decisions with confidence

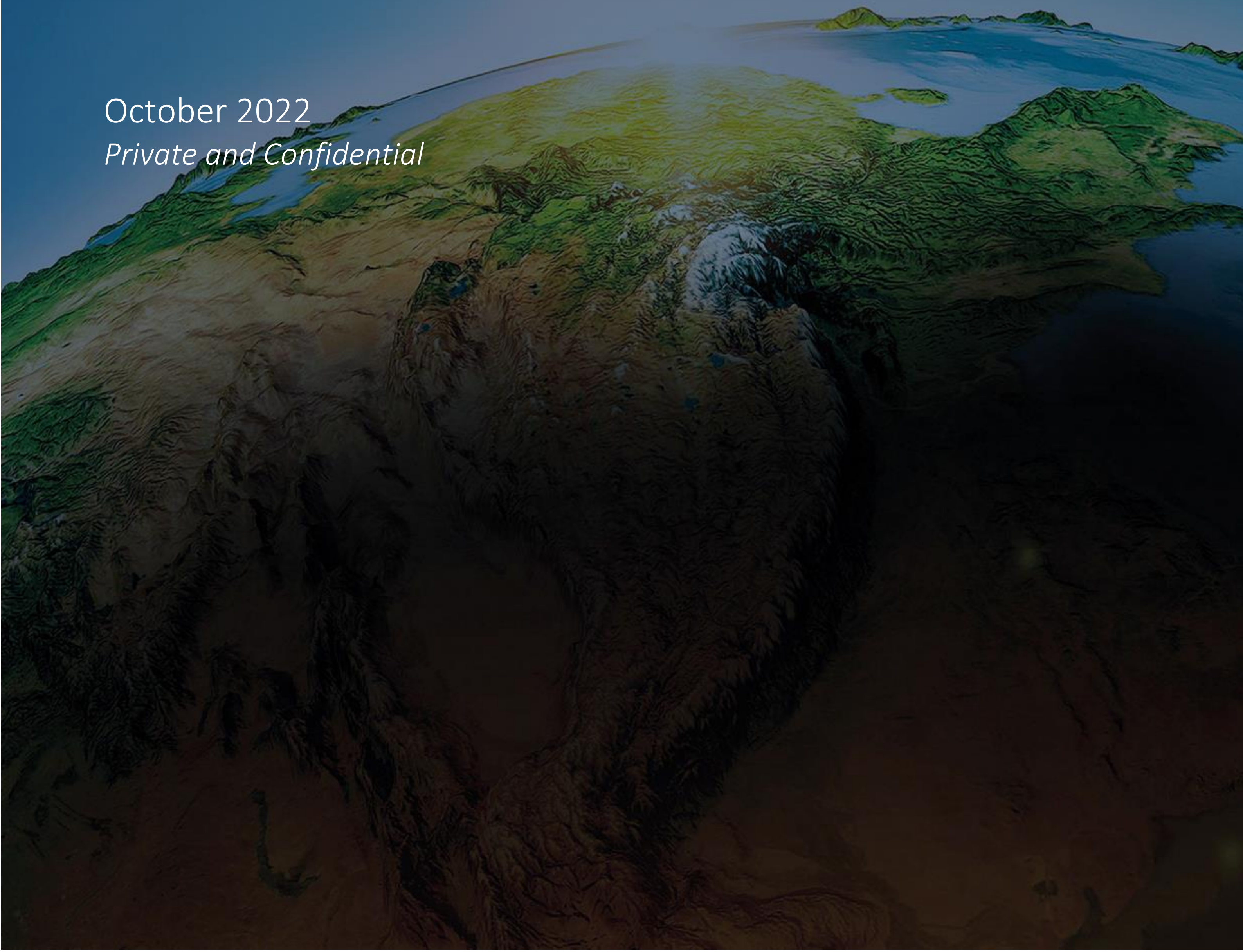
Independent Technical Specialist Report

On certain assets of Jupiter Energy Ltd

For BDO Corporate Finance (WA) Pty Ltd
on behalf of Jupiter Energy Ltd

October 2022

Private and Confidential



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24 October 2022

Dear Sirs,

Independent Technical Specialist Report – Jupiter Energy Ltd.

Jupiter Energy Ltd ('Jupiter') has engaged BDO Corporate Finance (WA) Pty Ltd ('BDO') to prepare an Independent Expert Report ('IER') for inclusion within a Notice of Meeting to be provided to the shareholders of the company regarding a proposed transaction.

The shareholders are being asked to approve a debt restructure in respect to promissory note holders and the issue of new shares in the Company. As per the instruction letter received from BDO dated 6 October 2022, RISC Advisory Pty Ltd ('RISC') was to provide an independent opinion on the reserves and resources of the assets of Jupiter including production and operating costs and other technical assumptions relevant to the assets.

RISC has completed our independent technical assessment and valuation and our work is documented in this Independent Technical Specialist Report ('ITSR').

Independence

RISC confirms that it is independent of Jupiter and that RISC is unaware of any circumstance which may compromise that independence.

Consent

RISC has consented to this report, in the form and context in which it appears, being included, in its entirety, in the Notice of Meeting.

1. Executive summary

BDO Corporate Finance (WA) Pty Ltd ('BDO') has been engaged by Jupiter Energy Ltd. ('Jupiter') to prepare an Independent Experts Report ('IER') for inclusion in a Notice of Meeting seeking shareholder approval for a proposed debt restructure transaction. RISC was requested to prepare an independent opinion report on the technical project assumptions of Jupiter's assets and to provide an opinion on the reasonableness of the assumptions and inputs to the cash flow model to be used to value the assets. Our report is to be included in BDO's IER.

Jupiter holds a 100% working interest in in Block 36 onshore Kazakhstan (also known as Block 31). Block 31 is located in the Mangistau Basin, also referred to as the Middle Caspian Basin and South Mangyshlak Basin, on the eastern shore of the Caspian Sea.

Since acquisition of Block 31 in 2007, Jupiter has acquired 3D seismic, drilled a number of wells and established oil production from the Akkar North (East Block), Akkar East and West Zhetybai oil fields. Five wells have produced 1.54 MMBbl from 2010 to date with a peak production rate of approximately 1,200 bopd.

Production has been constrained at about 240 bopd since September 2021 due to regulatory gas flaring constraints. Jupiter are undertaking a gas utilisation project which should enable unconstrained production from 2Q 2023.

Jupiter have advised work program commitments of 24 new wells in Block 31, amounting to 20 production wells and 4 water injection wells, and the intention to drill 4-wells per year over the period 2024-29.

RISC was specifically instructed to provide an opinion on technical inputs to a cash flow model:

- Recoverable quantities incorporated into the model
- Oil and gas production
- Capital expenditure, production and operating costs
- Any other relevant technical assumptions

RISC has seen few details of the 24 new wells which provide 80% of the forecast future production. Independent reserves and resource reports compiled in 2011 and 2013 included reserves ascribed to additional wells, a significant portion of which have not been drilled or failed to produce.

RISC has reviewed the Block 31 production history and has generated production forecasts which include uncertainty regarding the performance of new wells, the proportion that are productive, and the proportion of incremental oil rather than acceleration of oil developed by existing wells.

In summary RISC was unable to support the production forecasts and hence recoverable quantities as included in the cash flow model. In the mid case we estimate 8.6 MMstb will be recovered from 1/10/2022 to licence expiry in 2044 with a low – high range of 4 - 14 MMstb.

We note that this represents a relatively low recovery factor based on oil in-place estimates by third parties. If the oil in-place estimates are correct there appears to be scope for drilling additional wells and hence increasing the quantity of oil recovered by the end of the licence in 2044.

In general, we found the cost forecasts in the model to be reasonable, we have made some minor adjustments. Total capital costs are forecast to be US$145 million with operating costs of US$135 million, averaging approximately US$6 million pa.

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2. Introduction

2.1. Asset description

Jupiter Energy Ltd ('Jupiter') through its wholly owned and Singapore registered subsidiary Jupiter Energy Pte Ltd, holds a 100% participating interest in Block 36 onshore Kazakhstan. Block 36 is the legal reference to the petroleum property title and which Jupiter refers to as "Block 31" in reference to the property's original tender designation. In our report we shall refer to 'Block 36' as 'Block 31' and consider the terms interchangeable.

Block 31 is located onshore Kazakhstan in the Mangistau Basin, also referred to as the Middle Caspian Basin and South Mangyshlak Basin. The license is located east of the city of Aktau on the eastern shore of the Caspian Sea (Figure 2-1). Block 31 was originally awarded to Zher-Munai LLP in 2006 and was subsequently acquired by Jupiter in 2007.

Since acquisition, Jupiter has acquired 3D seismic over the license, drilled a number of wells and established oil production from the Akkar North (East Block), Akkar East and West Zhetybai oil fields. Contracts 2275 and 4803 between the regulator (Ministry of Energy of the Republic of Kazakhstan) and Jupiter govern petroleum activities within the license. A summary of Block 31 is shown in Table 2-1.

Table 2-1: Jupiter asset summary as at October 2022

Asset		Operator	Working Interest	Status	Licence expiry date	Licence area (km^2)
Country	Block					
Kazakhstan	Block 36, or "Block 31"	Jupiter Energy Pte Ltd	100%	Producing	Refer notes	140.65

Notes to the table:

1. Block 36 was originally awarded in 2006 with an initial exploration period of 6-years and production period of 25-years. The exploration period has been extended a number of times to 2 March 2023 for Akkar North (East Block) and 1 September 2023 for West Zhetybai to accommodate the 'preparatory period' oil production for both fields.
2. Akkar East production contract for a period of 25-years is yet to be ratified and is currently producing in the preparatory period which ends 2 March 2023.

The Block 31 contract is not a Production Sharing Contract and therefore attracts taxes and royalties according to the Republic of Kazakhstan tax regime.

2.2. Terms of reference

BDO Corporate Finance (WA) Pty Ltd ('BDO') has been engaged by Jupiter to prepare an Independent Experts Report ('IER') for inclusion in a Notice of Meeting seeking shareholder approval for a proposed debt restructure transaction.

RISC has been engaged by Jupiter but acts under instruction from BDO in this matter. RISC was requested to prepare an independent opinion on the technical project assumptions of Jupiter's assets and to provide an opinion on the reasonableness of the assumptions and inputs to the cash flow model to be used to value the assets.

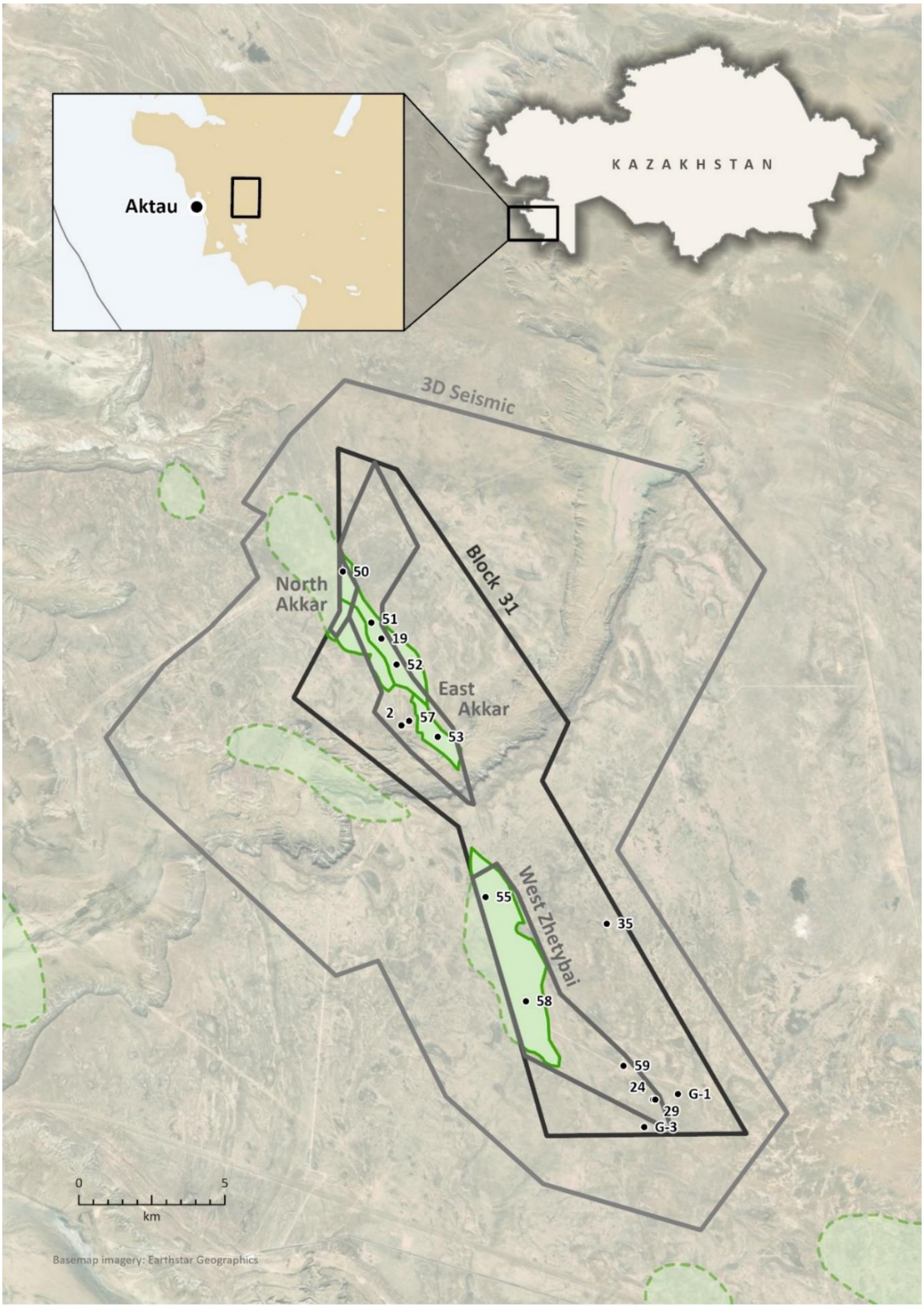


Figure 2-1: Location map, Block 31, Kazakhstan

RISC was specifically instructed to provide an opinion on:

- Resources and resources incorporated into the cash flow model
- Oil and gas production
- Capital expenditure, production and operating costs, and
- Any other relevant technical assumptions.

As per the instruction from BDO, our ITSR is compliant with the Australian Securities and Investments Commission ('ASIC') Regulatory Guides 111 and 112 and includes consent for the report to be included in a Notice of Meeting and for RISC to be named as technical specialist/expert in accordance with ASX listing rule 5.41.

2.3. Basis of assessment

The data and information used in the preparation of this report were provided by Jupiter and supplemented by public domain information. RISC has reviewed the information provided and has undertaken the evaluation on the basis of a review and audit of existing interpretations and assessments as supplied, making adjustments that in our judgment were necessary.

Our assessment for the assets is based on data to 1 October 2022 and this is the reference date of this report. Unless otherwise stated, all resources presented in this report are gross (100%) quantities with an effective date of 1 October 2022. All costs are in US$ real terms with a reference date of 1 October 2022 (RT2022).

RISC has reviewed the reserves and resources in accordance with the Society of Petroleum Engineers internationally recognised Petroleum Resources Management System ('PRMS'), 2018[1].

RISC's methodology was to review the technical information provided by Jupiter including but not limited to production data, capital and operating expenditures and the following documents which RISC consider as relevant:

- Competent Persons Reports ('CPR's) prepared by Senergy in 2011 and McDaniel & Associates in 2013
- A draft report prepared by Senergy in April 2014 reviewing the factors affecting the hydrocarbons in place and ultimate recovery on Block 31
- Various reserves reports (in Russian) prepared by the Reservoir Evaluation Services ('RES') for Akkar North East Block (2020), Akkar East (2019) and West Zhetybai (2021)

We have not conducted a site visit of the project area or exploration rights and do not consider one necessary as the asset value relates to potential future production, comparable transactions and metrics that cannot be verified by a site visit.

[1] Petroleum Resources Management System, prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the American Association of Petroleum Geologists (AAPG), World Petroleum Council (WPC), Society of Petroleum Evaluation Engineers (SPEE), Society of Exploration Geophysicists (SEG) and approved by the Board of the SPE in March 2007. The PRMS was subsequently updated in June 2018.

3. Regional information

Kazakhstan is a significant oil and gas producing country, with proven oil reserves of 30 billion barrels and proven natural gas reserves of 79.7 TCF[2]. Production primarily comes from the Tengiz, Karachaganak and Kashagan fields.

3.1. Regional geology

Block 31 is located onshore Kazakhstan in the Mangistau Basin, also referred to as the Middle Caspian Basin and specifically the South Mangyshlak Basin, east of the city of Aktau on the eastern shore of the Caspian Sea (Figure 2-1, Figure 3-1).

