The Directors

Zeta Petroleum plc,

1 Berkeley Street,

London W1J 8DJ

20th May 2015

Dear Sirs

Competent Person's Report on Zeta Petroleum Plc

In response to your request Rockflow Resources Ltd ("Rockflow") has conducted an independent assessment of the potential reserves and resources of Zeta Petroleum Plc's assets in Romania, namely the Suceava, Bobocu and Jimbolia licences.

Following this evaluation Rockflow can report that the assets contain Reserves and Contingent Resources as of 31st December 2014 as follows:

The Suceava licence contains Gas Reserves in the producing Climauti and Dornesti Sud-1 Fields.

Gas Reserves	**Gross Bcf**			**Net Attributable Bcf**		
Operator: Raffles Energy	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
Climauti	0.622	0.685	0.801	0.311	0.342	0.400
Dornesti Sud	0.682	1.198	1.937	0.341	0.599	0.968
Total Suceava Licence	1.303	1.883	2.737	0.652	0.941	1.369

Table 0-1 Gas Reserves

The Suceava licence also contains the Granicesti SE-1 gas discovery which is planned for testing and development in 2016. Granicesti SE-1 is currently classified as Contingent Resources whilst permitting and testing continues.

The Bobocu licence contains Contingent Resources (gas) in the partially depleted Bobocu Field. These resources are potentially economic, but require further appraisal, a field development plan, relevant approvals and investment for re-development of the field to classify the volumes as reserves. At the present time, progress depends upon the successful farm-out of the opportunity to bring in a partner to help finance the required work programme.

Contingent Resources (Gas)	**Gross Bcf**			**Net Attributable Bcf**			
Operator: Zeta	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**	**Risk Factor**
Granicesti SE-1	1.097	2.059	3.78	0.549	1.029	1.89	90%
Bobocu	6.68	22.67	54.25	6.68	22.67	54.25	75%
Total	**7.78**	**24.73**	**58.03**	**7.23**	**23.70**	**56.14**	

Table 0-2 Contingent Resources (Gas)

The Jimbolia licence contains Contingent Resources (oil) in the Pliocene VIII reservoir of the Jimbolia Veche Field. There are no Contingent Gas Resources assigned as it is expected that any gas production would require reinjection due to the high CO_2 content, which is a requirement of both EU and Romanian law. It is the high CO_2 content of the gas which makes development difficult from environmental and cost perspectives.

Contingent Resources (Oil)	Gross MMstb			Net Attributable MMstb			
Operator: Zeta	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**	**Risk Factor**
Jimbolia	0.490	0.746	1.082	0.191	0.291	0.422	50%

Table 0-3 Contingent Resources (Oil)

There is potential for gas resources to be assigned in future in the Pliocene V, VI and VII following testing in well Jimbolia-100 in Q4 2014 which tested gas at very low rates. At present the volumes appear to be very small and economically immaterial, but subject to further testing there is a possibility of assigning resources in future.

The Bobocu licence contains prospective gas resources in 5 prospects. There are currently no plans for exploratory drilling of these prospects.

Prospective Resources (Gas)	Reservoir	Gross Bcf			Net Attributable Bcf			PoS
Operator: Zeta		**Low**	**Mid**	**High**	**Low**	**Mid**	**High**	
HJ Southwest	H J	1.02	2.54	5.12	1.02	2.54	5.12	17%
HJ West	HJ	1.90	4.92	10.55	1.90	4.92	10.55	23%
J South	J	0.83	1.85	3.64	0.83	1.85	3.64	21%
J North	J	0.72	1.48	2.76	0.72	1.48	2.76	28%
K2 West	K2	0.37	0.91	1.83	0.37	0.91	1.83	13%
Total		**4.85**	**11.70**	**23.91**	**4.85**	**11.70**	**23.91**	

Table 0-4 Prospective Resources (Gas)

The work was undertaken by a team of Rockflow professional petroleum engineers and geoscientists based on data supplied by Zeta. The data comprised details of licence interests, seismic and well data, technical interpretations, reports and presentations. Rockflow have exercised due diligence and independent analysis where appropriate on all technical information supplied by Zeta. Rockflow have not independently checked title interests with Government or licence authorities. No site visits were undertaken for the preparation of this report. Photographs of the well and facilities sites included in the report were provided by Zeta.

Qualifications

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

In estimating reserves, contingent and prospective resources Rockflow have used the standard petroleum engineering techniques. These estimates are made in accordance with the Petroleum Resources Management System (PRMS) approved in March 2007 by the Society of Petroleum Engineers (SPE), the World Petroleum Congress (WPC), the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Evaluation Engineers (SPEE). The PRMS standard was used because it is the primary standard approved by the LSE for oil and gas reserves and resources reporting.

The Report has been prepared in accordance with the requirements of the London Stock Exchange and the European Securities and Markets Authority (ESMA) Regulations, ESMA/2013/319 Appendix III (Oil and Gas Competent Persons Report – recommended content). The Report has been prepared for the inclusion in the Prospectus to be published in connection with the admission of Zeta Petroleum Plc to the standard listing segment of the Official List maintained by the UK Listing Authority, and to trading on the main market for listed securities of the London Stock Exchange.

