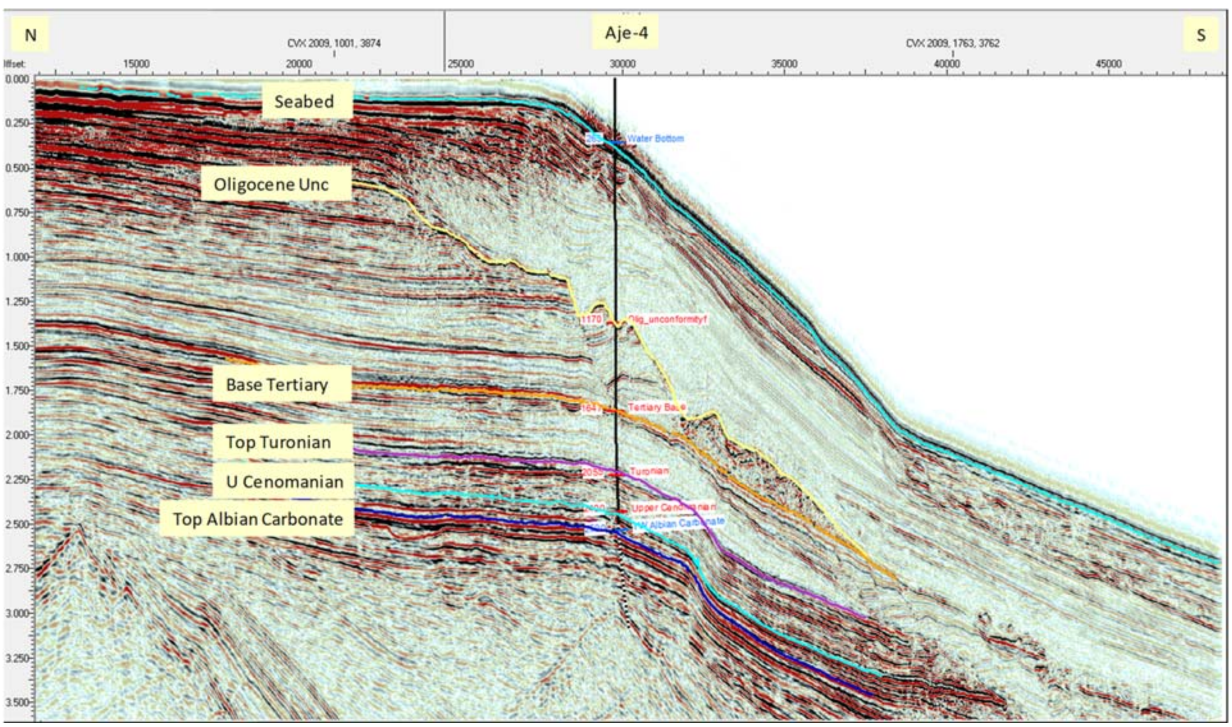

Figure 2.4: North-South TWT seismic line from the 2014 survey across Aje-4 showing steep shelf edge

NOTE: The Aje structural trap is not easy to identify in time as illustrated in Figure 2.4 above, because when viewed in time (rather than depth) the section progressively steepens towards the deeper water. When depth converted, the structure is much clearer. There are also a number of deep erosional canyons in the sea-bed above the field, as shown in the 3D display in Figure 2.5 below, which may influence the seismic data-quality.

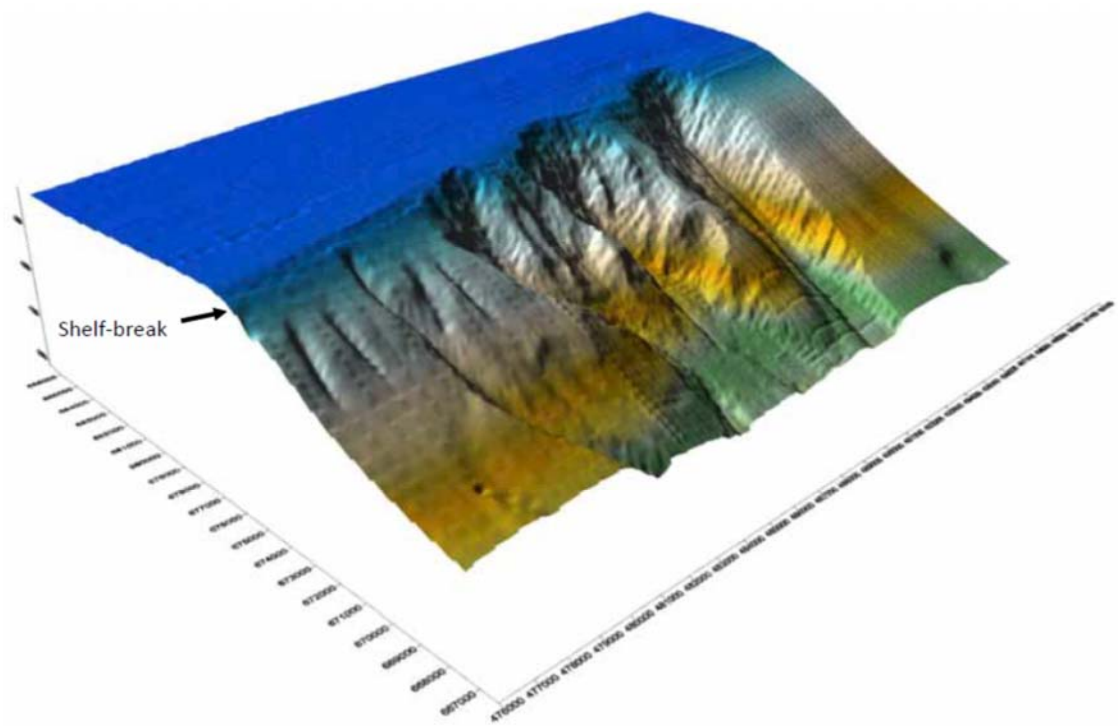

Figure 2.5: 3D view of deep erosional canyons and steep shelf break in the sea-bed above the Aje field
(Source: FASL 2017 Aje Gas Field FDP [Ref. 2])

2.1.3 Turonian mapping

The Turonian structure has not been updated since the 2008 CPR [Ref. 4], and the same map was used in the subsequent reviews. However, with the availability of both a new 3D seismic volume and three new well penetrations the Turonian reservoir mapping has been revisited.

The old map was derived from interpreting the 1997 Two-Way Time (TWT) 3D seismic data, which was then depth converted using various depth conversion schemes. The resulting depth map was a reasonable representation of the Aje structure based on the information at the time. However, when compared with the latest 2014 PSDM data, it appears that the conventional depth conversion method did not capture the flank structure very accurately (Figure 2.6 show seismic line 1735 comparing the 2008 surface and the FDP interpretation). This is understandable given the lack of well control on the flanks of the structure.

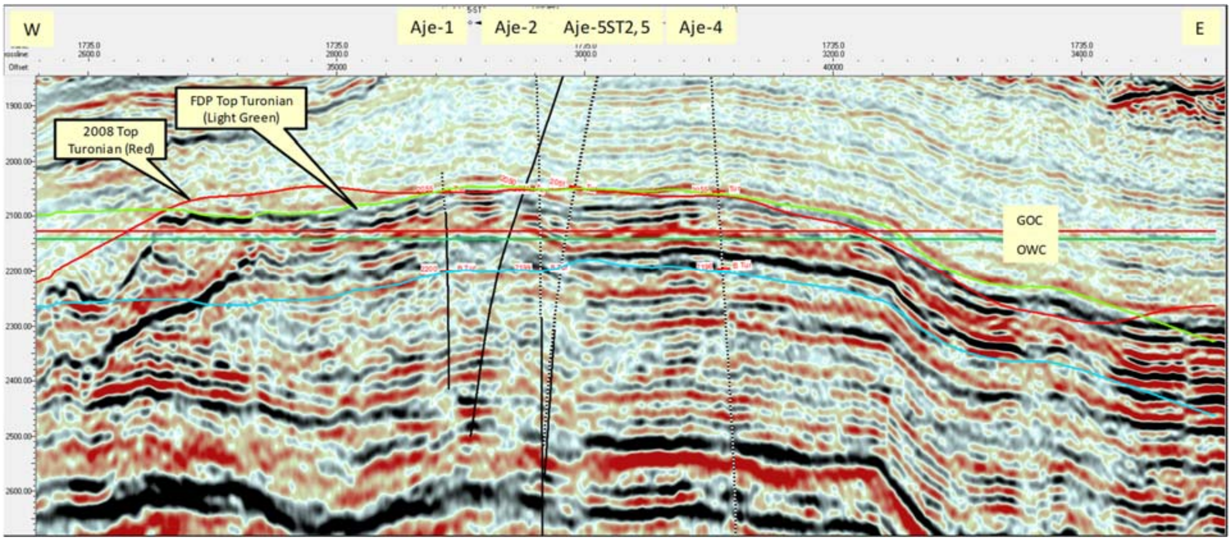

Figure 2.6: Inline 1735 showing 2008 and FDP Turonian picks
(For line location see Figure 2.7)

The latest map used in the Turonian FDP is based on the new 2014 PSDM seismic data volume. This map was found to tie the Aje-5 well and the two sidetracks quite well with the largest mistie being 8.5m at the Aje-5ST2 penetration. This suggests that the PSDM is providing a reasonable solution in terms of the depth at this level. The map has been tied to the new wells, and the resulting map is shown in Figure 2.7.

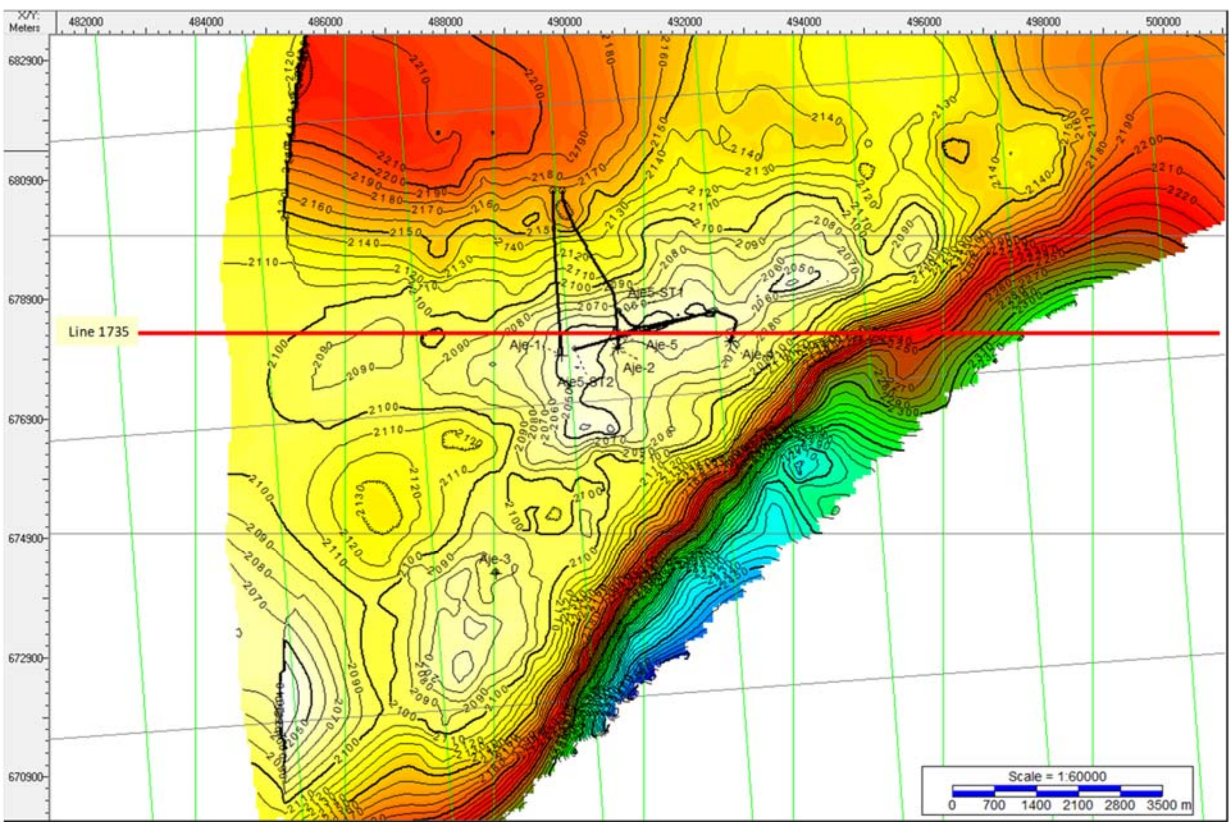

Figure 2.7: FDP Top Turonian depth structure map tied to the new well penetrations
(Source: FASL 2017 Aje Gas Field FDP [Ref. 2])

No new data has been provided that effects the facies interpretation so it remains the view that the environment of deposition is a shallow marine, wave dominated sandy shelf. The 2014 3D seismic data was analysed to determine whether the new data might provide additional insights into the reservoir distribution using amplitude mapping. However, following this analysis, no improvement in the amplitude response was seen.

2.1.4 Cenomanian mapping

The Cenomanian FDP mapping has required a significant update following the drilling of the Aje-5 well and its associated sidetracks. The pre-drill maps showed significant structural elevations, which the well results have proven not to be present. Figure 2.8 shows the Xodus mid case map which was used in the Cenomanian FDP report [Ref. 5]. A similar map provided by NewAge in 2014 (Figure 2.9) also showed substantial highs where the sidetracks were targeted. The misties seen at the new wells were in excess of 18m on the FDP maps and were as much as 65m on the NewAge map.

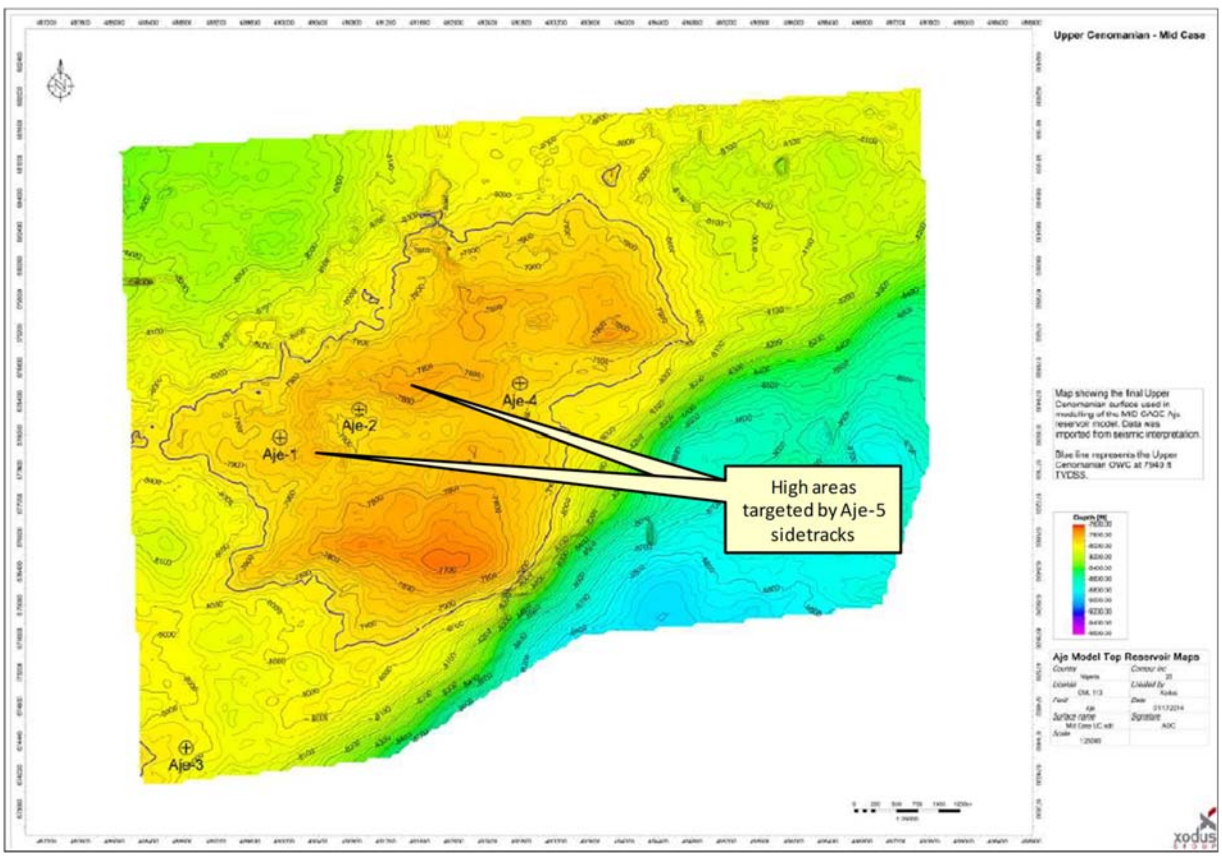

Figure 2.8: FDP Upper Cenomanian depth structure map – Xodus Mid Case – Pre-Aje-5 well
(Source: FASL 2014 Aje Cenomanian FDP [Ref. 4])

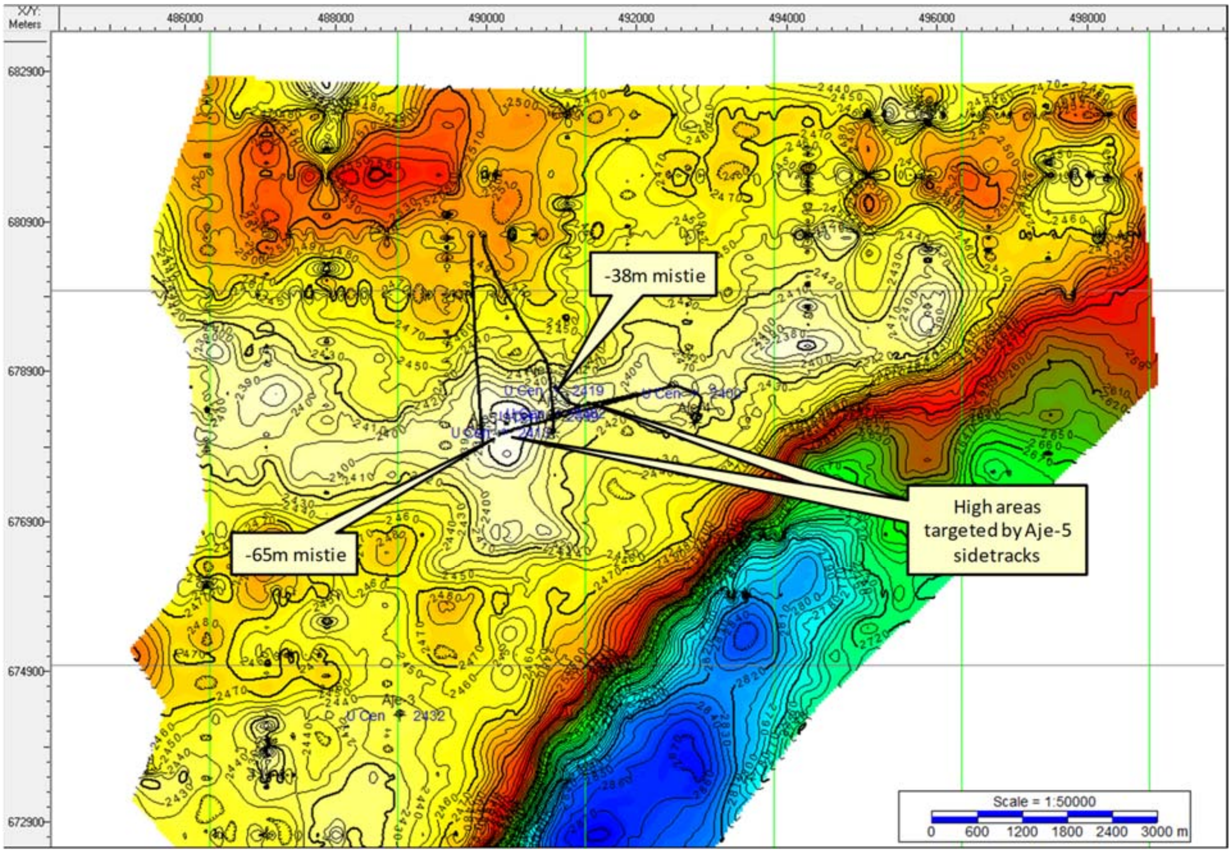

Figure 2.9: NewAge Upper Cenomanian depth structure map – Pre Aje-5 well
(Source: NewAge 2014)

It was initially assumed that the PSDM data was failing to correctly image the Aje Cenomanian structure due to an inaccurate velocity model. Whereas the velocity model may well need refining, having reviewed the interpretation it now appears that the wrong seismic reflector may have been picked, resulting in an overly optimistic map. This incorrect picking is considered to have caused the majority of the misties seen on both the FDP and NewAge maps. Figure 2.10 shows a seismic line illustrating the Top Cenomanian interpretations prior to drilling the Aje-5 well and sidetracks.

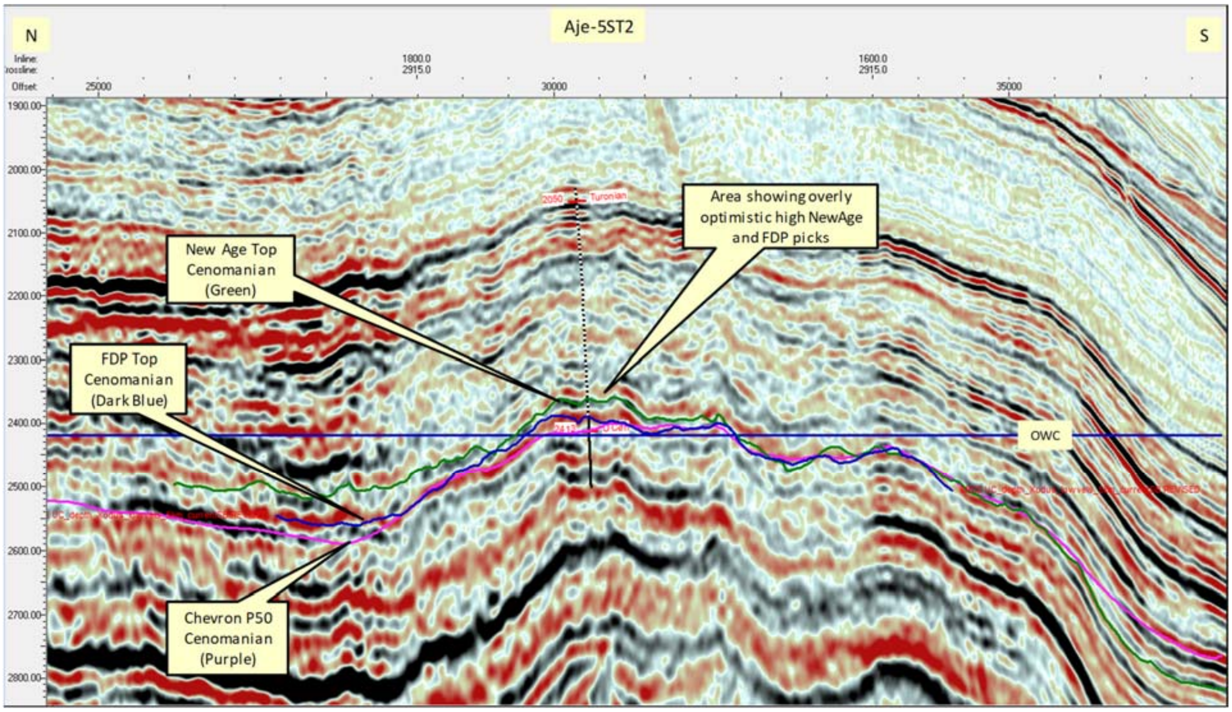

Figure 2.10: Crossline 2915 showing pre-Aje-5 Upper Cenomanian interpretations
(For line location see Figure 2.11)

Currently, no new interpretation has been carried out, hence Panoro provided an alternative set of maps that more accurately tied the new well penetrations. The maps were generated by Chevron during their 2009 evaluation of Aje, and their maps representing the P10, P50 and P90 cases were found to provide a more reasonable representation of the Upper Cenomanian structure. Although these maps were interpreted on the 2009 reprocessed data, they follow the form of the Aje structure reasonably well, even when compared to the 2014 3D depth data.

Figure 2.11 shows the Chevron P50 map after it has been tied to the new wells. The maximum mistie before tying was 12m. Figure 2.10 above shows a N-S seismic line through the Aje-5 well to illustrate the various interpreted horizons. The Chevron tied maps were used to re-estimate the Cenomanian volumes (see Section 5).

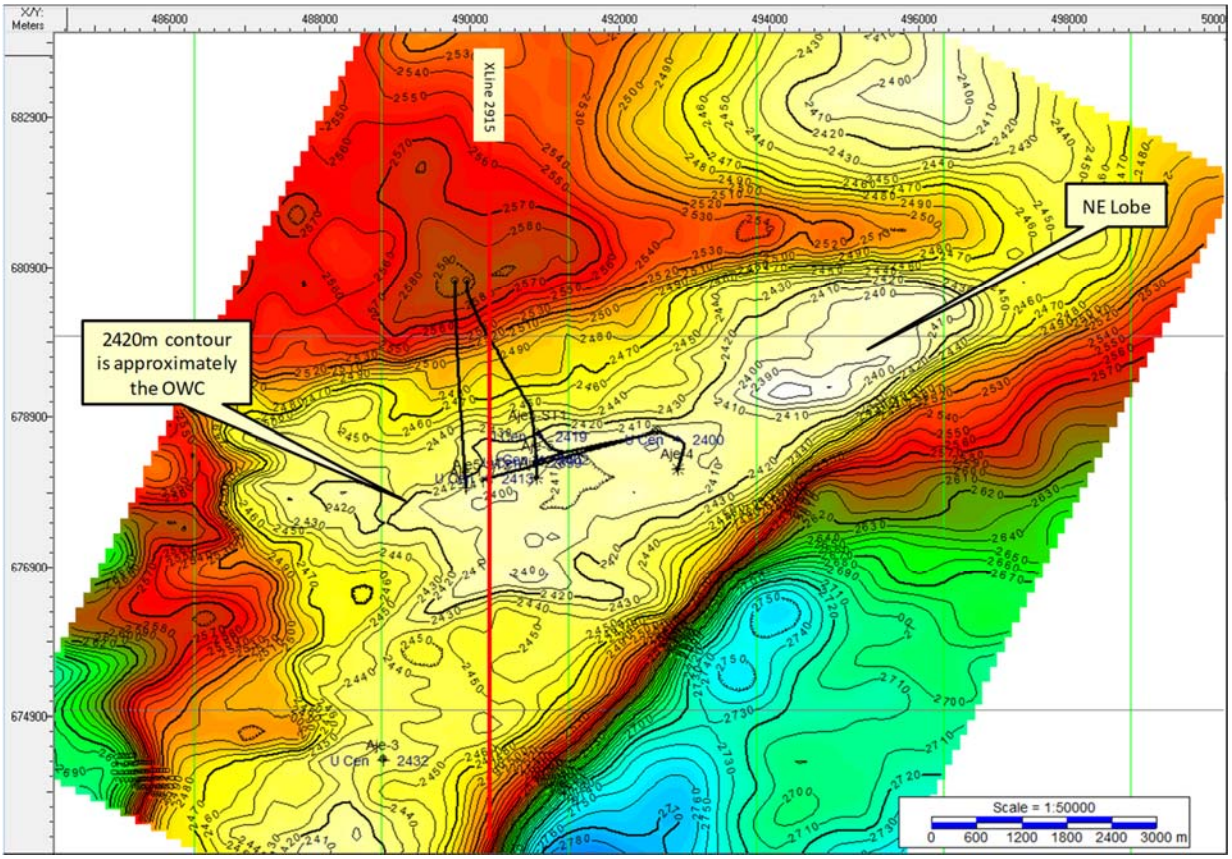

Figure 2.11: Chevron P50 Upper Cenomanian depth structure map tied to wells.

It is recommended that a new interpretation is carried out fully integrating the new seismic and well data in order to provide a more accurate interpretation of the Aje Cenomanian structure. This should include rebuilding the static and dynamic models to improve the understanding of the field, and ought to be carried out prior to any further development drilling.

The new well penetrations have not resulted in a significant change in the interpretation of the Cenomanian reservoir facies. The previous view that the reservoir consists of a series of sands and shales, which can be divided into an upper and lower unit, remains valid (Figure 2.12).

The Upper Cenomanian consists of three sand units separated by shales, and these sands have good to excellent reservoir properties. The Lower Cenomanian consists of more interbedded sands and shales and is generally a poorer quality reservoir than the Upper interval.

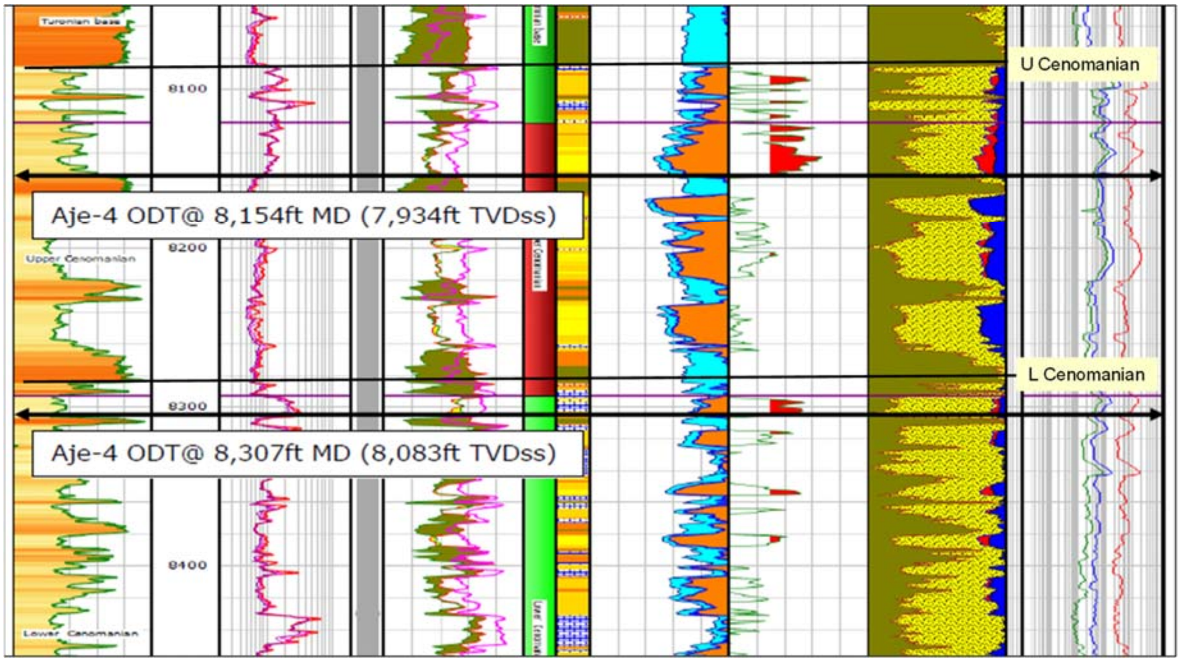

Figure 2.12: Aje-4 Upper and Lower Cenomanian reservoirs
(Source: 2008 and 2012 AGR TRACS reviews)

2.1.5 Albian

No new information has been acquired for the Albian reservoir from any of the Aje-5, Aje-5ST1 and Aje-5ST2 wells as these wells did not penetrate the Albian reservoir. Consequently, the Albian reservoir has not been re-analysed for this CPR and the results of the previous assessment remain valid.

3 Aje Petrophysical Analysis

Petrophysical analyses for the first 4 Aje wells were carried out or reviewed by AGR as part of the 2014 CPR [Ref. 3]. Aje-2, Aje-3 and Aje-4 were analysed incorporating updated formation tops in the Turonian. Aje-1 was not updated as stated in the 2014 CPR since no porosity logs were available. The object of the petrophysical update for the 2018 CPR is to integrate results from the subsequently drilled Aje-5 well including the two sidetracks.

3.1 Data

All available data for the initial four Aje wells was available in LR's Interactive Petrophysics (IP) including measured logs, latest interpretations, deviation surveys, formation tops and core analysis. Further data for wells Aje-5, Aje-5ST1 and Aje-5ST2 were supplied by the client and added to the IP database. Measured logs, deviation surveys and petrophysical reports were supplied for Aje-5ST1 and -5ST2. Only LWD logs were available digitally for well Aje-5ST1. The interpretation was still a good match to the interpretation from wireline logs and results from the LWD data was included in the property output.

3.2 Log Analysis

The petrophysical reports [Ref. 5], and the interpretation parameters for the previous wells were all gathered and petrophysical analysis of the three new wells was carried out in IP. No porosity logs are available for a full interpretation of Aje-5 in the Turonian. Existing interpretations for the previous wells from 2012 [Ref. 6] were reviewed as part the 2014 CPR [Ref. 3] and deemed to be robust. Core analysis was available in Aje-4 and porosity from core and logs (in clean sand) were in good agreement.

3.3 Methodology

The Aje-5 wells were interpreted using input parameters consistent with the previous wells and with the petrophysical reports supplied for wells Aje-5ST1 & -5ST2.

Clay Volume (Vcl) was calculated using a combination of the Gamma Ray Log and the Neutron/Density and cross-plot. Vcl from both methods was very similar and the minimum Vcl was taken as input for porosity (Phi) and water saturation (Sw) calculations.

Porosity was calculated using the Neutron/Density cross-plot where both logs were available or the Density log where necessary.

Water Saturation was calculated using the Indonesia equation (the Archie equation in clean formations with clay corrections applied elsewhere).

$$Sw = \sqrt[n]{\frac{a \times Rw}{Phi^m \times Rt}}$$

Rt = Deep Resistivity

Ø = porosity (decimal)

a = 1

m = 2 (cementation exponent from Archie equation)

n = 2 (saturation exponent from Archie equation)

Rw = water resistivity (ohmm)

Formation water resistivity (Rw) is 0.07ohmm at reservoir temperature in the Turonian (~235°F). The temperature gradient used was Temp (DegF) = 16.31+0.031*TVDss where TVDss is in feet.

3.4 Results

The CPI log over the Aje-4 Turonian section from the 2014 CPR [Ref. 3] is shown below (Figure 3.1) for reference.