The Middle Caspian Basin occupies the eastern Northern Caucasus region, the central portion of the Caspian Sea and a series of depressions east of the Caspian Sea. One of these depressions is the South Mangyshlak Basin which is bound to the north-east by the Mangyshlak fold belt. The Zhetybai Step is a structural terrace to the south of the Mangyshlak fold belt and it is on this terrace that Block 31 is located.

Proved hydrocarbon reserves of the South Mangyshlak Basin exceed 6 billion BOE, most of which (84 percent) is oil. Most hydrocarbons are in Middle Jurassic clastic reservoirs on the Zhetybai step (structural terrace) south of the Mangyshlak fold belt.[3]

3.1.1. Reservoirs

The dominant petroleum reserves in the region are in sandstone reservoirs of Jurassic age with minor reserves in carbonates and sandstones of Triassic aged reservoirs. Minor accumulations are recognised in Cretaceous sandstones and fractured basement granites.

The reservoirs of Block 31 are Middle Triassic aged dolomitic limestones which unconformably overly lower Triassic marine deposits. The thickness of the Middle Triassic is reported to range between 85 to 315 m. The best reservoir quality is noted in ‘Bed B’ of local definition which is 30 - 180 thick consisting of alternating volcanic tuff and leached oolitic dolomites. Porosities exceeding 20% and permeability of 200 – 300 mD is observed.[3]

The overlying Upper Triassic is composed of non-reservoir bearing clastic sediments. The Triassic is in turn unconformably overlain by Middle Jurassic sediments with a prominent angular unconformity.

3.1.2. Source rocks

Source rocks whilst not fully characterised, are thought to be present in the Lower to Middle Triassic marine shales which is reported to be about 750 m thick on the Zhetybai Step. Total organic carbon is reported to reach 9.8% and organic matter is dominated by oil prone type II kerogens.

[2] BP Statistical Review of World Energy, 2021.

[3] Petroleum Geology and Resources of the Middle Caspian Basin, Former Soviet Union, USGS Bulletin 2201-A (2001).

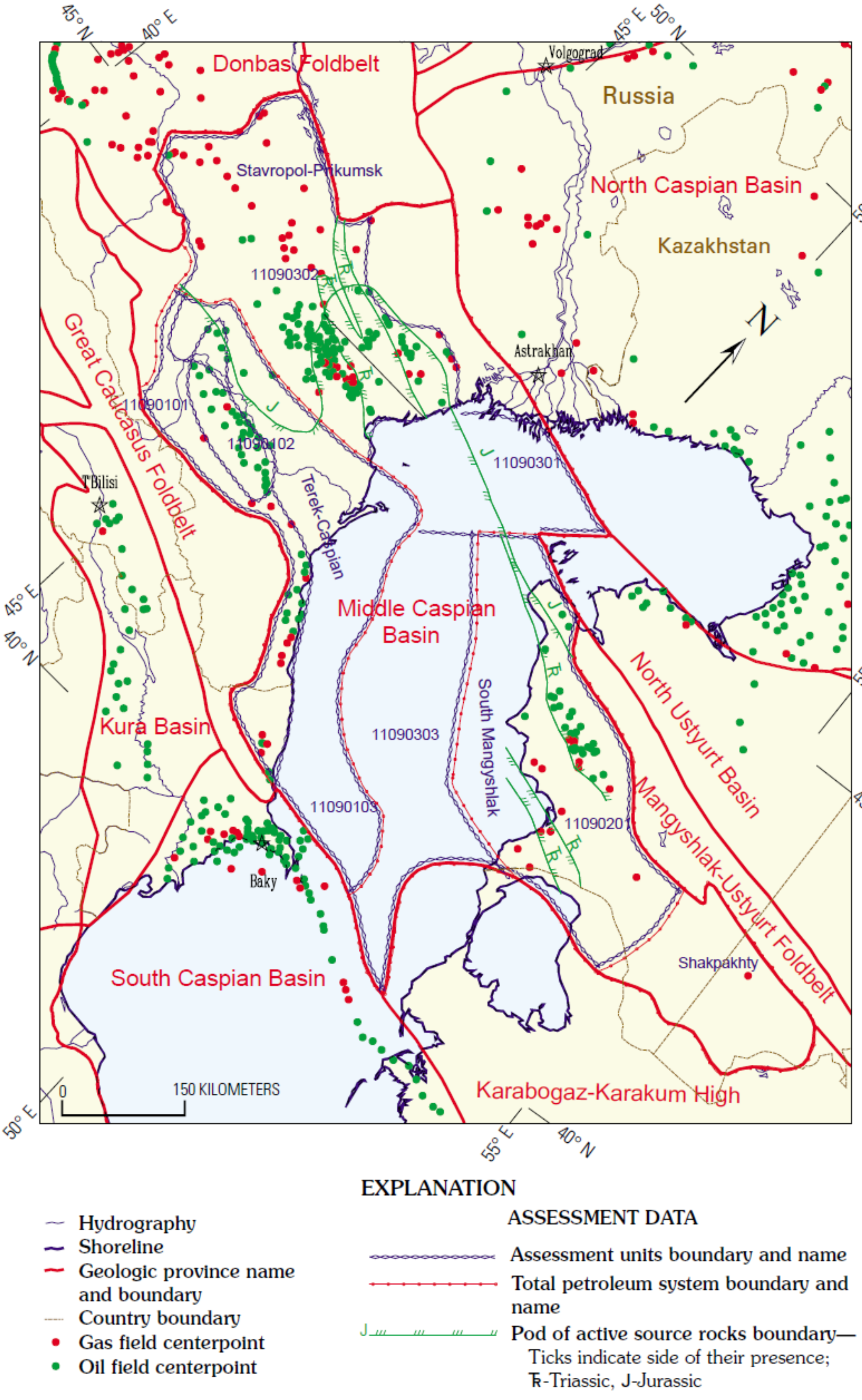


Figure 3-1: Middle Caspian Basin location map (USGS)

3.1.3. Traps

Hydrocarbon traps in the South Mangistau Basin and Zhetybai Step in particular are typically elongate anticlinal structures orientated in a north-west to south-east orientation and parallel to the Mangyshlak fold belt (Figure 3-2).

The structure are compressive is nature and wrenching is noted. Although principal thrusting of Triassic rocks took place in pre-Jurassic time, some trap modification through compression and movement along thrust planes continued during late Mesozoic and Tertiary time.[3]

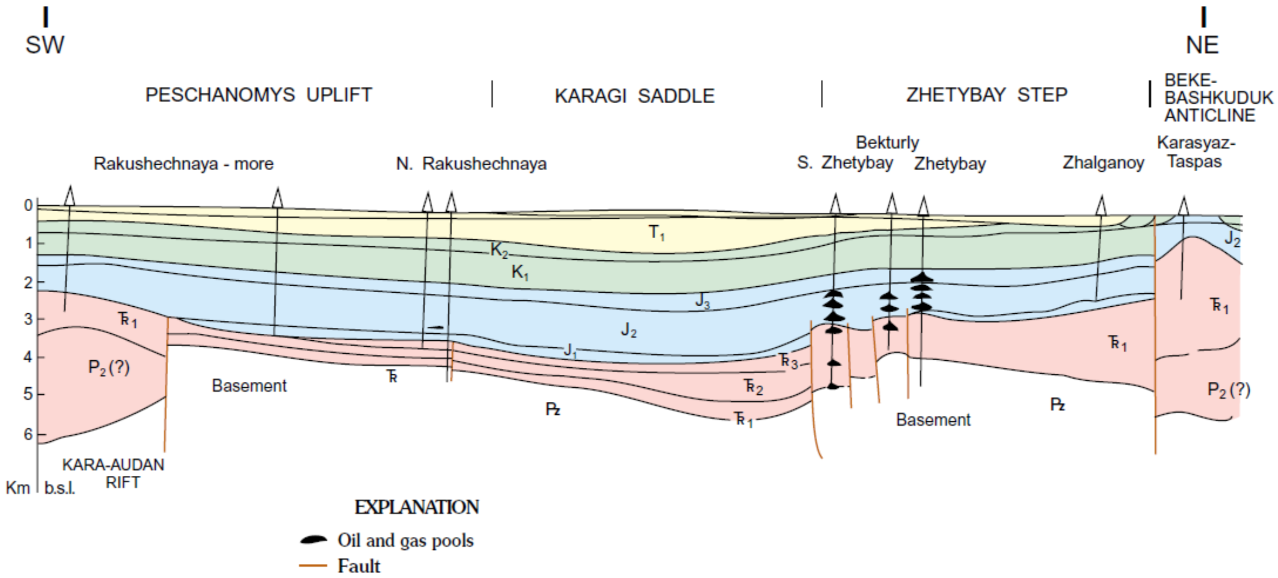


Figure 3-2: Cross section through South Mangistau Basin (USGS)

4. Block 31 asset

Block 31 is located onshore Kazakhstan in the Mangistau Basin, to the east of the city of Aktau on the eastern shores of the Caspian Sea. Jupiter acquired its interests in Block 31 from Zher-Munai LLP in December 2007. Zher-Munai LLP was originally awarded the exploration rights to Block 31 on 29 December 2006.

Key terms of the Block 31 license are shown in Table 4-1.

Table 4-1: Summary of key terms, Block 31

Initial term	6-years for exploration (Note: extensions amounting to 7-years have been granted). 25-years for production period
Commencement date	Contract 2275 (Block 31) 29 December 2006 Contract 4803 (Akkar East field) 2 March 2020
Signature bonus	US$3 million (paid 2008)
Training, Administration & Local Development fees	As prescribed in the contracts (approx. US$50,000 p.a.)
Bonus Fees	Nil
Taxes	Republic of Kazakhstan taxes including corporate income tax, mineral extraction tax ('MET') between 5% - 18% for oil and 10% for gas, excess profit tax and rent tax for exports are also applicable.[4]
Minimum work program commitments	As prescribed in the contracts

Notes to the table:

1. Akkar East is in the preparatory period of the production period until 2 March 2023. Production period is until 2 March 2045.
2. Akkar North (Eastern Block) is in the preparatory period of the production period until 2 March 2023. Production period is until 5 March 2046.
3. West Zhetybai is in the preparatory period of the production period until 1 September 2024.
4. Training, Administration & Local Development fees are considered in line with accepted international petroleum contract provisions.

4.1. Tenure

RISC has been provided a draft legal opinion from Signum law firm of Almaty, Kazakhstan. This document addresses the subsurface use rights and contractual obligations of Jupiter is respect to Block 31. This indicates that Jupiter has right to tenure and that the licenses and contracts in relation to Block 31 petroleum

[4] Source: EY Kazakhstan oil and gas tax guide 2022 (https://assets.ey.com/content/dam/ey-sites/ey-com/en_kz/topics/oil-and-gas/ey-kazakhstan-oil-and-gas-tax-guide-2022.pdf)

related activities are in good standing. RISC was not asked to give an opinion on this and we have assumed that Jupiter has right of tenure based on this draft legal opinion.

In summary:

- Block 31 (or Block 36 in is legal standing) contract (#2275) was awarded on 29 December 2006 to Zher-Munai LLP for an initial exploration period of six years.
- Jupiter acquired Block 31 from Zher-Munai LLP in 2007, with registrations completed with the regulator (Ministry of Energy of the Republic of Kazakhstan) 20 June 2008.
- Various addendums to the contract have been entered into altering the work program and extending the exploration period.
- Production from the Akkar North (East Block), Akkar East and West Zhetybai fields has been during the exploration period ('trial production period') during which associated gas was flared and produced oil is sold domestically.
- The Block 31 contract has been extended to 2 March 2023 for the Akkar North (East Block) and 1 September 2024 for the West Zhetybai fields. It is expected that Commercial Production and the Preparatory Period shall commence at this time.
- Akkar East field has transitioned to commercial production with a new contract (#4803) entered into on 2 March 2020 with a Preparatory Period of three years till 2 March 2023. During the Preparatory Period flaring of associated gas is not permitted. A new contract was required as Akkar East trial production exceeded 3-years.

RISC has not been provided title documents or contracts or their English translations to review in the preparation of this report.

4.2. Exploration and permit history

Exploration activity in the area of Block 31 was undertaken by the Soviets with the acquisition of 2D seismic and the drilling of a number of exploration wells in the 1960's – 1970's, including drilling the North West Zhetybai-2 ('NWZ-2') well within Block 31. The North Akkar field to the north of Block 31 was discovered in 1988 and placed on production. The Zhetybai field to the south-east of Block 31 was discovered in 1961 and placed on production.

Post award, there was no exploration activity in Block 31 prior to Jupiter acquiring the block. Jupiter acquired 3D seismic in late 2008 over the north-west of Block 31, acquiring 195 km^2 of onshore 3D data. Jupiter re-entered and recompleted the NWZ-2 well which was originally drilled in 1969. The workover was successful with testing indicating rates of 400-500 bopd from a Jurassic reservoir.

Jupiter commenced drilling the SV Akkar well (J-50) in December 2009 which intersected 55 m of net oil pay in Middle Triassic dolomitic reservoir. In early 2010 Jupiter announced the results of an independent reserves and resources review of Block 31 by Senergy. Reserves associated with an on-block extension of the Akkar North oil field were recognised where J-50 was drilled. This area is known as Akkar North (East Block). Oil production from J-50 commenced in May 2010.

The J-52 and J-51 wells were drilled in 2011 in addition to additional 3D acquisition over an extended area of Block 31. The J-53 well commenced drilling in November 2011 and reached total depth in January 2012 intersecting 56 m of net oil pay. J-55 and J-58 were drilled in late 2012 on a separate structure and discovered oil in separate pools of the West Zhetybai field in Triassic aged reservoir. The J-59 well commenced drilling in late December 2012 and reached total depth in March 2013. The J-19 well commenced drilling in December 2014 and reached total depth in February 2015, intersecting 85 m of net oil pay.

The J-57 well was drilled in 2018 and intersected water wet Triassic reservoir within a separate fault compartment in the Akkar East field and remains the most recent well drilled. Failure of J-57 is attributed to a sealing fault separating the fault compartment drilled by J-57 and the adjacent oil-bearing fault compartments; NWZ-2 to the north-west, and J-53 to the south-east.

No further drilling or seismic acquisition has occurred since 2018.

4.3. Work program and commitments

Jupiter have provided the following guidance with respect to work program commitments in Block 31:

- Akkar East field, wells 17 to 35 (16 in total) over the period 1 April 2024 to 1 April 2029. Four of these wells are to be injector wells.
- Akkar North (East Block), wells 70 and 71, 1 July 2023 to 1 July 2024
- West Zhetybai field, wells 63 to 68 (6 in total) over the period 1 April 2025 to 1 April 2030.

In total 24 new wells, 20 as production wells and 4 for water injection.

4.4. Reserves and resources reports

Jupiter commissioned Synergy to prepare a reserves and resources report in 2010 and which was subsequently updated in May 2011.

As part of the Trial Production Period approvals process for the discovered oil pools, Jupiter was required by the regulator to complete preliminary and final reserves reports which are required to be compiled by an approved and independent Kazakh institute and submitted to the regulatory authorities for approval. These reserves reports have been compiled by Reservoir Evaluation Services ('RES') of Almaty, Kazakhstan. The reports are compiled in accordance with the Russian Federation Classification ('RF 2013') scheme of oil and combustible gases which became effective in 2016. This classification scheme differs significantly from the internationally recognised PRMS.

RISC has been provided copies of the RES reserves and resources reports for Akkar North (East Block) dated 2010, 2019, 2020; Akkar East dated 2019, 2020 and West Zhetybai dated 2013, 2020 and 2021. These reports are compiled in Russian and RISC has not received an English translation.

McDaniel & Associates ('McDaniel') was engaged in December 2012 to undertake a reserves and resources audit. Their report dated October 2013 is compiled in accordance with the PRMS. It must be noted that this report was compiled prior to the drilling of the J-19 and J-57 wells on the Akkar East field.

4.5. Data

Jupiter has acquired 3D seismic over Block 31 which it has used to delineate drilling. Jupiter has also acquired wireline logs in the wells it has drilled in the contract area. RISC has not been provided the raw or interpreted seismic or well data to review in the preparation of this report. We have relied upon representations made in the Synergy and McDaniel reports and various figures and PowerPoint extracts in the preparation of this report.

RISC has been provided daily oil, water and gas production data which has been used in our review.

4.6. Subsurface interpretation

4.6.1. Seismic interpretation

Jupiter has undertaken interpretation of the 3D seismic data which has been conducted by its technical consultants and associates. RISC has not been provided any Jupiter interpretations to review.