Our work is based on data and information available up to January 2015 and the effective date for the reserves volumes and valuation of the assets is 31st December 2014. We are not aware of any significant matters arising from our valuation that are not covered in the Report which might be of a material nature with respect to Admission.

We confirm that information extracted from this report and included elsewhere in the Prospectus is properly extracted in a manner which is not misleading, is accurate and not inconsistent with the report.

The project was managed and approved by Tom Gunningham, a chartered petroleum engineer, and reserves auditor with 26 years industry experience. Rockflow Resources has conducted valuations for many energy companies and financial institutions since 2012. The firm's professional staff including geoscientists, engineers and economists are engaged in the independent appraisal of oil and gas properties, and have at least 15 years industry experience and relevant professional qualifications.

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. Our work has been conducted within our understanding of the relevant petroleum legislation, taxation and other regulations that currently apply to the properties. however, Rockflow Resources is not in a position to attest to the property title, financial interest relationships or encumbrances relating to the properties.

Our estimates of Reserves and Contingent Resources are based on the data set available to us, provided by Zeta Petroleum Plc. We have accepted without independent verification the accuracy and completeness of these data.

This Report represents our best professional judgement and should not be considered a guarantee or prediction of results. 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. Rockflow Resources does not warrant that the work will be any form of guarantee of geological or commercial outcomes.

The Report relates specifically and solely to the subject assets and the information presented in this letter is subject to the definitions, assumptions, explanations, qualifications and conclusions that are contained in the Report.

We have given and not withdrawn our written consent to the issue of the Prospectus, with the name Rockflow Resources included within it, and to the inclusion of the Report and reference to the Report in the Prospectus in the form and the context in which they appear. We accept responsibility for the information contained in the Report and declare to the best of the knowledge and belief of Rockflow Resources (which has taken all reasonable care that such is the case), the information contained in the report is in accordance with the facts and does not omit anything likely to affect the import of such information.

Yours faithfully,

TWGunningham

Tom Gunningham

Chief Reservoir Engineer,

Rockflow Resources Ltd.

Competent Person's Report

For

Zeta Petroleum Plc

20th May 2015

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RESOURCES

CONSULTANTS TO THE
PETROLEUM INDUSTRY

This report was prepared in accordance with standard geological and engineering methods generally accepted by the oil and gas industry. 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.

Status	Final V3.6
Date	20th May 2015
Issued by	Graham Cocksworth, Terry Pimble, Andy Spriggs, Tom Gunningham.
Reviewed by	Andy Spriggs Managing Director Rockflow Resources
Approved by	Tom Gunningham Technical Director Rockflow Resources

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CONSULTANTS TO THE PETROLEUM INDUSTRY

Executive Summary

Zeta Petroleum holds interests in 3 licences (Table 1-1) in Romania through its local subsidiary companies.

The Suceava licence (Zeta 50%) contains Gas Reserves in two fields:

1. Climauti Field is currently producing gas from a single well with gas exported via the nearby Bilca gas plant to the national gas grid. A second well, Ruda-1 was drilled in December 2014 and will be tied-back in the near future (2015).
2. Dornesti Sud has been developed with a single well and is being prepared for production of electricity via an onsite electricity generator.

The reserves in each field are relatively small, but have low production costs and are economic at current gas prices.

Reserves Bcf	Project 100% Gross			Zeta 50% Net		
Operator: Raffles Energy	P90	P50	P10	P90	P50	P10
Climauti	0.622	0.685	0.801	0.311	0.342	0.400
Dornesti Sud	0.682	1.198	1.937	0.341	0.599	0.968
Suceava Total	1.303	1.883	2.737	0.652	0.941	1.369

Table 0-1 Suceava Gas Reserves

Reference Price	Project 100% Gross			Zeta 50% Net		
NPV10 US$ MM	P90	P50	P10	P90	P50	P10
High: Deregulation to market price +25% ($13.13/mcf)	6.75	5.57	6.75	3.38	2.79	3.38
Mid: Deregulation to current market price ($10.5/mcf)	3.97	4.59	5.58	1.98	2.30	2.79
Low: Deregulation to market price -25% ($7.88/mcf)	3.20	3.72	4.53	1.60	1.86	2.27
Min: Current regulated price ($6.70/mcf)	2.87	3.36	4.09	1.44	1.68	2.05

Table 0-2 Suceava Gas Reserves Valuation

Effective date: 31st December 2014.

The Suceava licence also contains Contingent Resources in the Granicesti SE-1 discovery which is awaiting testing and subsequent development. It is planned to develop the field with the existing single well, either for gas export or for a gas to power project. Permitting negotiations are currently ongoing with landowners, subject to successful outcomes, well testing may then commence. We consider there is a 90% chance the project will go ahead. As the Climauti and Dornesti Sud Fields already carry the Suceava licence overhead costs, the incremental value of adding a third producing field to the licence is significant. The Granicesti valuation shown below is the incremental value for the field as part of the Suceava licence, not a standalone value.