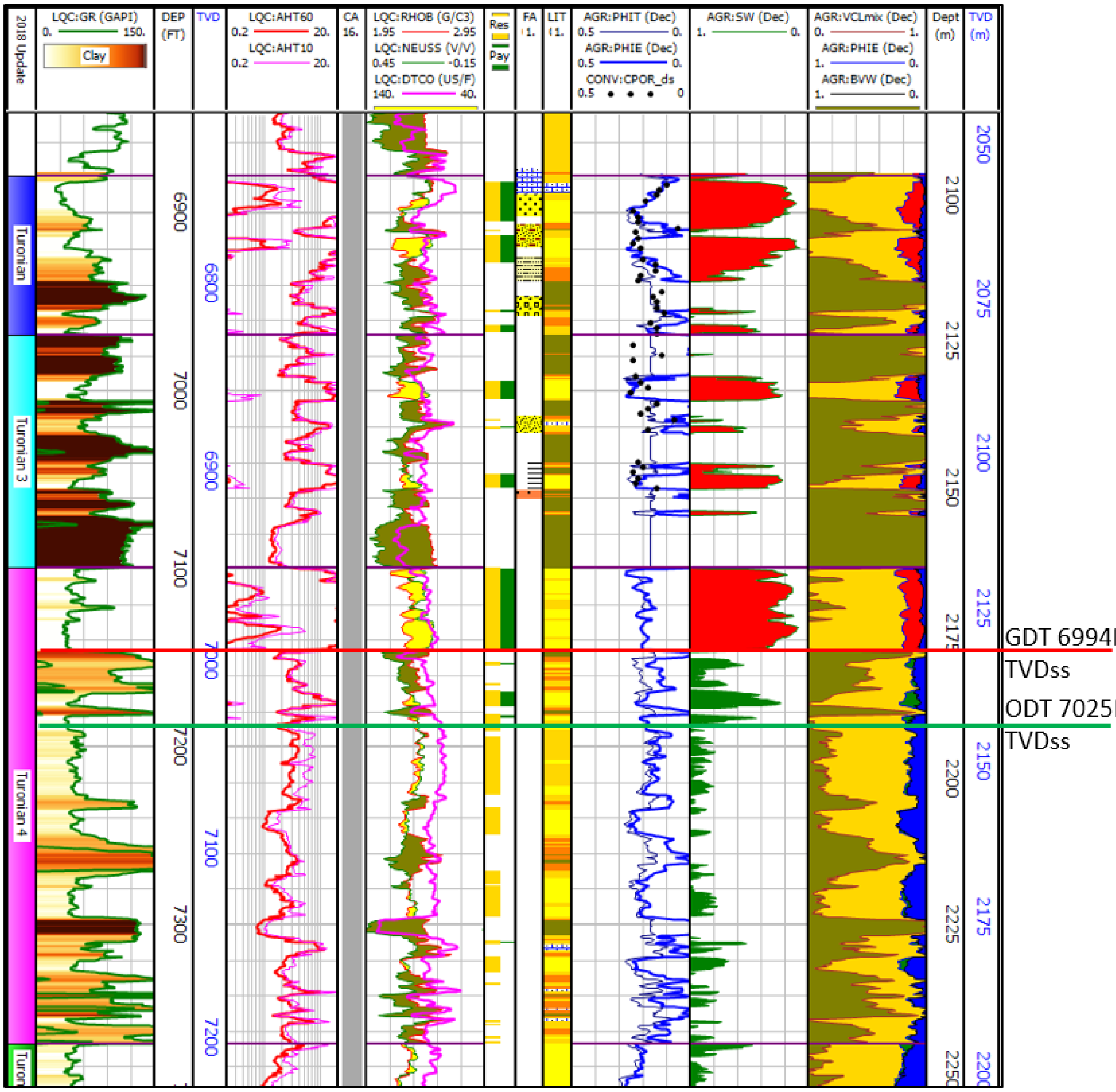

Figure 3.1: Aje-4 CPI log over Turonian section
(Source: Unchanged from 2014 AGR TRACS review [Ref. 3])

Aje-5ST1 and -5ST2 both encountered hydrocarbon-bearing sands with similar properties to the better previous Aje wells (e.g. Aje-4) as presented in the 2014 CPR [Ref. 3]. CPI logs derived from the LWD logs gathered in the two sidetracks are shown in Figure 3.2 and Figure 3.3 respectively.

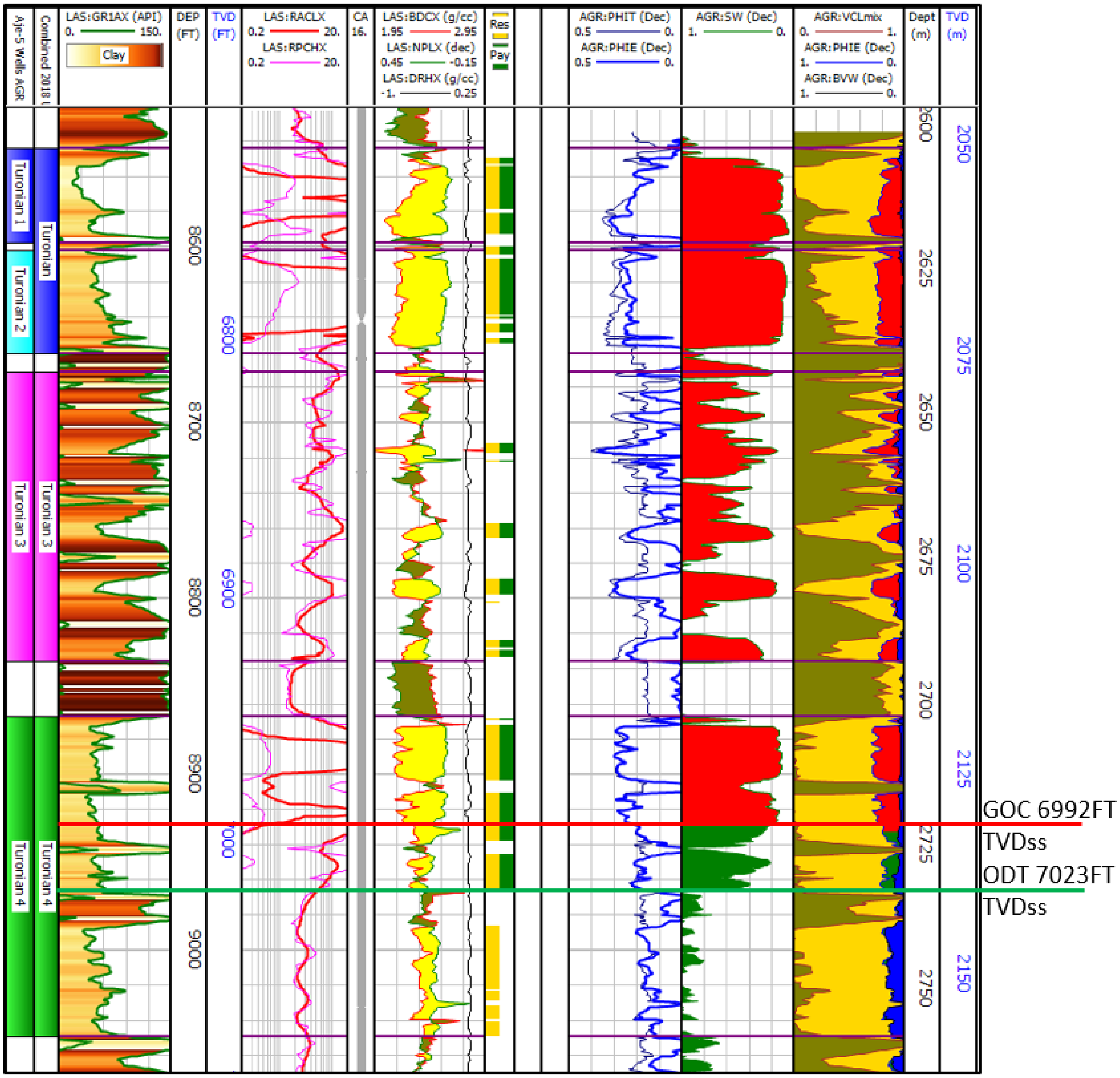

Figure 3.2: Aje-5ST1 Interpretation (CPI plot from LWD logs)
(Source: 2018 AGR TRACS review)

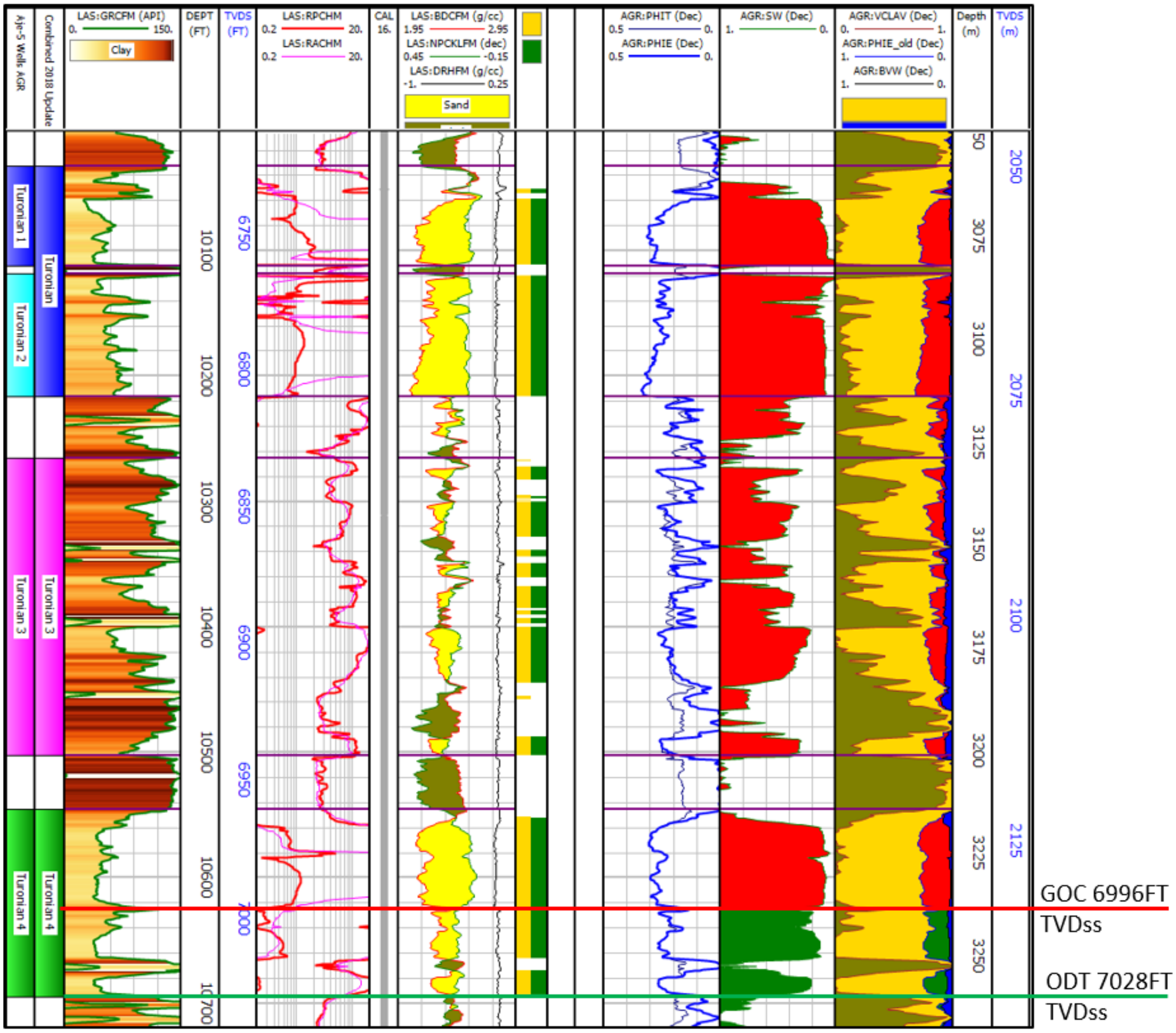

Figure 3.3: Aje-5ST2 Interpretation (CPI plot derived from LWD logs)
(Source: 2018 AGR TRACS review)

Net reservoir was defined as where VCL<40% and PHIE > 10%. The sequence is fairly binary and insensitive to the porosity cut-off in the Aje-5ST wells. The average porosity of all wells is 17% to 25% with the highest overall average of 22% in the Turonian. Average porosity is 20% in both Turonian 3 and 4. NTG is generally higher in the Aje-5ST wells (Table 3.1) though it is worth noting that the shale intervals between the main Turonian units are excluded from the Turonian units in these new wells.

In order to compare like with like Turonian 1 and Turonian 2 in the Aje-5ST wells have been combined into “Turonian” making them consistent with the older wells.

Aje Turonian Reservoir Units							NET RESERVOIR Parameters			
Well	**Zone Name**	**Type**	**Units**	**Top**	**Bottom**	**Gross**	**Net**	**N/G**	**Av Phi**	**Av Sw**
AJE-1	Turonian	MD	ft	11311.84	11741.48	429.64	271.00	0.63	0.20	0.15
AJE-2	Turonian	MD	ft	11025.53	11172.14	146.61	102.89	0.70	0.20	0.17
AJE-3	Turonian	MD	ft	6933.00	6981.33	48.33	3.34	0.07	0.20	0.53
AJE-4	Turonian	MD	ft	6878.64	6968.40	89.76	44.11	0.49	0.19	0.25
AJE-5ST1	Turonian	MD	ft	8544.25	8660.75	116.50	86.25	0.74	0.23	0.09
AJE-5ST2	Turonian	MD	ft	10033.00	10216.00	183.00	151.38	0.83	0.25	0.08
All Wells	**Turonian**	**MD**				**168.97**	**109.83**	**0.65**	**0.22**	**0.13**
AJE-1	Turonian 3	MD	ft	11741.48	12057.55	316.07	88.50	0.28	0.20	0.31
AJE-2	Turonian 3	MD	ft	11172.14	11358.06	185.92	17.61	0.10	0.17	0.40
AJE-3	Turonian 3	MD	ft	6981.33	7166.82	185.49	0.00	0.00	---	---
AJE-4	Turonian 3	MD	ft	6968.40	7099.14	130.74	19.50	0.15	0.22	0.30
AJE-5ST1	Turonian 3	MD	ft	8671.00	8835.75	164.75	33.75	0.21	0.24	0.20
AJE-5ST2	Turonian 3	MD	ft	10265.00	10502.50	237.50	147.88	0.62	0.19	0.31
All Wells	**Turonian 3**	**MD**				**203.41**	**51.21**	**0.25**	**0.20**	**0.30**
AJE-1	Turonian 4	MD	ft	12057.55	12495.60	438.05	200.50	0.46	0.18	0.59
AJE-2	Turonian 4	MD	ft	11358.06	11685.23	327.17	167.50	0.51	0.18	0.56
AJE-3	Turonian 4	MD	ft	7166.82	7490.57	323.75	60.62	0.19	0.20	0.68
AJE-4	Turonian 4	MD	ft	7099.14	7367.24	268.10	157.99	0.59	0.19	0.65
AJE-5ST1	Turonian 4	MD	ft	8867.50	9049.50	182.00	139.25	0.77	0.20	0.39
AJE-5ST2	Turonian 4	MD	ft	10545.75	10694.75	149.00	132.50	0.89	0.23	0.13
All Wells	**Turonian 4**	**MD**				**281.35**	**143.06**	**0.51**	**0.20**	**0.49**

Table 3.1: Average properties for Turonian net reservoir in all Aje wells

(Source: 2018 AGR TRACS review)

The range of average properties used for the volumetric estimates (Section 4.0) has more up-side than the 2014 CPR since a larger proportion of the wells encountered good quality reservoir.

3.5 Cenomanian

The tops of the Upper and Lower Cenomanian in the Aje-5ST wells were found deeper than the previously observed oil-water contacts (OWC), and were consequently water bearing. Insufficient logs were available for a full interpretation in Aje-5 so the supplied interpretation is presented with the two 5ST wells in Figure 3.4. The porosity in the Cenomanian is within the range previously carried for the Cenomanian (Table 3.2).

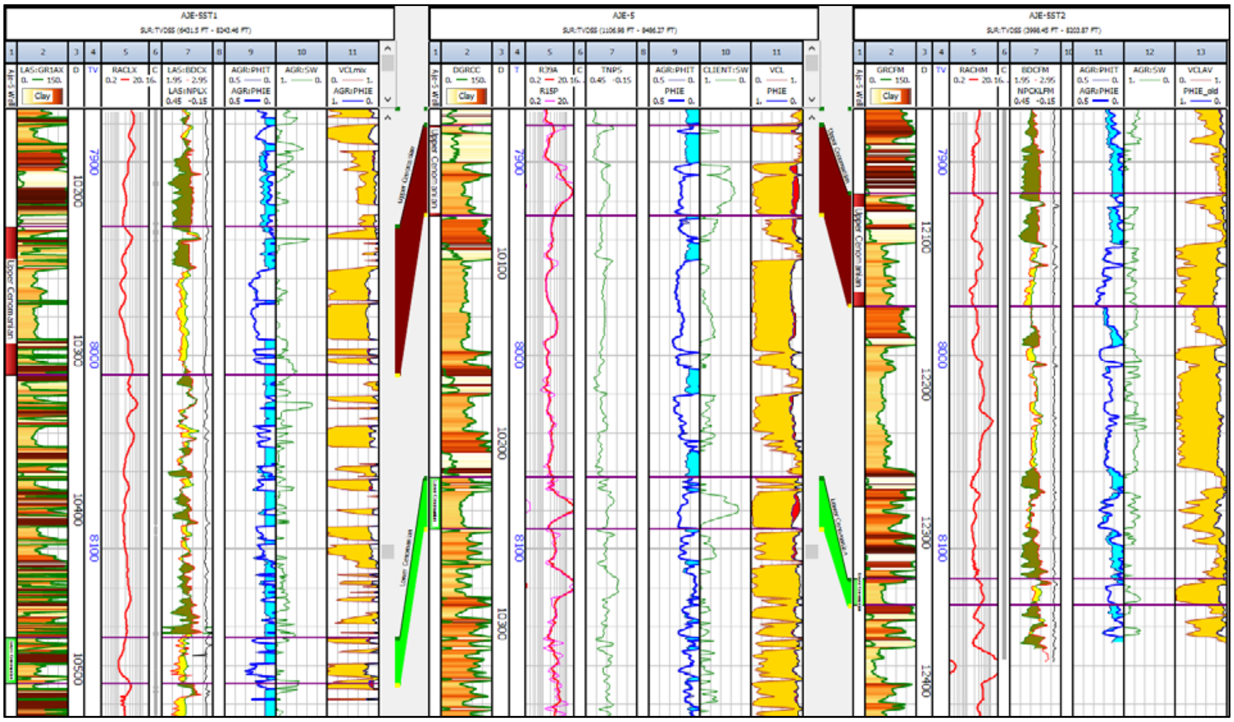

Figure 3.4: CPI plots for the Cenomanian sections in Aje-5, -5ST1 and -5ST2
(Source: MX OIL)

Well	Unit	Gross (ft)	Net (ft)	N/G (%)	Av Phi	Av Sw
Aje-2	U Cenomanian	178	100	56	0.18	0.52
	L Cenomanian	267	130	48	0.09	1
Aje-3	Cenomanian	179	59	33	0.10	0.53
Aje-4	U Cenomanian	184	25	13	0.21	0.52
	L Cenomanian	301	14	4	0.14	0.59

Table 3.2: Cenomanian reservoir properties from Aje-2, -3 and -4

(Source: 2008 & 2012 AGR TRACS reviews, Refs. [4] and [6])
Note that Aje-1 did not penetrate the Cenomanian

3.6 Fluid contacts review

3.6.1 Fluid contacts Turonian reservoir

The gas-oil contact (GOC) for the Turonian formation was identified based on the test results from Aje-1, Aje-2, and Aje-4, plus the recent log data from Aje-5ST1 and -5ST2. The Turonian contacts assumed for the volumetric estimates presented in this report were Turonian GOC of 6,995ft/2,132m TVDss, and a Turonian OWC at 7,028ft/2,142m TVDss. There has been a degree of uncertainty surrounding the depths to these two contact depths, and previous evaluations assumed a GOC of 6,979ft/2,127m TVDss and an ODT of 7,025ft/2,141m TVDss.

MDT/RFT data for the Turonian reservoir was available from wells aje-3 and Aje-4. The Aje-3 pressure data was recorded during fluid sampling in the water zone, and no data is available from the Turonian oil or gas zones. The MDT/RFT data from Aje-4 comprises several points in the gas zone as well as the oil rim and water-bearing zones (see Figure 3.5 and Figure 3.6).

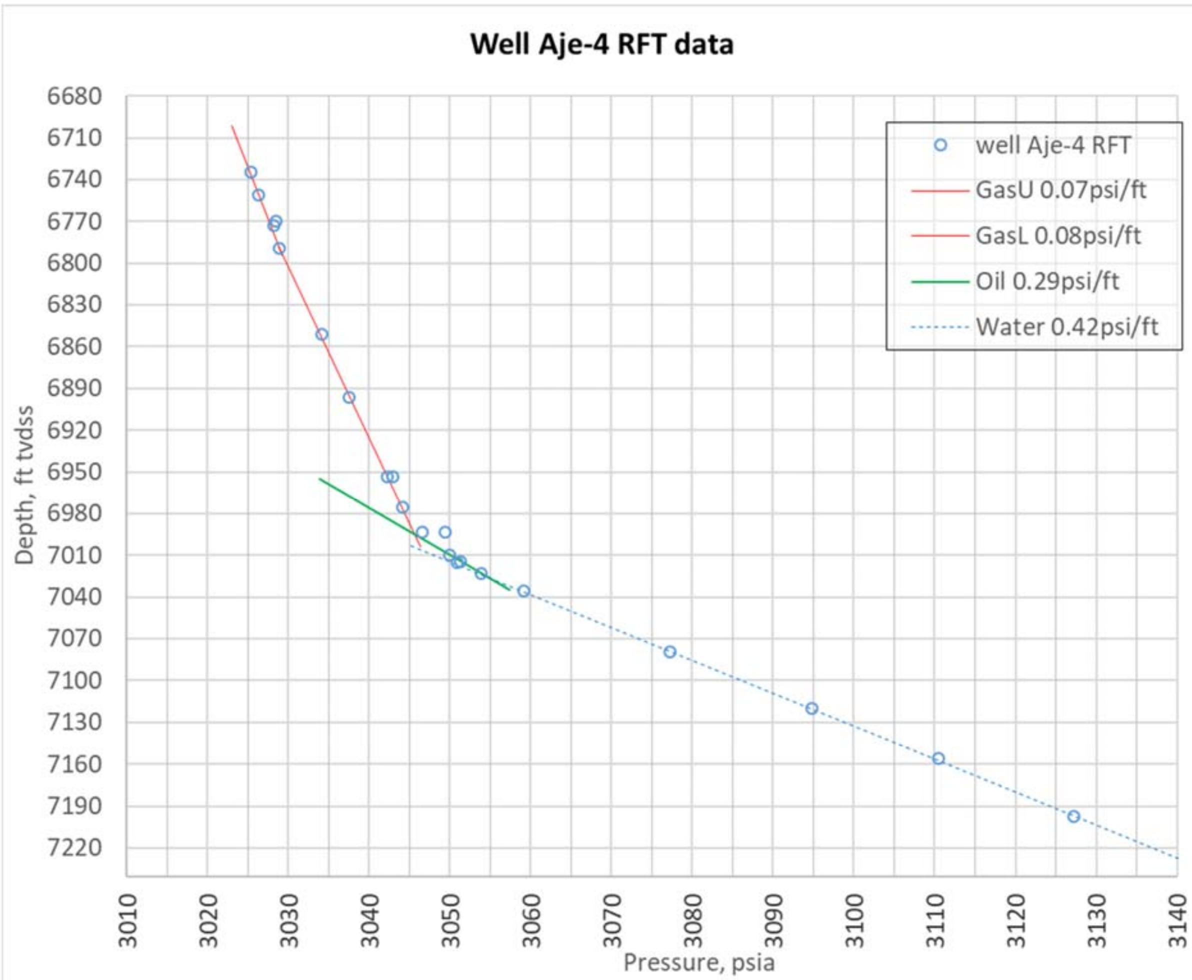

Figure 3.5: Aje-4 - MDT pressure measurements
(Source: Chevron 2008)

The log data appears reasonably conclusive (see Section 3.4); however, due to the high angle of some of these well and the presence of shale intervals the assessment of True Vertical Depths of the contacts is still somewhat uncertain. The RFT tool measures formation pressure of the connected (continuous) phase, and less ambiguous results have been obtained in the gas column and the water-bearing interval. In tight intervals and in the transition zones the recorded pressure measurements are somewhat uncertain (see Figure 3.6).

Reliable fluid contacts were difficult to identify, but a few conclusions could be drawn:

- The gradient of the gas zone pressure data is 0.07-0.08psi/ft, which is in line with PVT for Turonian gas;
- The Turonian gas reservoirs are likely to be in the same hydrodynamic regime.

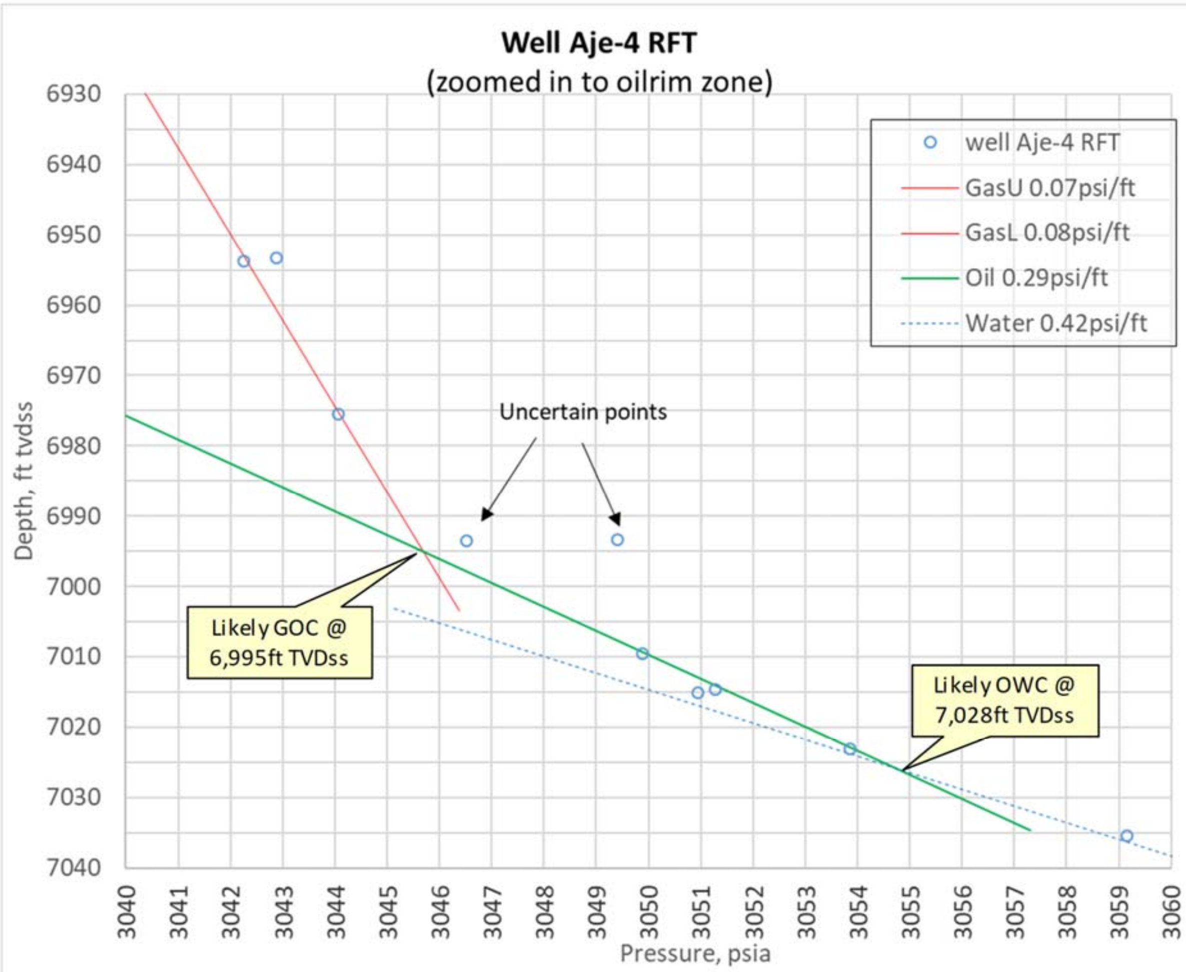

Figure 3.6: Aje-4 - MDT pressure measurements (zoomed in to oil rim interval)
(Source: Chevron 2008)

GIIP and STOIIP volumes assuming the shallower contacts have also been estimated as a sensitivity, see Section 4.1.1.

For the Turonian formation the GIIP volume is not significantly sensitive (~12%) to the GOC depth, since the range of uncertainty (ca. 25 feet) is small compared to the gas column height. However, the STOIIP estimates vary by about 11% depending on the gas and water contacts depths assumed (see Section 4.1.1).

Aje-5ST1 and -5ST2 both encountered gas in the Turonian, Turonian 3 and Turonian 4 intervals (see section 3.4). Gas and oil were both present in the Turonian 4 with a gas-oil contact (GOC) at around 6,995ft/2,132m TVDss. The wells encountered oil down to (ODT) 7,023ft/2,140.5m (Aje-5ST1), 7,025ft/2,141m (Aje-4) and 7,028ft/2,142m (Aje-5ST2) TVDss (see Figure 3.7). Water is calculated up to 7,029ft/2042.2m in Aje-4 and 7,032ft/2,143.4m TVDss in Aje-5ST1. The shale between the true oil-bearing sands and the water bearing sand hinders the identification of a true OWC, but for the current volumetric estimates an OWC at 7,028ft/2,142m TVDss has been assumed.

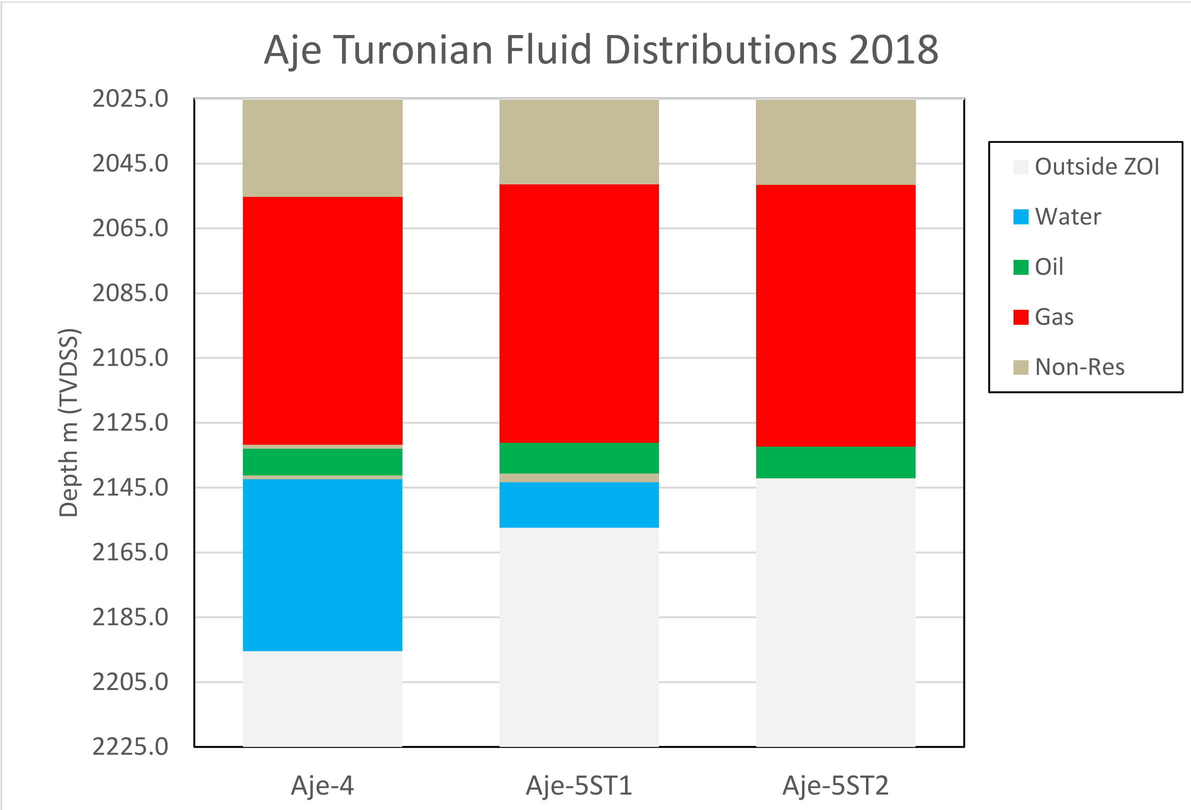

Figure 3.7: Fluid distribution from logs in the Turonian
(Source: 2018 AGR TRACS review)

Inputs for the chart in Figure 3.7 above are provided in both feet and metres in Table 3.3 below:

Markers	ft TVDss				m TVDss		
	Aje-4	Aje-5ST1	Aje-5ST2		Aje-4	Aje-5ST1	Aje-5ST2
Top Turonian	6742	6727	6725		2055.0	2050.4	2049.8
GUT	6743	6730.5	6731		2055.3	2051.5	2051.6
GDT	6994				2131.8		
GOC		6992	6996			2131.2	2132.4
OUT	6998				2133.0		
ODT	7025	7023	7028		2141.2	2140.6	2142.1
WUT	7029	7032			2142.4	2143.4	
WDT	7203	7078			2195.5	2157.4	
Base Turonian	7203	7078	7028		2195.5	2157.4	2142.1

Table 3.3: Observed fluids from logs (metric and imperial) for Fluid Distribution Chart
(Source: 2018 AGR TRACS review)

3.6.2 Fluid contacts Cenomanian reservoir

For the Cenomanian formation, the results of well testing (Aje-2) and oil PVT data (Pbub1,825 psi) indicate the presence of an under-saturated oil reservoir without a gas cap. In the Aje-4 well the MDT results from the Upper Cenomanian have confirmed the previous results from Aje-2, the well also tested water from a depth of 8,176ft MD which helped in defining the OWC. According to the test results, Aje-4 flowed hydrocarbons from a lower interval of the Cenomanian formation, which confirmed the additional oil reservoir. Based on the test information an OWC has been interpreted at a depth of 7,937ft/2,419.2m TVDss for the Upper Cenomanian, and a second OWC at a depth of 8,108ft/2,471.3m TVDss (ODT in Aje-4) in the Lower Cenomanian.

The MDT data from Aje-4 does not show a clear OWC, but it is possible to see the evidence for two different OWC depths within the Cenomanian reservoir (Figure 3.8).