The 2013 McDaniel reserves and resources audit included a middle Triassic reservoir depth structure map which is shown in Figure 4-1. RES it is also assumed have undertaken independent interpretation of the 3D seismic data which it has used in its estimation of reserves and resources. The RES T2A (middle Triassic) reservoir depth structure map is shown in Figure 4-2.

RISC notes differences in the depth structure maps of Figure 4-1 and Figure 4-2, predominantly associated with fault interpretation and correlation. In particular, the RES structure map indicates that most interpreted faults do not form closed compartments. For instance, the J-57 well (water bearing) is not fault closed or isolated from the oil bearing NWZ-2 or J-53 wells.

Seismic data quality and uncertainty in the interpretations would explain the differences in the mapping.

4.6.2. Reservoir description

The primary reservoir in Block 31 are Middle Triassic aged dolomitic limestones with typically tight matrix porosity and permeability. Porosity and permeability is enhanced through secondary porosity development of vugs and fractures. The lowermost 30 to 40 m of this sequence displays the best reservoir quality.[5] Permeabilities from cores acquired in the wells is reported to be between 0.01 – 0.1 mD.[5]

Reservoir parameters from McDaniel and Synergy reports are shown in Table 4-2. RISC notes that no discrimination between matrix porosity (and water saturation) and that of vuggy or fracture porosity has been made. It is this secondary porosity development that is expected to dominate well production.

Table 4-2: Middle Triassic reservoir parameters

	McDaniel & Associates (2013)			Senergy (2011)
	East Akkar Field	East Akkar Field (J-53)	West Zhetybai	East Akkar Field
Net to Gross (ave)	48%	18%	53%	52.6%
Porosity (ave)	9.4%	8.7%	9.7%	13.1%
Water saturation (ave)	29.2%	35.7%	32.6%	31.8%

Notes to the table:

1. Matrix (primary) and secondary porosity and water saturation are not delineated separately.

Jupiter undertakes acid treatment when completing wells for production. This is an appropriate stimulation treatment for these reservoirs.

[5] McDaniel & associates Competent Persons Report, October 2013.

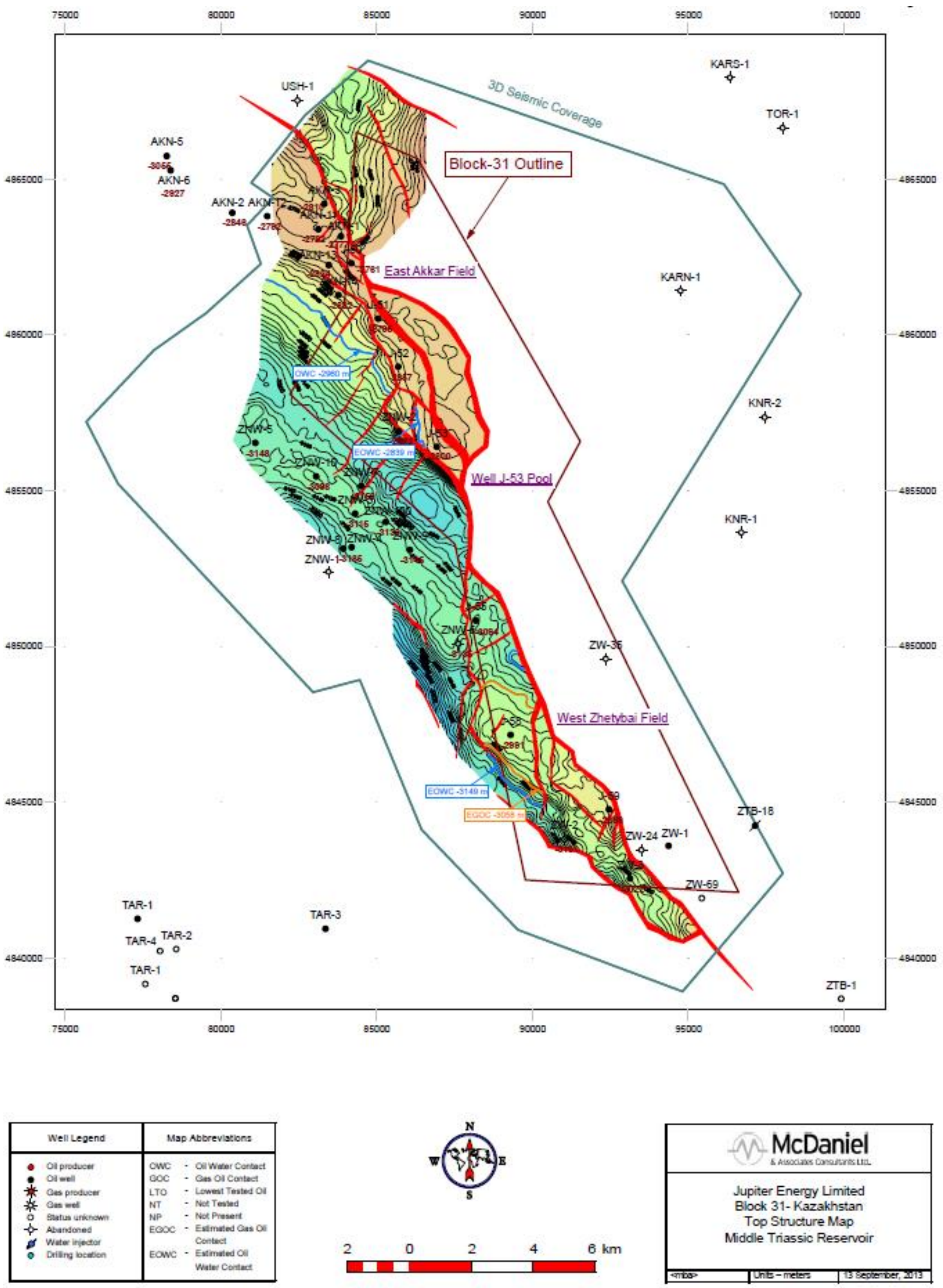


Figure 4-1: Middle Triassic reservoir depth structure map (McDaniel)

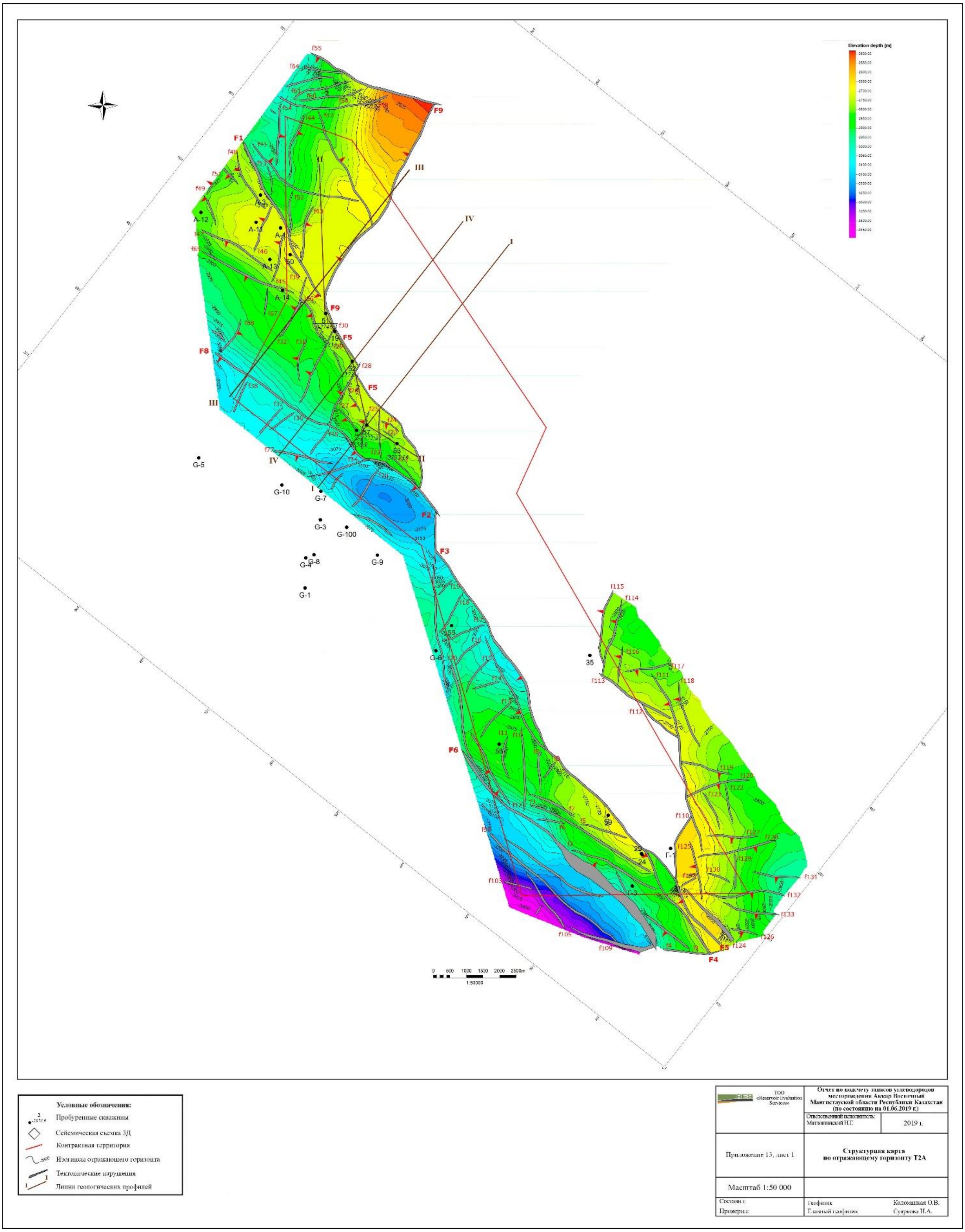


Figure 4-2: T2A reservoir, middle Triassic depth structure map (RES)

4.6.3. Fluid properties

Block 31 fields contain a light (40 API) oil with an in-situ viscosity of 0.9 cp, solution GOR of 600 to 800 scf/stb and bubble point pressure slightly below initial reservoir pressure, Table 4-3.

The surface GOR and oil density depends upon the oil processing. A single flash and differential liberation are the two extremes to processing. The average surface oil specific gravity is 0.80 or 7.82 stb/tonne.

Table 4-3: Oil PVT Properties

Property	Property value			
Well	J-19		J-51	
Sample	1.03		1.02	
Depth (m)	1,955		2,985	
Res Temp (deg C)	114.6		114.9	
Res Press (psia)	2,716		3,077	
Pb (psia)	2,580		2,696	
Bo	1.525		1.482	
Uo (cp, res conditions))	0.87		0.98	
Oil processing:	Single flash	Diff Lib	Single flash	Diff Lib
GOR (scf/stb)	787	740	598	598
Oil SG (surface)	0.825	0.779	0.832	0.780
stb/tonne	7.62	8.07	7.56	8.07

4.6.4. Fluid contacts

An oil water contact ('OWC') is not known in the Akkar North, Akkar East or West Zhetybai fields. McDaniel report an expected OWC of 2,960 mTVDSS for Akkar North and Akkar East, and 3,149 mTVDSS for West Zhetybai.

5. Field Development

5.1. Planned activities

Little information was available on the existing facilities and wells. We know 5-wells are on production and that 3 additional wells drilled as producers did not produce oil at commercial rates. The field has produced at rates of up to 1,200 bopd so we presume that at least this much production and process capacity exists in the field.

The short-term initiative is a gas utlisation plan to reduce or eliminate flaring. We are unaware of the details but presume that gas will be used for fuel and/or compressed and exported through a pipeline though no revenue from gas sales is anticipated. Jupiter have advised the gas utilisation plan is underway and will be operational by 2Q 2023. Our production forecasts reflect the assumption that oil production becomes unconstrained from 1/4/2023 when the gas utilisation project becomes operational.

After this, the focus turns to development drilling. Jupiter have advised they intend to drill 12-wells between 2023 and 2030. We have assumed 4-wells are drilled in each year 2024-29. Jupiter have provided the following guidance with respect to contract work program commitments in Block 31:

- Akkar East field, wells 17 to 35 (16 in total) over the period 1 April 2024 to 1 April 2029. Four of these wells are to be injector wells.
- Akkar North (East Block), wells 70 and 71, 1 July 2023 to 1 July 2024
- West Zhetybai field, wells 63 to 68 (6 in total) over the period 1 April 2025 to 1 April 2030.

In total 24 new wells, 20 as production wells and 4 for water injection.

5.2. Capital, operating and abandonment costs

Our approach to cost forecasting has been to review the capital and operating costs in an economic model provided by Jupiter, review it for reasonableness and make changes where necessary. In general, we consider the costs in the model were reasonable and have only made minor adjustments.

All costs are in US dollars, 2022 real terms.

5.2.1. Capital costs

Total capital costs are forecast to be US$145 million from 2023 to 2044 in the P50 case, summarised in Table 5-1 below. Costs for the high and low cases will differ slightly. Most of the costs are incurred by 2030, cost phasing is shown in Figure 5-1.

The major driver of capital costs is well costs. Jupiter have estimated costs of US$3 million per well going forward. Assuming the well design remains similar to existing wells we consider this reasonable on the basis that one of the existing production wells cost approximately US$2.5 million to drill and complete. We would expect some cost increases due to inflationary forces on materials and services.

Table 5-1: Capital cost assumptions

	Cost US$ million
G&G	6.5
Drill & Complete	72.0
Workover	15.3
Facilities	21.7
HSE	1.0
Other	0.2
Contingency	28.1
Total	**144.9**

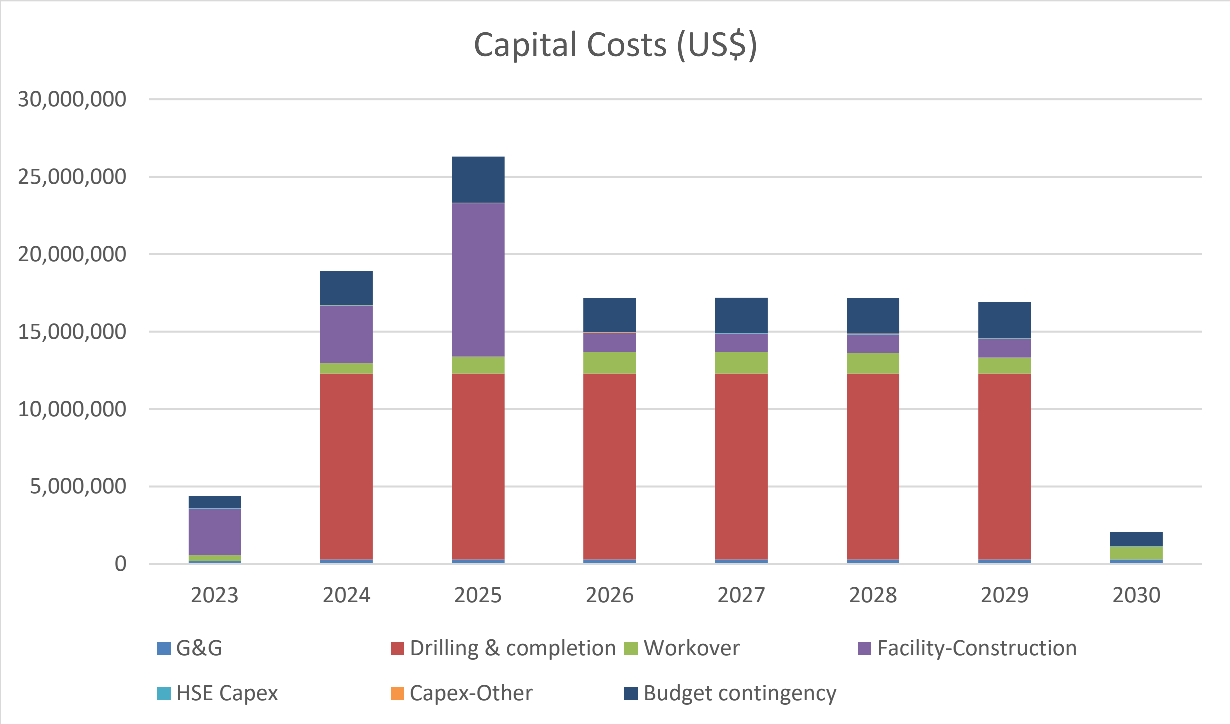


Figure 5-1: Capital cost phasing

The other major cost is for the gas utilisation project and facilities to gather and process the increased production from the new wells. Total facilities costs are forecast to be approximately US$22 million including procurement, construction and installation.

Additional capital costs are for geological and geophysical ('G&G'), health safety and environment ('HSE') and other costs are estimated on an annual basis. In reality it is unlikely the costs will be same every year but it is not possible to predict the timing of this expenditure. The annual averages seem reasonable.