Contingent Resources (Gas)	Gross Bcf			Net Attributable Bcf			
Operator: Raffles Energy	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**	**Risk Factor**
Granicesti SE-1	1.097	2.059	3.78	0.549	1.029	1.89	90%

Table 0-3 Suceava Contingent Resources

Reference Price	Project 100% Gross			Zeta 50% Net		
NPV10 US$ MM	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
High: Deregulation to market price +25% ($13.13/mcf)	3.80	11.08	19.12	1.90	5.54	9.56
Mid: Deregulation to current market price ($10.5/mcf)	3.98	7.98	13.89	1.99	3.99	6.95
Low: Deregulation to market price -25% ($7.88/mcf)	2.28	5.04	8.86	1.14	2.52	4.43
Min: Current regulated price ($6.70/mcf)	1.46	3.69	6.62	0.73	1.84	3.31

Table 0-4 Suceava Contingent Resource Valuation

The Bobocu licence (Zeta 100%) contains Contingent Resources (gas) in the partially depleted and abandoned Bobocu Field. These resources are potentially economic, but require further appraisal, a field development plan, relevant approvals and investment for re-development of the field before the volumes can be classified as reserves. At the present time, progress depends upon the successful farm-out of the opportunity to bring in a partner to help finance the required work programme. The farm-out process is currently underway, and given the significant remaining volumetric potential and low cost environment, we consider there is a high chance (75%) that the project will go ahead.

Contingent Resources (Gas)	Gross Bcf			Net Attributable Bcf			
Operator: Zeta	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**	**Risk Factor**
Bobocu	6.68	22.67	54.25	6.68	22.67	54.25	75%

Table 0-5 Bobocu Contingent Resources (Gas)

Effective Date: 31st December 2014.

Reference Price	Project 100% Gross		
NPV10 US$ MM	**P90**	**P50**	**P10**
High: Deregulation to market price +25% ($13.13/mcf)	6.2	54.45	143.45
Mid: Deregulation to current market price ($10.5/mcf)	1.1	38.9	108.4
Low: Deregulation to market price -25% ($7.88/mcf)	-4.0	23.5	55.35
Min: Current regulated price ($6.70/mcf)	-6.35	16.65	57.8

Table 0-6 Bobocu Contingent Resources Valuation

The Jimbolia licence (Zeta 39%) contains Contingent Resources (oil) in the Pliocene VIII reservoir of the Jimbolia Veche Field. There are no Contingent Gas Resources assigned as it is expected that any gas production from this zone would require reinjection due to the high CO_2 content. It is the high CO_2 content of the gas which makes development difficult from environmental and cost perspectives. Small amounts of gas have been tested from the Pliocene V and VII, but volumes were considered too small for resources to be assigned. Zeta is carried by the operator for the costs of the current work programme which will be used to decide whether or not to retain the licence and proceed towards development.

Contingent Resources (Oil)	Gross MMstb			Net Attributable MMstb			
Operator: NIS	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**	**Risk Factor**
Jimbolia	0.490	0.746	1.082	0.191	0.291	0.422	50%

Table 0-7 Jimbolia Contingent Resources (Oil)

The Bobocu licence contains prospective gas resources in 5 prospects. There are currently no plans for exploratory drilling of these prospects, and they are currently considered to have immaterial value to Zeta.

Prospective Resources (Gas)	Reservoir	Gross Bcf			Net Attributable Bcf			PoS
Operator: Zeta		**Low**	**Mid**	**High**	**Low**	**Mid**	**High**	
HJ Southwest	H J	1.02	2.54	5.12	1.02	2.54	5.12	17%
HJ West	HJ	1.90	4.92	10.55	1.90	4.92	10.55	23%
J South	J	0.83	1.85	3.64	0.83	1.85	3.64	21%
J North	J	0.72	1.48	2.76	0.72	1.48	2.76	28%
K2 West	K2	0.37	0.91	1.83	0.37	0.91	1.83	13%
Total		**4.85**	**11.70**	**23.91**	**4.85**	**11.70**	**23.91**	

Table 0-8 Prospective Resources (Gas)

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1. Introduction

1.1. Licences

Zeta Petroleum Plc holds interests in 3 licences (Table 1-1) in Romania through its local subsidiary companies (Figure 1-1).

Asset	Operator	Interest	Status	Licence Expiry	Area km^2	Comment
E IV-1 Suceava	Raffles Energy	50%	Exploration Development & Production	31.12.2016	1734	Granicesti SE-1 discovery
			Production	2033	2.71	Climauti gas in production
			Experimental Production	31.12 2015	2.99	Dornesti Sud-1 gas in production
Bobocu	Zeta	100%	Exploration & Development	2028	24.97	Bobocu Field development potential
DEE V-20 Jimbolia	NIS Gazpromneft	39%	Exploration & Development	2028	23.9	Jimbolia Veche and Vest oil and gas potential.