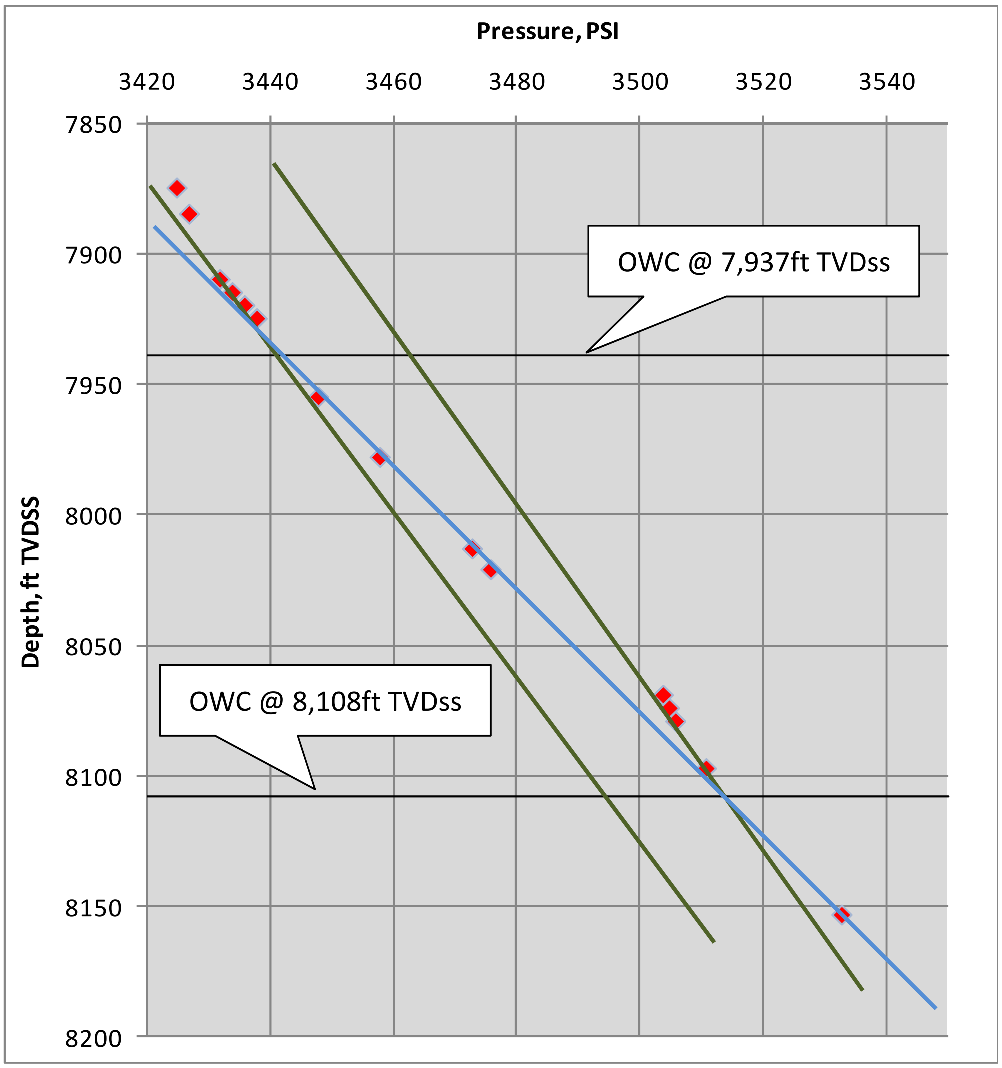

Figure 3.8: Aje-4 - MDT pressures from the Cenomanian interval
(Source: 2008 AGR TRACS review)

4 Probabilistic Volumetrics

Hydrocarbon volumes for the Turonian, Cenomanian and Albian reservoirs have been estimated using a probabilistic (Monte Carlo) approach. Property ranges for Gross Rock Volumes (GRV), Net to Gross (N/G), porosity and Water Saturation (Sw), have been derived from the well log data and applied to the various reservoirs.

The following sections summarise the results of this analysis.

4.1 Turonian

Following the updating of the Turonian mapping, a probabilistic approach was taken to estimate the Turonian Gas Initially In Place (GIIP) and Stock Tank Oil Initially In Place (STOIIP). Polygons were used to constrain the area of the map that contributes to the volumetric estimation and these are shown in Figure 4.1. The Gross Rock Volumes (GRVs) are also constrained by the Gas Oil Contact (GOC), which in previous evaluations was taken to be at 6,979ft/2,127m TVDss, and the Oil Water Contact (OWC) of 7,025ft/2,141m TVDss. There is some uncertainty regarding the positioning of the GOC, and it has been reported by NewAge to be slightly deeper at 6,995ft/2,132m TVDss based on the latest log data from the Aje-5 wells and sidetracks (see Sections 3.4 and 3.6). Similarly, the OWC has been revised slightly based on the latest data (to 7,028ft/2,142m TVDss). Volumes for the GIIP and STOIIP assuming these deeper contacts have also been estimated, and are tabulated below (compare Table 4.2, Table 4.4, Table 4.5, and Table 4.7, Table 4.9 and Table 4.10). Following a comprehensive review of the latest data AGR TRACS have based the notional production profiles and associated economic evaluations on the in-place volumes derived from the deeper contacts.

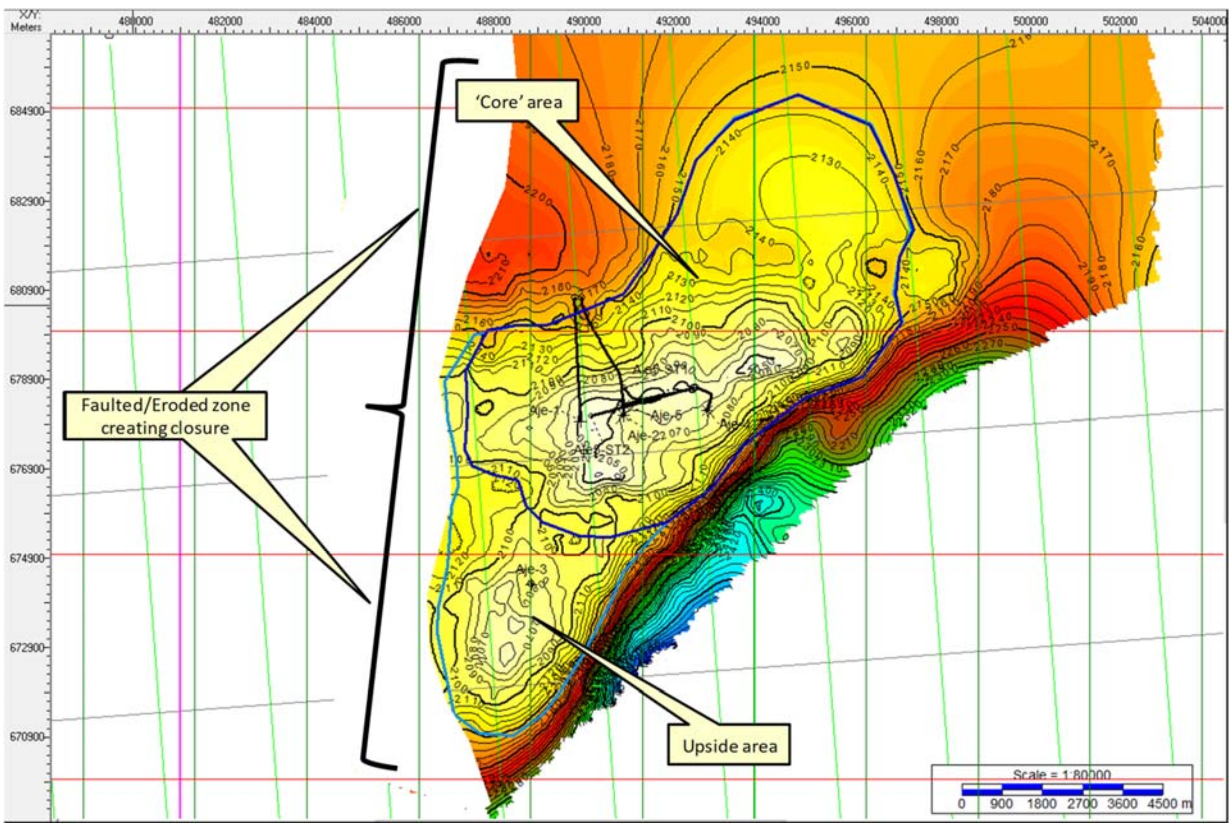

Figure 4.1 Top Turonian Depth map showing volumetric polygons
(Source: FASL 2017 Aje Gas Field FDP, edited by AGR TRACS)

The reservoir parameters and the in-place volumetric estimates derived from Monte Carlo analysis for the Turonian Gas and Oil intervals with both sets of contacts are presented below in sections 4.11 and 4.1.2 respectively.

4.1.1 Turonian gas and oil – shallower contacts

The input ranges for the Turonian gas reservoir parameters were derived from the well log data (Section 3.4), and are provided below in Table 4.1:

Reservoir (GOC @ 6,979ft/2,127m TVDss)	GRV (MM m^3)			N/G (Fraction)			Porosity (Fraction)			Sw (Fraction)		
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
Turonian	500	740	1095	0.30	0.65	0.85	0.19	0.22	0.25	0.09	0.13	0.30
Turonian 3	366	480	630	0.10	0.25	0.60	0.17	0.20	0.23	0.20	0.30	0.40
Turonian 4	30	38	50	0.30	0.50	0.90	0.18	0.20	0.22	0.12	0.22	0.60

Table 4.1: Turonian property ranges for Monte Carlo input (Gas) for shallower GOC
(Source: 2018 AGR TRACS review)

A range of Gas Expansion Factors was used for the three reservoirs derived from analysis of the gas properties (the range used was 168-181-192). The range of CGRs indicated by the sample analyses is only 46.1-46.9 bbls/MMscf (see Section 5.1.3) which is not a wide enough distribution to provide a meaningful range for the Monte Carlo assessment; hence a constant CGR of 46.7stb/MMscf has been applied.

The resulting GIIP and CIIP ranges (assuming a GOC of 6,979ft/2,127m TVDss) are provided in Table 4.2 below:

Reservoir (GOC @ 6,979ft/2,127m TVDss)	GIIP (Wet Gas, BCF, 100%)			CIIP (Cond., MMstb, 100%)		
	P90	P50	P10	P90	P50	P10
Turonian	326.6	547.3	901.9	15.3	25.6	42.1
Turonian 3	39.8	104.2	264.3	1.9	4.9	12.3
Turonian 4	7.0	16.9	33.7	0.3	0.8	1.6
TOTAL (prob.)	**447.9**	**700.3**	**1108.0**	**20.9**	**32.7**	**51.7**
TOTAL (arithm.)	373.4	668.4	1205.9	17.4	31.2	56.3

Table 4.2: Turonian Probabilistic Range of GIIP (Wet gas) and CIIP (Condensate Initially In Place) for shallower GOC
(Source: 2018 AGR TRACS review)

(Note: the Totals are summed both probabilistically and arithmetically)

To estimate the Turonian STOIIP, the ranges of Gross Rock Volume were applied together with the ranges of input parameters that were derived from the well log data, and are listed in Table 4.3 below:

Reservoir (shallower contacts)	GRV (MM m^3)			N/G (Fraction)			Porosity (Fraction)			Sw (Fraction)		
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
Turonian	125	177	250	0.30	0.65	0.85	0.19	0.22	0.25	0.15	0.20	0.30
Turonian 3	153	240	375	0.10	0.25	0.60	0.17	0.20	0.23	0.23	0.32	0.45
Turonian 4	94	106	120	0.30	0.50	0.90	0.18	0.20	0.22	0.15	0.25	0.60

Table 4.3: Turonian property ranges for Monte Carlo input (Oil) for shallower contacts
(Source: 2018 AGR TRACS review)

A range of Formation Volume Factors was used for the three Turonian reservoirs derived from PVT analysis of the oil (the range used was 1.38, 1.46 and 1.73).

The resulting STOIIP ranges (assuming the GOC at 6,979ft/2,127m TVDss and OWC at 7,025ft/2,141m TVDss) are provided below in Table 4.4:

Reservoir (shallower contacts)	STOIIP (MMbls, 100%)		
	P90	**P50**	**P10**
Turonian	50.0	81.5	131.5
Turonian 3	11.4	32.0	89.5
Turonian 4	13.5	29.7	57.2
TOTAL (prob.)	**103.7**	**155.2**	**235.1**
TOTAL (arithm.)	74.9	143.2	278.2

Table 4.4: Turonian Oil Rim - Probabilistic Range of STOIIP assuming shallower contacts
(Source: 2018 AGR TRACS review)

(Note: the Totals are summed both probabilistically and arithmetically)

The oil contains some solution gas, which has been estimated probabilistically using a range of Gas Oil Ratios (GOR). The GOR range used was 685 – 760 – 1150. The resulting volumes of solution gas are provided in Table 4.5 below.

Reservoir (shallower contacts)	Solution Gas (Wet Gas, BCF, 100%)		
	P90	**P90**	**P90**
Turonian	41.9	69.3	113.5
Turonian 3	9.6	27.6	77.3
Turonian 4	11.0	25.5	49.4
TOTAL (prob.)	**88.3**	**132.4**	**202.1**
TOTAL (arithm.)	62.5	122.4	240.2

Table 4.5: Turonian Oil Rim - Probabilistic Range of Solution Gas In Place assuming shallower contacts
(Source: 2018 AGR TRACS review)

(Note: the Totals are summed both probabilistically and arithmetically)

4.1.2 Turonian gas and oil – deeper contacts

The Turonian gas reservoir parameters assumed for the case with the deeper GOC (at 6,995ft/2,132m TVDss)are summarised below in Table 4.6, but note that only the GRVs differ from the parameters assumed above.

Reservoir (deeper GOC @ 6,995ft / 2,132m TVDss)	GRV (MM m^3)			N/G (Fraction)			Porosity (Fraction)			Sw (Fraction)		
	P90	**P50**	**P10**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
Turonian	546	816	1219	0.30	0.65	0.85	0.19	0.22	0.25	0.09	0.13	0.30
Turonian 3	440	569	735	0.10	0.25	0.60	0.17	0.20	0.23	0.20	0.30	0.40
Turonian 4	35	50	71	0.30	0.50	0.90	0.18	0.20	0.22	0.12	0.22	0.60

Table 4.6: Turonian property ranges for Monte Carlo input (Gas) for deeper GOC
(Source: 2018 AGR TRACS review)

As indicated in Section 3.6 based on the latest well results it now appears more likely that the GOC is deeper at 6,995ft/2,132m TVDss, which has an impact on the GIIP, STOIIP and Solution Gas. The consequences of this deeper contact have been investigated, and the resulting ranges of hydrocarbons in place are provided in the tables below. Note that all the reservoir properties and other input parameters remain unchanged.

The resulting GIIP and CIIP ranges (assuming a GOC of 6,995ft/2,132m TVDss) are provided in Table 4.7 below:

Reservoir (GOC @ 6,995ft/2,132m TVDss)	GIIP (Wet Gas, BCF, 100%)			CIIP (Cond., MMstb, 100%)		
	P90	P50	P10	P90	P50	P10
Turonian	359.1	603.1	1010.6	16.8	28.2	47.2
Turonian 3	47.1	123.6	322.3	2.2	5.8	15.1
Turonian 4	9.0	21.7	45.9	0.4	1.0	2.1
TOTAL (prob.)	**501.2**	**789.4**	**1246.4**	**23.4**	**36.9**	**58.2**
TOTAL (arithm.)	415.2	748.4	1378.8	19.4	35.0	64.4

Table 4.7: Turonian Probabilistic Range of GIIP (Wet gas) and CIIP (Condensate Initially In Place) for deeper GOC
(Source: 2018 AGR TRACS review)

(Note: the Totals are summed both probabilistically and arithmetically)

The Turonian oil rim reservoir parameters assumed for the case with the deeper GOC and OWC (at 6,995ft/2,132m TVDss and 7,028ft/2,142m TVDss respectively) are summarised below in Table 4.8, but note that only the GRVs differ from the oil rim reservoir parameters assumed above.

Reservoir (deeper contacts)	GRV (MM m^3)			N/G (Fraction)			Porosity (Fraction)			Sw (Fraction)		
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
Turonian	135	176	228	0.30	0.65	0.85	0.19	0.22	0.25	0.15	0.20	0.30
Turonian 3	106	173	281	0.10	0.25	0.60	0.17	0.20	0.23	0.23	0.32	0.45
Turonian 4	82	88	94	0.30	0.50	0.90	0.18	0.20	0.22	0.15	0.25	0.60

Table 4.8: Turonian property ranges for Monte Carlo input (Oil) for deeper contacts
(Source: 2018 AGR TRACS review)

The resulting STOIIP ranges (assuming the GOC at 6,995ft/2,132m TVDss, and OWC at 7,028ft/2,142m TVDss) are provided below in Table 4.9:

Reservoir (deeper contacts)	STOIIP (MMbls, 100%)		
	P90	P50	P10
Turonian	52.9	80.9	121.0
Turonian 3	7.9	22.9	66.9
Turonian 4	11.1	24.5	46.5
TOTAL (prob.)	**95.4**	**137.5**	**200.4**
TOTAL (arithm.)	71.9	128.3	234.4

Table 4.9: Turonian Oil Rim - Probabilistic Range of STOIIP assuming deeper contacts
(Source: 2018 AGR TRACS review)

(Note: the Totals are summed both probabilistically and arithmetically)

The oil contains some solution gas which has been estimated probabilistically using a range of Gas Oil Ratios (GOR). The GOR range used was 685 – 760 – 1150. The resulting volumes of solution gas based on the deeper contacts are given in Table 4.10 below.

Reservoir (deeper contacts)	Solution Gas GIIP (Wet Gas, BCF, 100%)		
	P90	**P90**	**P90**
Turonian	44.5	69.2	107.7
Turonian 3	6.7	19.7	57.9
Turonian 4	9.3	21.0	41.0
TOTAL (prob.)	**81.1**	**118.5**	**175.6**
TOTAL (arithm.)	60.5	109.9	206.6

Table 4.10: Turonian Oil Rim - Probabilistic Range of Solution Gas In Place assuming deeper contacts
(Source: 2018 AGR TRACS review)

(Note: the Totals are summed both probabilistically and arithmetically)

The consequence of the deeper GOC is to increase the P50 Wet Gas GIIP by approximately 12%. However, the P50 STOIIP and Solution Gas volumes are reduced by approximately 11% assuming the deeper GOC and adjusted OWC.

4.2 Cenomanian

Following the review of the Cenomanian re-mapping, AGR TRACS has carried out a probabilistic estimation of the Stock Tank Oil Initially In Place (STOIIP) for the Upper and Lower Cenomanian reservoirs.

Since the maps used for the volumetric estimations are not based on new maps, these volumes are considered to be interim estimates. Should updated maps become available based on a new interpretation these volumes will need to be revisited.

In order to constrain the GRVs, polygons were used to restrict the area included in the calculation. Two polygons were used; a smaller one that represents the 'Core' area and a larger, upside version. These are shown in the Chevron P50 map included as Figure 4.2 below.

The area of greatest uncertainty with the Cenomanian reservoir is the GRV. Three maps have been used, based on Chevron's 2009 interpretation that represent the P90, P50 and P10 cases. The GRV has been constrained by polygons and the Oil-Water Contact (OWC). For the upper Cenomanian, the contact used was 7,937ft/2,419m TVDss. For the Lower Cenomanian, the OWC used was 8,108ft/2,471m TVDss.

There is some uncertainty as to the presence of the NE lobe and so two scenarios have been analysed. In the first case, it is assumed that the NE lobe is present as an upside and so is included in the P10 case. For the P50 and P90, it is assumed that the NE lobe is not present, or not contributing, so the 'Core' area polygon is used to exclude it in the P50 and P90 cases.

In the second scenario, it has been assumed that the NE lobe is present in the P90, P50 and P10 cases so the GRV is calculated using the upside polygon in all cases. The GRVs for this scenario were provided by MX OIL, and the P10 GRVs are broadly in line with GRVs estimated by AGR TRACS. All other property ranges are assumed to be the same. The different GRV ranges are shown in Table 4.11 and Table 4.12 below and the resulting STOIIP ranges are shown in Table 4.13 and Table 4.14.

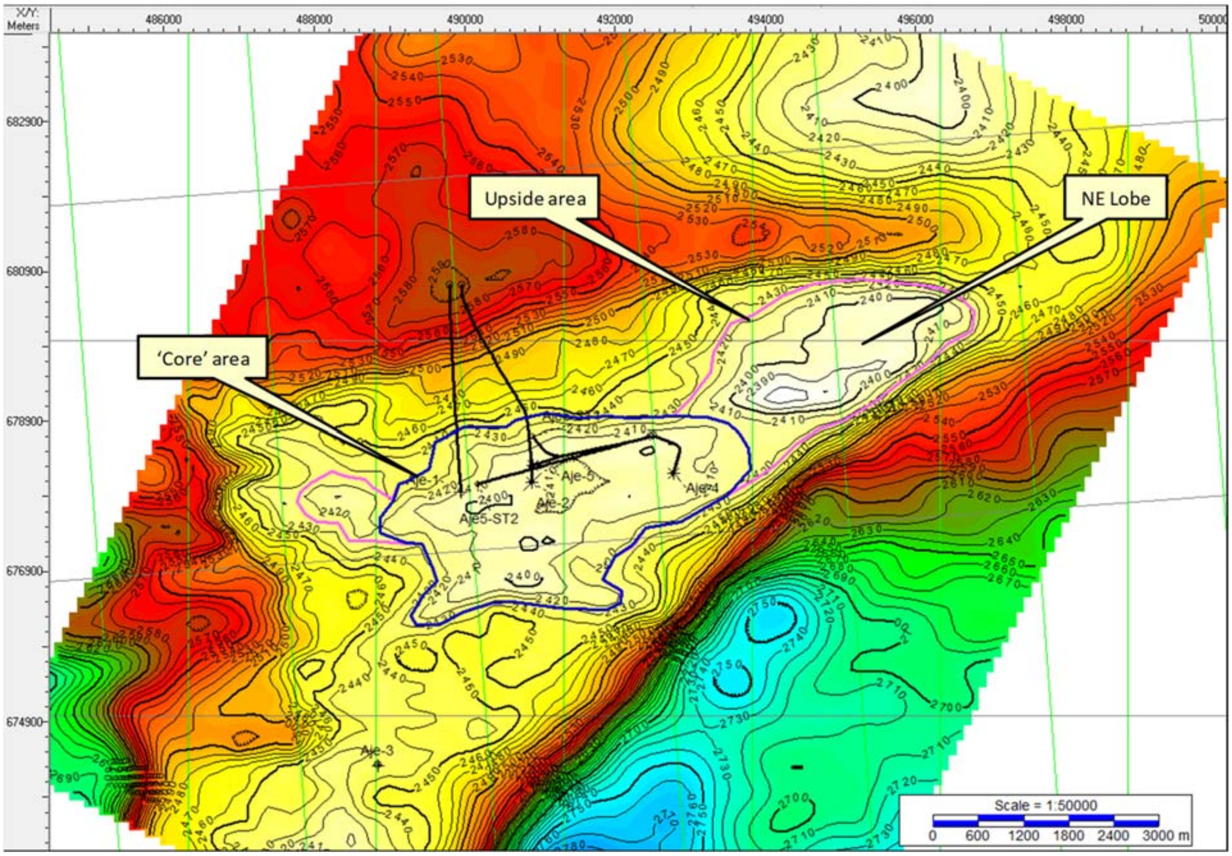

Figure 4.2: Upper Cenomanian Depth showing volumetric polygons
(Source: Chevron P50 map, 2009 review)

The input ranges for the Cenomanian reservoirs are based on the various depth maps and the rock properties seen in the wells. The parameters are summarised in Table 4.11: (for the case which excludes the NE lobe in the P50 and P90), and Table 4.12 (for the case that includes the NE lobe in all cases).

Reservoir	GRV (MM m^3)			N/G (Fraction)			Porosity (Fraction)			Sw (Fraction)		
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
U. Cenomanian	46.5	90.5	135	0.38	0.46	0.70	0.16	0.19	0.22	0.30	0.40	0.50
L. Cenomanian	13.7	28.0	57.2	0.35	0.42	0.66	0.10	0.13	0.16	0.40	0.50	0.60

Table 4.11: Cenomanian property ranges for Monte Carlo input using the 'Core' area polygon for all three cases

Reservoir	GRV (MM m^3)			N/G (Fraction)			Porosity (Fraction)			Sw (Fraction)		
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
U. Cenomanian	61	139	312	0.38	0.46	0.70	0.16	0.19	0.22	0.30	0.40	0.50
L. Cenomanian	30	80	211	0.35	0.42	0.66	0.10	0.13	0.16	0.40	0.50	0.60

Table 4.12: Cenomanian property ranges for Monte Carlo input using the Upside polygon in all cases
(Source: 2018 AGR TRACS review)

Note: MX OIL provided the GRVs shown in Table 4.12.

The range of Formation Volume Factors (FVF) used for the Cenomanian reservoirs was 1.245 – 1.278 – 1.306 which are the FVFs provided in the Field Development Plan.

The resulting STOIIP ranges are provided in Table 4.13 below for the case that excludes the NE lobe in the all three cases, and Table 4.14 that includes the NE lobe in all cases:

Reservoir	STOIIP (MMbls, 100%)		
	P90	P50	P10
U. Cenomanian	12.2	25.0	40.9
L. Cenomanian	1.9	4.2	9.1
TOTAL (prob.)	**16.8**	**30.1**	**46.5**
TOTAL (arithm.)	14.1	29.2	50.0

Table 4.13: Cenomanian Probabilistic Range of STOIIP (excluding NE lobe in all cases)
(Source: 2018 AGR TRACS review)

(Note: the Totals are summed both probabilistically and arithmetically)

Reservoir	STOIIP (MMbls, 100%)		
	P90	P50	P10
U. Cenomanian	16.6	39.4	91.0
L. Cenomanian	4.3	12.0	32.6
TOTAL (prob.)	**27.8**	**55.7**	**112.4**
TOTAL (arithm.)	20.9	51.4	123.6

Table 4.14: Cenomanian Probabilistic Range of STOIIP (including NE lobe in all cases)
(Source: 2018 AGR TRACS review)

(Note: the Totals are summed both probabilistically and arithmetically)

Note: MX OIL provided the range of GRVs used for the estimation of volumes in Table 4.14, hence the volumes in Table 4.14 cannot be directly compared with the volumes in Table 4.13.

As has been alluded to in the text above, AGR TRACS considers there to be significant uncertainty in the presence of the NE lobe. This is due to the complexity of the depth conversion as shown by the recent well results. The predicted depths can be (and were) markedly different from the actual depths and this could well be the case in the NE Lobe area. It is possible that the NE lobe may not be present so there may be no, or negligible, oil volumes trapped. It is difficult to include this in a probabilistic distribution where the P90 is potentially zero so the Mid and High cases have been estimated deterministically using the Chevron P50 and P10 maps, while the Low case has been set to zero. The resulting range of deterministic STOIIP volumes for the NE lobe are summarised below in Table 4.15.

Reservoir	NE lobe Deterministic STOIIP (MMbls)		
	Low	Mid	High
U. Cenomanian	0	20.9	37.9
L. Cenomanian	0	7.1	13.6
TOTAL (arithm)	**0**	**28.0**	**51.5**

Table 4.15: Cenomanian NE lobe Deterministic Range of STOIIP
(Source: 2018 AGR TRACS review)

Although the NE lobe is a smaller area than the core area, it has greater relief so the estimated NE lobe Mid and High case STOIIP volumes are similar to the Core area.

For the purposes of defining notional production profiles for the NE lobe, a range of 0 – 21 – 38 MMbbls was used, representing the Upper Cenomanian STOIIP range in Table 4.15. It is assumed that the Lower Cenomanian is too thin to be viable.

4.3 Albian

No new data has been acquired for the Albian section and so there is no new interpretation for the Albian reservoir. The previous volumetric estimations remain unchanged.

The input ranges, which are derived from the available well data, are provided in Table 4.16 below.

Reservoir	GRV (MM m^3)			N/G (Fraction)			Porosity (Fraction)			Sw (Fraction)		
	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
Albian Sst	40	220	400	0.50	0.60	0.95	0.09	0.13	0.17	0.55	0.60	0.65

Table 4.16: Albian property ranges for Monte Carlo input
(Source: 2014 AGR TRACS review)

Using the range 176, 193, 221 for the Gas Expansion Factor, the resulting GIIP ranges are provided in Table 4.17 below:

Reservoir	GIIP (BCF, 100%)		
	P90	P50	P10
Albian Sst.	9	30	101

Table 4.17: Albian Probabilistic Range of GIIP
(Source: 2014 AGR TRACS review)

5 Aje Reservoir Engineering Review

The current development on the Aje field (block OML 113) was initially focused on oil production from the Cenomanian reservoir with two wells (Aje-4 and -5) tied back to a FPSO. Following the disappointing performance of the Aje-5 well it was side-tracked twice (Aje-5ST1 and -5ST2) to alternative bottom-hole targets in the Cenomanian, but the well results were disappointing, thus the -5ST2 well-bore was completed as a deviated oil producer in the Turonian oil rim. The recent fast-track FDP focuses on the Turonian gas-condensate (gas cap) as a separate subsea development project with offshore separation and LPG processing, and with the gas piped ashore. The condensates will be sent to the oil FPSO and hence evacuated to shore, while there will be separate LPG storage and export facilities (see Facilities Engineering review in Section 6.0)

Additional (horizontal) production wells for the Turonian oil rim could potentially be a viable project, but are not in the current development plan. The deeper Albian gas-condensate accumulation is relatively small, and does not form part of the current development scheme.

Assumptions for the production forecast and key reservoir and fluid properties for the producing reservoirs (Cenomanian oil and Turonian oil rim) and gas development project (Turonian gas-condensate) are discussed in Sections 5.1 to 5.3 below.

5.1 Reservoir fluid properties

5.1.1 Cenomanian oil PVT properties

PVT surface samples were acquired during DST-3 in well Aje-2, and the analysis [Ref. 8] of these samples was provided to AGR TRACS. Based on this PVT data, P90-P50-P10 ranges for the Cenomanian fluid properties for the specific surface conditions were estimated by Xodus [Ref. 4; Table 2.9 FDP p.22]. This work was reviewed and used by AGR TRACS for the latest volumetric estimates (Table 5.1). The Cenomanian oil is light; with ~39.4° API, 0.56cP viscosity and 375-480scf/stb GOR.

Fluid model	Zero flash GOR, scf/stb	Separator* GOR, scf/stb	Psat at 260°F, psia	FVF** at 260°F, 3450psia, rb/stb	In-situ density at 260°F, 3450psia, g/cm3	In-situ viscosity at 260°F, 3450psia, cP
P90	540	483	2,238	1.306	0.665	0.47
P50	485	433	2,053	1.278	0.674	0.51
P10	420	375	1,821	1.245	0.685	0.57
* three stage separator at 815psia / 80degF, 65psia /80degF and 14.7psia /59degF ** adjusted to separator conditions						

Table 5.1: Cenomanian oil PVT properties for dynamic modelling and volumetrics
(Source: Table 2.9 p.22 of 2014 Aje Cenomanian FDP [Ref. 3])

5.1.2 Turonian oil rim PVT properties

The Turonian oil rim was sampled in drill stem tests in the Aje-1 (DST1) and Aje-2 (DST4) wells and by MDT during the drilling of the Aje-4 well. Having reviewed the available data, AGR TRACS are of the opinion that obtaining representative fluid samples for PVT analysis was a challenging undertaking due to the limited thickness of the oil rim, approximately 46 feet (TVDss). The column height of the oil rim meant that only limited stand-off could be achieved between the top of the DST interval and the GOC, with the consequent risk of gas cusping.

The black oil correlation (Standing) input parameters used to determine formation volume factors for the oil rim volumetrics are summarised in Table 5.2 below.

Fluid Model	Reservoir temp. °F	Oil Density API°	Gas S.G. (air =1.0)	Saturation Pressure psia	Solution gas-oil ratio (Rs) scf/bbl	FVF (Bo) rb/stb
P90	245	42	0.6	3035	685	1.39
P50		44	0.7		760	1.46
P10		46	0.8		1,150	1.73

Table 5.2: Turonian Oil rim PVT properties for volumetrics and dynamic modelling
(Source: MX OIL)

The Turonian oil rim is overlain by a gas cap and is therefore at saturation pressure, which is estimated to be around 3,035 psia.

The reservoir temperature was selected based on review of DST data from Aje-2 (DST4). It was not considered necessary to apply a range of temperatures due to the following factors:

- The limited thickness of the oil rim (typical geothermal gradients are in the order or 1.5°F/100ft) thereby constraining the vertical temperature variation along the column.
- The reliability of downhole temperature measurements (typical wellbore-fluid temperature measurements have a resolution in the range of 0.05°F and accuracy in the range of 1°F).

The oil density range was selected based on the variation seen in the PVT data across wells Aje-1, Aje-2 and Aje-4. Molecular weight and specific gravity for the gas were not reported, so it has been assumed that the gas gravity could reasonably vary within the range of 0.6 to 0.8 (as per the 2014 CPR [Ref. 3]).

The variation in the solution gas oil ratio selected for calculations reflects the uncertainty surrounding the nature of the fluid and attempts to address the concerns over potentially non-representative samples due to cusping from the gas zone during DSTs in the exploration and appraisal wells. During the first week of production, 16th to 22nd of May 2017, average Rs for well Aje-5 ST2 was around 760 scf/stb, this was taken as Mid case. The P90 Rs is in line with a “typical black oil”, whilst the higher Rs in the P10 case represents a more volatile black oil.

5.1.3 Turonian gas condensate

The well tests indicate a production GOR within the range 21.3 to 21.7 Mscf/stb (average values per test) and a condensate yield from 46.1 to 46.9 stb/MMscf. Neither the molecular weight nor specific gravity for the gas was reported. However, on the assumption that the gas gravity could reasonably vary within the range of 0.6 to 0.8 (w.r.t. the air), this gives the following estimation of the gas PVT properties (2008 AGR AGR TRACS evaluation [Ref. 5]), see Table 5.3. The compositional analyses for the Turonian gas & fluid samples are summarised in Table 5.4, which show that the CH4 content is about 78%, with some 20% of C2+ components and 2% N2 and CO2.