In addition, workover costs of approximately US$15 million are forecast. These are estimated based on production referenced to US$360,000 for 2022 production. This results in costs of over US$1 million pa at high production rates reducing to approximately US$200,00 pa when production decreases.

5.2.2. Operating costs

Jupiter advise operating costs were approximately US$2 million in 2021 and are forecast to be similar this year. Going forward costs are expected to increase as more wells come online and production increases. We would expect a slight reduction in costs as production declines. All costs are in real terms US$.

It can be seen in Figure 5-2 that Jupiter classify most costs as operating support. This would include personnel in the field and office (staff and contractors), well servicing, maintenance, support services and consumables. Production costs include transportation costs, waste disposal and emissions tax.

Operating costs for the P50 case total US$137 million, averaging approximately US$6 million pa. Costs will vary slightly for the high and low cases. Operating costs for the P50 case are shown in Figure 5-2.

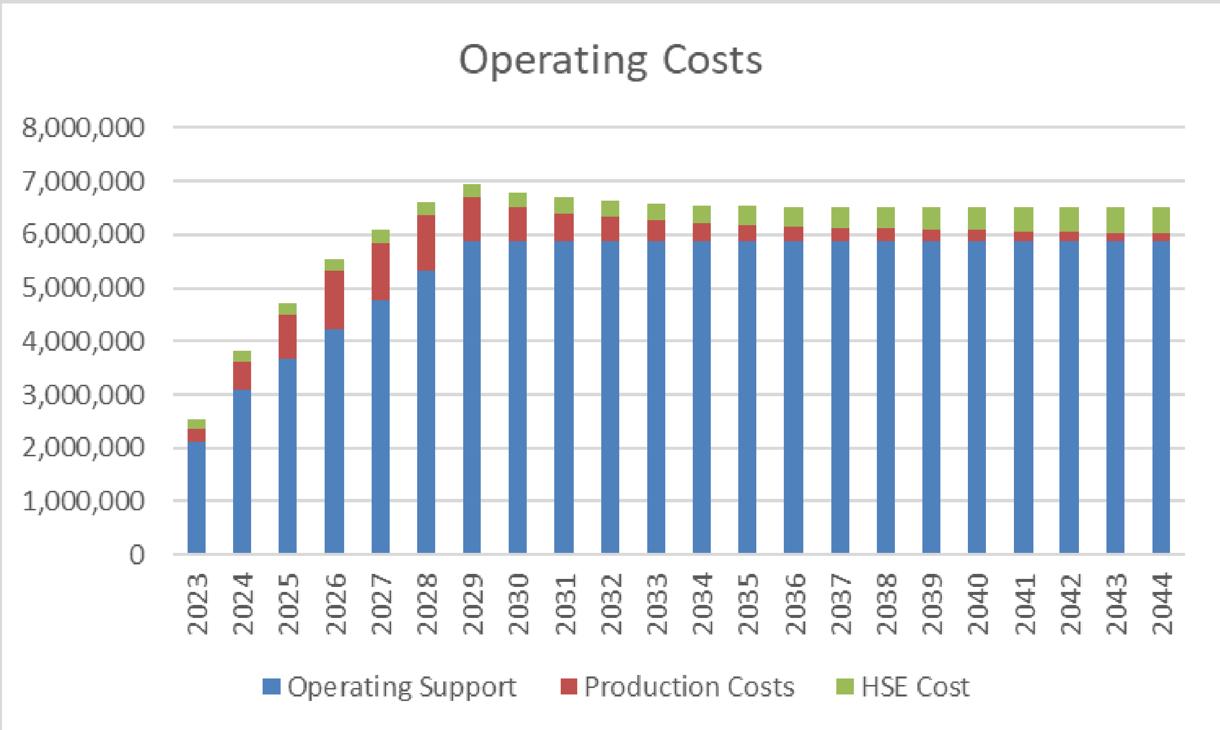


Figure 5-2: Operating costs

5.2.3. General and administrative costs

Jupiter estimate general and administrative ('G&A') costs of US$1.7 million in 2023. We consider it likely that costs will remain at around this level during the drilling campaign before reducing to approximately US$1 million pa thereafter, resulting in total G&A costs of US$28 million to 2044.

5.2.4. Abandonment costs

No abandonment costs appear explicitly in the model. As unit operating costs are forecast to be approximately US$50/bbl in 2044 the field will be cashflow positive at current oil prices and therefore abandonment would not be required.

6. Production Analysis

6.1. Production history and decline analysis

RISC has reviewed the production history and conducted well by well decline analysis.

RISC interprets the drive mechanism to be depletion drive supplemented by solution gas drive as the reservoir pressure depletes below the bubble point. The produced GOR has largely been steady in early time with modest increases later in well life. The wells have not gassed-out when the pressure has depleted below the bubble point. Therefore, we expect a high initial oil decline rate followed by a slowing in decline as solution gas comes out of solution. Such a drive mechanism typically results in hyperbolic to harmonic decline.

For decline curve analysis we have used:

- Hyperbolic (b=0.4) for 1P reserves estimates
- A conservative harmonic fit for 2P reserves estimates
- An optimistic harmonic fit for 3P reserves estimates

Well by well oil, water and gas production data were available to 6/10/2022. Other operational data such a THP, BHP or pump settings were not available to RISC. Figure 6-1 shows the field production history.

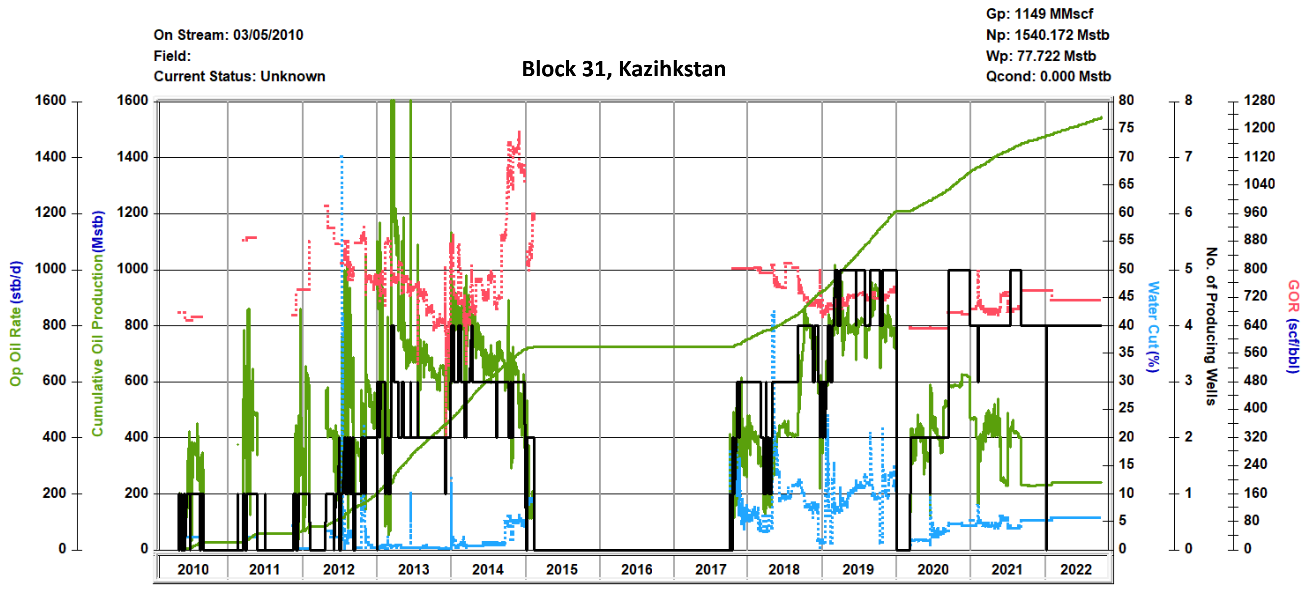


Figure 6-1: Production History

- Up to 5-wells have produced
- Oil production rate has been constrained at about 240 stb/d since September 2021 due to gas flaring rate constraints, so we have conducted decline analysis on the history prior to September 2021
- There has been minor water production with water cut currently less than 10%
- The GOR has generally been around the solution GOR with occasional periods of increased GOR

The individual well decline analysis are include in Appendix A, with results summarized in Table 6-1.

Table 6-1: Decline analysis results as at 6/10/2022

Well	Np Mstb	1P			2P			3P		
		Qo	EUR	Resources	Qo	EUR	Resources	Qo	EUR	Resources
J-19	135	117	290	155	117	483	349	117	886	751
J-50	226	119	292	66	107	500	274	115	624	398
J-51	374	144	530	156	148	704	330	139	1,141	767
J-52	501	192	887	386	185	1,444	943	181	1,813	1,313
J-53	2	-	2	0	-	2	0	-	2	0
J-58	302	222	449	147	246	621	318	270	1,034	731
Total	**1,540**	**794**	**2,450**	**910**	**803**	**3,754**	**2,214**	**822**	**5,498**	**3,960**

Notes to the table:

1. EUR is estimated to a final oil rate of 10 stb/d per well. Economic cut-off may need to be applied.
2. Np, EUR and Reserves are in Mstb. Qo in the estimated current unconstrained oil rate (stb/d)

The cumulative oil to date per well varies from 0.02 to 0.5 MMstb, Figure 6-2. Well J-53 has barely produced, been shut since 2017 and is assigned no reserves.

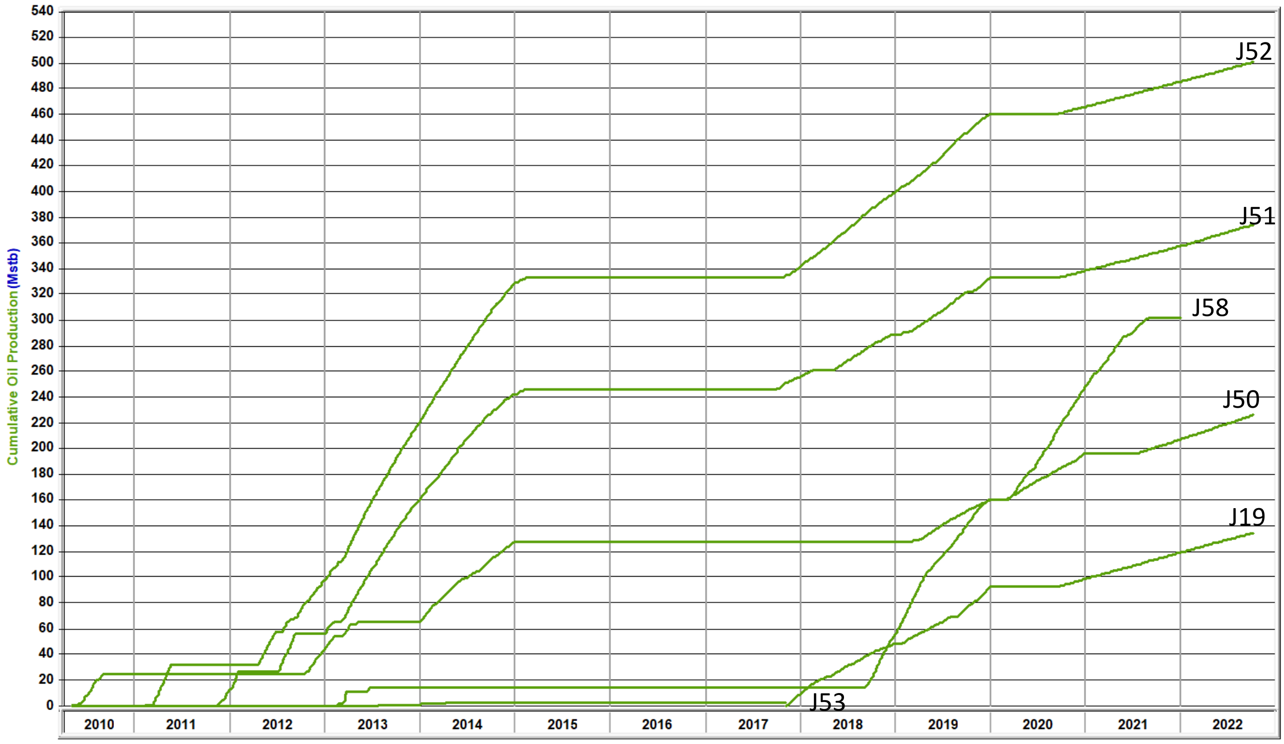


Figure 6-2: Cumulative oil per well

There is no obvious degradation in well performance with time which indicates that the later wells are developing new oil. The peak oil rate of the six producers varies from 70 (J-53) to 600 bpd (J-51, J-52) with an average of 400 bopd.

6.2. Undeveloped reserves

There are plans to drill 24 addition wells, although RISC has seen no details and well locations are not yet available.

Senergy (May 2011) and McDaniel (30 June 2013) conducted field evaluations estimating STOIIP and ultimate recovery. Senergy divided the East Akkar Field into three segments and estimated a P90, P50, P10 STOIIP and EUR for each area based on 2 existing wells plus 12 additional wells from March 2011 (7 additional wells in 1P case), Table 6-2. Their corresponding oil recovery factor estimates range from 18% to 27%. They did not analyse the West Zhetybai field. Zero P90 resources were assigned to the then undrilled MG segment.

Table 6-2: East Akkar STOIIP and EUR (Senergy, May 2011)

Area	STOIIP (MMstb)			EUR (MMstb)		
	P90	P50	P10	P90	P50	P10
NJ50	23.4	27.1	31.3	4.3	6.4	8.5
SJ50	30.3	36.1	40.4	5.6	8.2	10.8
MG	35.5	41.4	47.9	0	9.6	12.8
Total	**89.2**	**104.6**	**119.5**	**9.8**	**24.2**	**32.1**

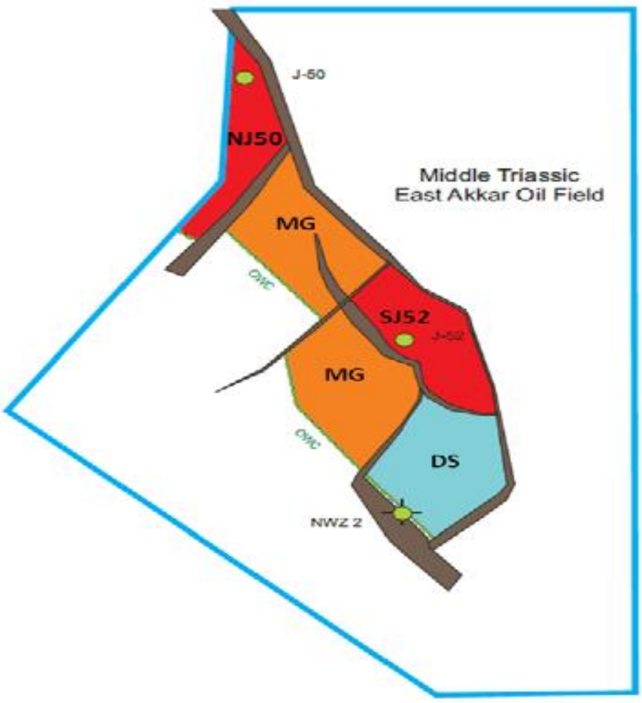


Figure 6-3: East Akkar Areas (Senergy)

McDaniel analysed both fields and estimated developed and undeveloped reserves, Table 6-3. The ultimate recovery estimate was based on the 4 existing wells and 11 new wells drilled 2015 to 2017.

- Only 1 of these additional wells (J-19) has since started production in 2017.
- Three additional wells J-55, J-57 and J-59 have been drilled but failed to produce.

Table 6-3: Block 31 STOIIP and EUR (McDaniel 2013)

Field	STOIIP (MMstb)			Dev + Undev EUR (MMstb)		
	P90	P50	P10	P90	P50	P10
East Akkar	60.1	75.3	77.5	6.0	10.5	14.5
West Zhetybai	32.1	60.1	72.6	4.0	9.0	14.5
Total	**92.2**	**135.4**	**150.1**	10.1	19.5	29.0

McDaniel's estimated field recovery factors are 10 to 20% which RISC supports as feasible for a primary depletion plus solution gas drive mechanism. However, the number of wells required to achieve this recovery is unclear.

Jupiter plan to drill a total of 24 infill wells with 4 wells per year 2024 to 2028, two in 2029 and 2 in 2030. Six producers will be in West Zhetybai, two in Akkas North and 16 in Akkar East. In Akkar East 4 wells are planned to be water injectors and 12 producers. RISC estimate that water injectors may initially be used as producers if they find oil bearing productive reservoir.

Effective water injection in tight vuggy carbonates is difficult as it requires adequate connectivity between injectors and producers without high permeability conduits that would result in early water breakthrough and poor sweep. RISC has not assigned any incremental to water injection until it's benefit has been demonstrated in this challenging reservoir.

Table 6-4 shows the range of performance of the 6 existing productive wells.