Table 1-1 Zeta Petroleum Licence Interests

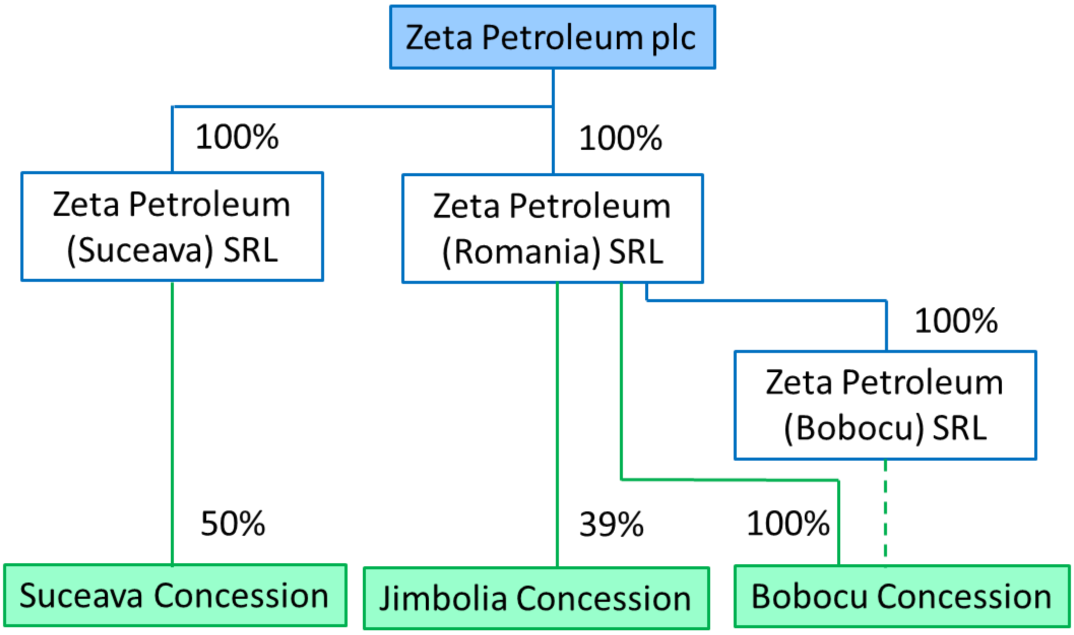


Figure 1-1 Zeta Petroleum plc Group Structure

1.1.1. Suceava

Zeta Petroleum holds a 50% non-operated interest in the Suceava Concession through its subsidiary Zeta Petroleum (Suceava) SRL. The licence partner is Raffles Energy SRL which holds a 50% interest and is the Operator. The Suceava Concession is an Exploration, Development and Production Licence which

The concession licence was originally awarded for 30 years on 18th June 2003 and ratified on 8th July 2004. The initial exploration period of 5 + 2.5 + 2.5 years was extended to 31st December 2014 and in December 2014 was further extended to 31st December 2016, subject to a 670km^2 relinquishment and additional work commitments. There is an option to extend for a further 1 year to 2017, subject to further work commitments.

Within the Suceava licence are three gas fields. Climauti is currently in production within a 2.71km^2 production licence which expires in 2033. Climauti is developed with 1 well tied back to the third party owned Bilca gas processing plant operated by Raffles. A second well, Ruda-1 was successfully drilled in 2014, which in our opinion encountered an extension of the Climauti gas field. It is planned to hook up Ruda-1 for production via Climauti to the Bilca gas plant.

Dornesti Sud-1 is currently in production, with the gas used to generate electricity via a generator located at the wellhead tied back to the local power grid. Dornesti Sud-1 started electricity production on 5th December 2014 under a 1 year experimental production licence which will be converted to a 25 year production licence subject to successful production performance. The experimental licence originally expired at end 2014, together with the Suceava licence, but on 28th January 2015, the operator, Raffles submitted an application to extend the experimental production period to 31st December 2015. At time of writing, no reply had been received, but Zeta believes there is no reason why the extension will not be granted.

Granicesti SE-1 is a discovery which is planned for testing and development. Subject to gaining permits from local landowners, it is planned to test and if successful develop the field in 2016 with the existing single well. The base case plan is for gas export to the Transgaz transmission system. In case of poor test results, the well may be developed for electricity generation, similar to Dornesti Sud-1.