Parameter	Minimum	Most Likely	Maximum	Units
T reservoir	245	225	215	°F
P reservoir	3,030	3,040	3,050	Psia
S.G. gas	0.60	0.75	0.80	w.r.t. air
Z-factor(1)	0.90342	0.86793	0.83570	
Cond. density		59.9		°API
CGR		46.7		stb/MMscf
Gas FVF	0.005925	0.005513	0.005214	rcf/scf
	168.76	181.39	191.81	scf/rcf
(1) Hall and Yarborough correlation for “z” factor				

Table 5.3: Uncertainty ranges for PVT properties for the Turonian gas accumulation

Description	Recombined	Recombined	Recombined	Subsurface	Subsurface
Source	Gas Cap	Gas Cap	Gas Cap	Gas Cap	Gas Cap
Year	1996	1997	1996	2008	2008
Sample ID	Aje1DST2	Aje2DST5	Aje1DST3	Aje-4 MDT	Aje-4 MDT
Dew Point	3007	3035	2895	3035	3035
Component					
N2	0.78	0.89	0.81	0.95	1.04
CO2	1.25	1.25	1.27	1.25	1.14
C1	78.14	77.36	77.75	78.85	77.81
C2	7.48	7.37	7.52	6.99	6.89
C3	5.02	5.01	5.01	4.85	5.03
IC4	1.22	1.25	1.23	1.13	1.21
NC4	1.69	1.78	1.70	1.55	1.70
IC5	0.67	0.75	0.69	0.60	0.65
NC5	0.53	0.61	0.55	0.44	0.54
C6	0.65	0.79	0.71	0.55	1.01
C7	0.78	0.93	0.86	0.10	0.07
C8	0.72	0.93	0.86	0.11	0.10
C9	0.33	0.37	0.35	0.13	0.14
C10	0.23	0.24	0.24	0.16	0.17
C11	0.14	0.10	0.15	0.17	0.20
C12+	0.37	0.48	0.39	2.17	2.23

Table 5.4: Aje Turonian gas reservoir - gas & fluid compositional data
(Source: Table 2.10, Aje Fast Track Gas FDP [Ref. 2])

5.2 Reservoir rock properties

Detailed analyses of the Aje field reservoirs, including information on the production tests carried out and the reservoir models constructed can be found in previous reports and the 2017 FDP [Ref. 2]. According to these documents, the Aje reservoirs have good flow properties and this is restated below.

The Cenomanian reservoir is currently on production from a single well Aje-4. Excellent reservoir deliverability allowed this well to attain initial production rates of 5000-6000bopd without artificial lift (originally), with maximum production rates in excess of 7,000 bopd.

The Turonian reservoir was extensively tested in wells Aje-1 and Aje-2, when the reservoir was found to have good hydrodynamic properties with an average permeability of 190mD. It is understood that the Turonian gas cap is to be developed with deviated wells (30-45 degrees through the reservoir section), and deliverability from these wells is expected to be in line with the results from wells Aje-1 and Aje-2.

5.3 Aje field production history review (oil)

AGR TRACS have reviewed the production data for the period from May 2016 to 31st December 2018 for the Aje Field. The data comprised the field level production for the wells Aje-4 (Cenomanian reservoir), Aje-5 (Cenomanian reservoir) and Aje-5ST2 (Turonian oil rim). The oil, water and gas rate data represents a commingled flow from the three production wells, with allocation on an individual well basis made by the Operator and provided to AGR TRACS. AGR TRACS undertook a production allocation review exercise on the wells, and then derived production forecasts for the two wells (Aje-4 and Aje-5ST2) that were producing at the end of 2018. Only a few production tests have been carried out during the life of the field; hence the production allocation is somewhat uncertain.

First oil from the Aje field commenced in May 2016 with wells Aje-4 and Aje-5 producing from the Cenomanian reservoir. Initial Cenomanian reservoir production was approximately 6,100 bopd (Figure 5.1) and the wells were producing without the aid of artificial lift.

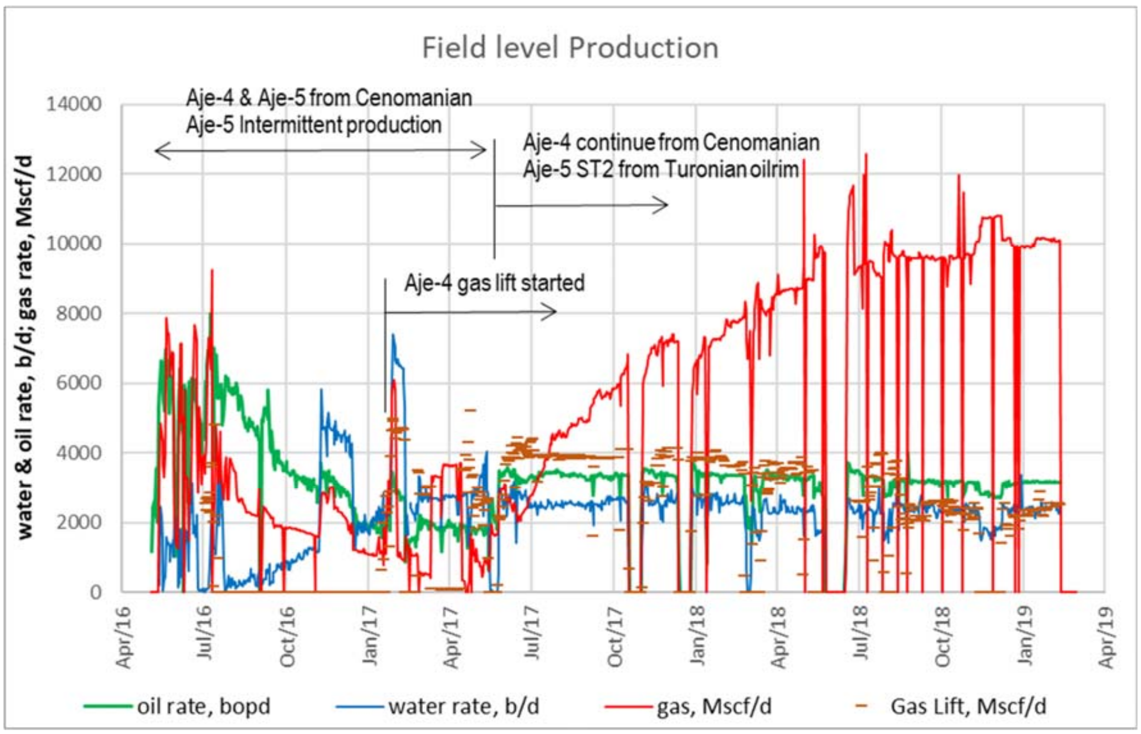

Figure 5.1: Aje field production history (field level) May 2016 – Jan. 2019
(Source: 2019 AGR TRACS review)

The Aje-5 well, producing from the Cenomanian reservoir, started cutting water early and was producing intermittently (Figure 5.2), mostly due to early water breakthrough and rapid watercut increase. The early onset of watercut development and frequent well shut-ins, aided the allocation of produced fluids between Aje-4 and Aje-5. No production allocation testing was undertaken while the original well Aje-5 was producing, thus the allocation was carried out using the 'by difference' approach, whereby changes in field level production rates due to wells going offline are used as a basis for apportioning production rates to individual wells.

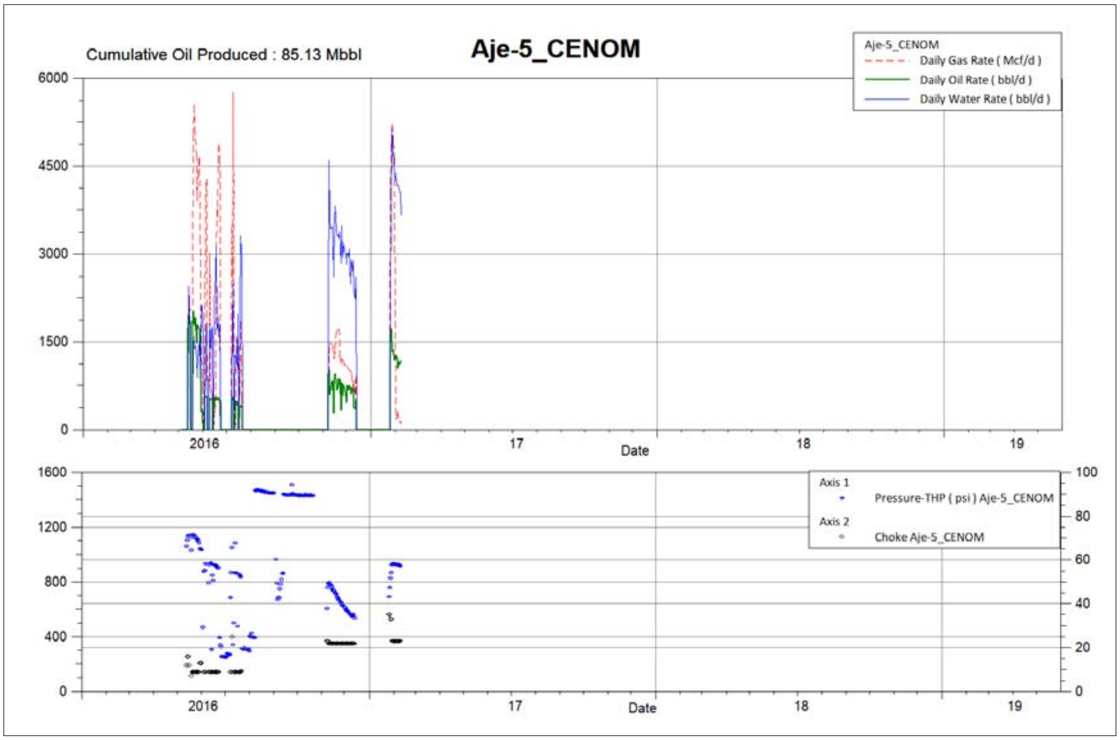

Figure 5.2: Aje-5 well production from Cenomanian reservoir 2016-early 2017
(Source: 2019 AGR TRACS review)

The original well Aje-5 was side-tracked to Aje-5ST1 and then immediately to Aje-5ST2. The Cenomanian reservoirs were found to be almost entirely water-wet in both side-tracks, and Aje-5ST2 was completed as Turonian oil rim producer. Production from Aje-5ST2 started in May 2017 (Figure 5.3) and is characterised by rapid gas breakthrough and high oil production rates. Production of Aje-5ST2 was choked to optimise oil recovery from the oil rim and to reduce gas production rates.

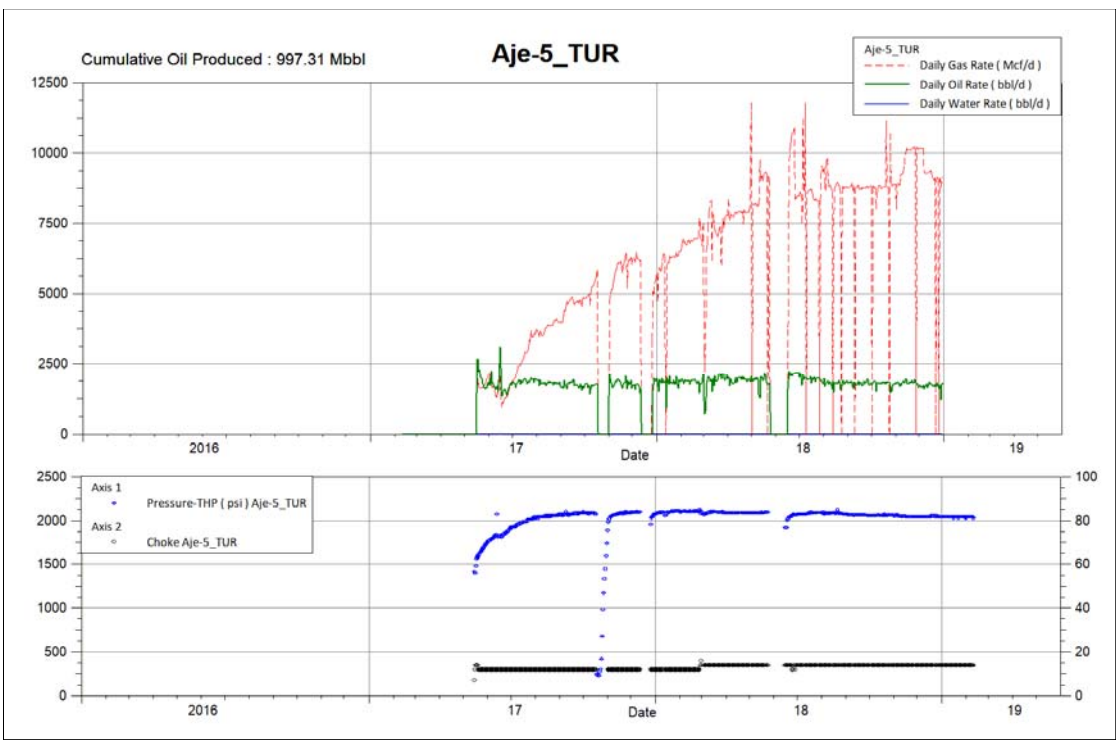

Figure 5.3: Aje-5ST2 production history to end-2018
(Source: 2019 AGR TRACS review)

The Aje-4 Cenomanian well had more consistent oil production rates with a higher uptime. Water broke through to the well around July 2016, and after that watercut has progressively increased (Figure 5.4). However, after gas lift was installed (Jan-2017), the rate of watercut development has slowed and the oil decline rate has reduced noticeably.

During the production allocation exercise it was assumed that from May 2017 onwards Aje-4 is responsible for most water production on the field and that GOR stays constant. The production allocation from May 2017 is uncertain for the wells, and it is therefore recommended that both wells (Aje-4 and Aje-5ST2) be tested on a regular basis in the future to check production allocation and adjust production forecasts.

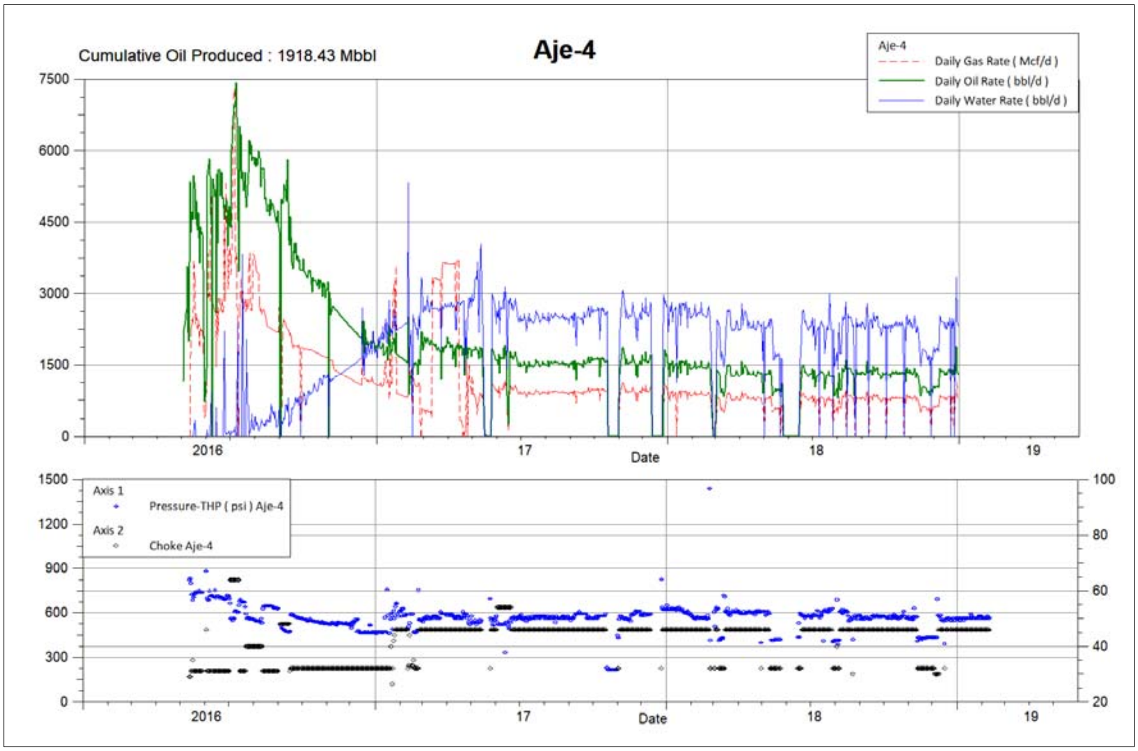

Figure 5.4: Aje-4 production history to end-2018
(Source: 2019 AGR TRACS review)

The Aje field has been on production from 4th of May 2016 with a few shut-ins only. The average uptime for the 3 years of operation was 95% (Table 5.5 and Figure 5.5), and 95% uptime was assumed for the production forecasts for Aje-4 and Aje-5 ST2.

Year	Days total	Prod days	Uptime, %	Comment
2016	242.0	238.0	98	prod start 4-May-2016
2017	365.0	338.0	93	
2018	365.0	344.0	94	
Average			**95**	

Table 5.5: Aje field historic uptime

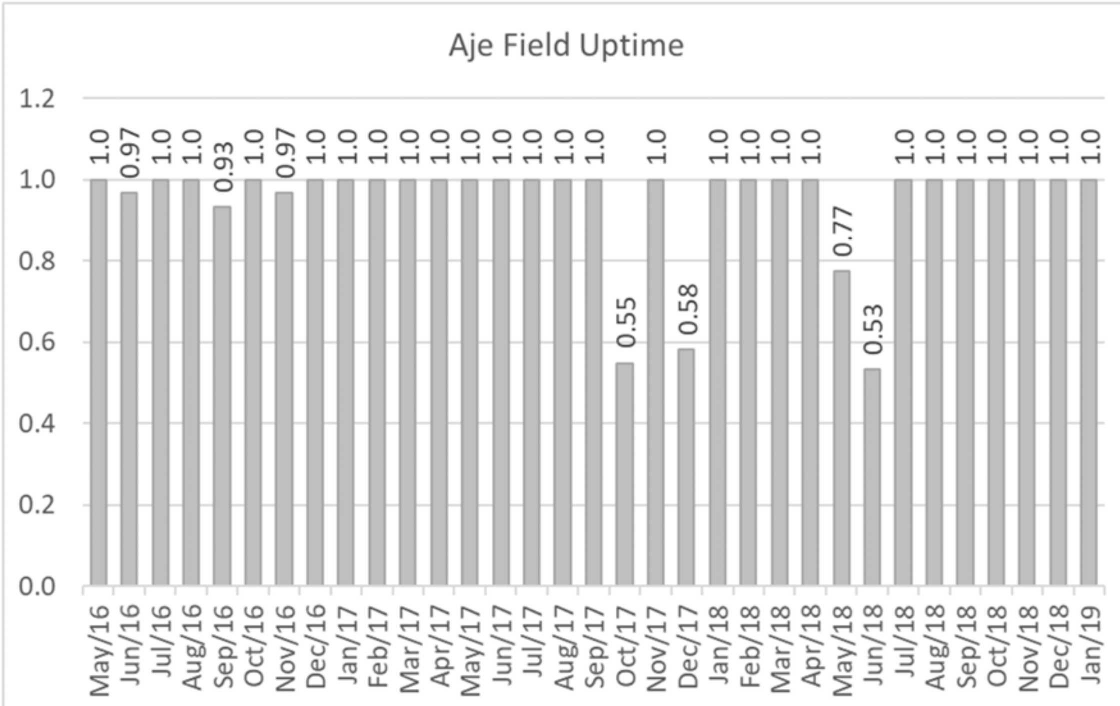

Figure 5.5: Aje field uptime (fraction) monthly May 2016 to Jan. 2019

5.4 Aje-4 and -5ST2 production forecasts

The production forecasts were derived for the two producing wells at Year-end 2018: well Aje-4 producing from the Cenomanian reservoir on gas-lift and depletion drive with aquifer support, and well Aje-5ST2 producing from the oil rim of the Turonian reservoir. The associated gas volumes from the oil production are assumed to be used for fuel aboard the FPSO with any surplus flared, thus no sales volumes are anticipated from the associated gas production from the Cenomanian reservoirs. The notional production profiles derived for the planned Turonian reservoir gas cap development for the June 2018 CPR were not revised, except for a 12-month delay to the 1st gas date assumed in the economic evaluations (now 1.1.2022).

5.4.1 Production forecasts for Aje-4 (Cenomanian producer)

The oil production forecasts for the Aje-4 well were derived as follows:

- Watercut from mid-2017 was reported to be constant for the Aje-4 well during 2018 and it was therefore not possible to use a Watercut vs. Cumulative oil type diagnostic plot for the production forecast.
- Oil production rates were reasonably stable in 2018 with a modest decline in the oil rate oil, which was used for the Low case forecast. The Low case forecast with exponential decline (Figure 5.6) amounted to approximately 3.1MMstb Estimated Ultimate Recovery (EUR) prior to economic cut-offs.
- Oil recovery for the Mid and High cases is expected to be higher and has been derived with hyperbolic decline. The coefficients 'b' of 0.25 and 0.50 were used for the Mid and High cases respectively.
- Estimated Ultimate Recovery for the Mid and High cases prior to cut-offs is 3.5MMstb and 4.0MMstb respectively. The cumulative Aje-4 well oil recovery at Year-end 2018 was 1.9MMstb, and hence the remaining technically recoverable volumes prior to cut-offs are estimated to be 1.6MMstb to 2.1MMstb for Mid and High cases (prior to economic cut-offs).

A plot of the production forecasts is shown in Figure 5.7, while Table 5.6 summarises the annual average daily L-M-H production rates for the Aje-4 well prior to any economic cut-offs.

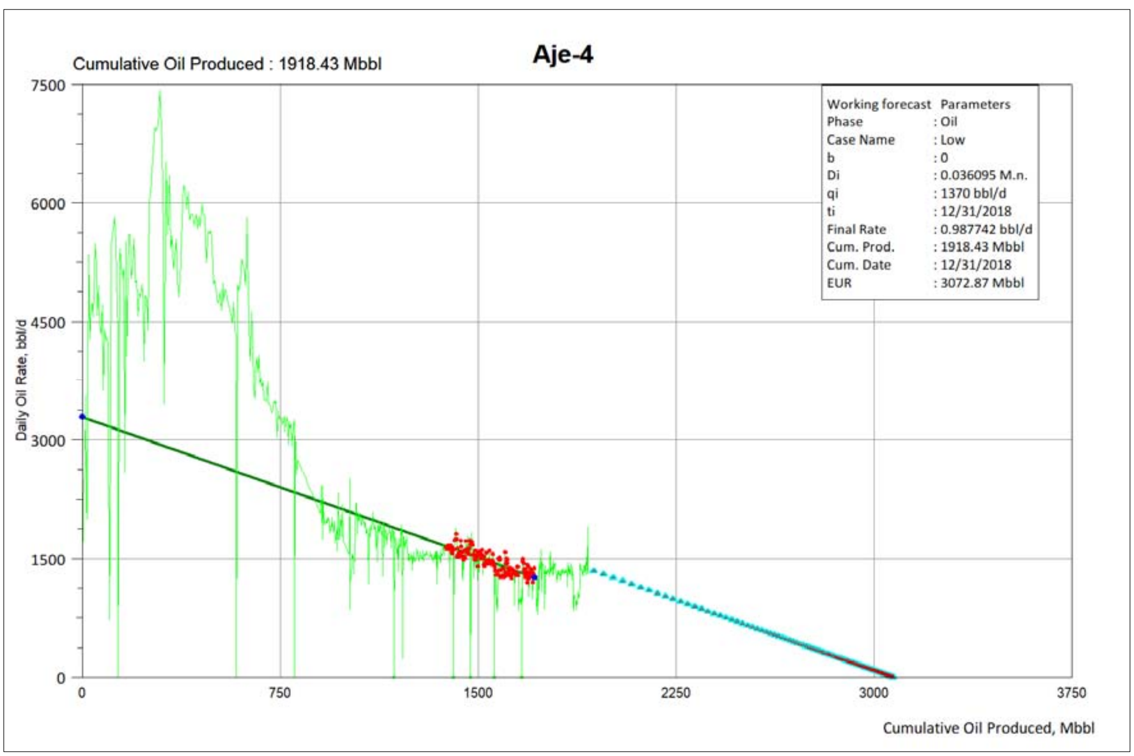

Figure 5.6: Aje-4 Low case forecast [oil rate vs. cumulative oil plot]
(Source: 2019 AGR TRACS review)

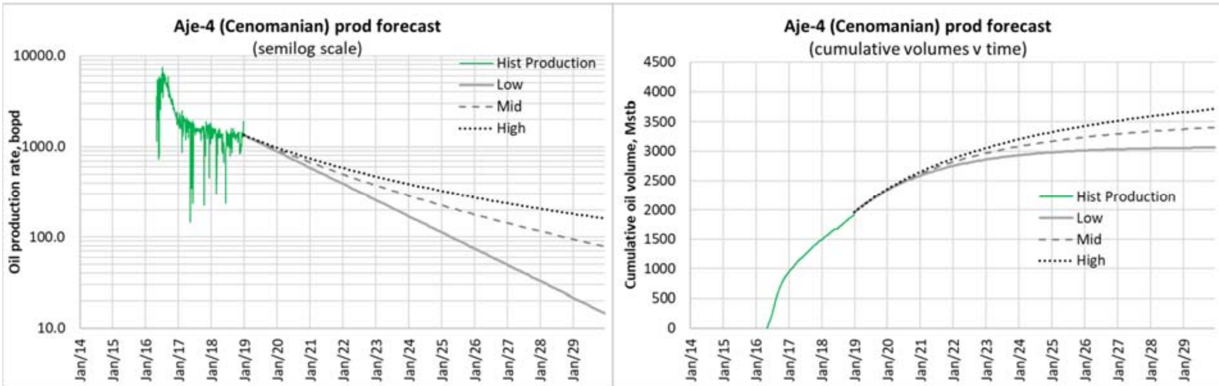

Figure 5.7: Aje-4 (Cenomanian) oil production forecast
[Left plot: oil rate on a log scale vs. time; right plot: cumulative oil vs. time;]

(Source: 2019 AGR TRACS review)

Aje-4	Low		Mid		High	
Year	Oil prod. rate	Incr. Cum. Oil Prod.	Oil prod. rate	Incr. Cum. Oil Prod.	Oil prod. rate	Incr. Cum. Oil Prod.
	(bopd)	(Mstb)	(bopd)	(Mstb)	(bopd)	(Mstb)
Cumulative Production to 31.12.2018 estimated at 1918Mstb						
2019	1067.1	389.5	1090.1	397.9	1108.7	404.7
2020	707.0	648.3	771.4	680.2	822.2	705.6
2021	468.3	819.2	561.1	885.0	634.1	937.0
2022	310.4	932.5	418.0	1037.6	504.0	1121.0
2023	205.8	1007.6	317.8	1153.6	410.2	1270.7
2024	136.3	1057.5	245.8	1243.5	340.4	1395.3
2025	90.3	1090.5	193.1	1314.0	286.9	1500.0
2026	59.9	1112.3	153.8	1370.2	245.2	1589.5
2027	39.7	1126.8	124.1	1415.5	211.9	1666.9
2028	26.3	1136.4	101.1	1452.5	185.0	1734.6
2029	17.4	1142.8	83.3	1482.9	162.9	1794.1
2030	11.6	1147.0	69.2	1508.1	144.6	1846.8
2031	7.6	1149.8	58.0	1529.3	129.1	1894.0
2032	5.1	1151.6	48.9	1547.2	116.1	1936.4
2033	3.4	1152.9	41.6	1562.4	104.8	1974.7
2034	2.2	1153.7	35.6	1575.4	95.2	2009.5
2035	1.2	1154.1	30.6	1586.5	86.8	2041.2
2036		1154.1	26.5	1596.2	79.5	2070.3
2037		1154.1	23.0	1604.6	73.1	2097.0

Table 5.6: Aje-4 Cenomanian L-M-H technical oil production profiles from 1.1.2019
(Source: 2019 AGR TRACS review)

5.4.2 Additional infill drilling potential in the Cenomanian

The Top Cenomanian depth map presented in Figure 4.2 (and reproduced below as Figure 5.8) shows an upside area comprising an undrilled lobe of the field extending to the NE from the core area currently being drained by the Aje-4 well (while the Aje-5 well has watered out). Two side-tracks of the Aje-5 well found thin oil columns in the Cenomanian reservoir and were not completed for production from the Cenomanian. Oil production from the Aje-4 part of the Core Area to YE 2017 was 1,607 Mstb; of which 1,522 Mstb were produced from Aje-4 and 85 Mstb were from the Aje-5 well.

Due to the uncertainties in the depth map, this NE lobe is considered to have a deterministic L-M-H STOIIP range of 0-21-38MMstb (100%), see discussion in Section 4.1.1. MX OIL requested AGR TRACS to provide an opinion on the technically recoverable volumes from a possible future appraisal well in this NE Lobe. If such a future well (Aje-6) is drilled as a near-horizontal well into the local high within this lobe it appears possible that the Mid and High case ultimate recovery could be similar or greater than estimated for the Aje-4 well due to the higher relief of the NE Lobe compared to the Aje-4 location. The L-M-H range of technically recoverable contingent volumes for the NE lobe is therefore estimated as 0-3.0-5.5 MMstb (100%).

These volumes would be contingent on the JV Partners defining and approving a drilling plan for such an appraisal well, which could quickly be completed as a producer and tied back to the oil FPSO if sufficient additional volumes were confirmed. At present the Chance Of Commercial Success (COCS) for such a well is deemed to be 50% due to the lack of any definite drilling proposals, but this could improve should the JV progress with such plans.

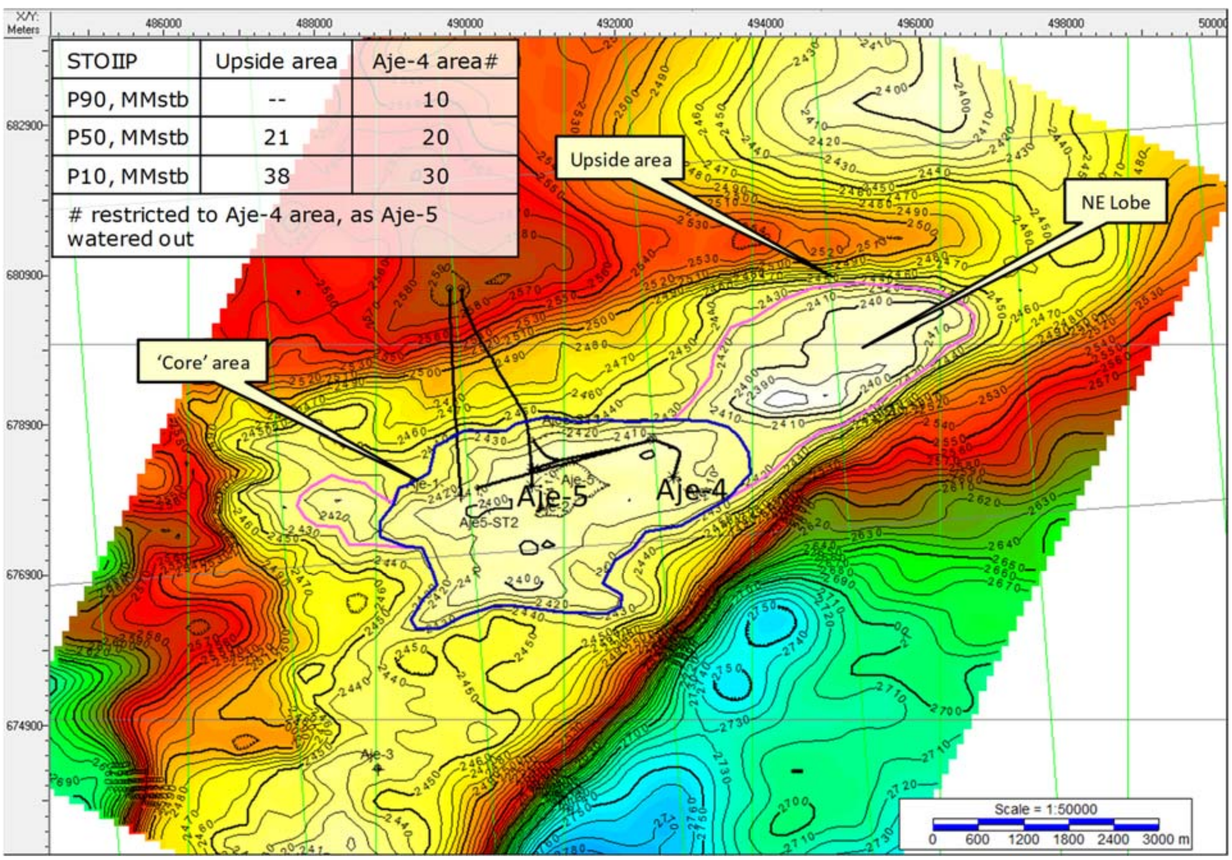

Figure 5.8: Upper Cenomanian Depth showing volumetric polygons
(Source: Chevron P50 map, 2009 review)

5.4.3 Production forecasts for Aje-5ST2 (Turonian oil rim producer)

The production performance of the Aje-5ST2 oil rim producer has been better than anticipated. This is believed to be due to several barriers (baffles) to vertical flow that may be delaying gas cusping and water production into the well. Shales sections are most likely acting as local or extensive baffles and can be observed on the well logs, see Figure 5.9. Note also that there is some uncertainty in the depths of the GOC and OWC for the oil rim, as denoted on Figure 5.9. The impact of this uncertainty on the in-place volumetric estimates has been discussed in Section 3.1.1.

To estimate possible oil recovery a simple dynamic model was tested and the historic production was analysed with decline curves methods to derive production forecasts.

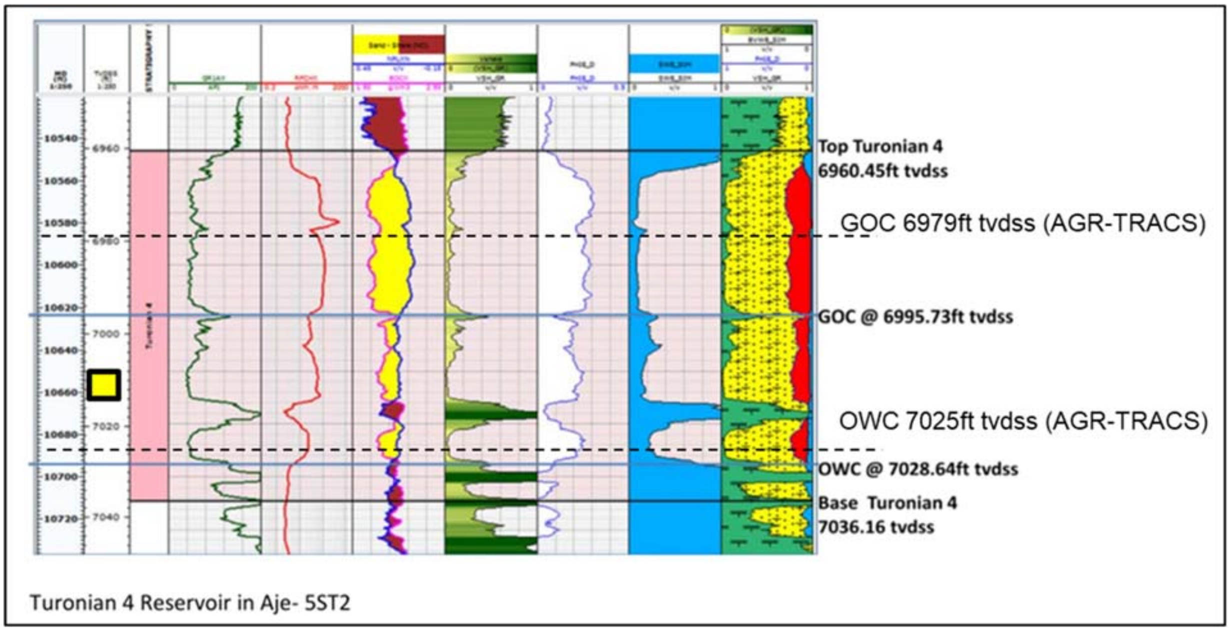

Figure 5.9: Aje-5ST2 Turonian 4 - CPI panel over oil rim reservoir section

The perforated interval is denoted with the symbol

(Source: Aje-5ST1 and -5ST2 Petrophysics report [Ref. 6])

Decline Curve Analysis (DCA) was performed on Aje-5 ST2 production data and estimates of the recovery were made. Ultimate recovery for the Low case was constrained at ~ 3.1MMstb (Figure 5.10), while for the High case EUR of 5.5Mmstb was calculated with the best fit on 2018 production data and 'b' = 0.35. Mid case was taken as an average of Low and High cases with EUR of 4.3MMstb.