Table 6-4: Existing successful well performance uncertainty

	Low	Average	High
Initial oil rate (bpd)	200	400	600
EUR Oil (MMstb)	0.408	0.626	0.916

Key questions are:

- Will infill wells will provide 100% incremental oil, accelerate oil from existing wells or a combination of both?
- Will infill wells perform as well as historic wells? There is no clear reduction in the performance between initial wells and wells drilled several years after start-up. However, at some point, further infill drilling is

not worthwhile as the field is fully developed and infill wells encounter depleted reservoir and only accelerate production.

6.3. Production forecasts

Jupiter has informed RISC that the current gas flaring restriction will be removed from 1/4/2023 with commissioning of the gas utilisation project.

The developed producing reserves has been estimated from summing the well-by-well decline analysis and assuming:

- Field oil production is constrained to 240 bopd due to gas flaring restriction up to 31/3/2023 when the gas utilization project is commissioned.
- The full field potential is used from 1/4/2023

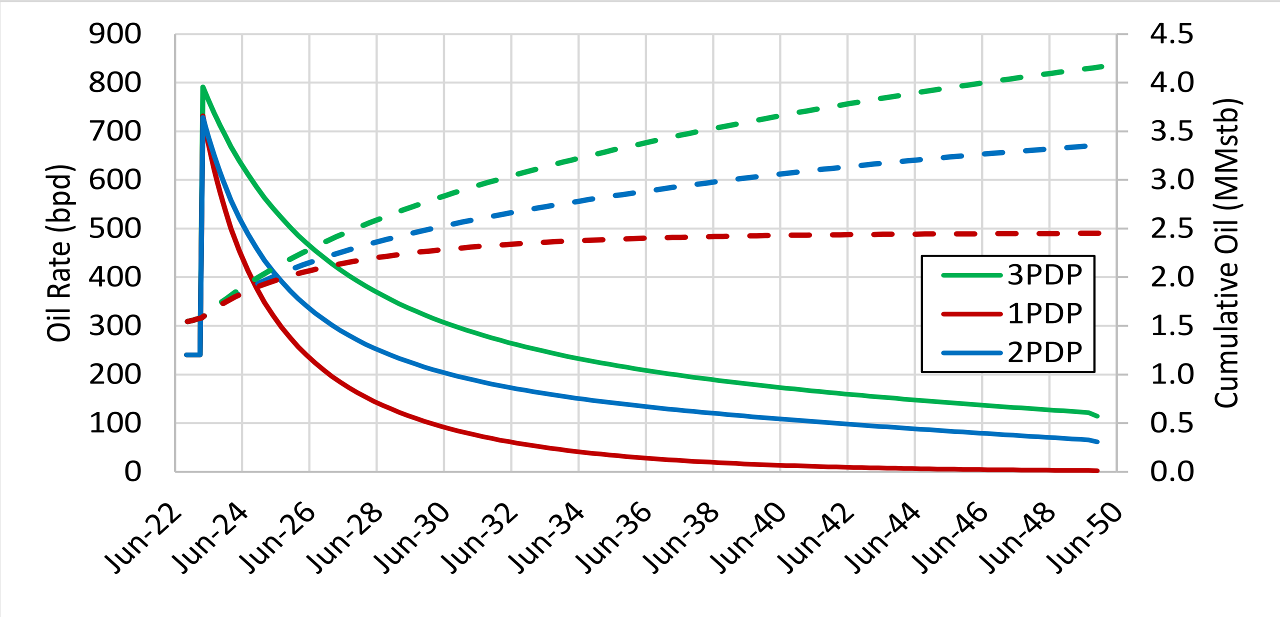


Figure 6-4: Developed producing oil reserve forecast

Figure 6-5 shows the associated gas production forecast that is based on the produced GOR which has stabilised at approximately 720 scf/stb.

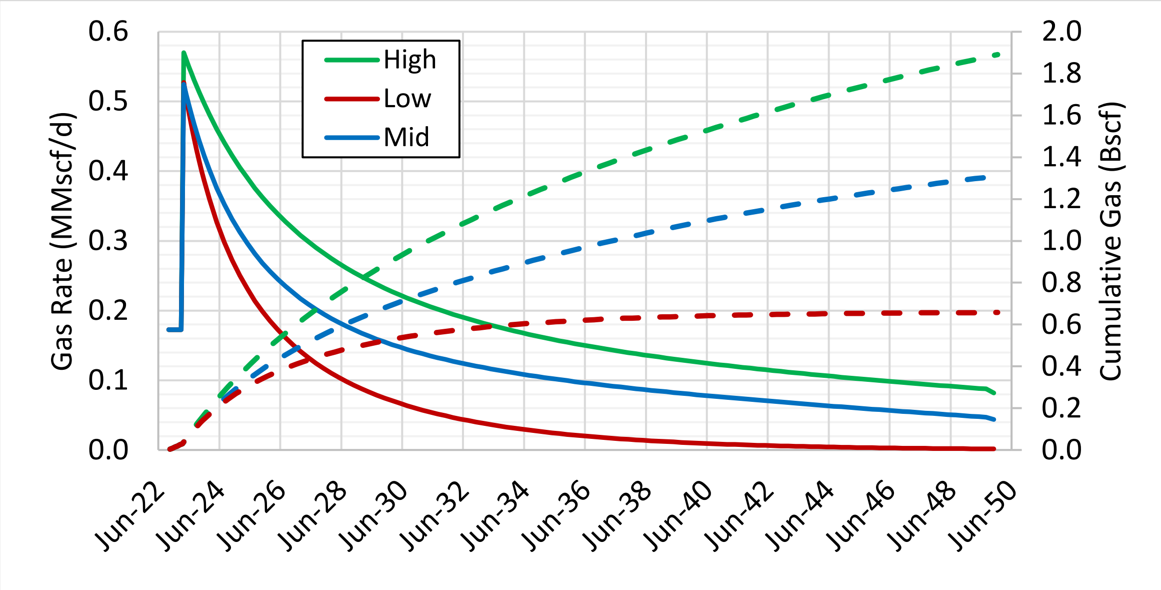


Figure 6-5: Developed producing gas forecast

The contribution from future infill wells is estimated from the existing well performance although the EUR is discounted for three reasons:

- Infill wells target less attractive locations in the reservoir as the best locations have already been drilled. Therefore, it is expected reduced performance in later wells
- Production from infill wells is a combination of new incremental oil and oil that would have been produced from existing wells (acceleration)
- Only six of the nine wells drilled to date have produced, the others having found tight or water productive reservoir. Therefore, 2/3 or 16 of the 24 infill wells planned are assumed to be productive.

The infill well parameters in Table 6-4 were used for the first 25% of infill wells. RISC estimate the EUR from subsequent 25% batches on infill wells to be reduced by 17.7%, 33.3% and 50%. A mid case hyperbolic decline (b=0.7) with 95% uptime is assumed. Figure 6-6 shows the estimated production from existing plus 16 successful infill wells.

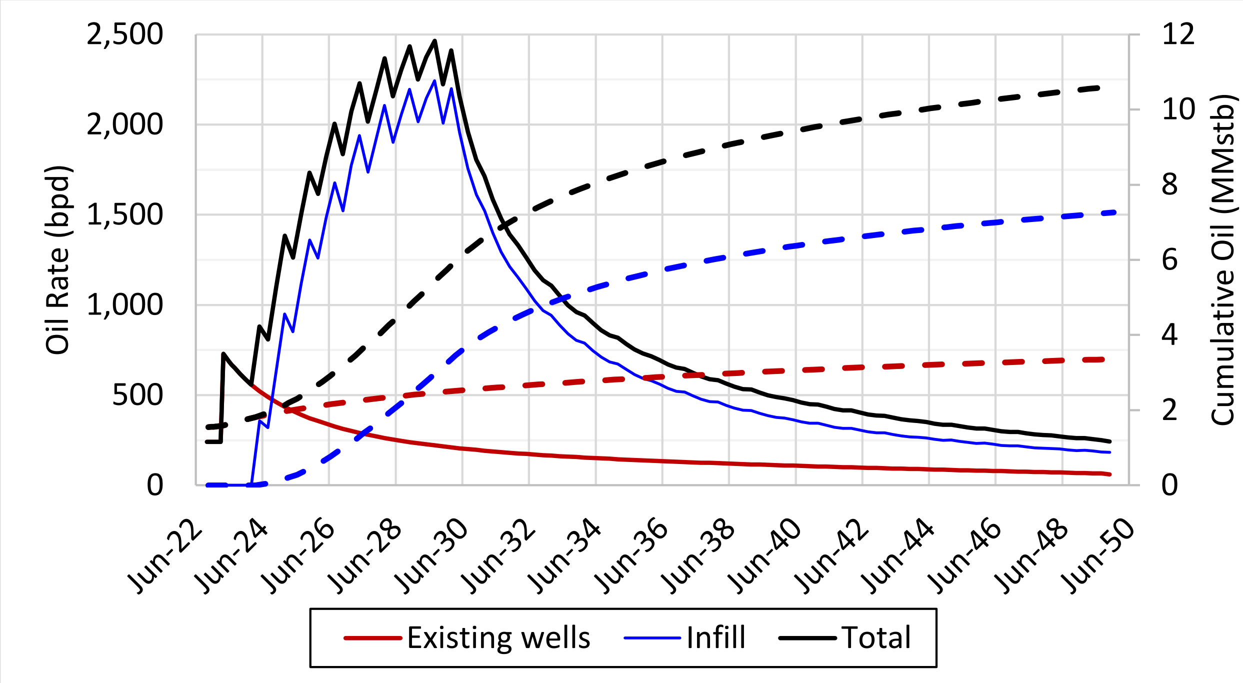


Figure 6-6: Mid Case developed plus undeveloped oil forecast

For input to the economic model:

- RISC's oil production forecasts have been converted to tonnes using 7.82 stb/tonne (Section 4.6.3)
- 2022 production was for 4Q 2022 only (1/10/2022 to 31/12/2022)

This P50 production forecast results in the EUR of 9.2 MMstb by end 2049, which still represents modest oil recovery factor based on previous STOIIP estimates. Therefore, further infill drilling may be worthwhile, subject to the results of these wells.

6.3.1. Low and high forecasts

The low and high forecasts for existing wells are based on conservative and optimistic decline analysis shown in Figure 6-4, discussed in Section 6.1 and Appendix A. However, the production forecasts are dominated by production from the 24 planned infill wells and infill well performance is the main uncertainty.

Table 6-4 showed the range in well performance determined from the analysis of existing wells. The P90 and P10 estimates are for a single well, so if only one infill well is planned these are valid low and high estimates. However, if multiple wells are drilled, the probability of all wells performing at the low level is extremely low and the probability of all wells performing at the high is equally low. As more infill wells are drilled the average infill well performance will approach the mid estimate. RISC has estimated the average low and high case well performance for a 24 well campaign with 16 successful producers using probabilistic addition, Table 6-5.

Table 6-5: Existing successful well performance uncertainty (16-well campaign)

	Low	Mid	High
Initial rate (bpd)	350	400	450
EUR (MMstb)	0.57	0.626	0.70

Other key uncertainties are how many of the new infill wells find productive reservoir and much of the infill well production is addition oil and how much is acceleration of oil that would have been produced from existing wells. RISC has estimated these from our extensive experience in oil field evaluation.

Table 6-6: Proportion of EUR that is new oil, remainder accelerated

	1st four wells	2nd four wells	3rd four wells	4th four wells	Productive wells
Low forecast	100%	73.3%	46.7%	20%	10
Mid Forecast	100%	83.3%	66.7%	50%	16
High Forecast	100%	90%	80%	70%	22

Figure 6-7 shows the resulting Block 31 low, mid and high case oil forecasts.

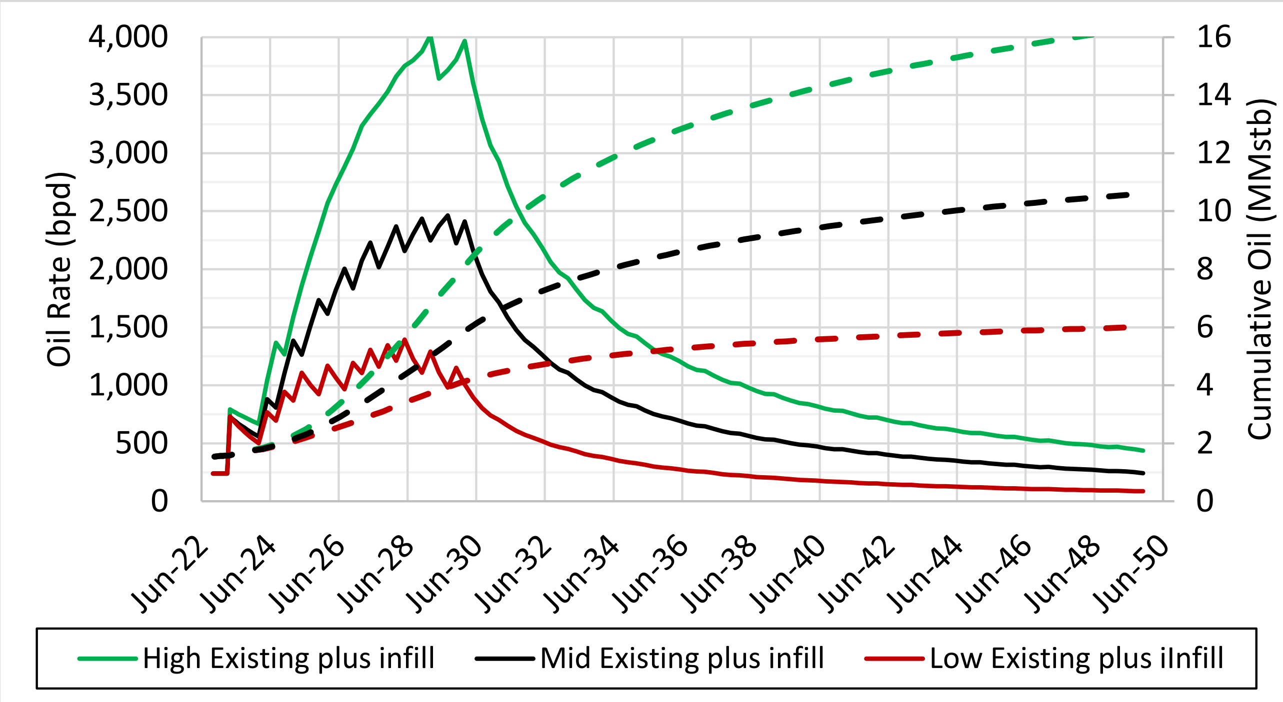


Figure 6-7: Developed plus undeveloped oil forecast

Figure 6-8 shows the associated gas production forecast that is based on the produced GOR which has stabilized at approximately 720 scf/stb.

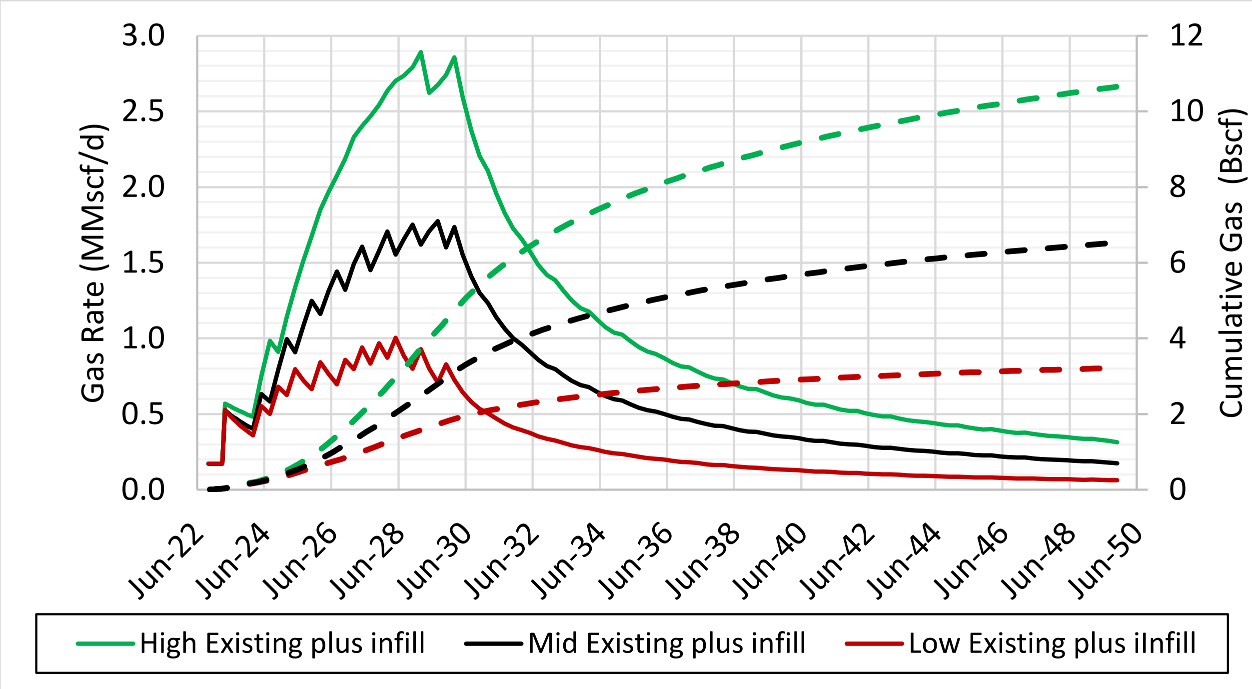


Figure 6-8: Developed plus undeveloped gas forecast

7. Resources

There have been a number of resource estimates for the asset performed over the years. Senergy conducted its initial Independent Resources Assessment of the asset in 2010 (subsequently updated in 2011) and a "Preliminary Review of Factors Affecting HIIP and UR" in 2014. McDaniel &Associates conducted its Competent Person's Report in 2013. These three reports use the PRMS system which differentiates resources into Proven, Probable and Possible.