The original work commitments were fulfilled, and additional work commitments were taken on when the licence was extended in 2012 to 2014. These commitments were:

- Drill the Ruda-1 appraisal well (completed in December 2014)
- Complete Dornesti Sud-1 gas to power project (completed in December 2014)
- Re-Test Granicesti SE-1 (delayed by permitting, but rolled over to 2016)

When the licence was extended in 2014 to 2016, the following new mandatory work commitments were agreed:

- Acquisition of 100km 2D seismic (or 3D equivalent) with approved budget of Euro 1 million.
- Comprehensive analysis of all existing information and evaluation of remaining exploration potential (with selective reprocessing of existing seismic data and integration with newly acquired information) in order to delineate any new prospects for drilling - with approved budget of Euro 500,000.
- Completion of the investments for the Dornesti Sud-1 gas to power project with approved budget of Euro 750,000 (completed in December 2014).
- The re-entry and testing of Granicesti SE-1 with approved budget of Euro 750,000.
- Construction and installation of production facilities and export pipeline for the Ruda-1 well - with approved budget of Euro 500,000.
- A programme of technology transfer and training to the value of US$ 25,000 per year (Euro 30,000).

If the option to extend the licence to 2017 is taken, the following optional work programme:

- Drill an exploration well to a depth of 600m to test a target in the Sarmatian (subject to the results of studies of the mandatory work programme and access to required land) with budget of Euro 1.5 million.
- Drill a second exploration well to a depth of 600m to test a target in the Sarmatian (subject to the results of studies of the mandatory work programme, the results of the first well and access to required land) with budget of Euro 1.5 million.
- A programme of technology transfer and training to the value of US$ 25,000 (Euro 30,000).

The Operator plans to continue with the licence extension and mandatory work programme. The development of Ruda-1 will require permitting to install a 750m pipeline to Climauti. Zeta expects the well to be put on production in 2015. The schedule for testing Granicesti SE-1 depends on the outcome of ongoing negotiations with local landowners. Zeta hope to be able to develop the well in 2016, and a date of November 2016 has been assumed. The gas associated with these the Climauti and Dornesti Sud wells is currently classified as Reserves as they are currently in production. The gas associated with Granicesti SE-1 remains as Contingent Resources until permitting and testing is achieved and the development plan is confirmed.

1.1.2. Bobocu

Zeta Petroleum holds a 100% operated interest in the Bobocu licence through its subsidiary Zeta Petroleum (Romania) SRL. Zeta has applied for Bobocu to be transferred to a new subsidiary Zeta Petroleum (Bobocu) SRL. Zeta was awarded a 20 year concession on 19th December 2007 which expires on 1st January 2028. The licence may be subsequently renewed for up to a further 15 years. The Bobocu Concession contains the depleted Bobocu field which ceased production in 2001 but has remaining development potential.

The original work commitments comprising geological study work and the workover of a well were fulfilled. Zeta completed initial studies, after which the licence area was extended on 17th December 2008. Zeta acquired 75km^2 3D seismic in 2010 and then drilled a new well, Bobocu-310 in 2012. Bobocu-310 had gas shows, but failed to produce gas on test.

To retain the licence without production, work commitments are agreed on an annual (or biannual) basis. A technical review was performed in 2014, and a letter was submitted to the NAMR stating that Zeta wishes to retain the licence. New work commitments will be agreed in Q1 2015. Zeta is currently seeking a farm-out to bring in a partner with funding to progress the appraisal and development of Bobocu. It is likely that Zeta will have to commit to drilling a sidetrack or a new well in 2015 to retain the licence.

Zeta's current intention is to retain the licence and continue to appraise the remaining potential of Bobocu, with the hope to develop the field. There is no current field redevelopment plan in place, but a range of conceptual development plans have been evaluated, and the gas associated with these plans is currently classified as Contingent Resources.

1.1.3. Jimbolia

Zeta Petroleum holds a 39% non-operated interest in the Jimbolia licence through its subsidiary Zeta Petroleum (Romania) SRL. The licence partners are NIS Petrol SRL (Gazprom Neft) which holds a 51% interest and is the Operator and Armax Gaz SA which holds 10%. Zeta was awarded the Concession licence on 27th August 2007 and ratified on the effective date of 26th March 2008. The licence expires in 2028, but may be extended for a further 15 years subject to continuation of production.

The Jimbolia licence contains two undeveloped discoveries Jimbolia Veche and Jimbolia Vest field which have future development potential, but no current development plan.

The initial work commitments comprising Phase 1a (technical studies) and 1b (well workover) were completed by 2010. Phase 2 commitments comprising drilling 1 well (Jimbolia-100) was completed by 2013. Jimbolia-100 discovered oil with a gas cap with a high CO_2 content.

In 2014 additional work commitments were agreed and completed comprising:

- Reprocessing and interpretation of existing 2D seismic profiles, amounting to 50.000 USD;
- Testing the intervals with gas indications in Jimbolia-100, amounting to 900.000 USD;
- Technical and economic study estimating resources/reserves of hydrocarbons in Block DEE V 20 Jimbolia, amounting to 50.000 USD;
- Professional development and transfer of technology: 5.000 USD.

Zeta was fully carried by NIS Petrol for the testing of Jimbolia-100, and is only liable to contribute to the reserves study. Following these studies, the licence holders will decide whether to retain the licence and incur further work commitments, which may include development of the discovered oil/condensate, or further appraisal of gas zones, otherwise, they will be required to relinquish the licence. The discovered oil within the licence is classified as Contingent Resources.