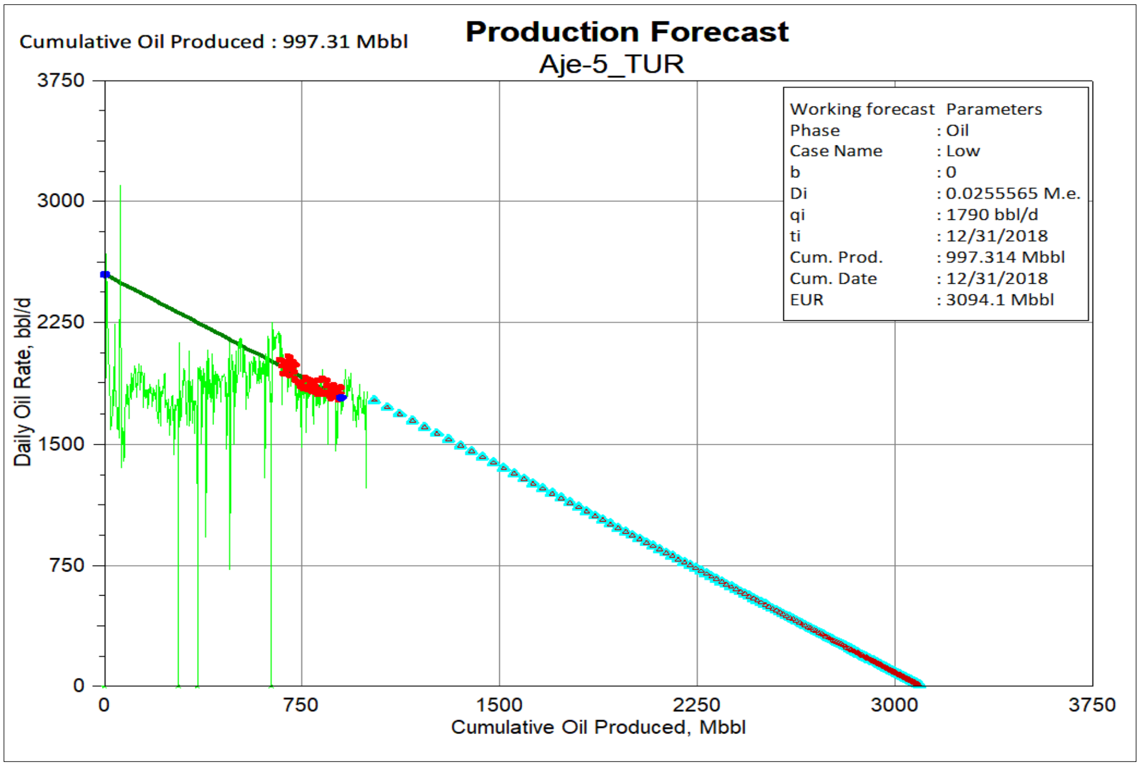

Figure 5.10: Low case production forecast for Aje-5 ST2 well [oil rate vs. cumulative oil plot]
(Source: 2019 AGR TRACS review)

The Aje-5ST2 well and the Aje field production are constrained by the gas production rate limit. As of January 2019 the gas production is constrained to a maximum 12MMscf/d (~12MMscf/d including gas-lift gas) to maintain the velocity limit through the swivel, based on present oil and water rates. The vessel flare system is designed for 15 MMscfd; achievable if HP separator pressure is increased or less water and oil is produced at the present set point. If required, minimal topside modification of the flare tip can increase capacity to approx. 22-23 MMscfd according to the Operator.

A check was made of whether estimated (future) oil production rates would be constrained by the gas production limit. Gas production data for the Age-5ST2 was analysed and the relationship of Gas Oil Ratio (GOR) with cumulative oil recovery for Aje-5ST2 was developed (Figure 5.11). Estimated gas production rates for the current production forecast (Figure 5.12) are not expected to be constrained by the 15MMscf/d gas production limit.

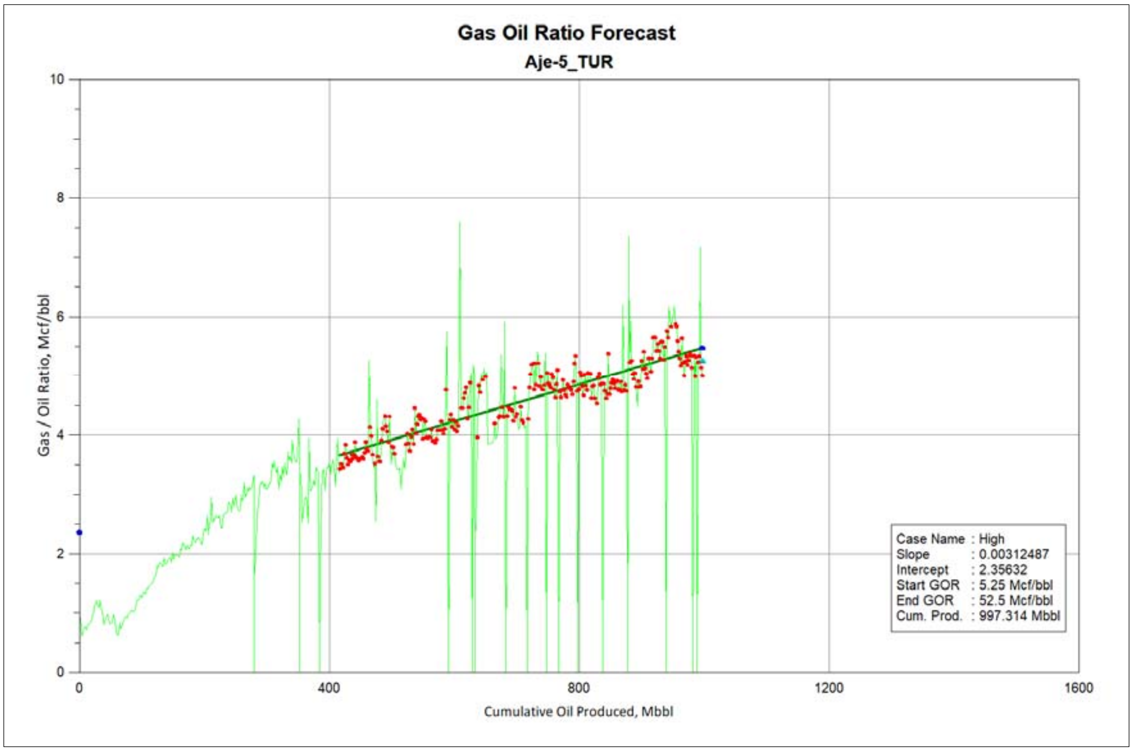

Figure 5.11 GOR vs Cumulative oil plot for Aje-5 ST2 (Turonian)
(Source: 2019 AGR TRACS review)

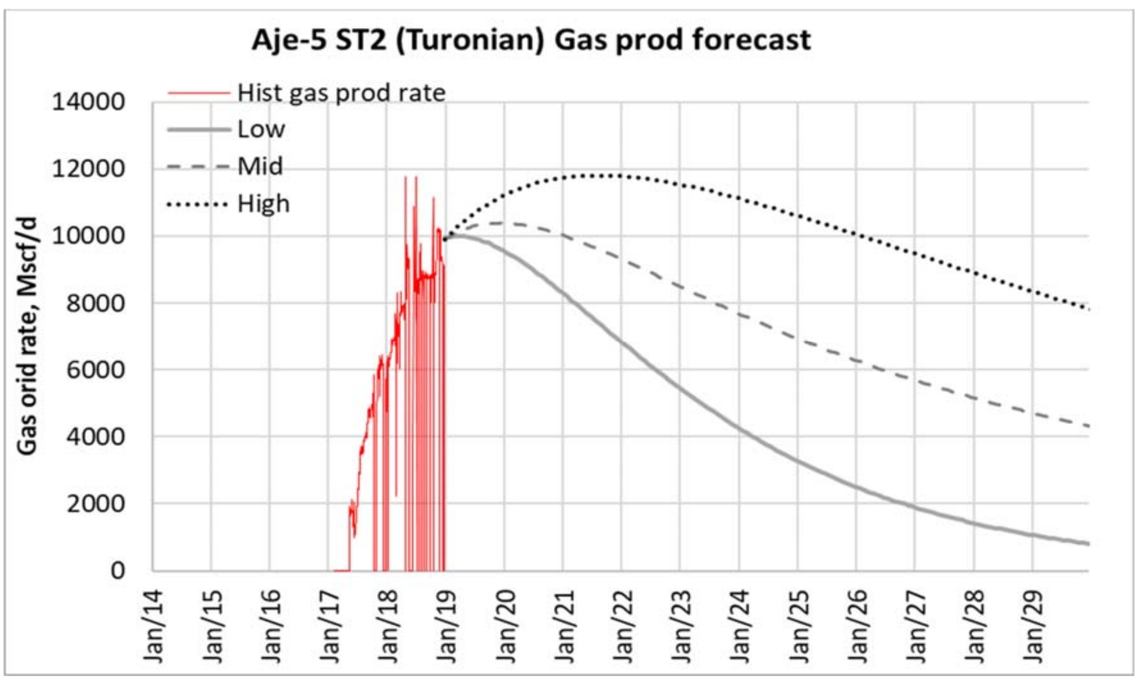

Figure 5.12 Aje-5 ST2 gas production forecast (to check against facilities constraints)
(Source: 2019 AGR TRACS review)

The estimated L-M-H technical production forecasts (prior to any economic cut-offs) for the Aje-5ST2 well are shown in Figure 5.13**Error! Reference source not found.** and Table 5.7.

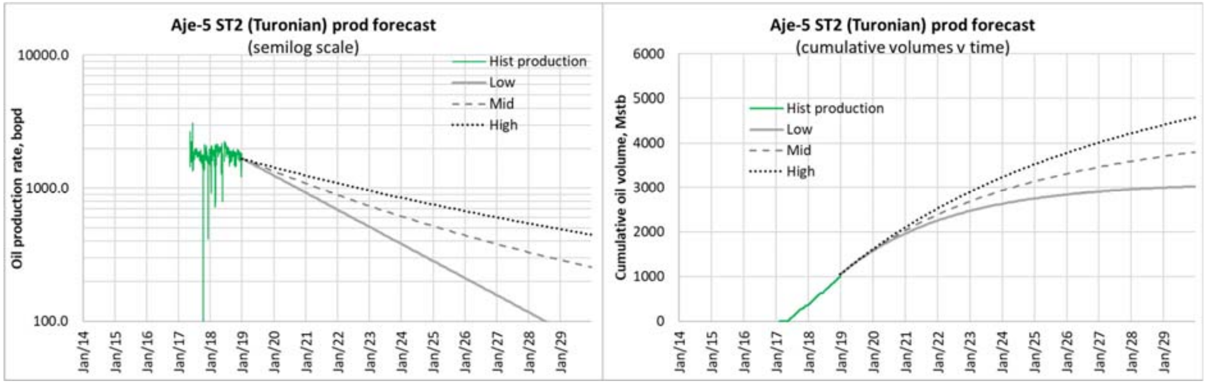

Figure 5.13: Aje-5ST2 (Turonian oil rim) L-M-H oil production forecasts
(Source: 2019 AGR TRACS review)

Aje-5ST2	Low		Mid		High	
Year	Oil prod. rate	Incr. Cum. Oil Prod.	Oil prod. rate	Incr. Cum. Oil Prod.	Oil prod. rate	Incr. Cum. Oil Prod.
	(bopd)	(Mstb)	(bopd)	(Mstb)	(bopd)	(Mstb)
Cumulative Production to 31.12.2018 estimated at 997.3Mstb						
2019	1472.7	537.5	1517.0	553.7	1561.3	569.9
2020	1096.1	938.7	1223.3	1001.4	1350.5	1064.1
2021	815.8	1236.5	996.1	1365.0	1176.3	1493.5
2022	607.4	1458.2	819.4	1664.1	1031.4	1869.9
2023	452.3	1623.3	680.9	1912.6	909.5	2201.9
2024	336.6	1746.5	571.4	2121.7	806.2	2497.0
2025	250.5	1837.9	484.3	2298.5	718.1	2759.1
2026	186.5	1906.0	414.6	2449.9	642.7	2993.7
2027	138.9	1956.7	358.2	2580.6	577.5	3204.5
2028	103.4	1994.5	312.2	2694.9	520.9	3395.2
2029	77.0	2022.6	274.2	2795.0	471.6	3567.3
2030	57.3	2043.5	242.8	2883.6	428.4	3723.6
2031	42.7	2059.1	216.5	2962.6	390.3	3866.1
2032	31.7	2070.7	194.2	3033.7	356.7	3996.6
2033	23.6	2079.4	175.2	3097.6	326.8	4115.9
2034	17.6	2085.8	158.9	3155.7	300.3	4225.5
2035	13.1	2090.6	144.8	3208.5	276.6	4326.5
2036	9.8	2094.1	132.5	3257.0	255.3	4419.9
2037	7.3	2096.8	121.7	3301.5	236.2	4506.2

Table 5.7: Aje-5ST2 Turonian oil rim L-M-H technical production profiles
(Source: 2019 AGR TRACS review)

5.4.4 Overview of planned Turonian gas production wells

The Base Case Turonian development described in the FDP assumes 5 deviated producers (Aje-I, -J, -K, -L and –M) located in 450-600m water depths. Four wells are firm and a 5th well may be required to extend the plateau and improve recovery. The primary target is the Turonian reservoir with TD at least 150m below the base of the Turonian. The operator has assessed various types of drilling units available in West Africa, and concluded that a semi-submersible or drillship rig (4th – 6th Generation Dynamically Positioned) would be the most appropriate choice.

The data from the two most recent wells (Aje-4 and -5) was taken as the basis for the drilling, geological and reservoir requirements for well design and trajectory in the Aje FDP. The maximum inclination angle and dog-leg severity (DLS) are fixed as 50° and 3°/30m for the conceptual well design in the FDP, but the trajectories will be optimised during the detailed engineering design stage. The maximum inclinations for the 5 proposed wells range from 19.5° (Aje-M) to 43.9° - 49.9° in the other four wells (see below). Note that the Aje-L location might be drilled later, although within the costs estimates all 5 wells are included. Furthermore, the subsurface targets listed were defined on the Top Turonian map presented in the FDP (see Figure 5.14). These downhole locations have been replotted on the AGR TRACS Top Turonian depth map where four of the five planned wells are considered valid as they are targeting the highest parts of the structure (Figure 5.15), while the Aje-I well targeting the western edge of the field in the FDP (see Figure 5.14) may need to be adjusted.

Well Name	Subsurf. Easting	Subsurf. Northing	TVDss	Surface Easting	Surface Northing	Max Incl.	Well Depth	Well Depth
Proj. ID	(m)	(m)	(m)	(m)	(m)	(°)	(m TVD)	(m MD)
Aje-I	488333.0	678813.0	-2075.3	489762.1	678838.2	48.67	2263.7	2919.2
Aje-J	490190.0	678205.0	-2029.6	491210.0	678400.0	43.91	2214.3	2655.6
Aje-K	490477.0	676871.0	-2037.5	491495.8	677837.2	49.87	2200.9	2859.0
Aje-M	491391.0	678249.0	-2059.1	491729.0	678147.0	19.51	2260.3	2327.4
Aje-L	494472.0	679515.0	-2040.8	493189.4	679000.0	49.20	2204.3	2844.5

Table 5.8: Aje Turonian – proposed new development wells
(Source: FASL 2017 Aje Gas FDP [Ref. 2])

The kick-off point (KOP) is restricted to 220m (700ft) or deeper below the mudline for all options. The FDP outlines a generalised drilling and casing scheme based on the casing setting points for Aje-4 as follows:

i) 36” hole will be drilled vertically until 85m using seawater with Hi-Vis swabs for enhanced hole cleaning

   30” run and cemented to +/- 75-85m below sea bed

ii) 26” hole will be drilled directionally using sea-water pre-treated with KCL for formation reactivity control and Hi-Vis swabs for enhanced hole cleaning

   20” at +/- 650-700m TVD, and set in a competent formation above the Mid-Oligocene unconformity

iii) 17 1/2” hole will be directional using SOBM (mud design to be covered in Basis of Design Engineering)

   13 3/8” at +/- 1,400-1,500m TVD at a competent formation above the Upper Cretaceous Sealing Shale above the Upper Turonian Transition Zone

iv) 12 ¼” hole will be directional using SOBM (mud design to be covered in Basis of Design Engineering). Aje-M will reach TD in the 12 ¼” section as the inclinations are low and allows for casing string optimization.

   9 5/8” at 1,850-1,950m TVD at a competent formation +/- 120m below the base of the Turonian reservoir providing adequate logging and production sump.

v) 8 1/2” hole will be directional using SOBM (mud design to be covered in Basis of Design Engineering)

   7” at well TD at a competent formation +/- 120m below the base of the Turonian reservoir

vi) 4 ½” production tubing with frac-pack sand control installed

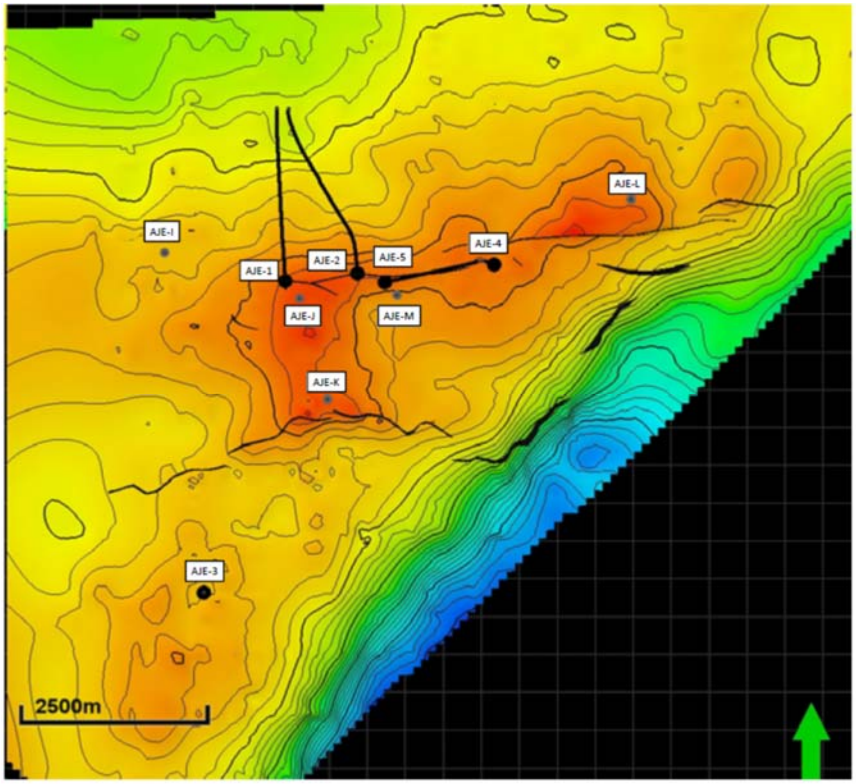

Figure 5.14: Aje FDP Top Turonian Depth Map with existing wells and bottom-hole locations for planned development wells (Aje-I to –M)
(Source: Fig. 2.12, FASL 2017 Aje Gas FDP [Ref. 2])

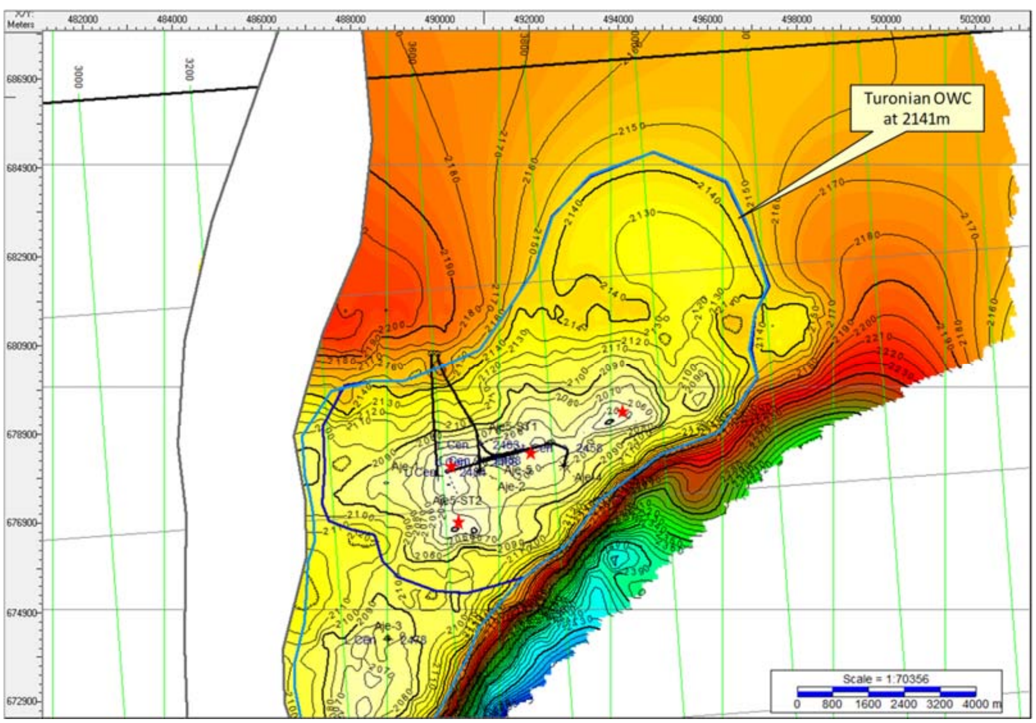

Figure 5.15: AGR TRACS Top Turonian depth map showing bottom-hole locations for Turonian gas development wells
(Map Source: AGR TRACS 2018; Well Locations modified from FDP Fig. 2.12 [Ref. 2])

Legend: Development well locations ★

The wells are planned to be completed with 4 ½" tubing. This was chosen as the optimum for the gas rates required and to aid with lifting of water should water develop during the production lifetime of the wells. Each well will be have a permanent downhole gauge installed to monitor pressure depletion.

Based on sand control studies it is concluded that sand management is needed for the wells. A Frac-Pack management solution will be adopted for each of the wells. This will be further evaluated during the detailed design phase.

AGR TRACS considers the well design to be suitable for the gas rates required. There is an opportunity to possibly reduce the number of wells by increasing tubing size. However, this needs to be balanced with the risk and need to manage water production in the wells should it arise.

5.4.5 Potential drilling risks and mitigation for planned Turonian producers

The proposed Turonian development wells will be drilled through the same overburden section as already penetrated in the previous Cenomanian development wells and the earlier exploration and appraisal wells, which provides a comprehensive basis for drilling risk assessment.

H2S: No H2S has been seen in any of the previous wells drilled in the field.

Well Bore Stability: The maximum well angle has been limited to 50° based on previous drilling data and geomechanics studies, and all the well targets listed in can be reached within the maximum deviation specified. The wells will be drilled with adequate mud weights and a real-time modelling system will be implemented to closely monitor the wells while drilling. A synthetic oil based mud system (SOBM) may be preferred in order to mitigate problems due to shale reactivity or sloughing shales. Aje-4 and -5 were drilled with SOBM and encountered few or no hole instability problems.

Shallow Gas: The surface locations are close to the existing Cenomanian producers, which were drilled safely without encountering any shallow gas, hence the Aje JV Partners expect this risk to be minimal. Despite the 3D seismic data does not showing any indications of shallow gas horizons, shallow gas mitigation measures will be put in place.

Pore and Fracture Pressure: The final pore pressure analyses from the Aje-4 and -5 wells indicated almost hydrostatic pressure from surface to the Turonian, thus a similar pre pressure profile is assumed for the 5 planned Turonian development wells.

Differential Sticking: The Turonian reservoir has medium to high permeability, thus there is a risk of differential sticking resulting from high overbalance based on the mud weights required due to hole instability mitigation measures. The Aje JV Partners will carry out further studies during the detailed design stage.

Ballooning Issues: This hazard has not been encountered during the previous drilling campaigns, but will be analysed further during the detailed design stage.

All the risks identified are well understood from previous drilling experience in the field.

There has been no comprehensive review of the drilling program and well design by AGR TRACS. However, AGR TRACS considers that the key risks and possible mitigations have been adequately identified, and the existing database from previous drilling campaigns offers valuable experience and insights to drill the wells successfully.

5.4.6 Production forecasts for the Turonian gas cap

The following estimates were derived for the in-place volumes and technically recoverable gas, condensate and LPG resources in the Turonian (see Table 5.9). Note that these estimates include associated gas liberated from the oil rim as the pressure declines over time once the field is on stream. No economic cut-offs have been applied to these resource volumes.

Case	GIIP – Wet Gas	GIIP - Assoc. Gas	CIIP (in Wet Gas)	Wet Gas Resources	Assoc. Gas Resources	Wet Gas Resources incl. Assoc. Gas	Dry Sales Gas Resources	Conden-sate Resources	LPG Resources
	BCF	BCF	MMbbls	BCF	BCF	BCF	BCF	MMstb	MMstb
P90	501	81	23	350	49	393	330	10.9	22.7
P50	789	119	37	592	78	660	554	18.4	38.1
P10	1,246	176	58	935	115	1,050	882	29.3	60.6

Table 5.9: Aje field – AGR TRACS in-place volumes and technical resources for the Turonian reservoir
(Source: 2018 AGR TRACS review)

Several risks were identified that could hamper dynamic behaviour of the Turonian gas producers and reduce gas recovery efficiency. Water influx is one of the largest risks followed by potential reservoir compartmentalisation, the possibility of Turonian reservoirs being isolated vertically and a risk of possible sand production. The Aje Fast Track Gas FDP [Ref. 2] explains in detail the plans to mitigate the impact of these risks. In particular:

- The planned production wells will be drilled at the crest of the structure to delay water production (if any). Smaller 4.5” production tubings are planned to be installed;
- Four to five wells are planned in case the field is compartmentalised, and all 5 wells will be deviated to penetrate all the Turonian reservoirs. However, the seismic data does not suggest a significant degree of faulting within the Turonian section, and as the N/G ratio and overall sand content are high, the risk of compartmentalisation is considered to be low. Although the Top Turonian depth map from the FDP (Figure 5.14) shows some minor faulting oriented mainly E-W these have limited vertical throw. AGR TRACS has reviewed these faults and consider them to be minor noise artefacts caused by the very irregular overburden. Even if there were small-scale faults it appears very likely that sands would be juxtaposed across such faults thereby providing adequate flow paths.
- Frac-packs are planned to be installed in the wells to reduce risk of sand production.

The Turonian gas cap production forecasts were generated by AGR TRACS based on the Aje Fast Track Gas FDP [Ref. 2] with the following assumptions:

- Based on the data listed in Table 5.9 the implied L-M-H technical recovery factors are 67.5%-72.7%-73.8% for the aggregate wet & associated gas volumes, and 47.4%-49.7%-50.5% for the condensate volumes. Reservoir pressure at 70% gas recovery would be around 1000psi. The FDP assumed 500psia THP with minimal positive impact due to additional compression. The Base Case development costs include compression, and the FDP assumes compression modules might be added after about 3.5 years production in order to achieve higher recovery factors and maintain LPG extraction.
- The FDP assumes four production wells (with a fifth in reserve), which are all planned to be deviated at 20-50 degrees through reservoir section penetrating all Turonian reservoirs (see Section 5.4.4). Four wells are planned to be drilled at the crest of the structure and producing from Day 1, and these locations are shown in Figure 5.15. The High case may require an additional well to attain recovery efficiency of 75% (hence the 5th well included as a spare in the proposed drilling programme), but the location has not yet been confirmed. The Base Case drilling costs include the costs for all five producers.
- The production wells are planned to be completed with 4.5-inch production tubing. Larger tubing would be less constraining and allow higher production rates, and possibly similar gas recovery with a smaller number of wells. However, the selected 4.5” tubing would allow production for longer without interventions even if water broke through to the wells, hence it is the preferred solution.

- In addition to the free gas in-place, the volumes of associated gas (expected to be liberated from the oil in the Turonian oil rim) were added to the total (connected) gas volumes. Approximately 80% of the associated gas originally dissolved in the oil is expected to be liberated due to the reservoir pressure reduction by the time gas cap gas recovery is approaching 70-75%. However, only 60-70% of the associated gas is expected to be produced through the gas cap production wells, while some part of the associated gas would remain trapped or dissolved in the oil.
- Spread-sheet based forecasts underpinned by well deliverability analysis were generated with an average daily plateau production rate of 150MMscf/d until 40-45% of GIIP has been produced, with gas production rates declining after that at 11% to 28% per year. The FDP does not provide any estimates of likely uptime % for the planned facilities, or the processing capacity required, but an uptime of around 95% seems reasonable for the proposed development; hence a processing capacity of some 160MMscf/d seems appropriate.
- The Turonian reservoir sands have excellent rock properties and initial rate deliverability is not expected to be a problem.
- Condensate production forecast are derived as follows:
    - o The Condensate to Gas Ratio (CGR) is assumed to change linearly from the initial 46.7bbls/MMscf to 23.3bbls/MMscf until reservoir pressure is 1,500 psi. Thereafter the CGR is assumed to decline linearly from 23.3bbls/MMscf to 11.7bbsl/MMscf at the end of the field life (CGR is in barrels of condensate per MMscf wet gas).
    - o The condensate production rate is a product of CGR and gas production rate.
- Based on the information provided it was assumed that the LPG yield would be 57.7blpg/MMscf wet gas, thereby bringing the sales gas up to the minimum 85% CH_4 content required for the WAGP.
- The LPG separation and condensate drop out are assumed to result in some 11% gas shrinkage, and with a fuel gas requirements estimated at 5% the overall wet gas to sales gas shrinkage is estimated at 16%, hence the dry sales gas volumes represent 84% of the wet gas resource estimates. This is higher than the 10% shrinkage assumed in the FDP Base Case (comprising 8% due to liquids separation and 2 % for fuel gas), but this fuel gas requirement is considered too low for the overall facilities and processing capacity planned in the Base Case gas development.

The technically recoverable volumes (prior to economic cut-offs) based on 16% shrinkage are listed in Table 5.10 below.

Hydrocarbon type (Techn. Recoverable Resources)	Units	AGR TRACS 16% shrinkage		
		LOW	**MID**	**HIGH**
Wet Gas Resources incl. Assoc. Gas	BCF	393	660	1,050
Dry Sales Gas	BCF	330	554	882
Condensate	MMbbls	10.9	18.4	29.3
LPG	MMbbls	22.7	38.1	60.6
TOTAL (MMboe)		**88.6**	**148.9**	**236.9**

Table 5.10: Technically recoverable resources for 16% shrinkage factor
(Source: 2018 AGR TRACS review, 6,000scf = 1boe)

The AGR TRACS annual technical profiles (prior to economic cut-offs) for the Turonian reservoir gas cap based on 16% shrinkage were used in the economic evaluations; these are shown in Figure 5.16 and summarised in Table 5.11, Table 5.12 and Table 5.13. Note that the revenue streams in the economic evaluations are based on the sales gas forecasts plus condensate and LPGs.

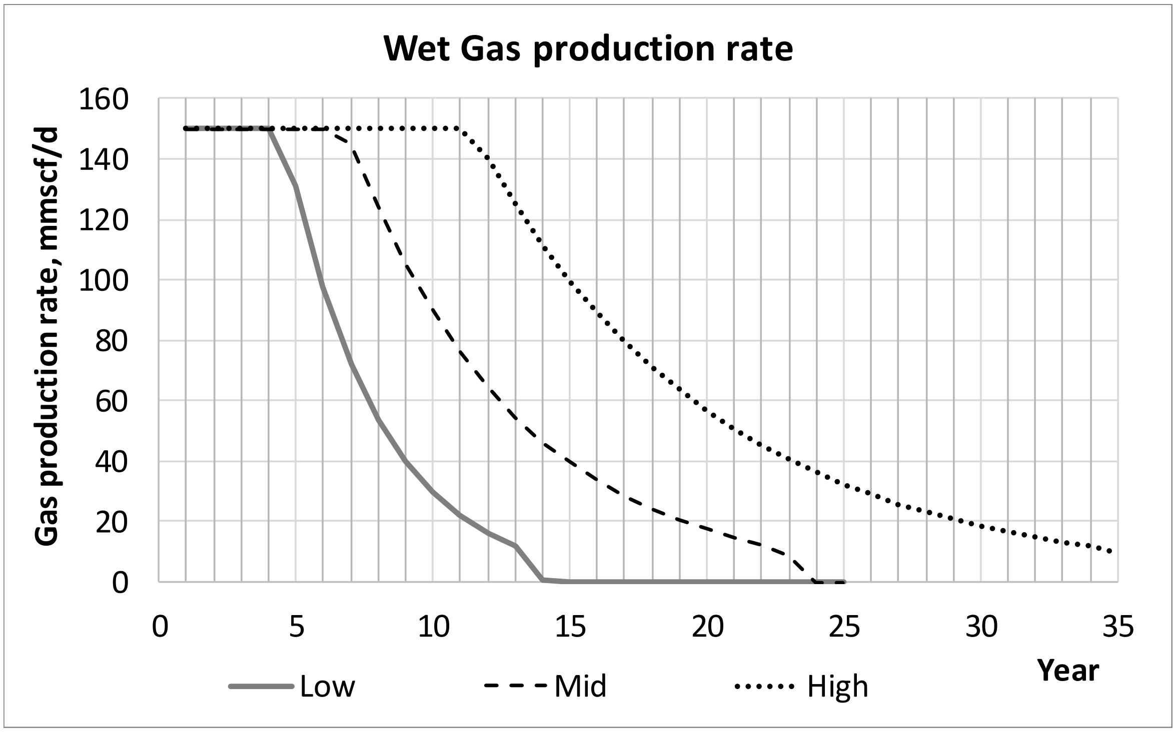

Figure 5.16: Aje Turonian (gas cap) – AGR TRACS L-M-H wet gas production forecasts
(Source: 2018 AGR TRACS review)

In all three cases the minimum economic threshold is estimated to be 40-45MMscf/d wet gas (or 34-38MMscf/d sales gas) at US$60/bbl and US$4.00/Mscf.