In addition, RES has prepared preliminary and final resource estimates. RES uses the RF 2013 system which differentiates between commercial inflows of hydrocarbons in wells and positive results of geological and geophysical studies of untested wells (category C1), and reserves of hydrocarbons whose presence is justified by the data of geological and geophysical studies with consideration of a more known part of the reservoirs or via analogy with an explored field (category C2). Both categories are independent of an economic assessment, and thus cannot be directly compared to the PRMS system.

7.1. In-place resource estimates

Different wells, well testing data and production data was available for the various historical reserves and resources reports:

- Senergy had access to data from wells J-50, J-52 with well J-53 untested. Their estimates are based on a data quality control of the 2010 top structure map and on J-50 and J-52 well logs.
- The area labelled "MG" (middle graben) in the 2011 Senergy report refers to the area between wells J-50 (south thereof) and J-52 (to the west of J-52). The area labelled "DS (J-52-downthrow)" refers to the area immediately to the south-west of J-52.
- McDaniel (2013) had wells J-50 to J-59 with J-53 untested and J-59 partially tested.
- Well J-19 was drilled in 2014 and is not reported in any of the earlier CPRs. Likewise, the J-57 well result has not been incorporated.
- It is important to note that the different assessments of in-place volumes are based on different maps and on different block boundaries.

Table 7-1 shows the reported in-place volumes from the Senergy and McDaniel reports. RISC has not undertaken an independent assessment of in-place to verify these estimates. RISC notes the variation in in-place estimates which is due in part to differences in the mapping assumptions, but also the reservoir parameter assumptions for the highly variable nature of the Block 31 reservoir.

Table 7-1: Block 31 STOIIP from Senergy (2011) and McDaniel (2013)

<table>
<tr><th rowspan="2">Source</th><th rowspan="2">Field</th><th rowspan="2">Area</th><th colspan="3">STOIIP (MMstb)</th></tr>
<tr><th>P90</th><th>P50</th><th>P10</th></tr>
<tr><td rowspan="4">Senergy</td><td rowspan="4">East Akkar</td><td>NJ50</td><td>23.4</td><td>27.1</td><td>31.3</td></tr>
<tr><td>SJ50</td><td>30.3</td><td>36.1</td><td>40.4</td></tr>
<tr><td>MG</td><td>35.5</td><td>41.4</td><td>47.9</td></tr>
<tr><td>Total East Akkar</td><td>89.2</td><td>104.6</td><td>119.5</td></tr>
<tr><td rowspan="3">McDaniel</td><td colspan="2">East Akkar</td><td>60.1</td><td>75.3</td><td>77.5</td></tr>
<tr><td colspan="2">West Zhetybai</td><td>32.1</td><td>60.1</td><td>72.6</td></tr>
<tr><td colspan="2">Total Block 31</td><td>92.2</td><td>135.4</td><td>150.1</td></tr>
</table>

7.2. Reserves

RISC classify production from existing wells as producing developed reserves. The remaining oil resources to end 2044 (end of contract term) are shown in Table 7-2. An economic cut-off may need to be applied to these forecasts.

Table 7-2: Block 31 producing developed volumes to end 2044 as of 1 October 2022

Remaining oil to end 2044	1P	2P	3P
MMstb	0.906	1.683	2.385
tonnes	115,847	215,190	304,924
An economic cut-off may need to be applied to these volumes			

The producing developed reserves plus 1.54 MMstb cumulative production 1 October 2022 result in modest oil recovery factors and indicate that further development drilling is justified.

7.3. Contingent resources

Jupiter propose 24 infill wells from 2024 coming on stream at a rate of one per quarter. Resources associated with further drilling were included in previous independent resource assessments by Senergy in 2011 and McDaniel in 2013. However, these additional wells were not drilled.

RISC has not seen detailed plans for the infill drilling, the proposed well locations or confirmation well approval or drilling contracts. Therefore, RISC classify the resources associated with infill wells as contingent resources (development pending), contingent upon being confirmed with drilling contracts and approvals.

Table 7-3 summaries the contingent resources to end 2044 (end of contract term) associated with drilling the 24 wells proposed. An economic cut-off may need to be applied to these forecasts.

Table 7-3: Block 31 undeveloped infill volumes to end 2044 as of 1 October 2022

Contingent Resources to end 2044 (MMstb)	1C	2C	3C
MMstb	3.379	6.871	11.500
tonnes	432,152	878,680	1,470,615
An economic cut-off may need to be applied to these volumes			

The developed reserves and undeveloped contingent resources still result in modest oil recovery factors, based on estimated STOIIP. This indicates that subject to the performance of planned infill drilling, further infill drilling may be justified.

7.4. Prospective resources

Jupiter recognises prospective drilling target in Block 31 (Figure 7-1). No details or prospective resource assessments have been provided to RISC to review and they do not form part of the valuation.

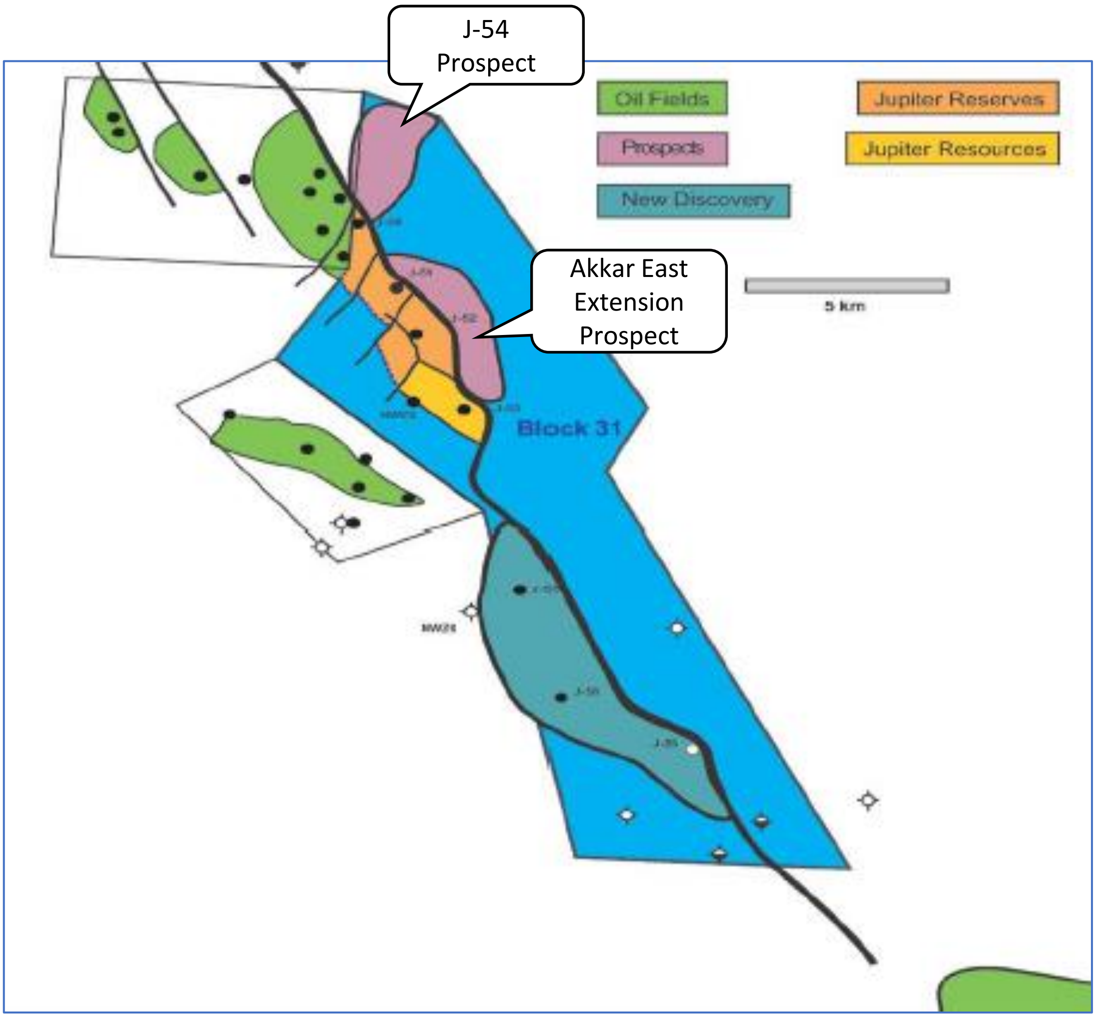


Figure 7-1: Block 31 prospects (Jupiter, 2013)

8. RISC opinion on economic model assumptions

RISC was provided a cashflow model and was requested by BDO to comment on the following. Costs are in US dollars, 2022 real terms.

Technical input	RISC to opine on	RISC Comment
Conversion factor from tonnes to barrels	The appropriateness of the conversion factor of 7.4 used to convert tonnes into barrels of oil.	RISC verified conversion factor based on available PVT data and based on the available data the average conversion factor is 7.82 barrels/tonne.
Drilling and completion CAPEX	Timing and quantum	RISC can accept drill and complete cost of US$3 million per well. We have assumed 4 wells are drilled per year 2024-2029. This is considered technically achievable though we have not seen a drilling schedule or firm plan
Working days in year	Assumed number of days oil wells can operate in a year (360 days)	Downtime of ~1.5% (360 days/year) represents excellent operational performance. We consider prudent to adopt 2.5% downtime ~355 operational days pa
Average annual well production decline	Assumed rate (7.76%)	RISC generated production forecasts based on production history and available technical information, this included an independent assessment of initial rate per well and appropriate decline rate
New well's production rate (t/d)	Assumed rate (25 tpd)	
Production from wells	Timing, quantum and confirmation that Jupiter has the reserves/resources to support this level of production.	We support increase in production in 2023 given the gas utilisation project is due to be completed in early 2023. We assume the gas utilisation project will allow the current oil production constraint, due to gas handling (flaring) limitation, to be lifted.

27% discount embedded within export oil price	As applied a 27% discount to the global (Brent) oil price explaining that this represents a net price: - 22% of this is allocated for transport costs, export duties, insurance and other costs associated with the sale of oil. - 5% of this relates to the mineral extraction tax in Kazakhstan	22% does seem high based on global experience. Jupiter has confirmed it includes all export duties, rent tax, transportation costs via pipeline to the Black Sea, insurance/ hedging costs, pipeline losses and downtime tanker costs. It may also include a quality discount
OPEX	Timing and quantum.	General methodology of ~US$2.5 million pa + US$140 thousand per well onstream seems reasonable. We will make slight modifications to reflect trucking costs of US$5/t advised by Jupiter
G&A - Aktau Cost and Training Cost	Please assess quantum of the annual costs.	We do not think it is realistic to reduce G&A expenditure from 2024 when the development drilling programme is underway. We recommend maintaining G&A levels of ~US$1.5 million experienced in 2022 throughout the drilling programme (to 2030)
CAPEX and contingency	Timing and quantum of capex figures.	CAPEX generally seems reasonable other than contingency. We recommend 10% contingency instead of 3% in the model provided.

9. Declarations

9.1. Qualifications

RISC is an independent oil and gas advisory firm. All of the RISC staff engaged in this assignment are professionally qualified engineers, geoscientists or analysts, each with many years of relevant experience and most have in excess of 20 years.

RISC was founded in 1994 to provide independent advice to companies associated with the oil and gas industry. Today the company has approximately 40 highly experienced professional staff at offices in Perth, Brisbane, Jakarta and London. We have completed over 2,000 assignments in 70+ countries for nearly 500 clients. Our services cover the entire range of the oil and gas business lifecycle and include:

- Oil and gas asset valuations, expert advice to banks for debt or equity finance;
- Exploration/portfolio management;
- Field development studies and operations planning;
- Reserves assessment and certification, peer reviews;
- Gas market advice;
- Independent Expert/Expert Witness;
- Strategy and corporate planning.

The preparation of this report has been managed by Mr Adam Craig who is an employee of RISC. Mr Craig is a highly experienced Geoscientist and Manager, with over 30 years' experience in the upstream oil & gas sector working for small and mid-size independents, as well as NOC related entities. He is a member and Certified Practising Geologist (#6446) of the AAPG. Adam is also a member of PESA (2021-22 WA Branch President) and a Fellow of the Geological Society. He holds BSc in Geology from Curtin University, Western Australia and is a qualified petroleum reserves and resources evaluator (QPRRE) as defined by ASX listing rules.

9.2. Terms of engagement

This report, any advice, opinions or other deliverables are provided pursuant to the Engagement Contract agreed to and executed by the Client and RISC.

9.3. Standard

Reserves and resources are reported in accordance with the definitions of reserves, contingent resources and prospective resources and guidelines set out in the Petroleum Resources Management System (PRMS) prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the American Association of Petroleum Geologists (AAPG), World Petroleum Council (WPC), Society of Petroleum Evaluation Engineers (SPEE), Society of Exploration Geophysicists (SEG), Society of Petrophysicists and Well Log Analysts (SPWLA) and European Association of Geoscientists and Engineers (EAGE), revised June 2018.

This Report has been prepared in accordance with the Australian Securities and Investment Commission (ASIC) Regulatory Guides 111 and 112.

9.4. Limitations

The assessment of petroleum assets is subject to uncertainty because it involves judgments on many variables that cannot be precisely assessed, including reserves/resources, future oil and gas production rates, the costs associated with producing these volumes, access to product markets, product prices and the potential impact of fiscal/regulatory changes.

The statements and opinions attributable to RISC are given in good faith and in the belief that such statements are neither false nor misleading. While every effort has been made to verify data and resolve apparent inconsistencies, neither RISC nor its servants accept any liability, except any liability which cannot be excluded by law, for its accuracy, nor do we warrant that our enquiries have revealed all of the matters, which an extensive examination may disclose. In particular, we have not independently verified property title, encumbrances or regulations that apply to these assets.

Our review was carried out only for the purpose referred to above and may not have relevance in other contexts.

9.5. Independence

RISC makes the following disclosures:

- RISC is independent with respect to Jupiter and confirms that there is no conflict of interest with any party involved in the assignment.
- Under the terms of engagement between RISC and Jupiter, RISC will receive a time-based fee, with no part of the fee contingent on the conclusions reached, or the content or future use of this report. Except for these fees, RISC has not received and will not receive any pecuniary or other benefit whether direct or indirect for or in connection with the preparation of this report.
- Neither RISC Directors nor any staff involved in the preparation of this report have any material interest in Jupiter or in any of the properties described herein.

9.6. Copyright

This document is protected by copyright laws. Any unauthorised reproduction or distribution of the document or any portion of it may entitle a claim for damages. Neither the whole nor any part of this report nor any reference to it may be included in or attached to any prospectus, document, circular, resolution, letter or statement without the prior consent of RISC.

9.7. Consent

RISC has consented to this report, in the form and context in which it appears, being included, in its entirety, in the Notice of Meeting. Neither the whole not any part of this report nor any reference to it may be included or attached to any other document, circular, resolution, letter or statement without the prior consent of RISC.

10. List of terms

10.1. Abbreviations

The following table lists abbreviations commonly used in the oil and gas industry and which may be used in this report.