Figure 1-2 Zeta Licence Location Map

1.2. Legal, Environmental and Infrastructure Issues

1.2.1. Overriding rights

There are no overriding rights on Zeta's licence interests.

1.2.2. Abandonment Requirements

The licences are subject to Romanian abandonment regulations (NAMR order no 175/2009) which require the licence holders to Plug and abandon wells with casing cut 2.5m below ground level and remove production facilities, leaving the land restored. Abandonment cost estimates are included in the economic analyses below.

1.2.3. Infrastructure and Human Resource Requirements

Romania has had an active Petroleum industry since the 1800's, and remains active with an extensive oil and gas infrastructure and oil field service industry. The proposed investments by Zeta can be considered as relatively small scale, using conventional technology in a mature hydrocarbon province. As such, we consider that there are no special infrastructure requirements which threaten the developments, and that the existing trained human resources and oil field services assets available within Romania can be considered to be sufficiently available to enable the proposed works to be performed. The proposed investments within the Suceava and Bobocu licences will utilise existing national grid infrastructure to export gas and electricity.

Although Zeta is already a licensed operator in Romania, work performed on the Suceava and Jimbolia licences will be performed by the existing staff of the operators Raffles and NIS. If work proceeds on the Bobocu licence, Zeta will need to recruit additional staff unless operatorship is transferred to a new partner. Zeta currently maintains only a small technical and administrative staff in their Bucharest office.

2. Suceava

2.1. Suceava Overview

The Suceava Exploration Permit covers a large area of the Moldovan Platform located to the east of the Carpathian fold belt in north-eastern Romania (Figure 2-1). Numerous wells have been drilled in the area, leading to the discovery of several gas fields which produce from Sarmatian, Eocene and Cretaceous reservoirs. The Suceava license is operated by Raffles Energy SRL (50% participation) with partner Zeta Petroleum (50%), and includes:

- The Climauti gas field, discovered by well Climauti-1, which has been converted to a gas producer. The field came on-stream in March 2011, and is currently producing 8000 scm/day. A second well, Ruda-1 was drilled in the field area in 2014. It is planned to hook up and put this well on production in May 2015.
- The Dornesti Sud gas field which was put into production via a single well (Dornesti Sud-1) on 5th December 2014. The gas is used to fuel an electric generator located at the wellhead, and the electricity is exported via a connection to the local electricity grid. Production is 0.9 MW.
- The Granicesti SE gas discovery, which the operator plans to test and bring on-stream during 2016. The discovery well Granicesti SE-1 is the only well in the field.
- Exploration leads which will be further evaluated by the 2015-16 work programme.

The current study involved an independent assessment of the resources for the Suceava licence, and comprised of the following:

- A review of the seismic interpretation (previously prepared by the operator).
- A review of the geological environment and reservoir quality.
- An independent petrophysical evaluation of wells Climauti-1, Dornesti Sud-1 and SE-1.
- A probabilistic estimate of initial in-place gas volumes (GIIP) for Climauti, Dornesti Sud and Granicesti SE.
- Recovery factor assessment & resource volumes

Figure 2-1 Suceava Location Map

2.2. Database

- Zeta provided the following data to enable the evaluation:
  - A Kingdom seismic project (Figure 2-2) containing:
  - 94 2D seismic lines totalling 1,600km, with interpreted horizons and grids;
  - 56 wells within and adjacent to the Suceava licence;
  - Log suites for 9 wells (5 wells had data other than SP and resistivity);
  - Formation tops for 13 wells.
- A seismic interpretation report for the license area (October 2005)
- End of well reports with associated logs and test data for Dornesti Sud-1 and SE-1
- A sedimentological study for core from Dornesti Sud-1
- An evaluation of Ruda prospectivity (January 2014; in Romanian)
- End of well report for Ruda-1 (December 2014)
- Climauti production data