LOW CASE	Wet gas rate	Cum wet gas	Dry sales gas rate	Cum. dry sales gas	Cond. rate	Cum. Cond.	LPG	Cum. LPG
Year	MMscf/d	BCF	MMscf/d	BCF	stb/d	MMstb	blpg/d	MMbbl LPG
1	150.0	54.9	126.0	46.1	6553	2.4	8655	3.2
2	150.0	109.7	126.0	92.1	5736	4.5	8655	6.3
3	150.0	164.4	126.0	138.1	4924	6.3	8655	9.5
4	150.0	219.2	126.0	184.1	4112	7.8	8655	12.6
5	131.3	267.2	110.3	224.4	2973	8.9	7575	15.4
6	97.4	302.8	81.8	254.3	1903	9.6	5620	17.5
7	72.3	329.1	60.7	276.5	1248	10.0	4171	19.0
8	53.7	348.7	45.1	292.9	836	10.3	3096	20.1
9	39.8	363.3	33.5	305.2	571	10.5	2299	21.0
10	29.6	374.1	24.8	314.2	396	10.7	1705	21.6
11	21.9	382.1	18.4	321.0	279	10.8	1266	22.0
12	16.3	388.0	13.7	326.0	199	10.9	939	22.4
13	12.1	392.5	10.2	329.7	143	10.9	698	22.6
14	0.9	392.8	0.7	329.9	10	10.9	50	22.7
15	0.0	392.8	0.0	329.9	0	10.9	0	22.7

Table 5.11: Aje Turonian (gas cap) – AGR TRACS Low case production forecasts
(Source: 2018 AGR TRACS review)

MID CASE	Wet gas rate	Cum wet gas	Dry sales gas rate	Cum. dry sales gas	Cond. rate	Cum. Cond.	LPG	Cum. LPG
Year	MMscf/d	BCF	MMscf/d	BCF	stb/d	MMstb	blpg/d	MMbbl LPG
1	150.0	54.9	126.0	46.1	6729	2.5	8655	3.2
2	150.0	109.7	126.0	92.1	6244	4.7	8655	6.3
3	150.0	164.4	126.0	138.1	5761	6.8	8655	9.5
4	150.0	219.2	126.0	184.1	5277	8.8	8655	12.6
5	150.0	274.1	126.0	230.2	4793	10.5	8655	15.8
6	150.0	328.8	126.0	276.2	4310	12.1	8655	19.0
7	145.3	381.8	122.1	320.8	3715	13.5	8386	22.0
8	124.7	427.4	104.8	359.0	2852	14.5	7198	24.7
9	105.8	466.1	88.9	391.5	2221	15.3	6107	26.9
10	89.8	498.9	75.4	419.1	1743	15.9	5179	28.8
11	76.1	526.7	64.0	442.4	1378	16.4	4394	30.4
12	64.6	550.3	54.3	462.2	1096	16.8	3727	31.7
13	54.8	570.3	46.0	479.1	878	17.2	3162	32.9
14	46.5	587.3	39.0	493.3	707	17.4	2682	33.9
15	39.4	601.7	33.1	505.4	572	17.6	2275	34.7
16	33.4	613.9	28.1	515.7	466	17.8	1930	35.4
17	28.4	624.3	23.8	524.4	381	17.9	1637	36.0
18	24.1	633.0	20.2	531.8	313	18.1	1389	36.5
19	20.4	640.5	17.1	538.0	258	18.2	1178	37.0
20	17.3	646.8	14.5	543.3	214	18.2	999	37.3
21	14.7	652.2	12.3	547.8	178	18.3	848	37.6
22	12.5	656.7	10.5	551.7	148	18.4	719	37.9
23	8.9	660.0	7.5	554.4	105	18.4	515	38.1
24	0.0	660.0	0.0	554.4	0	18.4	0	38.1

Table 5.12: Aje Turonian (gas cap) – AGR TRACS Mid case production forecasts
(Source: 2018 AGR TRACS review)

HIGH CASE	Wet gas rate	Cum wet gas	Dry sales gas rate	Cum. dry sales gas	Cond. rate	Cum. Cond.	LPG	Cum. LPG
Year	MMscf/d	BCF	MMscf/d	BCF	stb/d	MMstb	blpg/d	MMbbl LPG
1	150.0	54.9	126.0	46.1	6825	2.5	8655	3.2
2	150.0	109.7	126.0	92.1	6521	4.9	8655	6.3
3	150.0	164.4	126.0	138.1	6217	7.1	8655	9.5
4	150.0	219.2	126.0	184.1	5913	9.3	8655	12.6
5	150.0	274.1	126.0	230.2	5609	11.4	8655	15.8
6	150.0	328.8	126.0	276.2	5305	13.3	8655	19.0
7	150.0	383.6	126.0	322.2	5001	15.1	8655	22.1
8	150.0	438.3	126.0	368.2	4698	16.8	8655	25.3
9	150.0	493.2	126.0	414.3	4394	18.4	8655	28.5
10	150.0	547.9	126.0	460.3	4089	19.9	8655	31.6
11	149.9	602.7	125.9	506.2	3783	21.3	8648	34.8
12	139.8	653.7	117.5	549.1	3265	22.5	8069	37.7
13	125.0	699.4	105.0	587.5	2744	23.5	7211	40.4
14	111.7	740.2	93.8	621.8	2318	24.4	6443	42.7
15	99.8	776.6	83.8	652.4	1965	25.1	5757	44.8
16	89.2	809.2	74.9	679.7	1671	25.7	5144	46.7
17	79.7	838.3	66.9	704.2	1425	26.2	4597	48.4
18	71.2	864.3	59.8	726.0	1219	26.7	4107	49.9
19	63.6	887.5	53.4	745.5	1046	27.0	3670	51.2
20	56.8	908.3	47.7	762.9	901	27.4	3279	52.4
21	50.8	926.8	42.7	778.5	777	27.6	2930	53.5
22	45.4	943.4	38.1	792.5	672	27.9	2618	54.4
23	40.5	958.2	34.1	804.9	583	28.1	2339	55.3
24	36.2	971.4	30.4	816.0	507	28.3	2090	56.1
25	32.4	983.3	27.2	826.0	442	28.5	1868	56.7
26	28.9	993.8	24.3	834.8	386	28.6	1669	57.3
27	25.8	1003.3	21.7	842.7	338	28.7	1491	57.9
28	23.1	1011.7	19.4	849.8	296	28.8	1333	58.4
29	20.6	1019.3	17.3	856.2	260	28.9	1191	58.8
30	18.4	1026.0	15.5	861.8	229	29.0	1064	59.2
31	16.5	1032.0	13.8	866.9	201	29.1	951	59.5
32	14.7	1037.4	12.4	871.4	178	29.1	849	59.9
33	13.2	1042.2	11.1	875.4	157	29.2	759	60.1
34	11.8	1046.5	9.9	879.0	139	29.3	678	60.4
35	9.7	1050.0	8.1	882.0	113	29.3	557	60.6
36	0	1050.0	0	882.0	0	29.3	0	60.6

Table 5.13: Aje Turonian (gas cap) – AGR TRACS High case production forecasts
(Source: 2018 AGR TRACS review)

5.4.7 Turonian oil rim potential

The Aje-5ST2 well is currently producing from the Turonian oil rim as of March 2019 and achieving better rates than expected, probably due to a local shale baffle at the base of the sand which prevents/delays water influx from the underlying aquifer. The Aje JV Partners are prioritising the Turonian gas development, but a potential development of the oil rim is also under evaluation. Following a request from MX OIL AGR TRACS have carried out a brief assessment of the Turonian oil rim in order to provide indicative estimates of notionally technically recoverable contingent resources.

The Aje Turonian Gas FDP briefly discusses a possible oil rim development assuming four horizontal producers as a potential Phase 2 development of the Turonian reservoir once additional reservoir performance data becomes available.

AGR TRACS suggest the oil rim may need to be developed concurrently with the overlying gas reservoir, otherwise the oil rim may break up due to fluid movements within the reservoir due to gas production and pressure decline. However, the Aje JV Partners are in an ongoing dialogue with the DPR, which has encouraged the JV Partners to proceed with their developments plans for the gas development ahead of issuing the formal approval of the Gas FDP. To date the Aje JV Partners have not received any indications that the DPR will insists on an early or concurrent development of the Turonian oil rim.

Figure 5.17 below shows a schematic cross-section through the three layers of the Turonian reservoir sequence where the upper and lower layers have the best reservoir properties, with a poorer quality unit between these two. The other part of Figure 5.17 shows a plan view of the areal distribution of these three layers within the oil rim. The suggested horizontal oil rim producers are indicated around the outer rim of the main field area where the upper layer of good reservoir properties lies within the oil rim (between the green and blue stippled boundaries in the schematic cross-section in Figure 5.17). Note that there is a northern lobe, but the oil rim there is considered to be of very limited thickness, and hence not a viable target.

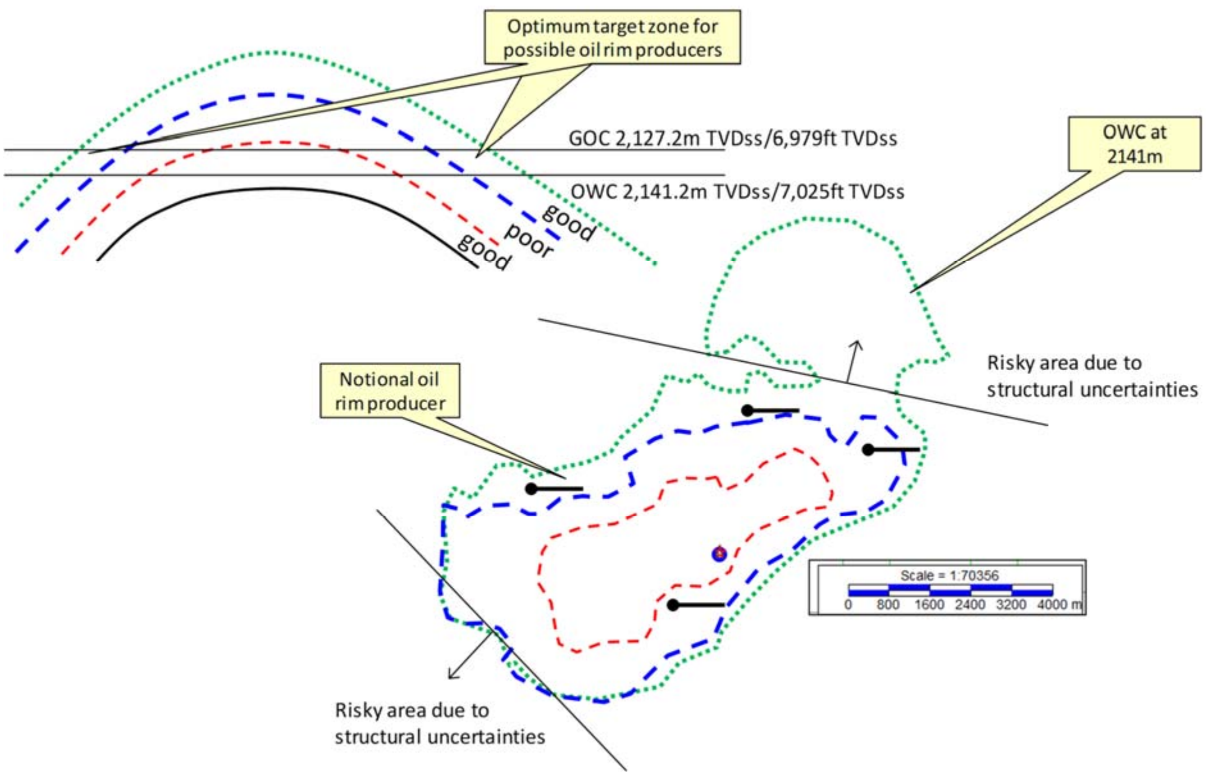

Figure 5.17: Schematic cross-section and plan view of Turonian oil rim reservoirs
(Source: 2018 AGR TRACS review)

AGR TRACS derived some basic estimates of oil recovery per horizontal oil rim producer based on analogue field studies and previous experience with oil rim reservoirs, as well as gas first or concurrent development scenarios. These estimates suggested a L-M-H range of 1.0-1.5-3.0 MMstb recovery per well could be achieved [Olamigoke and Peacock, Ref. 9]. If four horizontal producers were to be drilled into the oil rim as indicated above, then an arithmetic L-M-H range of technical contingent resources would be 4.0-6.0-12.0 MMstb. However, should the oil rim be developed first, then a greater recovery per well could be achieved. It also appears possible that more than four producers could be placed in the Turonian oil rim. The key success factors for oil rim development are summarised in Figure 5.18 below.

The Chance Of Commercial Success (COCS) for the possible future oil rim development wells is deemed to be 40% due to the immaturity of the project and the technical uncertainties. However, the encouraging production performance for the Aje-5ST2 well so far provides a strong incentive for further studies, and the Turonian oil rim remains a potentially valuable additional resource within the Aje field complex. It is therefore recommended that static and dynamic modelling of the oil rim should be carried out in order to derive more reliable estimates of recoverable volumes.

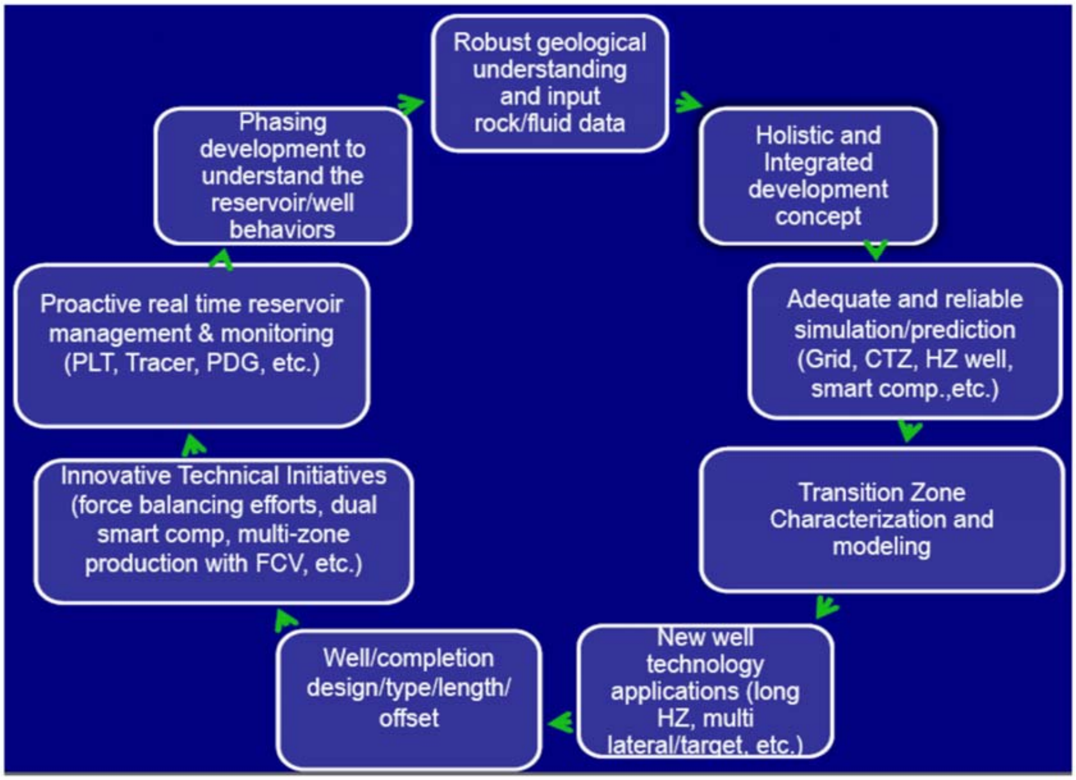

Figure 5.18: Oil Rim Development – Key Success Elements
(Source: Masoudi, Karkooti and Othman, 2013 [Ref. 10])

6 Cost and development assumptions for Aje

Exploration well Aje-1 and appraisal well Aje-2 were drilled from a jack-up in water depth of ca. 320ft bmsl, to a TVD depth of ca. 8,000ft, but deviated to the TD at 13,260ft ahbdf (ca. 8,000ft tvd) and 16,138ft ahbdf respectively. Drilling was conducted in this fashion to avoid the cost of deep water drilling but as a result they needed 6 and 5 strings of casing respectively to reach the objectives. Aje-3 was drilled from a semi-sub (a Sedco 700 series rig) in 3,000ft of water. The 2008 appraisal well Aje-4 was drilled with a deep-water drillship to achieve a less deviated well trajectory, but with day-rates in excess of US$500,000/day this resulted in an overall well cost of around US$74mln. The Aje-5 well was drilled in 2015 with a semi-sub from the Aje-4 surface location in 956ft of water, while the two sidetracks Aje-5ST1 and -5ST2 were drilled with the Pacific Bora drillship in the period February – April 2017.

The sea-bed topography over Aje comprises a steeply southward-dipping slope incised with canyons, see Figure 6.1. The water depth ranges from 250m (800ft) to almost 1,000m (3,300ft).

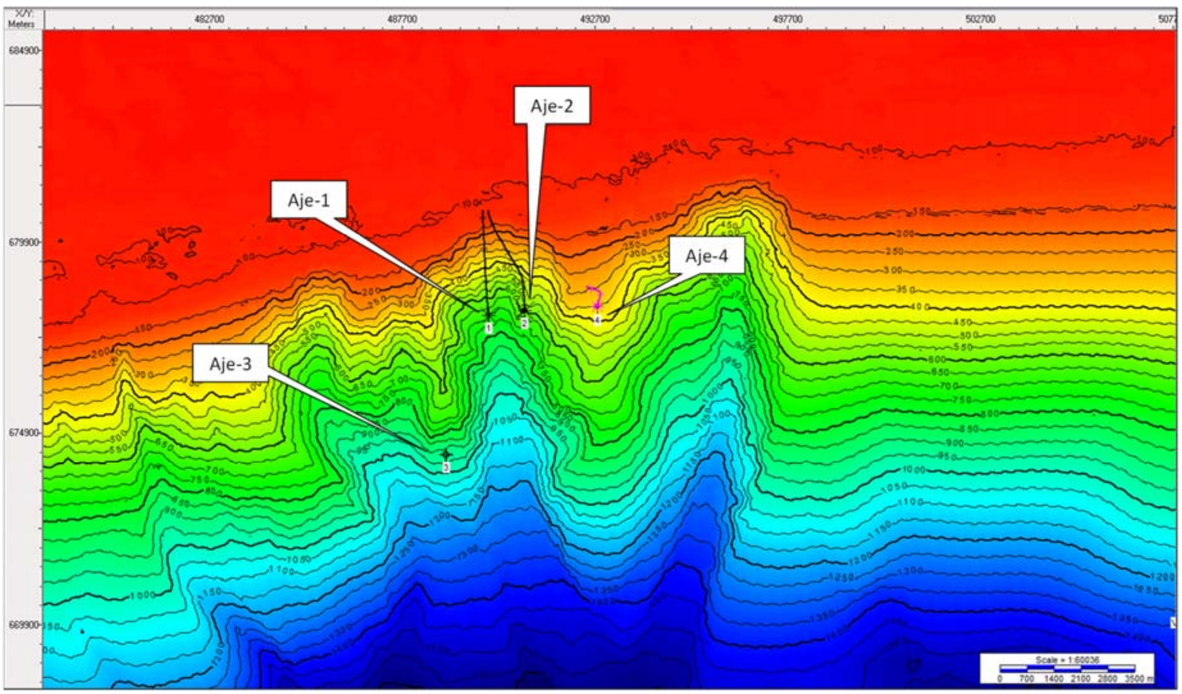

Figure 6.1: Sea-bed topography map over Aje
(Source: 2012 AGR TRACS review)

6.1 Aje Cenomanian Phase 1 Development

The Aje Cenomanian Phase 1 development was brought on stream in early May 2016 with the Aje-4 and Aje-5 wells tied back to the leased Front Puffin FPSO, which has a production capacity of 40,000 bbls/d and 12 MMscf/d, and storage capacity of 750,000 bbls. A schematic diagram of the Cenomanian Phase 1 development is shown below in Fig. 6.1, and the process flow scheme for the FPSO topsides is illustrated in Fig. 6.2.

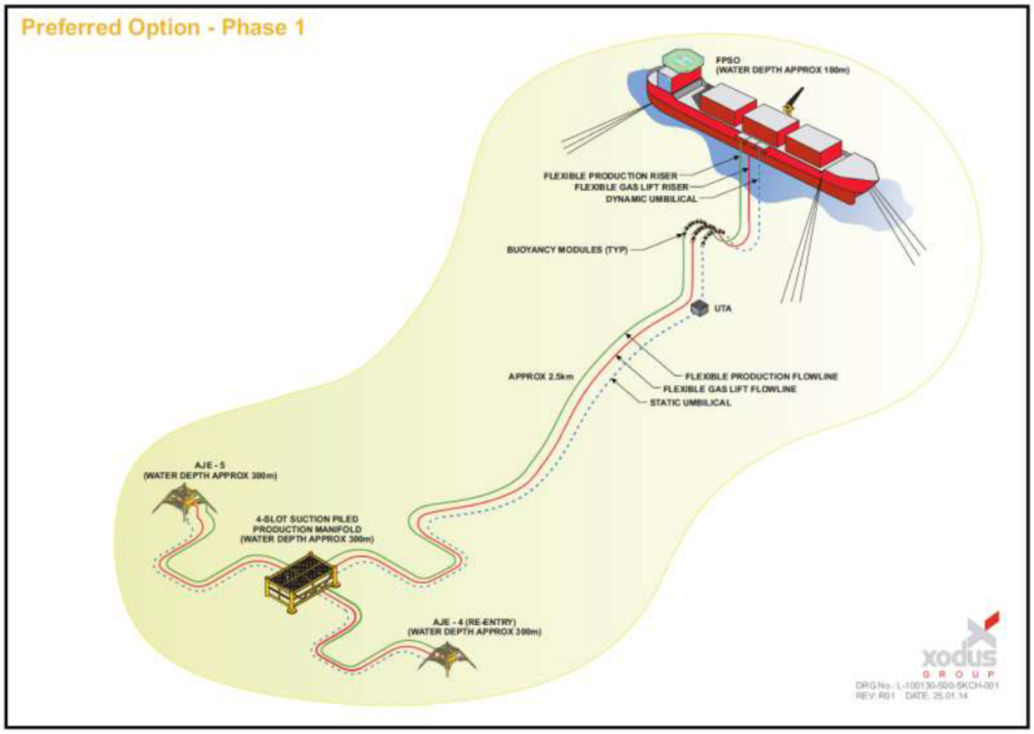

Fig. 6.1: Schematic of Aje Phase 1 Development
(Source: 2014 Aje FDP, [Ref. 4])

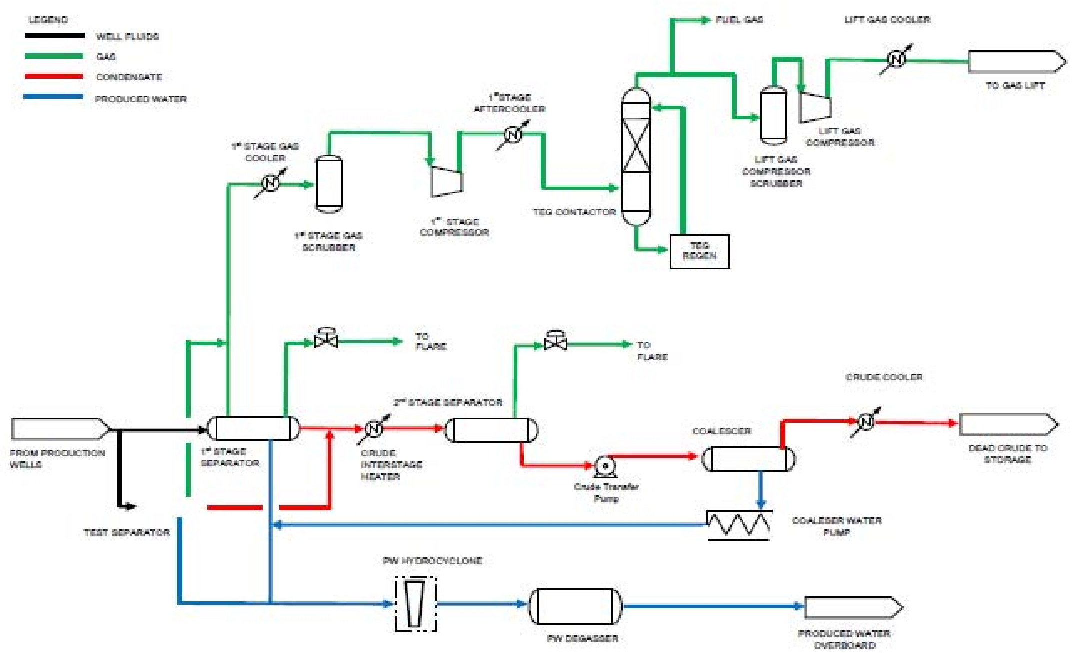

Fig. 6.2: Aje Phase 1 Development – FASL's process flow scheme for FPSO topsides
(Source: 2014 Aje FDP, [Ref. 4])

The annual fixed opex and G & A costs for the Cenomanian FPSO cases are summarised in Table 6.1 below. Note that due to the disappointing production from the Cenomanian reservoir the JV Partners renegotiated the bare-boat rate at a reduced rate of US$28,500/d for two years with effect from early July 2017, and for 2018 the effective rate was US$35,000/day. The JV Partners aim to keep that rate for the foreseeable future. There are additional costs comprising WHT, NIMASA & NCD levy estimated at US$1.58mln/yr to be added to the bare-boat rate, which is then subject to 5% VAT.

The Aje JV Partners are considering options for replacing the Front Puffin FPSO with a smaller vessel once the current lease expires in July 2019, but such a scenario is outside the scope of this CPR review.

CASE	All Cenomanian Cases			
Year	Bareboat Costs (incl. WHT, NIMASA, NCD levy and VAT) US$mln/yr	Fixed Opex US$mln/yr	TOTAL FPSO Opex US$mln/yr	Annual G & A US$mln
2019	14.89	25.20	40.09	4.00
2020	14.89	25.20	40.09	4.00
2021	14.89	25.20	40.09	4.00
2022	14.89	25.20	40.09	4.00
2023	14.89	25.20	40.09	4.00
2024	14.89	25.20	40.09	4.00
2025	14.89	25.20	40.09	4.00
2026	14.89	25.20	40.09	4.00
2027	14.89	25.20	40.09	4.00
2028	14.89	25.20	40.09	4.00
2029	14.89	25.20	40.09	4.00
2030	14.89	25.20	40.09	4.00
2031	14.89	25.20	40.09	4.00
2032	14.89	25.20	40.09	4.00
2033	14.89	25.20	40.09	4.00
2034	14.89	25.20	40.09	4.00
2035	14.89	25.20	40.09	4.00
2036	14.89	25.20	40.09	4.00
2037	14.89	25.20	40.09	4.00
TOTAL	**282.97**	**478.80**	**761.77**	**76.00**

Table 6.1: Overview of annual fixed opex and G & A costs for Cenomanian oil cases
(Source: MX OIL)

The Front Puffin FPSO acts as a terminal, thus there are no further oil tariffs once a cargo has been offloaded onto the shuttle tanker. The abandonment costs for the Cenomanian Phase 1 development (manifold, flowlines, and two subsea wells) are estimated to be US$40mln.

6.2 2017 Aje Turonian Gas Development FDP Turonian notional facilities description

A brief, fit-for-purpose, high-level Facilities Engineering (FE) review and assessment of field development concepts and costs for the Turonian Gas Field development of the Aje field offshore Nigeria has been carried out for MX OIL and their partners. The work was based mainly on the FE data presented in the “OML 113 – Aje Field Fast Track Gas Field Development Plan” (FDP) [Ref. 2]. This FDP assumes 1st gas production from late 2018, but this date has since been revised by the Aje JV Partners to late 2019, assuming an 18-month construction period following licence renewal. FID for the Turonian gas development is anticipated by the Aje JV Partners a couple of months after the licence renewal is confirmed, and the latest provisional project schedule envisages a fast-track development of some 20 months from FID to 1st gas sometime in 2020.

Due to the delay in securing the formal confirmation of the licence renewal AGR TRACS considers the original project schedule proposed in the March 2017 FDP for 1st gas by end-2019 is no longer realistic, and hence AGR TRACS has assumed 1st gas from 1.1.2022 in the economic assessments.

6.2.1 Surface Facilities Overview

The Base Case development as proposed in the Aje Fast Track Gas FDP assumes 5 deviated producers (designated A-I to A-M) with wet trees tied back to a floating platform with gas, condensate and LPG separation moored close to the existing Aje FPSO (see Figure 6.2, Figure 6.3 and Figure 6.4). The condensates will be transferred to the FPSO and evacuated by shuttle tanker from there, while the LPGs would be sent to a CALM buoy and evacuated by a dedicated pressurised shuttle tanker. The dry gas would be piped ashore and tied to the suction side of the Lagos compressor station on the WAGP, and then sold on to relevant customers; e.g. a gas-to-power plant and/or major industrial consumers.

Each of the planned 5 producers is estimated to be drilled in 47-62 days depending on the degree of deviation and the intended reach, with the FDP well costs ranging from US$52-63mln including drilling, logging, testing and completion. The FDP also states that a 25% contingency has been added to the drilling and completion components of the estimated well costs, resulting in an overall drilling cost estimate of US$357.8mln. The well costs proposed in the FDP are therefore about 18% higher than the AGR TRACS estimates of US$296.6mln. Note that the FDP costs include the compression modules and the 5th producer, but this well may be delayed until compression is installed ca 3.5 years after 1st gas.