Abbreviation	Full Term
1P	Proved
2P	Proved plus Probable
3P	Proved plus Probable plus Possible
A$	Australian dollars
API	American Petroleum Industry
Bbl(/d)	US barrels (per day)
bcf	Billion (10^9) cubic feet
bwpd	Barrels of water per day
CBM	Coal Bed Methane (see also CSG)
CCUS	Carbon Capture and Underground Storage
CO_2	Carbon dioxide
CSG	Coal Seam Gas (see also CBM)
DAF	Dry Ash Free
DCF	Discounted Cash Flow
DST	Drill Stem Test
EMV	Expected Monetary Value
ER	Exploration Right
EUR	Expected ultimate recovery
EV	Enterprise Value
FBHP	Flowing Bottom Hole Pressure
FDP	Field Development Plan
FTHP	Flowing Tubing Head Pressure
GIIP	Gas Initially In Place
GJ	Gigajoules (10^9 J)
JV(P)	Joint Venture (Parties)
km^2	Square kilometres
kPa	Kilopascal
LNG	Liquefied Natural Gas
m	Metres
mD	Millidarcies
MDT	Modular Dynamic Tester
mKB	Metres below Kelly Bushing
mGL	Metres below Ground Level
MGP	Mpumalanga Gas Project
MJ	Megajoules (10^6 J)
Ml (/d)	Megalitres (per day)
MMscf(/d)	Million standard cubic feet (per day)
MPa	Megapascal
Mscf(/d)	Thousand standard cubic feet (per day)
mSS	Metres subsea
MW(-h)	Megawatt (hour)
NPV	Net Present Value
OIIP	Oil initially In Place

Abbreviation	Full Term
PJ	Petajoules (10^{15} J)
PL	Production Lease
psi (a or g)	Pounds per square inch pressure (absolute or gauge)
RISC	Resource Investment Strategy Consultants
RT	Rotary Table or Real Terms, depending on context
scf	Standard cubic feet (measured at 60 F and 14.696 psia)
scm	Standard cubic metres (measured at 15 C and 101.325 kPa)
SPE	Society of Petroleum Engineers
SPE-PRMS	Society of Petroleum Engineers Petroleum Resources Management System
SUG	System Use Gas (fuel and flare)
Tcf	Trillion (10^{12}) cubic feet
TJ	Terajoules (10^{12} J)
UR	Ultimate Recovery
US$	United States dollars
ZAR	South African rand

10.2. Definitions

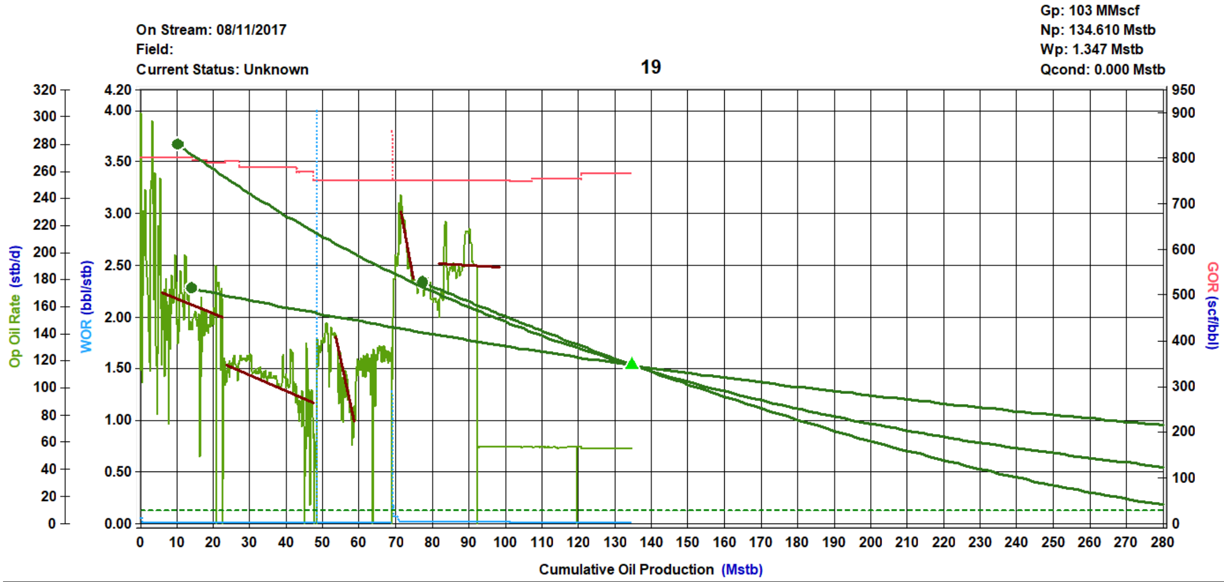
The following table lists some definitions for terms commonly used in the oil and gas industry and which may be used in this report.

Term	Definition
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. Contingent Resources are a class of discovered recoverable resources as defined in the SPE-PRMS.
Expectation	The mean of a probability distribution.
P90, P50, P10	90%, 50% & 10% probabilities respectively that the stated quantities will be equalled or exceeded. The P90, P50 and P10 quantities correspond to the Proved (1P), Proved + Probable (2P) and Proved + Probable + Possible (3P) confidence levels respectively if probabilistic techniques are used.
Possible Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.
Probable Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations as defined in the SPE-PRMS.

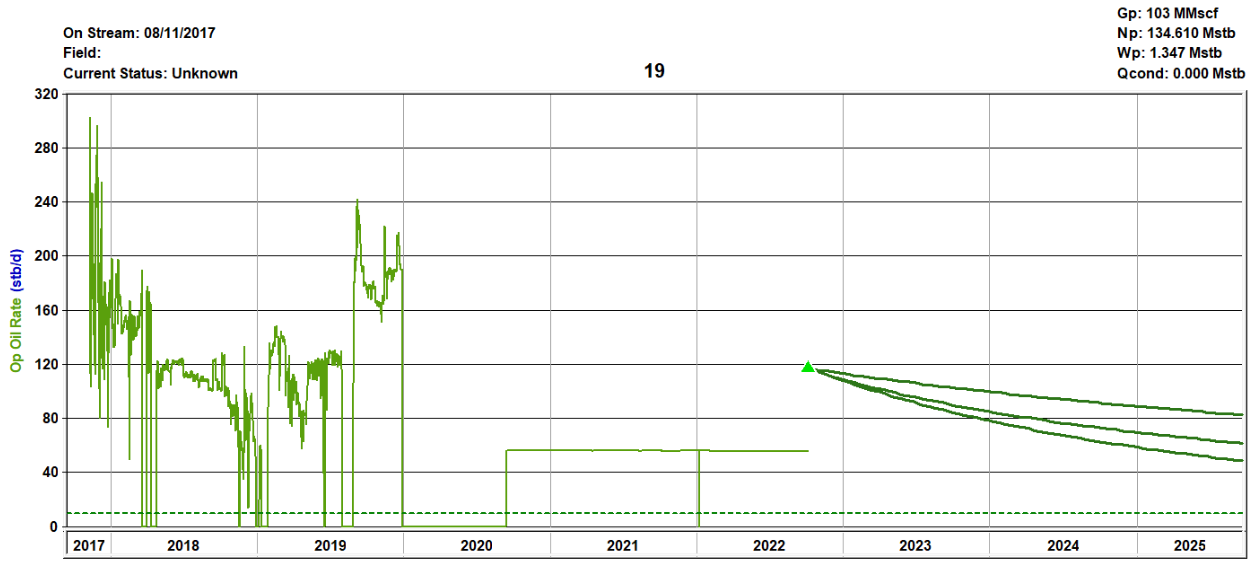
11. APPENDIX A: Decline Curve Analysis

Figures below show the decline curve analysis and forecast potential well oil rate (assuming no gas rate constraint) for each of the 5 producing wells. Available data was limited to allocated daily oil water and gas rates. Wellhead or downhole pressure data and artificial lift details were not available. It is understood that pumps are used to assist production.

11.1. Well J-19



Analysis Class. Name	EUR_o Mstb	N_p Mstb	RR_o Mstb	Start Date	q_i stb/d	Δt year	d_i sec %/year	d_i tan %/year	b	d_{lim} exp %/year	$(q_o)_f$ stb/d	End Date	$R^2_{q\ vs\ Q}$
RISC 1P	289.669	134.610	155.059	06/10/2022	117.2	11.80	28.257	29.893	0.400		10.0	26/07/2034	-3.350
RISC 3P	885.682	134.610	751.073	06/10/2022	117.0	76.47	12.272	13.055	1.000		10.0	24/03/2099	-1.026
RISC 2P	483.226	134.610	348.616	06/10/2022	116.5	35.53	23.069	25.909	1.000		10.0	18/04/2058	-3.291

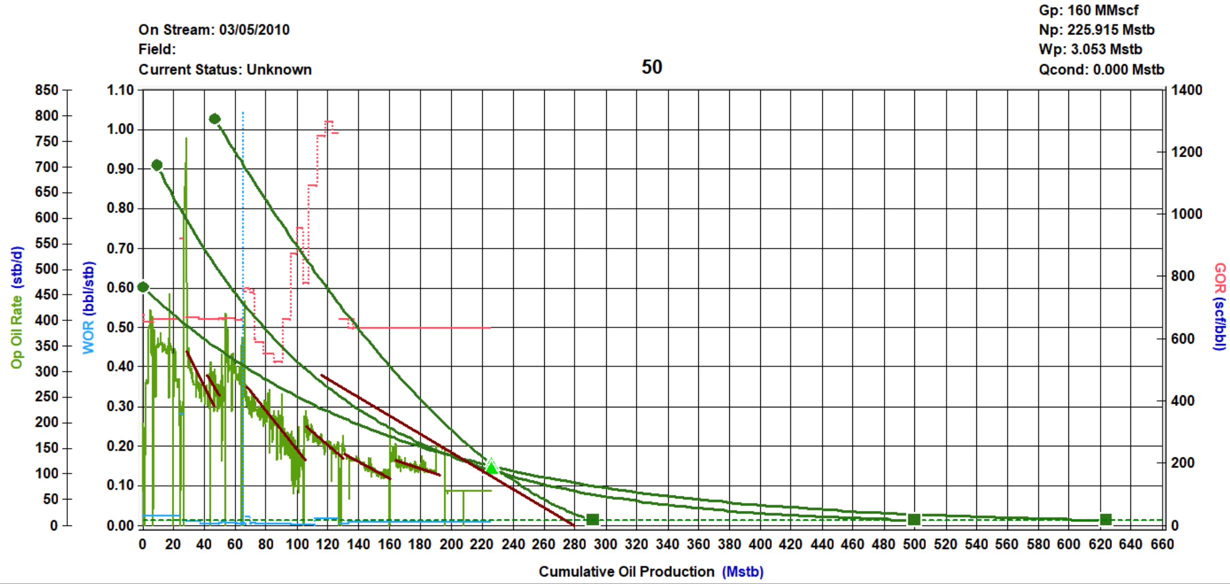


Analysis Class. Name	EUR_o Mstb	N_p Mstb	RR_o Mstb	Start Date	q_i stb/d	Δt year	d_i sec %/year	d_i tan %/year	b	d_{lim} exp %/year	$(q_o)_f$ stb/d	End Date	$R^2_{q\ vs\ Q}$
RISC 3P	885.682	134.610	751.073	06/10/2022	117.0	76.47	12.272	13.055	1.000		10.0	24/03/2099	-1.026
RISC 1P	289.669	134.610	155.059	06/10/2022	117.2	11.80	28.257	29.893	0.400		10.0	26/07/2034	-3.350
RISC 2P	483.226	134.610	348.616	06/10/2022	116.5	35.53	23.069	25.909	1.000		10.0	18/04/2058	-3.291

Note that production has been constrained since mid-2020 due to gas flaring constraints that are expected to remain until 31/3/2023. This constrained data is ignored in the decline curve analysis and low, mid and high unconstrained well potential is estimated assuming:

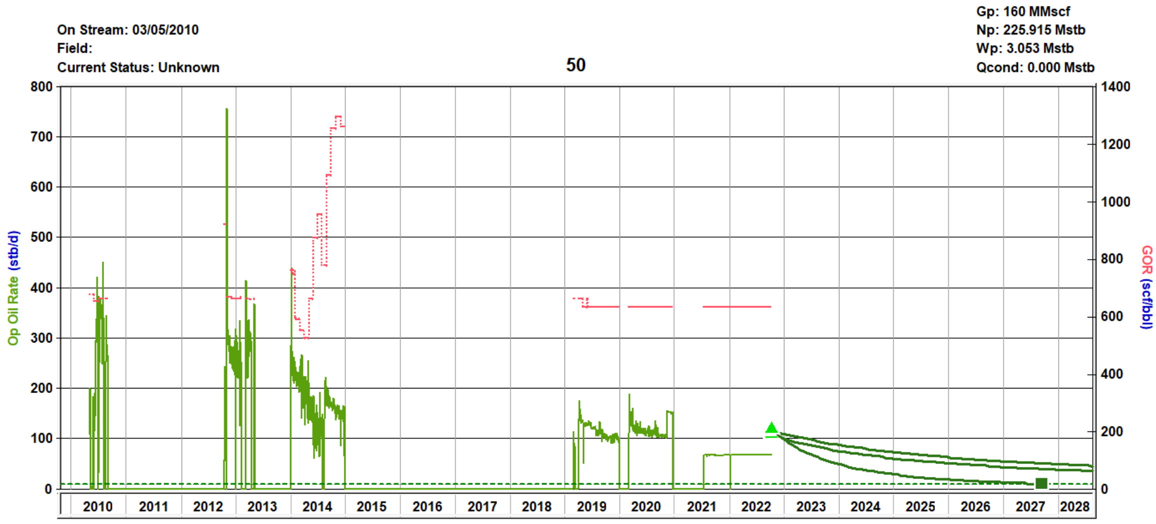
- RISC 1P case hyperbolic (b=0.4) decline
- RISC 2P conservative harmonic decline
- RISC 3P optimistic harmonic decline

11.2. Well J-50



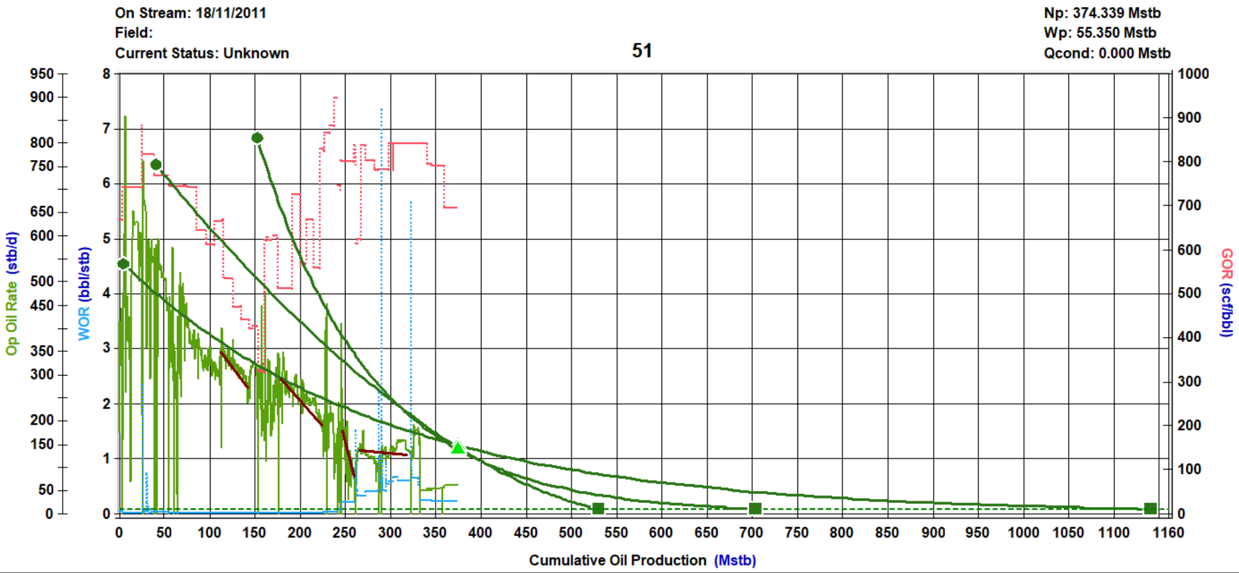
Analysis Class. Name	EUR_o Mstb	N_p Mstb	RR_o Mstb	Start Date	q_i stb/d	Δt year	d_i sec %/year	d_i tan %/year	b	d_{lim} exp %/year	$(q_o)_f$ stb/d	End Date	$R^2_{q\ vs\ Q}$
RISC 1P	291.524	225.915	65.609	06/10/2022	119.5	4.94	52.190	57.616	0.400		10.0	15/09/2027	-18.133
RISC 3P	623.752	225.915	397.838	06/10/2022	115.9	40.62	20.673	22.942	1.000		10.0	21/05/2063	-0.408
RISC 2P	499.845	225.915	273.931	06/10/2022	107.6	28.63	25.427	28.892	1.000		10.0	24/05/2051	-2.478

Decline in J50 above shows that exponential decline (straight line) is not appropriate as production shows a continued tail more like harmonic decline. The extended production may be due to the reservoir pressure declining to the bubble point and secondary gas creating additional pressure support. However, GOR data is scattered and not conclusive.