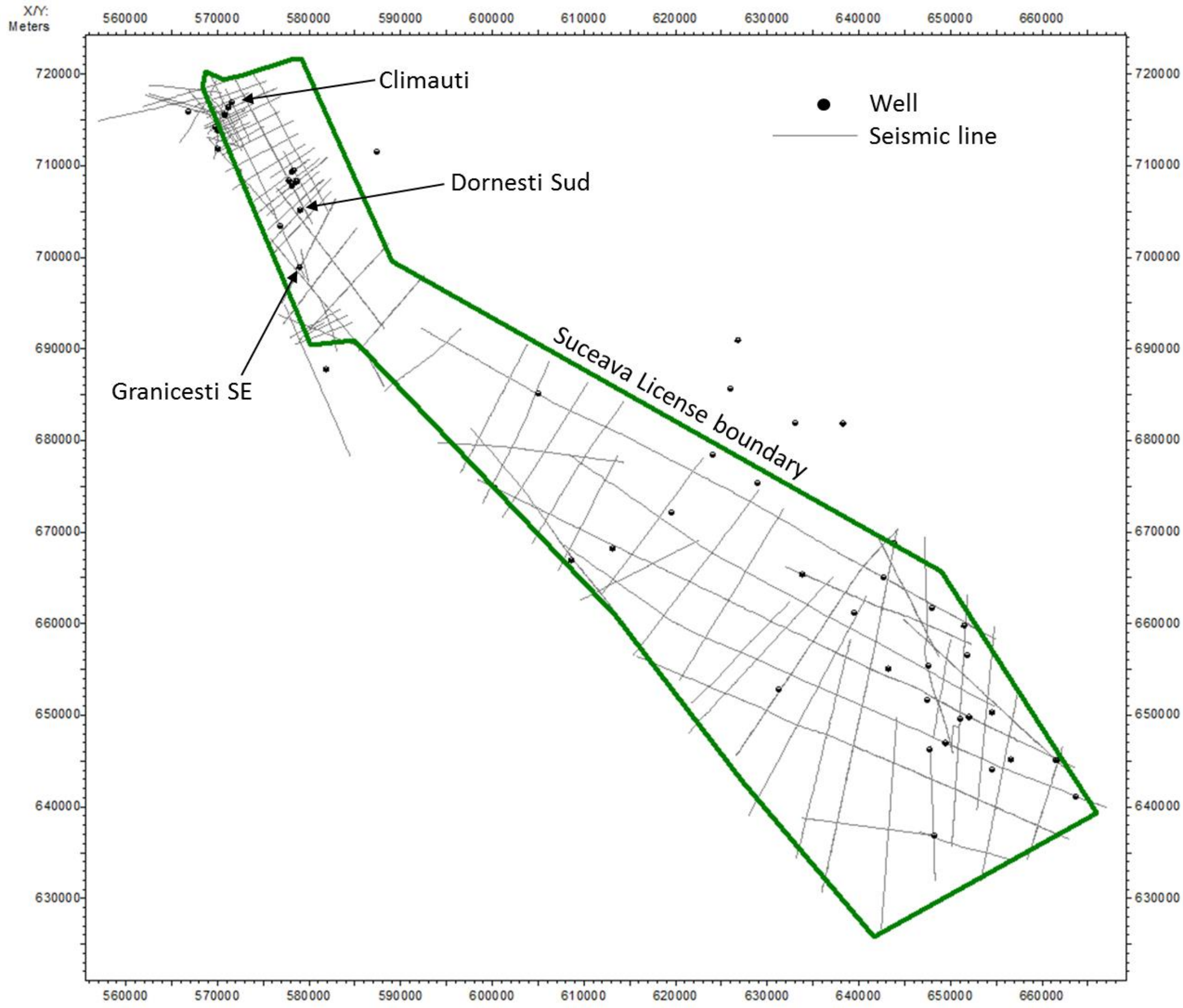


Figure 2-2 Suceava License up to 31.12.2014, Seismic and well locations

The block outline represents the retained area after a partial relinquishment in 2010