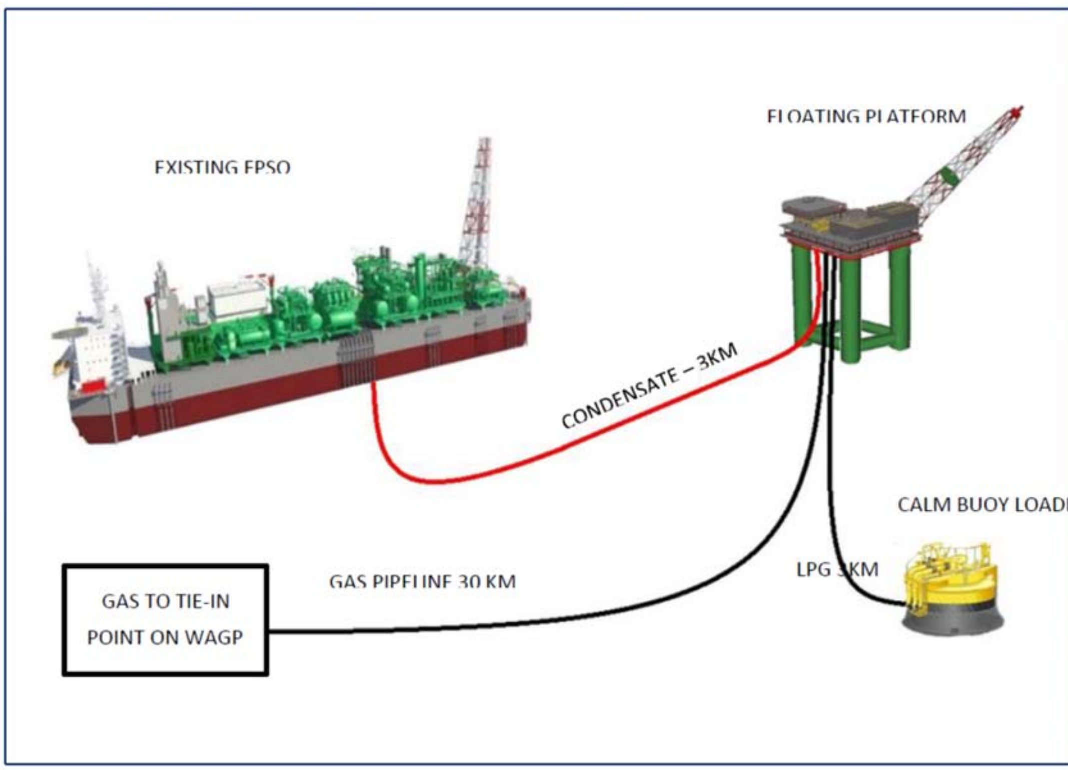

Figure 6.2: Aje FDP Base Case Turonian gas development concept
(Source: FASL 2017 Aje Gas FDP [Ref. 2])

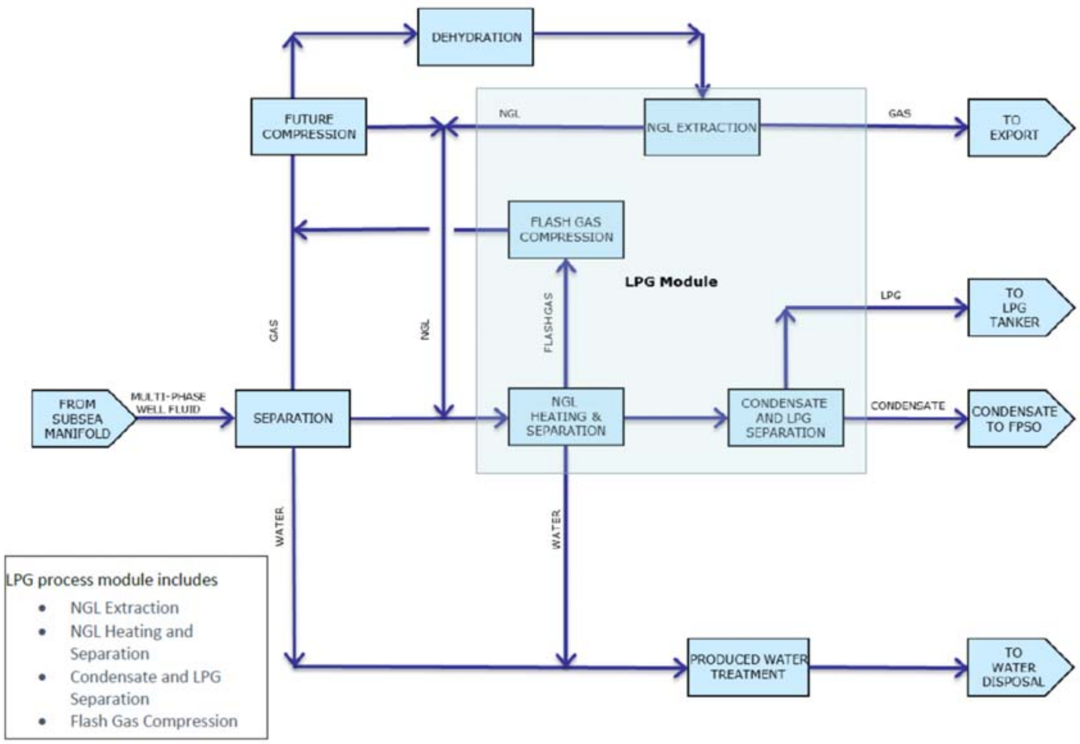

Figure 6.3: Process Flow Diagram for proposed Aje Gas Platform
(Source: FASL 2017 Aje Gas FDP [Ref. 2])

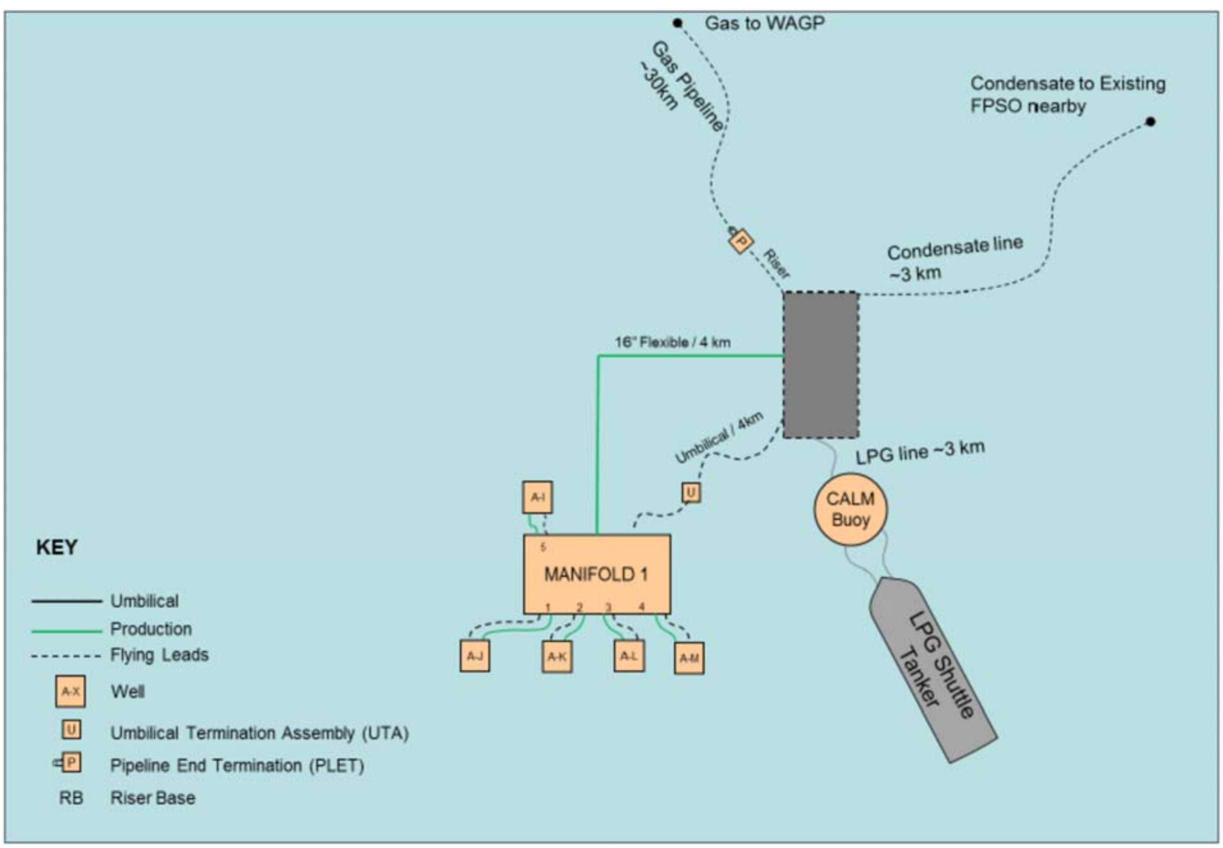

Figure 6.4: Aje Turonian Gas Development proposed subsea and facilities configuration
(Source: FASL 2017 Aje Gas FDP [Ref. 2])

6.2.2 Subsea Facilities Overview

The proposed subsea facilities configuration is summarised in the schematic diagram above (Figure 6.4), comprising 5 wells and associated subsea trees connected to a manifold, with the 5th well possibly drilled and tied into the manifold later in the development. The fluids from each well will be gathered and routed via an insulated gathering system to a floating production facility. The planned manifold will have six slots (including one spare), and the production wells will be tied into the manifold by jumpers. According to the FDP each well and jumper shall be designed for a maximum throughput rate of 40MMscf/d raw gas (with an additional margin). The distances shown in Figure 6.4 are only indicative, and will depend on the seabed topography and geology.

The proposed control system will comprise multiplex electro-hydraulic control umbilicals transmitting power, signals, chemical and hydraulic lines connected to the Master Control System on the topsides of the planned floating production facility (FPS).

As the likely location for the FPS is in shallow water of around 100m depth a few km away from the manifold location on the sea-bed, the flowlines will be short and hence an all-flexible flowline and riser system is proposed in the FDP. Two flexible flowlines will be required for export; one for LPG export to the CALM buoy and a second for condensate to the existing FPSO.

6.2.3 Summary of Capex and Opex Cost Estimates

The capex cost estimates for the Base Case stand-alone Turonian gas development case are listed in Table 6.2, and include the estimates from the 2017 FDP document totalling US$1,046.7mln as well as a revised set of costs (totalling US$760.4mln) from late March 2018 provided to AGR TRACS shortly before completing the CPR review. The March 2018 costs were submitted too late to be included in the AGR TRACS review, but these appear quite light. The AGR TRACS cost review focussed on the cost estimates presented in the 2017 Turonian FDP document, which were considered reasonable overall (compare Table 6.2 and Table 6.3).

Item / Description	Capex Costs US$mln (100%)	
	2017 FDP	March 2018 JV Pres.
Facilities Direct CAPEX	425.6	320.6
Engineering & Construction Management	55.6	37.3
Owner's Cost Total	69.9	45.8
Drilling	357.8	230.0
Overall Contingency (%, not applied to drilling)	137.8 (25%)	126.7 (20%)
TOTAL CAPEX	**1,046.7**	**760.4**

Table 6.2: Overview of 2017-2018 capex estimates for Turonian Gas Base Case
(Source: FASL 2017 FDP and AJE JV Presentations March 2018)

Case / Category	Capex Cost Phasing US$mln 1.1.2018 (100%)					
Tur L / M / H Gas	**2018**	**2019**	**2020**	**2021**	**End of econ. life**	**TOTAL**
Drilling:						
Tangible	2.10	18.95	16.85			**37.90**
Intangible	2.09	0.62	170.76	85.23		**258.70**
Facilities:						
Facilities	20.05	262.85	372.37			**655.27**
Pipelines		15.06	122.84			**137.90**
TOTAL CAPEX						***1089.77***
Abandonment					214.38	**214.38**

Table 6.3: Overview of capex phasing for Aje Turonian L-M-H Gas cases
(Source: 2018 AGR TRACS review)

The abandonment costs assumed for the combined Cenomanian and Turonian cases in the economic runs include US$40mln for the Cenomanian in addition to the abandonment costs listed above in Table 6.3.

The fixed and variable opex assumptions for the Turonian Low-Mid-High gas development cases are summarised below in Table 6.4:

OPEX CATEGORY	Turonian Gas Cases
	Low / Mid / High
Fixed Opex (US$mln/yr)	66.75
Gas Variable Opex (US$/MMscf Wet Gas)	0.492
Cond Variable Opex (US$/bbl)	1.28
LPG Variable Opex (US$/bbl)	1.28

Table 6.4: OPEX assumptions for Aje proposed Turonian L-M-H gas developments
(Source: 2018 AGR TRACS review)

It is suggested that the fixed operating costs for the combined Cenomanian Oil + Turonian gas development cases should be examined for possible efficiencies and synergies in the G & A, Logistics, Offshore Inspection & Maintenance, and Well Surveillance etc., as there ought to be some savings possible once the Turonian gas development is on stream. No estimates for such potential savings have been included in the economic results presented in this CPR, but there might be scope to save of the order of 15% of the combined opex costs through such efficiencies.

During the CPR review AGR TRACS requested the Risk Register for the planned gas development, but this was not available. It is therefore recommended that the Aje JV Partners compile a Risk Register for the surface and subsurface risks, their potential impact and possible mitigations as part of the next phase of detailed development studies.

7 Economic Evaluations

7.1 OML 113 fiscal terms

Yinka Folawiyo Petroleum (YFP) was awarded OPL-309 in June 1991 in the indigenous bid round, and the licence was later converted to OML 113. The OML 113 licence is a tax and royalty licence, where the Royalty is paid to the Nigerian Government and calculated based on water depth at the take point. The Royalty rate was confirmed as 4% for oil and gas in a letter dated 22nd May 2018 from the Nigerian Ministry of Petroleum (Department of Petroleum Resources) to YFP.

YFP is the operator and will be carried through the appraisal and development programme, but after start-up YFP will have a 25% Net Revenue interest and a 25% Paying Interest. YFP also holds a separate interest through its Deep Water subsidiary (YFP-DW), which has no preferential cost recovery entitlements.

Note: The 2019 updated economic evaluations are shown for MX OIL's revenue interest as detailed in Table 1.1 and are presented in Section 7.2. Note that MX OIL's revenue interest in the project varies according to the progress of YFP's preferential cost recovery.

OML 113 is located in a "Frontier Basin" and is held as a "Sole Risk" licence under the "Deep Offshore and Inland Basin Production Sharing Decree". The licence therefore benefits from lower royalty and PPT tax rates than projects located in the main petroleum production regions onshore and offshore in the Niger Delta. The key elements of the fiscal system are as follows:

Oil and Condensate Revenues:	4% Royalty + 50% PPT
Gas Revenues:	4% Royalty + 30% CITA
Capex Depreciation:	5 years straight line (only 19% in 5th yr)
Cost Oil:	80% of revenues after Royalty
Investment Tax Allowance (Oil):	50% (Sole Risk Licence Terms)
Investment Tax Allowance (Gas):	20% (NAPIMS)
VAT:	5%
Education Tax:	2% of Assessable Profits (Ed. Tax not cost recoverable)
Customs Duty:	Exempt
NDDC Tax:	Exempt; only applicable to companies with operations in the Niger Delta.
Training Fees:	US$0.15mln/yr
Concession Rental Fees:	US$20/km^2 per year
PV Reference Date:	1.1.2019

For OML 113 there are US$499.9mln of historic costs due to be recovered (at end Q4/2018), of which US$120mln were incurred prior to 2007, and US$379.9mln post-2007. There are no Signature or Production Bonuses due under the applicable fiscal terms.

Note that within the economic model the 5th year of capex depreciation is taken as 20% rather than 19%, but this is not significant in the context of the other uncertainties in the input data and related assumptions.

It is also assumed that 50% of the opex costs are subject to VAT at 5%.

7.2 AGR TRACS economic evaluations for Aje

The combined Cenomanian & Turonian cases have been screened under the same three oil price scenarios ($50, $60, and $70/bbl) and US$4.00/MMscf used for the June 2018 CPR, with condensate assumed to fetch the same price as oil while LPGs are assumed to be worth 65% of oil on a per barrel basis. The Aje JV Partners are negotiating with a number of potential customers for the Aje gas in the Lagos area. The indicative gas prices offered lie in the range US$3.80 - $4.15/Mscf, thus for the economic assessments carried out as part of this review a flat gas price of US$4.00/Mscf has been assumed for all three oil price scenarios. AGR TRACS has been provided with copies of Heads Of Terms (HOT) agreed with several potential gas customers, and their aggregate initial demands amount to 125MMscf/d (DCQ, with MCQ suggested as DCQ + 10%). The suggested DCQ is almost the entire planned plateau output from the Aje gas field once it is on stream (plateau assumed at 126 MMscf/d sales gas).

The cases evaluated are as follows:

- Combined Aje-4 & -5ST2 and Turonian cases:
  - (Aje-4 & -5ST2) LOW + Tur LOW,
  - (Aje-4 & -5ST2) MID + Tur MID,
  - (Aje-4 & -5ST2) HIGH +Tur HIGH

These three combined cases represent a deterministic L/M/H range of outcomes. The economic evaluations of the three different cases presented in this section show the value to MX OIL assuming MX OIL's revenue interest as explained in Section 1.0, subject to YPF's preferential cost recovery.

In addition to the above three cases AGR TRACS was asked to provide an opinion on the technically recoverable volumes from a possible new oil producer ("Aje-6") targeting the Cenomanian in the north-eastern part of the field, and also a possible development scheme for the Turonian oil rim. The Aje JV Partners are progressing with their development studies of these additional oil targets, thus at the time of this CPR review no definite development plans were available. However, the technically recoverable volumes associated with these potential oil developments have been included in the summary tables as Technical Contingent Resources, which require development plans and associated cost estimates as well as production forecasts before more detailed reviews can be completed. It is expected that the Aje-6 well planning will progress once the new static and dynamic reservoir models have been completed.

Due to the disappointing reservoir performance from the Cenomanian in the Aje-4 and -5 wells the oil project is marginal to sub-economic at present, and the Aje JV Partners have managed to reduce the operating costs significantly in 2018, as documented by the 2018 Aje JV Budget supplied to AGR TRACS in early April 2018. These cost reductions were incorporated in the economic runs for the June 2018 CPR, and further cost reductions are under negotiation.

It is the likely intention of the Aje JV Partners to retain the oil FPSO until the planned Turonian gas development comes on stream in early 2022, as the condensate volumes will be directed through the oil FPSO, and thereby help cover the FPSO operating costs and prolong the Cenomanian oil production. By then the Aje-6 well may also have been completed in the NE Lobe. However, one option would be to replace the Front Puffin FPSO with a smaller vessel once the current contract expires in July 2019, but such a sensitivity is outside the scope of this CPR review. It appears clear that a smaller FPSO for the liquid and condensate production would help reduce the overall operating costs and improve the overall project economics.

Based on these assumptions the oil production expected in 2019-2021 from Aje-4 (Cenomanian) and -5 ST2 (Turonian oil rim) is classed as "Reserves Developed Producing" (DP). It appears that the anticipated production during this period is marginal to sub-economic under US$60/bbl, but the Aje JV Partners intend to keep these wells on stream until the gas project commences production. Any oil volumes produced from 2022 onwards from these two wells together with the economically recoverable gas, condensate and LPG volumes from the Turonian are considered as "Reserves Justified for Development" (JD). Since the June 2018 CPR was issued, the Fast Track Gas FDP has been approved by the Nigerian Department of Petroleum Resources (DPR) and the licence renewal has been granted. However, the Aje JV Parnters have not yet reached FID for the Gas FDP, hence the "JD" classification has been retained.

The estimates NPVs for the assessed cases reveal that the Mid and High cases for the planned Turonian gas development combine with the remaining life of Aje-4 and -5ST2 are economically viable at PV(10%) under $60 and $70/bbl for the development scheme discussed in Section 6.2. However, the combined Cenomanian and Turonian Low case does not appear economically viable under any of the oil price scenarios assumed.

The economic results are summarised below in respectively Table 7.1 to Table 7.5 for the three combined Cenomanian + Turonian cases:

OML 113 Fiscal Terms – MX OIL Net Share, 1st Gas/Cond/LPG 1.1.2022					
Aje-4 & -5ST2 Oil + Turonian Gas/Cond/LPG (Aje-6 & Tur. oil rim not included)	**Reserves (DP+JD) Oil/Cond/LPG/Dry Gas (MMboe) @ $60/bbl**		**US $mln MOD PV(0%) 1.1.2019**		
	100%	**MX OIL Net Entitlement**	**$50**	**$60**	**$70**
LOW	82.4	5.2	-20.9	-9.6	5.9
MID	138.2	8.9	37.3	59.5	81.6
HIGH	220.8	12.8	110.8	137.7	161.8

Table 7.1: AGR TRACS PV(0%) econ. eval. MX OIL share Aje OML 113 (Aje-4 & -5ST2) Oil+Tur
(Source: 2019 AGR TRACS review)

OML 113 Fiscal Terms – MX OIL Net Share, 1st Gas/Cond/LPG 1.1.2022					
Aje-4 & -5ST2 Oil + Turonian Gas/Cond/LPG (Aje-6 & Tur. oil rim not included)	**Reserves (DP+JD) Oil/Cond/LPG/Dry Gas (MMboe) @ $60/bbl**		**US $mln MOD PV(10%) 1.1.2019**		
	100%	**MX OIL Net Entitlement**	**$50**	**$60**	**$70**
LOW	82.4	5.2	-23.9	-16.6	-7.0
MID	138.2	8.9	3.0	14.4	25.9
HIGH	220.8	12.8	26.3	38.3	49.8

Table 7.2: AGR TRACS PV(10%) econ. eval. MX OIL share Aje OML 113 (Aje-4 & -5ST2) Oil+Tur
(Source: 2019 AGR TRACS review)

OML 113 Fiscal Terms – MX OIL Net Share, 1st Gas/Cond/LPG 1.1.2022					
Aje-4 & -5ST2 Oil + Turonian Gas/Cond/LPG (Aje-6 & Tur. oil rim not included)	**Reserves (DP+JD) Oil/Cond/LPG/Dry Gas (MMboe) @ $60/bbl**		**US $mln MOD PV(15%) 1.1.2019**		
	100%	**MX OIL Net Entitlement**	**$50**	**$60**	**$70**
LOW	82.4	5.2	-23.5	-17.5	-23.8
MID	138.2	8.9	-4.5	4.1	12.8
HIGH	220.8	12.8	9.3	18.1	26.6

Table 7.3: AGR TRACS PV(15%) econ. eval. MX OIL share Aje OML 113 (Aje-4 & -5ST2) Oil+Tur
(Source: 2019 AGR TRACS review)

OML 113 Fiscal Terms – MX OIL Net Share, 1st Gas/Cond/LPG 1.1.2022					
Aje-4 & -5ST2 Oil + Turonian Gas/Cond/LPG (Aje-6 & Tur. oil rim not included)	Reserves (DP+JD) Oil/Cond/LPG/Dry Gas (MMboe) @ $60/bbl		US $mln MOD PV(20%) 1.1.2019		
	100%	MX OIL Net Entitlement	$50	$60	$70
LOW	82.4	5.2	-22.6	-17.6	-11.2
MID	138.2	8.9	-8.8	-2.1	4.6
HIGH	220.8	12.8	-0.4	6.4	12.9

Table 7.4: AGR TRACS PV(20%) econ. eval. MX OIL share Aje OML 113 (Aje-4 & -5ST2) Oil+Tur
(Source: 2019 AGR TRACS review)

OML 113 Fiscal Terms – MX OIL Net Share, 1st Gas/Cond/LPG 1.1.2022					
Aje-4 & -5ST2 Oil + Turonian Gas/Cond/LPG (Aje-6 & Tur. oil rim not included)	Reserves (DP+JD) Oil/Cond/LPG/Dry Gas (MMboe) @ $60/bbl		IRR for MX OIL net share (from MOD cashflows)		
	100%	MX OIL Net Entitlement	$50	$60	$70
LOW	82.4	5.2	-11.2%	-5.4%	3.3%
MID	138.2	8.9	11.7%	18.0%	24.4%
HIGH	220.8	12.8	19.7%	24.6%	29.7%

Table 7.5: AGR TRACS IRR summary MX OIL share Aje OML 113 (Aje-4 & -5ST2) Oil+Tur
(Source: 2019 AGR TRACS review)

The Undiscounted Maximum Exposure net to MX OIL for the combined Cenomanian + Turonian Mid case is estimated at US$58.1mln under US$60/bbl.

7.3 Reserves & Resource classifications and COCS assessment

The FDP for the Aje Cenomanian oil project was sanctioned by the Nigerian authorities in Q1/2014, and brought on stream in May 2016, thus the anticipated production for the period 2019-2021 from the two wells Aje-4 (Cenomanian) and -5ST2 (Turonian oil rim) is classified as "Reserves – Developed Producing (DP)". Any production from these two wells beyond 1.1.2022 will be dependent on the Turonian gas development coming on stream to support the continued operation of the oil FPSO, and hence classed as "Reserves – Justified for Development (JD)" (see Appendix A for an overview of the SPE PRMS Petroleum Resources Classification Systems).

The anticipated gas/condensate/LPG reserves associated with the Turonian gas-condensate development as presented in the Fast Track Gas Development FDP are classed as "Reserves – Justified for Development (JD)".

The indicated technically recoverable volumes from the possible Aje-6 well and the full development of the Turonian oil rim are both considered as "Contingent Resources – Development Unclarified", as development studies are still in progress. The Chance Of Commercial Success ("COCS") for these two possible projects are deemed to be 50% and 40% respectively, as the Aje-6 well is somewhat better defined at present.

The respective net Reserves (DP and JD) attributable to MX OIL are all quoted under $60/bbl, and have been derived from the economic analyses incorporating the varying revenue interests as discussed in Section 1.0.

The detailed tabulations of reserves and contingent resources compliant with the AIM June 2009 Guidance Note are shown below in Table 7.6, Table 7.7 and Table 7.8 as well as in Appendix 2.

Oil & Liquids: MMbbls Gas: Bscf	Gross			Net Attributable to MX OIL			Operator
DISCOVERY	**1P Proved**	**2P Proved & Probable**	**3P Proved, Probable & Possible**	**1P Proved**	**2P Proved & Probable**	**3P Proved, Probable & Possible**	
NIGERIA:							
OML 113 Aje OIL							
DP (Cen. 2019-2021)	0.82	0.89	0.94	0.04	0.04	0.05	YFP
DP (Tur. 2019-2021)	1.23	1.36	1.49	0.06	0.07	0.07	YFP
Sub-total DP (2019-2021)	**2.05**	**2.25**	**2.43**	**0.10**	**0.11**	**0.12**	YFP
JD (Cen. 2022 onwards)	0.32	0.69	1.16	0.02	0.04	0.07	YFP
JD (Tur. 2022 onwards)	0.79	1.79	3.01	0.05	0.12	0.18	YFP
Sub-total JD (2022 onwards)	**1.11**	**2.48**	**4.17**	**0.07**	**0.16**	**0.25**	YFP
OML 113 Aje CONDENSATE							
JD (2022 onwards)	10.32	17.41	27.87	0.65	1.12	1.66	YFP
OML 113 Aje LPG							
JD (2022 onwards)	20.11	33.86	54.39	1.29	2.20	3.14	YFP
TOTAL LIQUIDS (MMbbls)							
DP OIL (2019-2021)	2.05	2.25	2.43	0.10	0.11	0.12	YFP
JD (2022 onwards, OIL + COND + LPG)	31.54	53.75	86.43	2.01	3.48	5.05	YFP
SUB-TOTAL LIQUIDS#	**33.6**	**56.0**	**88.9**	**2.1**	**3.6**	**5.2**	YFP
OML 113 Aje DRY GAS (Bscf)							
Gas Cap Gas	261.6	442.0	704.9	16.8	28.8	40.7	YFP
Solution Gas	31.1	50.9	87.0	2.0	3.3	5.0	YFP
Sub-total Gas JD (2022 onwards)	**292.7**	**492.8**	**791.9**	**18.8**	**32.1**	**45.7**	YFP
TOTAL#, MMboe	**82.4**	**138.2**	**220.8**	**5.2**	**8.9**	**12.8**	YFP

Table 7.6: Aje OML 113 - Overview of gross and net attributable reserves (oil / gas / condensate / LPG)
(Source: 2018 AGR TRACS review)

Oil & Liquids: MMbbls Gas: Bscf	Gross Unrisked Technical Contingent Resources			Net Unrisked Technical Contingent Resources Attributable to MX OIL			Risk Factor	Operator
DISCOVERY	**1C Low Estimate**	**2C Best Estimate**	**3C High Estimate**	**1C Low Estimate**	**2C Best Estimate**	**3C High Estimate**	**COCS (%)**	
Oil & Liquids Contingent Resources per asset								
NIGERIA:								
OML 113 Aje OIL - Cen. Aje-6 near-horizontal well	0.00	3.00	5.50	0.00	0.15	0.28	50%	YFP
OML 113 Aje Turonian OIL rim with 4 notional producers	4.00	6.00	12.00	0.20	0.30	0.60	40%	YFP
Unrisked Totals for Oil and Liquids #, MMbbls	**4.00**	**9.00**	**17.50**	**0.20**	**0.45**	**0.88**		

Table 7.7: Aje OML 113 - Unrisked gross and net attributable technical contingent resources (oil) to MX OIL
(Source: 2018 AGR TRACS review)

Oil & Liquids: MMbbls Gas: Bscf	Net Unrisked Technical Contingent Resources Attributable to MX OIL			Risk Factor	Risked Technical Contingent Resources Net Attributable to MX OIL		
DISCOVERY	**1C Low Estimate**	**2C Best Estimate**	**3C High Estimate**	**COCS (%)**	**1C Low Estimate**	**2C Best Estimate**	**3C High Estimate**
Oil & Liquids Contingent Resources per asset							
NIGERIA:							
OML 113 Aje OIL - Cen. Aje-6 near-horizontal well	0.00	0.15	0.28	50%	0.00	0.08	0.14
OML 113 Aje Turonian OIL rim with 4 notional producers	0.20	0.30	0.60	40%	0.08	0.12	0.24
Totals for Oil and Liquids #, MMbbls	**0.20**	**0.45**	**0.88**		**0.08**	**0.20**	**0.38**

Table 7.8: Aje OML 113 - Unrisked and risked net attributable technical contingent resources (oil) to MX OIL
(Source: 2018 AGR TRACS review)

8 Conclusions and Recommendations

For the sake of completeness the key conclusions and recommendations from the 2018 Aje CPR Review are summarised below, and updated where relevant with the latest production data from Aje-4 and -5ST2:

Geoscience:

The Top Turonian depth map derived from the 2014 PSDM 3D volume provides a credible representation of the structure as it ties the three new wells Aje-5, -5ST1 and -5ST2 quite well. The NewAge Top Cenomanian depth map that was the basis for the 2014 Cenomanian Oil FDP is no longer credible, primarily because the Top Cenomanian seismic pick was incorrect resulting in an overly optimistic depth map, leading in turn to the misties at Top Cenomanian level encountered in the three new wells.

The 2009 P90-P50-P10 depth maps generated by Chevron based on the old 3D provided a reasonable representation of the top structure and tied the new wells satisfactorily, hence these maps were used as the basis for the AGR TRACS review of the Cenomanian in-place volumes.

The new well penetrations have not resulted in a significant change in the interpretation of the Cenomanian reservoir facies. The previous view that the reservoir consists of a series of sands and shales, which can be divided into an upper and lower unit, remains valid.

No new information has been acquired for the Albian reservoir from any of the Aje-5, Aje-5ST1 and Aje-5ST2 wells, as these wells did not penetrate the Albian reservoir. Consequently, the Albian reservoir has not been re-analysed for this CPR and the results of the previous assessment of in-place volumes remain valid.

GIIP and STOIIP estimates:

Turonian: The subsurface review of the Turonian reservoirs suggests that the Low and Mid cases in the FDP Low-Mid-High GIIP range are about 10-15% higher than the corresponding AGR TRACS Low-Mid-High GIIP range of 501-789-1246 BCF wet gas. An additional contribution (L-M-H of 81-119-176 BCF) is estimated from the solution gas in the underlying oil rim.

The difference is partly due to adjustments to the western part of the top Turonian reservoir depth map thereby reducing the GRV, and a residual depth uncertainty for the GOC of about 16ft/5m. Following a detailed review AGR TRACS now considers the deeper contacts a better fit to the new data from the most recent wells and sidetracks. This uncertainty also impacts the STOIIP estimates for the Turonian oil rim, thus a sensitivity on the oil rim STOIIP has been assessed which shows that the deeper GOC reduced the P50 oil rim STOIIP by 12% and increases the overlying gas column P50 GIIP by 11%. The Turonian oil rim P90-P50-P10 STOIIP range is estimated at 95-138-200 MMbbls with the deeper GOC. Note that there is no significant uncertainty in the OWC at the base of the Turonian oil rim.

Furthermore, the Turonian GRV to the south has been excluded in the P90 and P50 cases due to the lack of potential Turonian reservoir sands in the Aje-3 appraisal well.

Cenomanian: The updated STOIIP estimates without the NE Lobe (L-M-H 17-41-96 MMbbls) represent a substantial reduction in STOIIP from the Cenomanian P90-P50-P10 range quoted in the 2014 AGR TRACS CPR, which were based on the now discredited depth maps provided by NewAge for the FASL 2014 Cenomanian FDP. The updated 2018 P50 STOIIP estimates are 65-75% less than the P50 STOIIP in the 2014 FDP. No changes were made to these estimates for this March 2019 CPR update, but updates are likely once the new static and dynamic models have been completed.

Petrophysics:

The petrophysical evaluations for the first four Aje wells were reviewed or updated for the 2014 CPR. As part of the 2018 CPR review the Aje-2, -3 and -4 evaluations were updated with revised formation tops in the Turonian. In addition, the results from the three new wells were integrated into the overall reservoir evaluation for the Turonian and Cenomanian reservoirs. The updated Turonian evaluations are in broad agreement with the previous assessments, but the range of average properties used for the volumetric estimates has more up-side than the 2014 CPR since a larger proportion of the wells encountered good quality reservoir. There were insufficient logs available from the Cenomanian sections in the three new wells for a full evaluation, but the calculated porosities fall within the ranges previously carried for the Cenomanian.

Reservoir Engineering:

Cenomanian: AGR TRACS have reviewed the production data for the period May 2016 to January 2019 for the Aje Field. The data comprised field level production for the wells Aje-4 (Cenomanian reservoir), Aje-5 (Cenomanian reservoir, intermittent May 2016 to Jan. 2017) and Aje-5ST2 (Turonian oil rim from May 2017).

The oil rate data represents commingled flow from the three production wells, with no allocation on an individual well basis provided. AGR TRACS undertook a production allocation review exercise on the wells, and then derived production forecasts for the two wells (Aje-4 and Aje-5ST2) that were producing at YE 2018.

It is estimated that the Low-Mid-High Expected Ultimate Technical Recovery (EUR) range for the Aje-4 well is 3.1-3.5-4.0 MMbbls prior to economic cut-offs, of which 1.92 MMbls have been produced by YE 2018, The corresponding L-M-H Technical EUR range for the Aje-5ST2 well is estimated at 3.1-4.3-5.5 MMbbls, of which some 1.0 MMstb have been produced by YE 2018. In addition, around 85 MMstb were produced from Aje-5 before the well watered out and was side-tracked.

MX OIL requested AGR TRACS to provide an opinion on the technically recoverable volumes from a possible future appraisal well (Aje-6) in the NE Lobe of the Cenomanian structure. Due to the uncertainties in the depth map, this NE lobe is considered to have a deterministic L-M-H STOIIP range 0-21-38MMstb (100%). If such a future well is drilled as a near-horizontal well into the local high within this lobe, it appears possible that the Mid and High case ultimate recovery could be similar or greater than estimated for the Aje-4 well due to the higher relief of the NE Lobe compared to the Aje-4 location. The EUR range for the NE lobe is estimated to be in the range 0-3.0-5.5 MMbbls (100% basis), and these volumes are currently classed as Contingent Resources with a COCS of 50%.

Turonian: For the June 2018 CPR AGR TRACS also derived estimates for the in-place volumes and technically recoverable gas, condensate and LPG resources in the Turonian; see Table 8.1 below. Note that these estimates include associated gas liberated from the oil rim as the pressure declines over time once the field is on stream. No economic cut-offs have been applied to these technical resource volumes. Note that these estimates remain unchanged for this latest CPR update.

Case	GIIP – Wet Gas	GIIP - Assoc. Gas	CIIP (in Wet Gas)	Wet Gas Resources	Assoc. Gas Resources	Wet Gas Resources incl. Assoc. Gas	Dry Sales Gas Resources	Conden-sate Resources	LPG Resources
	BCF	BCF	MMbbls	BCF	BCF	BCF	BCF	MMstb	MMstb
P90	501	81	23	350	49	393	330	10.9	22.7
P50	789	119	37	592	78	660	554	18.4	38.1
P10	1,246	176	58	935	115	1,050	882	29.3	60.6

Table 8.1: Aje field – AGR TRACS in-place volumes and technical resources for the Turonian reservoir
(Source: 2018 AGR TRACS review)

The Turonian gas cap production forecasts were generated based on a range of assumptions in order to provide inputs for the economic evaluations and the resulting estimates of reserves (see below).

The Aje-5ST2 well is currently producing from the Turonian oil rim as of May 2017 and achieving better rates than expected, possibly due to a local shale baffle at the base of the sand which prevents/delays water influx from the underlying aquifer. Following a request from MX OIL AGR TRACS have carried out a brief assessment of the Turonian oil rim in order to provide indicative estimates of notionally technically recoverable contingent resources.

These estimates suggested a L-M-H range of 1.0-1.5-3.0 MMstb recovery per well could be achieved. If four horizontal producers were to be drilled into the oil rim as indicated above, then an arithmetic L-M-H range of technical contingent resources would be 4.0-6.0-12.0 MMstb. These estimates are based on the development concept underpinning the Gas FDP, which assumes that the gas cap will be the primary focus for the development, with the oil rim a possible secondary target. If the oil rim development were given priority then higher recoveries might be possible. In that context the performance of the Aje-5 ST2 well should be monitored carefully for gas and/or water breakthrough.

These additional oil rim volumes are currently classed as Contingent Resources with a COCS of 40% due to the immaturity of the project and the technical uncertainties.

Albian: The deeper Albian gas-condensate accumulation is relatively small, and does not form part of the current development scheme.

Facilities Engineering:

A brief, fit-for-purpose, high-level Facilities Engineering (FE) review and assessment of field development concepts and costs for the Turonian gas Field development of the Aje field offshore Nigeria has been carried out for MX OIL and their partners. The work was based mainly on the FE data presented in the "OML 113 – Aje Field Fast Track Gas Field Development Plan" (FDP). This FDP assumes 1st gas production from late 2018, but this date has since been revised to late 2019 or sometime in 2020, assuming an 18-month construction period following licence renewal and FID. The AGR TRACS evaluations assume that 1st gas production will commence from 1.1.2021 due to the uncertainty around when the licence renewal will be granted.

The conclusion is that the costs quoted in the FDP of some US$1,050mln including drilling are considered reasonable overall, but the schedule may need revising depending on when the licence renewal is approved.