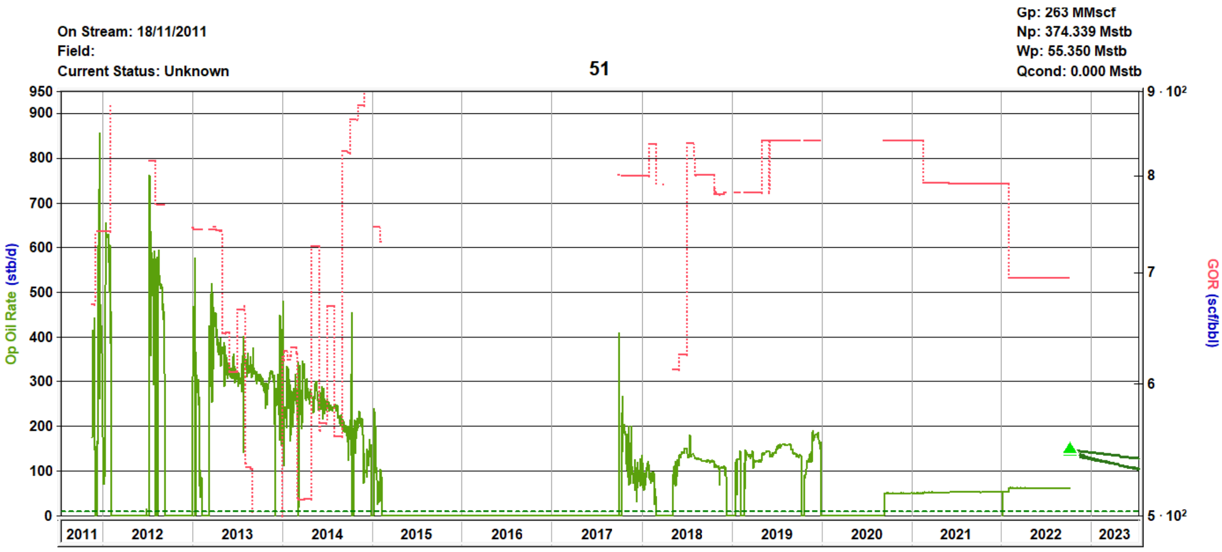


Analysis Class. Name	EUR_o Mstb	N_p Mstb	RR_o Mstb	Start Date	q_i stb/d	Δt year	d_i sec %/year	d_i tan %/year	b	d_{lim} exp %/year	$(q_o)_f$ stb/d	End Date	$R^2_{q\ vs\ Q}$
RISC 2P	499.845	225.915	273.931	06/10/2022	107.6	28.63	25.427	28.892	1.000		10.0	24/05/2051	-2.478
RISC 3P	623.752	225.915	397.838	06/10/2022	115.9	40.62	20.673	22.942	1.000		10.0	21/05/2063	-0.408
RISC 1P	291.524	225.915	65.609	06/10/2022	119.5	4.94	52.190	57.616	0.400		10.0	15/09/2027	-18.133

11.3. Well J-51

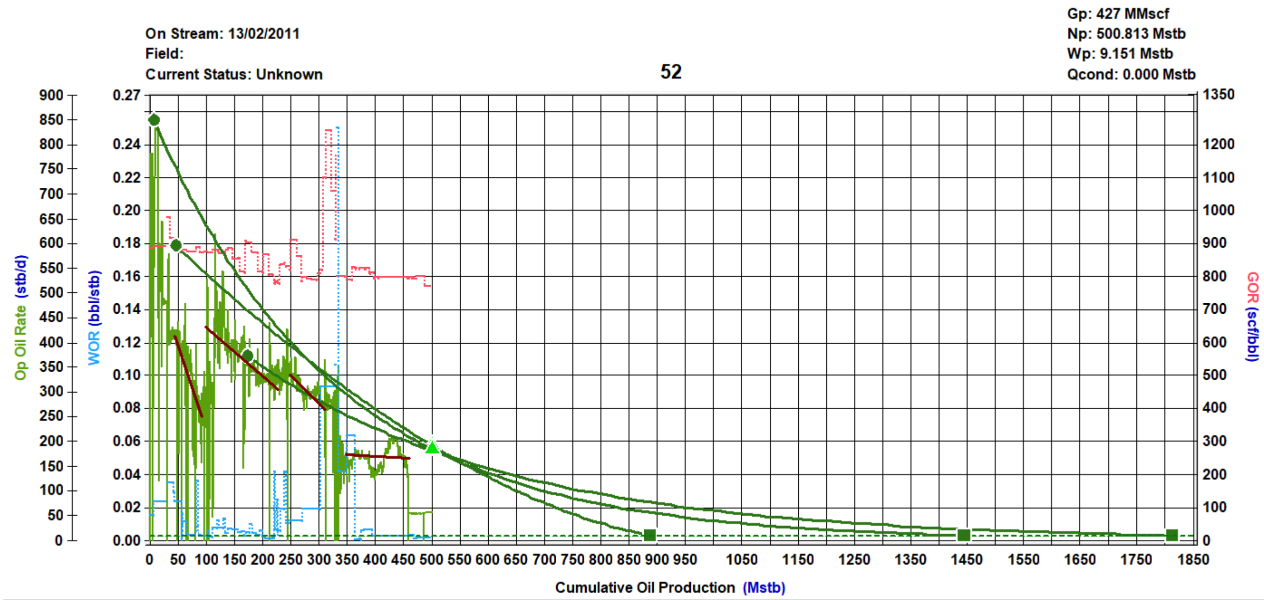


Analysis Class. Name	EUR_o Mstb	N_p Mstb	RR_o Mstb	Start Date	q_i stb/d	Δt year	d_i sec %/year	d_i tan %/year	b	d_{lim} exp %/year	$(q_o)_f$ stb/d	End Date	$R^2_{q\ vs\ Q}$
RISC 1P	530.441	374.339	156.102	06/10/2022	143.7	10.65	33.718	36.046	0.400		10.0	29/05/2033	-1.787
RISC 3P	1141.197	374.339	766.858	06/10/2022	147.7	72.69	15.927	17.258	1.000		10.0	16/06/2095	0.355
RISC 2P	704.194	374.339	329.855	06/10/2022	138.8	31.86	28.795	33.262	1.000		10.0	14/08/2054	-7.021

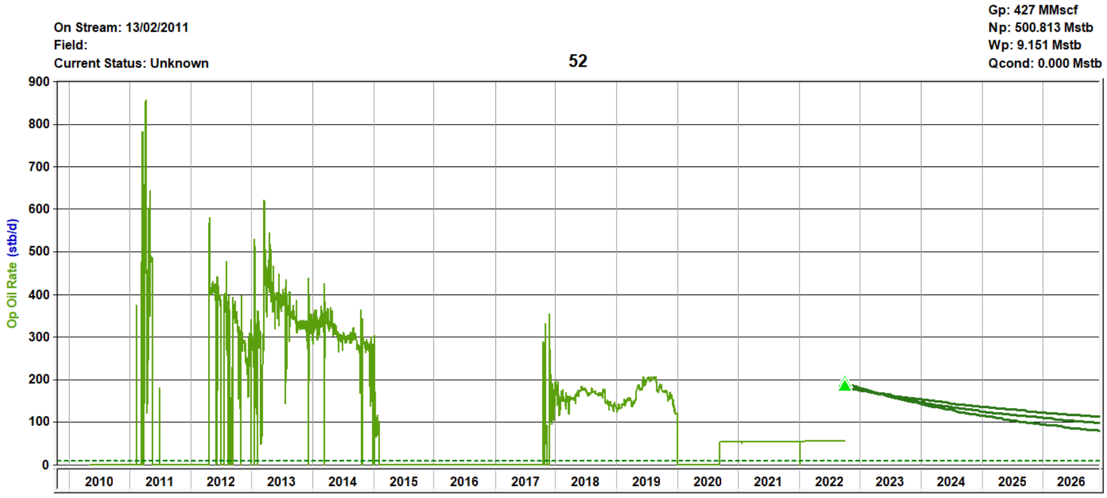


Analysis Class. Name	EUR_o Mstb	N_p Mstb	RR_o Mstb	Start Date	q_i stb/d	Δt year	d_i sec %/year	d_i tan %/year	b	d_{lim} exp %/year	$(q_o)_f$ stb/d	End Date	$R^2_{q\ vs\ Q}$
RISC 2P	704.194	374.339	329.855	06/10/2022	138.8	31.86	28.795	33.262	1.000		10.0	14/08/2054	-7.021
RISC 1P	530.441	374.339	156.102	06/10/2022	143.7	10.65	33.718	36.046	0.400		10.0	29/05/2033	-1.787
RISC 3P	1141.197	374.339	766.858	06/10/2022	147.7	72.69	15.927	17.258	1.000		10.0	16/06/2095	0.355

11.4. Well J-52

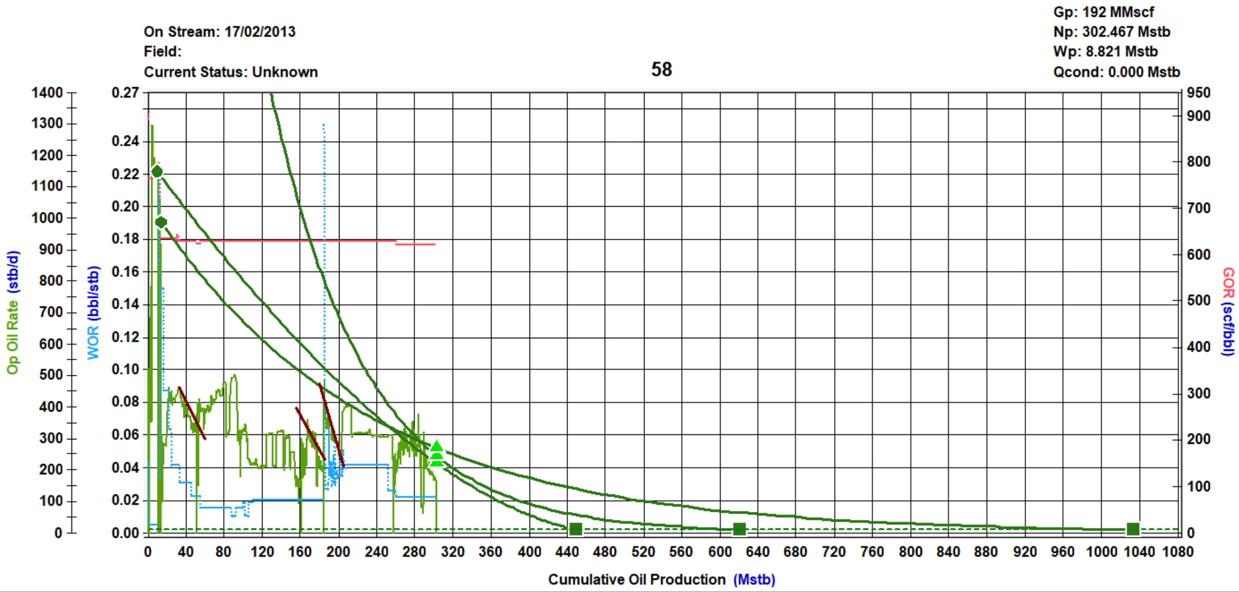


Analysis Class. Name	EUR_o Mstb	N_p Mstb	RR_o Mstb	Start Date	q_i stb/d	Δt year	d_i sec %/year	d_i tan %/year	b	d_{lim} exp %/year	$(q_o)_f$ stb/d	End Date	$R^2_{q\ vs\ Q}$
RISC 1P	887.241	500.813	386.428	06/10/2022	191.7	22.53	21.248	22.170	0.400		10.0	16/04/2045	-0.565
RISC 3P	1813.410	500.813	1312.597	06/10/2022	181.1	117.22	12.739	13.583	1.000		10.0	25/12/2139	0.081
RISC 2P	1443.570	500.813	942.758	06/10/2022	184.8	83.71	17.271	18.841	1.000		10.0	23/06/2106	-0.951

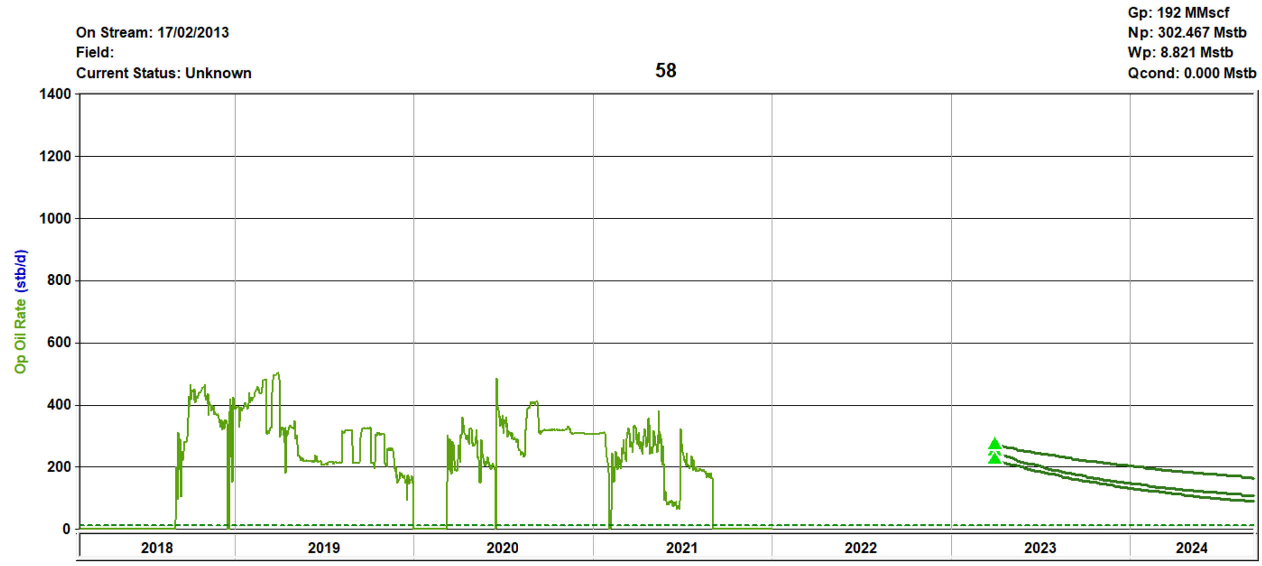


Analysis Class. Name	EUR_o Mstb	N_p Mstb	RR_o Mstb	Start Date	q_i stb/d	Δt year	d_i sec %/year	d_i tan %/year	b	d_{lim} exp %/year	$(q_o)_f$ stb/d	End Date	$R^2_{q\ vs\ Q}$
RISC 2P	1443.570	500.813	942.758	06/10/2022	184.8	83.71	17.271	18.841	1.000		10.0	23/06/2106	-0.951
RISC 1P	887.241	500.813	386.428	06/10/2022	191.7	22.53	21.248	22.170	0.400		10.0	16/04/2045	-0.565
RISC 3P	1813.410	500.813	1312.597	06/10/2022	181.1	117.22	12.739	13.583	1.000		10.0	25/12/2139	0.081

11.5. Well J-58



Analysis Class. Name	EUR_o Mstb	N_p Mstb	RR_o Mstb	Start Date	q_i stb/d	Δt year	d_i sec %/year	d_i tan %/year	b	d_{lim} exp %/year	$(q_o)_f$ stb/d	End Date	$R^2_{q\ vs\ Q}$
RISC 1P	449.242	302.467	146.774	31/03/2023	222.2	7.89	49.205	54.068	0.400		10.0	20/02/2031	-14.870
RISC 2P	620.950	302.467	318.482	31/03/2023	246.0	26.12	47.468	59.489	1.000		10.0	12/05/2049	-111.903
RISC 3P	1033.945	302.467	731.477	31/03/2023	269.9	58.52	30.750	35.856	1.000		10.0	06/10/2081	-10.484



Analysis Class. Name	EUR_o Mstb	N_p Mstb	RR_o Mstb	Start Date	q_i stb/d	Δt year	d_i sec %/year	d_i tan %/year	b	d_{lim} exp %/year	$(q_o)_f$ stb/d	End Date	$R^2_{q\ vs\ Q}$
RISC 2P	620.950	302.467	318.482	31/03/2023	246.0	26.12	47.468	59.489	1.000		10.0	12/05/2049	-111.903
RISC 1P	449.242	302.467	146.774	31/03/2023	222.2	7.89	49.205	54.068	0.400		10.0	20/02/2031	-14.870
RISC 3P	1033.945	302.467	731.477	31/03/2023	269.9	58.52	30.750	35.856	1.000		10.0	06/10/2081	-10.484