Economic Evaluations:

The combined Cenomanian & Turonian cases have been screened under three oil price scenarios ($50, $60, and $70/bbl) and US$4.00/MMscf, with condensate assumed to fetch the same price as oil while LPGs are assumed to be worth 65% of oil on a per barrel basis. The Aje JV Partners are negotiating with a number of potential customers for the Aje gas in the Lagos area. HOTs with three potential customers for a substantial part of the planned plateau production have already been negotiated, where the indicative gas prices offered lie in the range US$3.80 - $4.15/Mscf. Consequently, a flat gas price of US$4.00/Mscf has been assumed for all three oil price scenarios used in the economic assessments.

Due to the disappointing reservoir performance from the Cenomanian in the Aje-4 and -5 wells the oil project is marginal to sub-economic at present, and the Aje JV Partners have managed to reduce the operating costs significantly in 2018, as documented by the 2018 Aje JV Budget supplied to AGR TRACS in early April 2018. These cost reductions have been incorporated in the economic runs. The Aje-5ST2 well producing from the Turonian oil rim performed better than expected through 2018, but it is uncertain how long this performance will last, as water break-through may happen quite quickly. Consequently the estimated P90-P50-P10 range of reserves from 2022 onwards is quite wide.

It is the likely intention of the Aje JV Partners to retain the oil FPSO until the planned Turonian gas development comes on stream in early 2022, as the condensate volumes will be directed through the oil FPSO, and thereby help cover the FPSO operating costs and prolong the Cenomanian oil production. By then the Aje-6 well may also have been completed in the NE Lobe.

The estimates NPVs for the assessed cases reveal that the Mid and High cases for the planned Turonian gas development combine with the remaining life of Aje-4 and -5ST2 are economically viable at PV(10%) under $60 and $70/bbl for the development scheme outlined in the FDP. However, the combined Cenomanian and Turonian Low case does not appear economically viable under any of the oil price scenarios assumed (see Table 8.2 and Table 8.3 below).

OML 113 Fiscal Terms – MX OIL Net Share, 1st Gas/Cond/LPG 1.1.2022					
Aje-4 & -5ST2 Oil + Turonian Gas/Cond/LPG (Aje-6 & Tur. oil rim not included)	Reserves (DP+JD) Oil/Cond/LPG/Dry Gas (MMboe) @ $60/bbl		US $mln MOD PV(10%) 1.1.2019		
	100%	MX OIL Net Entitlement	$50	$60	$70
LOW	82.4	5.2	-23.9	-16.6	-7.0
MID	138.2	8.9	3.0	14.4	25.9
HIGH	220.8	12.8	26.3	38.3	49.8

Table 8.2: AGR TRACS PV(10%) econ. eval. MX OIL share Aje OML 113 (Aje-4 & -5ST2) Oil+Tur
(Source: 2019 AGR TRACS review)

<table>
<tr><th colspan="6">OML 113 Fiscal Terms – MX OIL Net Share, 1st Gas/Cond/LPG 1.1.2022</th></tr>
<tr><th rowspan="2">Aje-4 & -5ST2 Oil + Turonian Gas/Cond/LPG (Aje-6 & Tur. oil rim not included)</th><th colspan="2">Reserves (DP+JD) Oil/Cond/LPG/Dry Gas (MMboe) @ $60/bbl</th><th colspan="3">IRR for MX OIL net share (from MOD cashflows)</th></tr>
<tr><th>100%</th><th>MX OIL Net Entitlement</th><th>$50</th><th>$60</th><th>$70</th></tr>
<tr><td>LOW</td><td>82.4</td><td>5.2</td><td>-11.2%</td><td>-5.4%</td><td>3.3%</td></tr>
<tr><td>MID</td><td>138.2</td><td>8.9</td><td>11.7%</td><td>18.0%</td><td>24.4%</td></tr>
<tr><td>HIGH</td><td>220.8</td><td>12.8</td><td>19.7%</td><td>24.6%</td><td>29.7%</td></tr>
</table>

Table 8.3: AGR TRACS IRR summary MX OIL share Aje OML 113 (Aje-4 & -5ST2) Oil+Tur
(Source: 2019 AGR TRACS review)

Estimates of Reserves and Resources:

The FDP for the Aje Cenomanian oil project was sanctioned by the Nigerian authorities in Q1/2014, and brought on stream in May 2016, thus the anticipated production for the period 2019-2021 from the two wells Aje-4 (Cenomanian) and -5ST2 (Turonian oil rim) is classified as "Reserves – Developed Producing (DP)". Any production from these two wells beyond 1.1.2022 will be dependent on the Turonian gas development coming on stream to support the continued operation of the oil FPSO, and hence classed as "Reserves – Justified for Development (JD)".

The anticipated gas/condensate/LPG reserves associated with the Turonian gas-condensate development as presented in the Fast Track Gas Development FDP are classed as "Reserves – Justified for Development (JD)".

The overall net attributable L-M-H reserves (DP and JD) to MX OIL are estimated at 5.2-8.9-12.8 MMboe (Table 8.4), of which about 40% of the Mid case volume comprises liquids (oil, condensate and LPGs).

The respective net Reserves (DP and JD) attributable to MX OIL are all quoted under $60/bbl assuming a nominal participating interest of 6.5020% and a revenue interest of 12.1913% post project pay-out once YFP's preferential cost recovery has been completed.

AGR TRACS suggests that the 2C Best Estimate Unrisked Gross Technical Contingent Resources from the possible Aje-6 well and a development of the Turonian oil rim are 9.00 MMbbls, and the corresponding Unrisked Net Attributable Technical Contingent Resources to MX OIL are estimated at 0.45 MMbbls (see Table 8.5 below). The 2C Risked Net Attributable Technical Contingent Resources to MX OIL are estimated at 0.20 MMbbls (Table 8.6).

Although Aje-5ST2 has performed well since the June 2018 CPR, there are no changes to the estimates of Contingent Resources for the Turonian Oil Rim presented in this CPR, as the four notional horizontal producers would penetrate a different section of the Turonian reservoir compared to the currently producing Aje-5ST2. This well is draining an interval within the deepest Turonian 4 sequence in the core of the structure immediately above a local shale baffle, and is therefore not representative of the reservoir sequence expected for the four notional oil rim producers in the more peripheral locations within the uppermost Turonian sequence (which is expected to have optimum reservoir properties). It is also unclear when the oil rim producers would be brought on stream relative to the primary gas producers targeting the Turonian gas cap, and a later development would tend to have a reduced recovery per well. However, AGR TRACS acknowledges that the production performance of Aje-5ST2 has been better than initially expected, thus it is proposed that the potential oil rim exploitation should be reviewed more thoroughly once the new static and dynamic models become available.

Oil & Liquids: MMbbls Gas: Bscf	Gross			Net Attributable to MX OIL			Operator
DISCOVERY	**1P Proved**	**2P Proved & Probable**	**3P Proved, Probable & Possible**	**1P Proved**	**2P Proved & Probable**	**3P Proved, Probable & Possible**	
NIGERIA:							
OML 113 Aje OIL							
DP (Cen. 2019-2021)	0.82	0.89	0.94	0.04	0.04	0.05	YFP
DP (Tur. 2019-2021)	1.23	1.36	1.49	0.06	0.07	0.07	YFP
Sub-total DP (2019-2021)	**2.05**	**2.25**	**2.43**	**0.10**	**0.11**	**0.12**	YFP
JD (Cen. 2022 onwards)	0.32	0.69	1.16	0.02	0.04	0.07	YFP
JD (Tur. 2022 onwards)	0.79	1.79	3.01	0.05	0.12	0.18	YFP
Sub-total JD (2022 onwards)	**1.11**	**2.48**	**4.17**	**0.07**	**0.16**	**0.25**	YFP
OML 113 Aje CONDENSATE							
JD (2022 onwards)	10.32	17.41	27.87	0.65	1.12	1.66	YFP
OML 113 Aje LPG							
JD (2022 onwards)	20.11	33.86	54.39	1.29	2.20	3.14	YFP
TOTAL LIQUIDS (MMbbls)							
DP OIL (2019-2021)	2.05	2.25	2.43	0.10	0.11	0.12	YFP
JD (2022 onwards, OIL + COND + LPG)	31.54	53.75	86.43	2.01	3.48	5.05	YFP
SUB-TOTAL LIQUIDS#	**33.6**	**56.0**	**88.9**	**2.1**	**3.6**	**5.2**	YFP
OML 113 Aje DRY GAS (Bscf)							
Gas Cap Gas	261.6	442.0	704.9	16.8	28.8	40.7	YFP
Solution Gas	31.1	50.9	87.0	2.0	3.3	5.0	YFP
Sub-total Gas JD (2022 onwards)	**292.7**	**492.8**	**791.9**	**18.8**	**32.1**	**45.7**	YFP
TOTAL#, MMboe	**82.4**	**138.2**	**220.8**	**5.2**	**8.9**	**12.8**	YFP

Table 8.4: Aje OML 113 - Overview of gross and net attributable reserves (oil / gas / condensate / LPG)
(Source: 2019 AGR TRACS review)

Oil & Liquids: MMbbls Gas: Bscf	Gross Unrisked Technical Contingent Resources			Net Unrisked Technical Contingent Resources Attributable to MX OIL			Risk Factor	Operator
DISCOVERY	1C Low Estimate	2C Best Estimate	3C High Estimate	1C Low Estimate	2C Best Estimate	3C High Estimate	COCS (%)	
Oil & Liquids Contingent Resources per asset								
NIGERIA:								
OML 113 Aje OIL - Cen. Aje-6 near-horizontal well	0.00	3.00	5.50	0.00	0.15	0.28	50%	YFP
OML 113 Aje Turonian OIL rim with 4 notional producers	4.00	6.00	12.00	0.20	0.30	0.60	40%	YFP
Unrisked Totals for Oil and Liquids #, MMbbls	**4.00**	**9.00**	**17.50**	**0.20**	**0.45**	**0.88**		

Table 8.5: Aje OML 113 - Unrisked gross and net attributable technical contingent resources (oil) to MX OIL
(Source: 2018 AGR TRACS review)

Oil & Liquids: MMbbls Gas: Bscf	Net Unrisked Technical Contingent Resources Attributable to MX OIL			Risk Factor	Risked Technical Contingent Resources Net Attributable to MX OIL		
DISCOVERY	1C Low Estimate	2C Best Estimate	3C High Estimate	COCS (%)	1C Low Estimate	2C Best Estimate	3C High Estimate
Oil & Liquids Contingent Resources per asset							
NIGERIA:							
OML 113 Aje OIL - Cen. Aje-6 near-horizontal well	0.00	0.15	0.28	50%	0.00	0.08	0.14
OML 113 Aje Turonian OIL rim with 4 notional producers	0.20	0.30	0.60	40%	0.08	0.12	0.24
Totals for Oil and Liquids #, MMbbls	**0.20**	**0.45**	**0.88**		**0.08**	**0.20**	**0.38**

Table 8.6: Aje OML 113 - Unrisked and risked net attributable technical contingent resources (oil) to MX OIL
(Source: 2018 AGR TRACS review)

Recommendations:

Cenomanian structure: It is recommended that a new interpretation is carried out fully integrating the new seismic and well data in order to provide a more accurate interpretation of the Aje Cenomanian structure. This should include rebuilding the static and dynamic models to improve the understanding of the field, and ought to be carried out prior to any further development drilling (e.g. the Aje-6 well in the "NE Lobe"). AGR TRACS understand that updated static and dynamic models for both the Turonian and Cenomanian reservoirs are being developed at the time of writing (March 2019), and that once these are completed they will be made available for a future CPR review.

Reservoir Engineering – Cenomanian: The production allocation from May 2017 to year end 2018 (YE2018) is highly uncertain for the Aje-4 well, and it is therefore recommended that both wells (Aje-4 and Aje-5 ST2) be tested on a regular basis in the future to check production allocation and adjust production forecasts.

Reservoir Engineering – Turonian Gas Cap: There is still some uncertainty in the depth to the GOC and hence in the in place estimates in the gas cap and oil rim. There is also some uncertainty in the likely wet gas to sales gas shrinkage factor (gas shrinkage plus fuel gas requirement), but this has less impact on the overall estimated technically recoverable volumes than the GOC uncertainty. Further data should be therefore be gathered in order resolve both of these uncertainties.

Reservoir Engineering – Turonian Oil Rim: The encouraging production performance for the Aje-5ST2 well so far provides a strong incentive for further studies, and the Turonian oil rim remains a potentially valuable additional resource within the Aje field complex. It is therefore recommended that static and dynamic modelling of the oil rim should be carried out in order to derive more reliable estimates of recoverable volumes.

Facilities Engineering - Risk Register: It is recommended that the Aje JV Partners compile a Risk Register for the surface and subsurface risks, their potential impact and possible mitigations as part of the next phase of detailed development studies.

9 References

1. *AGR TRACS International, "Competent Person's Report on the AJE Field, OML 113, Nigeria for MX OIL Energy Limited", June 2018*
2. *Folawiyo Aje Services Limited ("FASL"), OML 113 – Aje Field Fast Track Gas Field Development Plan, Document No.: S00-REPT-004, April 2017.*
3. *AGR TRACS International Limited, "AGR TRACS Competent Persons Report on the 2014 AJE FDP, OML 113, Nigeria, for MX OIL Energy Limited", 25th July 2014.*
4. *Aje Field Development Plan, Folawiyo Aje Services Ltd, January 2014, document number S00-REPT-003, Rev R2.3 20.02. 2014.*
5. *TRACS International, "Independent Valuation on (part of) Energy Equity Resources Asset Portfolio in Nigeria, 16th Dec, 2008.*
   (Note: Shortly after this report was issued Energy Equity Resources split into two companies, EER and Panoro, and the Aje equity stake was transferred to Panoro.)
6. *Author unknown (FASL ?),"Aje 5st1 & 5st2 Petrophysical Reportnn", 2018.*
7. *AGR TRACS International, "Independent Valuation of MX OIL Energy's Asset Portfolio in OML 113 offshore Nigeria", 2012.*
8. *Schlumberger PVT Laboratory Study Report, "Field Aje, Well Aje-2, DST3, Date of sampling 16.02.1997".*
9. *O. Olamigoke and A. Peacock, "First-Pass Screening of Reservoirs with Large Gas Caps for Oil Rim Development", SPE 128603, Nigeria Annual International Conference and Exhibition, 3-5 August 2009, Abuja, Nigeria*
10. *R. Masoudi, H. Karkooti, M. B. Othman, "How to Get the Most Out of Your Oil Rim Reservoirs?", SPE 16740. This paper was prepared for presentation at the International Petroleum Technology Conference held in Beijing, China, 26–28 March 2013.*

10 Glossary of Terms

$	US Dollars
%	percent
°C	Degrees Celcius
2D	Two Dimensional
3D	Three Dimensional
API	American Petroleum Institute
AVO	Amplitude Variation with Offset
Av Phi	Average Porosity (from log evaluation)
Av Sw	Average water Saturation (from log evaluation)
bbls	Barrels
Bscf	Billion standard cubic feet of natural gas
bfpd	Barrels of fluid per day
boe	barrels of oil equivalent
boepd	barrels of oil equivalent per day
bopd	barrels oil per day
bpd	barrels per day
bwpd	barrels of water per day
Cali	Caliper
Capex	capital expenditure
CGR	Condensate Gas Ratio
CHP	Combined Heat-Power plant for gas-to-power generation
CIIP	Condensate Initially In Place
cm^3	cubic centimetre
COCS	Chance of Commercial Success
CPI	Computer Processed Interpretation (of logs)
CT	Corporation Tax
Den	Density log
DNP	Developed Non-producing
DP	Developed Producing
D res	Deep resistivity log (deep investigation)
DST	Drill Stem Test
DT	Sonic log
E & A	Exploration & Appraisal
FDP	Field Development Plan
ft	feet
FTHP	Flowing Tubing Head Pressure
FWL	Free Water Level
G & G	Geological and Geophysical
Gas sat	Gas saturation
GDT	Gas Down To
GEF	Gas Expansion Factor
GIIP	Gas Initially In Place
GOR	Gas to Oil Ratio
GR	Gamma Ray log
GRV	Gross Rock Volume
GUT	Gas Up To
GWC	Gas Water Contact
HCDT	Hydro-Carbon Down To
HCWC	Hydro-Carbon Water Contact
IRR	Internal Rate of Return (from MOD cashflows)
JD	Justified for Development
JV	Joint Venture
K	Permeability
km	Kilometre
km^2	Square kilometres
m	metre
m^3	cubic metre
Mbbls	thousand barrels of oil (unless otherwise stated)
Mboe	thousand barrels of oil equivalent
Mbopd	thousand barrels of oil per day
Mcf	thousand cubic feet
Mcfd	thousand cubic feet per day of natural gas
MD	Measured Depth
mD	milli Darcies
mln	million (monetary costs and values)
MM	Million (for volumes)
MMbbls	million barrels of oil
MMstb	million stock-tank barrels of oil
MMbo	million barrels of oil
MMboe	million barrels of oil equivalent
MMcf	million cubic feet of natural gas
MMscfd	million cubic feet of natural gas per day
MOD	Money Of the Day
N/G	Net to Gross
NCD Levy	Nigerian Content Development levy
Neu	Neutron log
NFA	No Further Activity
NIMASA	Nigerian Maritime Administration and Safety Agency

NPV	Net Present Value
NRU	Nitrogen Removal Unit
OBSC	Ocean Bottom Cable
ODT	Oil Down To
OML	Oil Mining Licence
Opex	operating expenditure
OUT	Oil Up To
OWC	Oil Water Contact
P & A	Plugged and Abandoned
p.a.	per annum
P10	10% probability of being exceeded
P50	50% probability of being exceeded
P90	90% probability of being exceeded
POS	Possibility Of Success
ppm wt	Parts per million by weight
PRMS	Petroleum Resource Management System
PSC	Production Sharing Contract
psi	pounds per square inch
psia	pounds per square inch absolute
PV	Present Value
PVT	Pressure Volume Temperature
RF	Recovery Factor
RFT	Repeat Formation Tester
RROR	Real Rate of Return (from RT cashflows)
RT	Real Terms
SG	Specific Gravity
SMT Kingdom	a PC-based interpretation workstation
SPE	Society of Petroleum Engineers
sq km	square kilometres
S res	Short resistivity log (shallow investigation)
ss	subsea
STOIIP	Stock Tank Oil Initially In Place
Sw	water Saturation
Swavg	average water Saturation
Sxo	water Saturation in invaded zone
TD	Total Depth
TVD	true vertical depth
TVDss	true vertical depth subsea
tvt	true vertical thickness
TWT	Two-Way Time
UAP	Unallocated Provision
WHT	Withholding Tax
WIinit	Well Initial
WI	Working Interest
YE	Year End

Appendix A - Summary of 2007 and 2011 SPE Petroleum Resources Classification Systems

The PRMS classification system draws a clear distinction between project maturity and the range of uncertainty on any particular activity or project. Whereas, there is some correlation between project maturity and certainty/uncertainty (proven, probable and possible categories) in common oil industry usage, the SPE PRMS classification system seeks to remove this conflict between maturity and uncertainty and define an entirely nested hierarchy as follows:

Level 1: Project Maturity

This highest level of distinction is characterised by three levels of project maturity, namely prospective resources, contingent resources and reserves. The conditions for each category are a combination of commercial and government approvals, technical evaluation maturity and field development maturity (mapping, drilling, logging, testing and producing wells).

Depending on the progress made along this axis, this will help determine the class of resource. Broadly speaking there are six classes (Table A.10.1), of which the top three (producing field, approved for development and justified for development) correlates with reserves and the next three (development pending, development unclarified or on hold, and development not viable) correlates with contingent resources and the rest correlates to either determined non-viable resources, or resources that are so early in the maturity chain that they are classified as prospective (e.g. seismic mapping of prospects and leads prior to drilling etc.). The key distinction between prospective resources vs. reserves and contingent resources are around the definitions of ‘discovered’ and ‘known’ reservoirs.

Level 2: DP, DNP, JD

The next level of granularity applies only to the reserves category, which are broken down into developed producing reserves, developed non-producing reserves and reserves justified for development. Producing reserves are those currently on production, and the distinction between non-producing reserves and undeveloped reserves are given in the Reference Terms Section of SPE PRMS 2011.

Level 3: Proven, Probable, Possible

Once a project has been assigned to one of the above categories then that project or activity will have a range of uncertainty of outcome associated with it, and this is reflected in the ‘proven’ (P1), ‘probable’ (P2) and ‘possible’ (P3) range, commonly, for example, with a statistical analysis, ‘proven’ (1P which equals P1) corresponds to the P90, ‘proven + probable’ (2P which equals P1+P2) corresponds to the P50 and ‘proven + probable + possible’ (3P which equals P1+P2+P3) corresponds to the P10 (in the USA P90 and P10 are reversed - P90 is high and P10 is low). Note, that any activity can be assigned a probability range or have its uncertainty of outcome reflected in a high, mid and low case.

Therefore, each of reserves, contingent resources and prospective resources can have a ‘proven’, ‘proven + probable’ and ‘proven + probable + possible’ breakdown associated with it, reflecting the uncertainty of outcome, and there is often a correlation as reserves are likely to be more certain and prospective resources more uncertain, which will be reflected in their probability distributions.

The understanding, which is commonly widespread in the industry is that reserves broadly equate to ‘proven’ volumes, contingent resources to ‘probable’ volumes and prospective to ‘possible’ volumes. This comes about if one defines the Proven, Probable and Possible as highest level distinction in the hierarchy; however, as mentioned above, PRMS does not define the classifications this way and instead sees resource category as a higher level distinction than uncertainty range (proven, probable, possible) and has the latter nested within the former.

The following table (Table A.10.1) has paragraphs that are quoted from the 2007 SPE PRMS Guidance Notes and summarise the key resources categories, while Figure A.10.1 shows the recommended resources classification framework, and Figure A.10.2 shows the classification based on project maturity.

Class / Sub-class	Definition
Reserves	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.
On Production	The development project is currently producing and selling petroleum to market.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.
Contingent Resources	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.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.
Development Unclarified or on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

Table A.10.1: Summary of 2007 SPE Petroleum Resources Classification

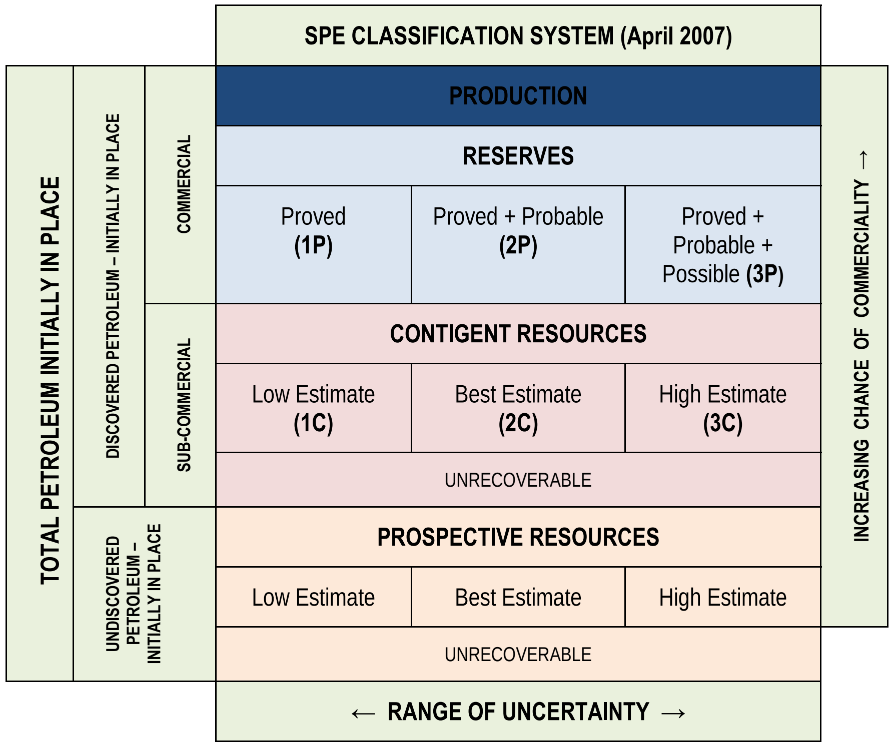

Figure A.10.1: SPE PRMS 2007 Petroleum Resources Classification Framework

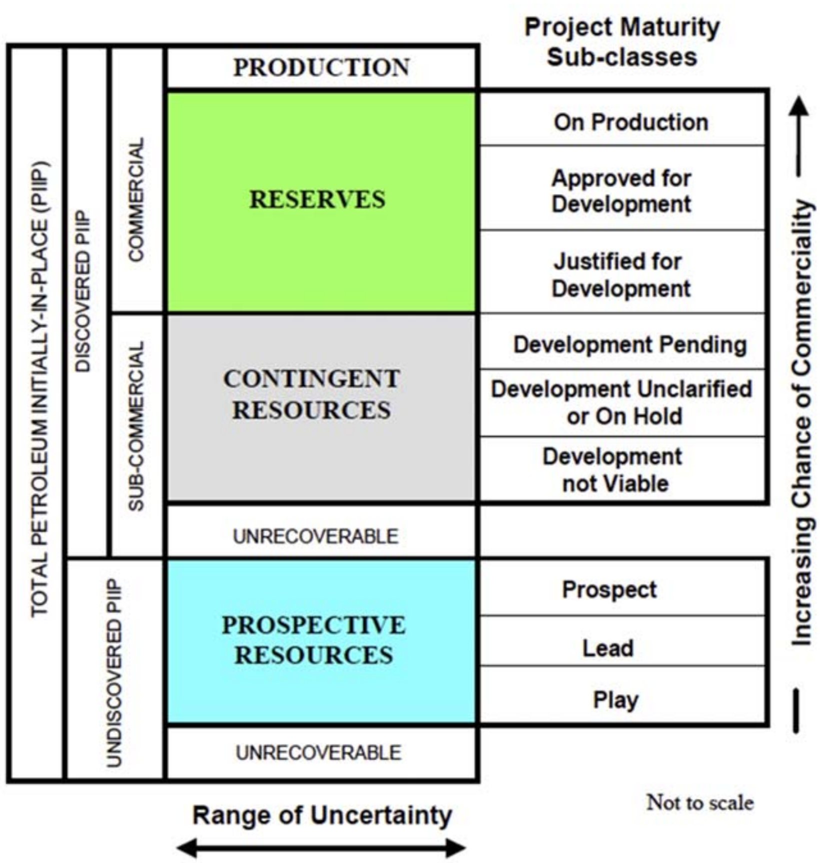

Figure A.10.2: Resource Classification Framework based on project maturity from SPE PRMS 2011

Appendix B - Reserves and Resources Summary Tables

The tables below have been compiled in a manner consistent with that prescribed by the London Stock Exchange June 2009.

Oil & Gas – Reserves

The Reserves attributable to Aje, OML 113, comprise the remaining production from the Aje-4 well (Cenomanian), the Aje-5ST2 well completed in the Turonian oil rim, and the forecast volumes from the development of the Turonian gas-condensate accumulation (with LPG separation).

Oil & Liquids: MMbbls Gas: Bscf	Gross			Net Attributable to MX OIL			Operator
DISCOVERY	**1P Proved**	**2P Proved & Probable**	**3P Proved, Probable & Possible**	**1P Proved**	**2P Proved & Probable**	**3P Proved, Probable & Possible**	
NIGERIA:							
OML 113 Aje OIL							
DP (Cen. 2019-2021)	0.82	0.89	0.94	0.04	0.04	0.05	YFP
DP (Tur. 2019-2021)	1.23	1.36	1.49	0.06	0.07	0.07	YFP
Sub-total DP (2019-2021)	**2.05**	**2.25**	**2.43**	**0.10**	**0.11**	**0.12**	YFP
JD (Cen. 2022 onwards)	0.32	0.69	1.16	0.02	0.04	0.07	YFP
JD (Tur. 2022 onwards)	0.79	1.79	3.01	0.05	0.12	0.18	YFP
Sub-total JD (2022 onwards)	**1.11**	**2.48**	**4.17**	**0.07**	**0.16**	**0.25**	YFP
OML 113 Aje CONDENSATE							
JD (2022 onwards)	10.32	17.41	27.87	0.65	1.12	1.66	YFP
OML 113 Aje LPG							
JD (2022 onwards)	20.11	33.86	54.39	1.29	2.20	3.14	YFP
TOTAL LIQUIDS (MMbbls)							
DP OIL (2019-2021)	2.05	2.25	2.43	0.10	0.11	0.12	YFP
JD (2022 onwards, OIL + COND + LPG)	31.54	53.75	86.43	2.01	3.48	5.05	YFP
SUB-TOTAL LIQUIDS#	**33.6**	**56.0**	**88.9**	**2.1**	**3.6**	**5.2**	YFP
OML 113 Aje DRY GAS (Bscf)							
Gas Cap Gas	261.6	442.0	704.9	16.8	28.8	40.7	YFP
Solution Gas	31.1	50.9	87.0	2.0	3.3	5.0	YFP
Sub-total Gas JD (2022 onwards)	**292.7**	**492.8**	**791.9**	**18.8**	**32.1**	**45.7**	YFP
TOTAL#, MMboe	**82.4**	**138.2**	**220.8**	**5.2**	**8.9**	**12.8**	YFP

Source: AGR TRACS review Q1/2019

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

"Gross" are 100% of the reserves attributable to the licence whilst "Net Attributable" are those attributable to the AIM company. Reserves calculated under US$60/bbl.

"MMbbls" – million barrels

"Bscf" – billion standard cubic feet, 6,000 scf/boe, "boe" barrel of oil equivalent

"Total…#" – implies totals have been derived by arithmetic summation without any probabilistic addition.

Oil & Gas – Contingent Resources in Aje, OML 113

The Contingent Resources comprise the indicative volumes anticipated from the possible Aje-6 well in the NE lobe of the Cenomanian structure, plus the volumes estimated from a possible development of the Turonian oil rim with four notional horizontal producers.

Oil & Liquids: MMbbls Gas: Bscf	Gross Unrisked Technical Contingent Resources			Net Unrisked Technical Contingent Resources Attributable to MX OIL			Risk Factor	Operator
DISCOVERY	**1C Low Estimate**	**2C Best Estimate**	**3C High Estimate**	**1C Low Estimate**	**2C Best Estimate**	**3C High Estimate**	**COCS (%)**	
Oil & Liquids Contingent Resources per asset								
NIGERIA:								
OML 113 Aje OIL - Cen. Aje-6 near-horizontal well	0.00	3.00	5.50	0.00	0.15	0.28	50%	YFP
OML 113 Aje Turonian OIL rim with 4 notional producers	4.00	6.00	12.00	0.20	0.30	0.60	40%	YFP
Unrisked Totals for Oil and Liquids #, MMbbls	**4.00**	**9.00**	**17.50**	**0.20**	**0.45**	**0.88**		

Source: AGR TRACS review Q1/2019

Note: "Risk Factor" for Contingent Resources means the chance, or probability, that the hydrocarbons will be commercially extracted.

Contingent Resources quoted above are estimates of technically recoverable volumes, pending completion of the relevant development and drilling plans.

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

"Gross" are 100% of the resources attributable to the licence whilst "Net Attributable" are those attributable to the AIM company. Contingent Resources calculated under US$80/bbl.

"MMbbls" – million barrels

"Bscf" – billion standard cubic feet, 6,000 scf/boe, "boe" barrel of oil equivalent.

"Total…#" – implies totals have been derived by arithmetic summation without any probabilistic addition.

"COCS" – the Chance Of Commercial Success (COCS) ratings are explained in Section 7.3.

Oil & Gas – Prospective Resources – see separate 2016 report.

AGR TRACS carried out a separate review for MX OIL of the exploration potential in OML 113 in the autumn of 2016. The resulting report is available upon request from MX OIL, hence the results are not included in this CPR.

Oil & Liquids: MMbbls Gas: Bscf	Gross			Net Attributable to MX OIL			Risk Factor	Operator
PROSPECT	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	POS (%)	
NIGERIA:								

Source: Not reviewed for this CPR.

Note: "Risk Factor" for Prospective Resources means the chance, or probability, of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. This, then, is the chance or probability of the Prospective Resources maturing into a Contingent Resource. Where a prospect could contain either oil or gas the hydrocarbon type with the higher probability of being discovered has been listed in the table.

"MMbbls" – million barrels

"Bscf" – billion standard cubic feet, 6,000 scf/boe, "boe" barrel of oil equivalent

"Total…#" – implies totals have been derived by arithmetic summation without any probabilistic addition.

Overview of Risked Technical Contingent Resources Net to MX OIL:

Oil & Liquids: MMbbls Gas: Bscf	Net Unrisked Technical Contingent Resources Attributable to MX OIL			Risk Factor	Risked Technical Contingent Resources Net Attributable to MX OIL		
DISCOVERY	**1C Low Estimate**	**2C Best Estimate**	**3C High Estimate**	**COCS (%)**	**1C Low Estimate**	**2C Best Estimate**	**3C High Estimate**
Oil & Liquids Contingent Resources per asset							
NIGERIA:							
OML 113 Aje OIL - Cen. Aje-6 near-horizontal well	0.00	0.15	0.28	50%	0.00	0.08	0.14
OML 113 Aje Turonian OIL rim with 4 notional producers	0.20	0.30	0.60	40%	0.08	0.12	0.24
Totals for Oil and Liquids #, MMbbls	**0.20**	**0.45**	**0.88**		**0.08**	**0.20**	**0.38**

Source: AGR TRACS review Q1/2018

Note: “Risk Factor” for Contingent Resources means the chance, or probability, that the hydrocarbons will be commercially extracted.

Contingent Resources quoted above are estimates of technically recoverable volumes, pending completion of the relevant development and drilling plans.

“MMbbls” – million barrels, “Bscf” – billion standard cubic feet, 6,000 scf/boe, “boe” barrel of oil equivalent.

“Total…#” – implies totals have been derived by arithmetic summation without any probabilistic addition.

“COCS” – the Chance Of Commercial Success (COCS) ratings are explained in Section 7.3.

Overview of Risked Prospective Resources Net to MX OIL:

Oil & Liquids: MMbbls Gas: Bscf	Unrisked Prospective Resources Net Attributable to MX OIL			Risk Factor	Risked Prospective Resources Net Attributable to MX OIL		
PROSPECT	Low Estimate	Best Estimate	High Estimate	POS (%)	Low Estimate	Best Estimate	High Estimate

Source: Not reviewed for this CPR.

Note: "Risk Factor" for Prospective Resources means the chance, or probability, of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. This, then, is the chance or probability of the Prospective Resources maturing into a Contingent Resource. Where a prospect could contain either oil or gas the hydrocarbon type with the higher probability of being discovered has been listed in the table.

"MMbbls" – million barrels

"Bscf" – billion standard cubic feet, 6,000 scf/boe, "boe" barrel of oil equivalent

"Total…#" – implies totals have been derived by arithmetic summation without any probabilistic addition.