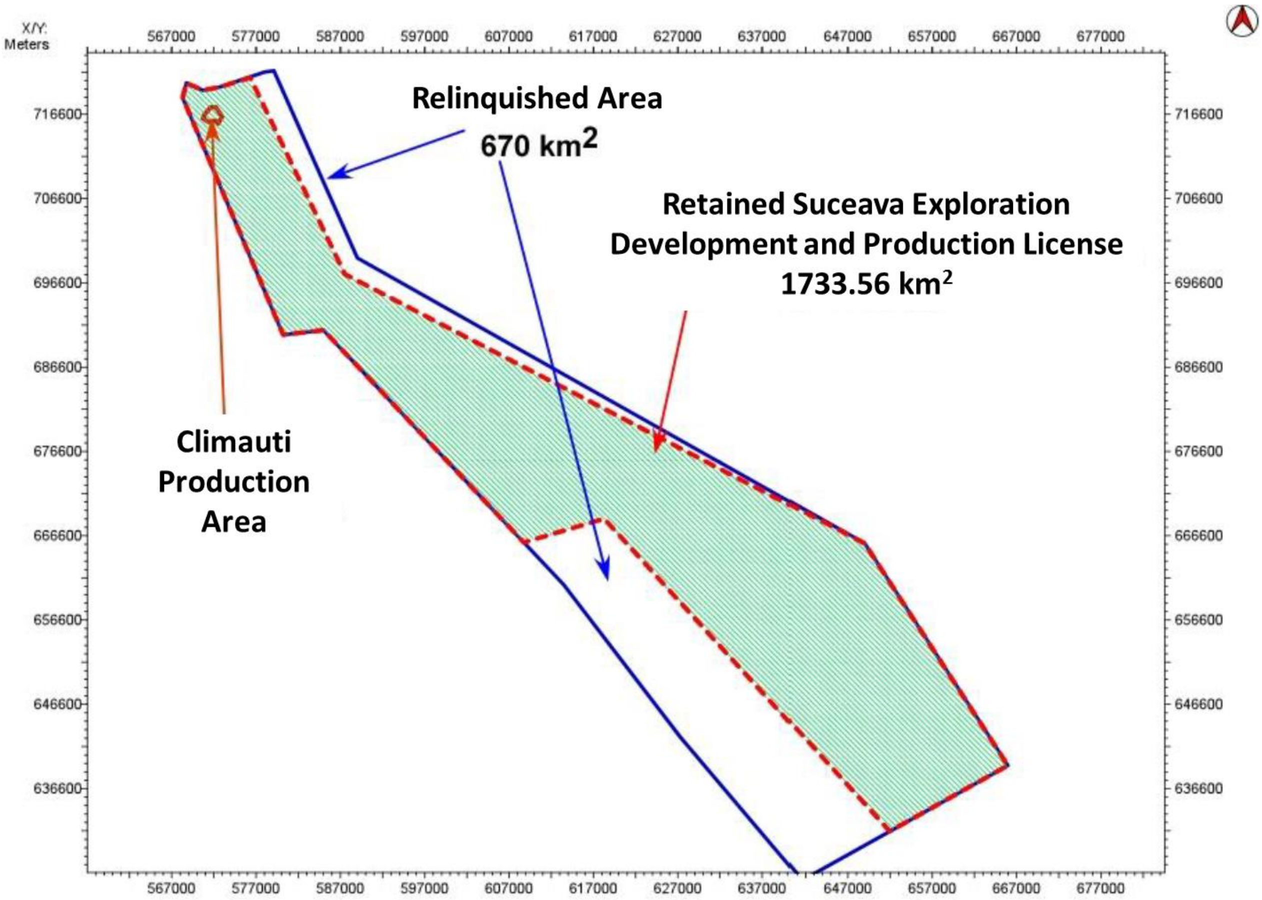


Figure 2-3 Suceava License from 1.1.15 following relinquishment

The block outline in red represents the retained area after a partial relinquishment in 2014

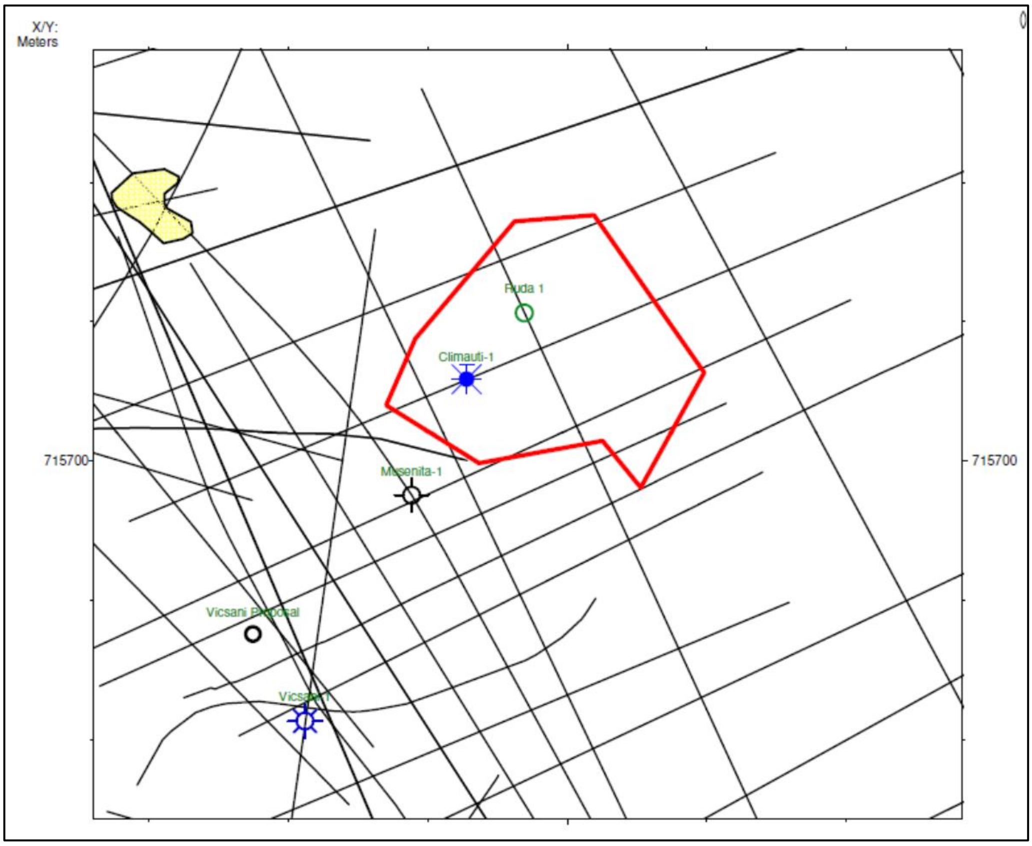


Figure 2-4 Climauti Production Licence area showing location of Climauti-1 and Ruda-1

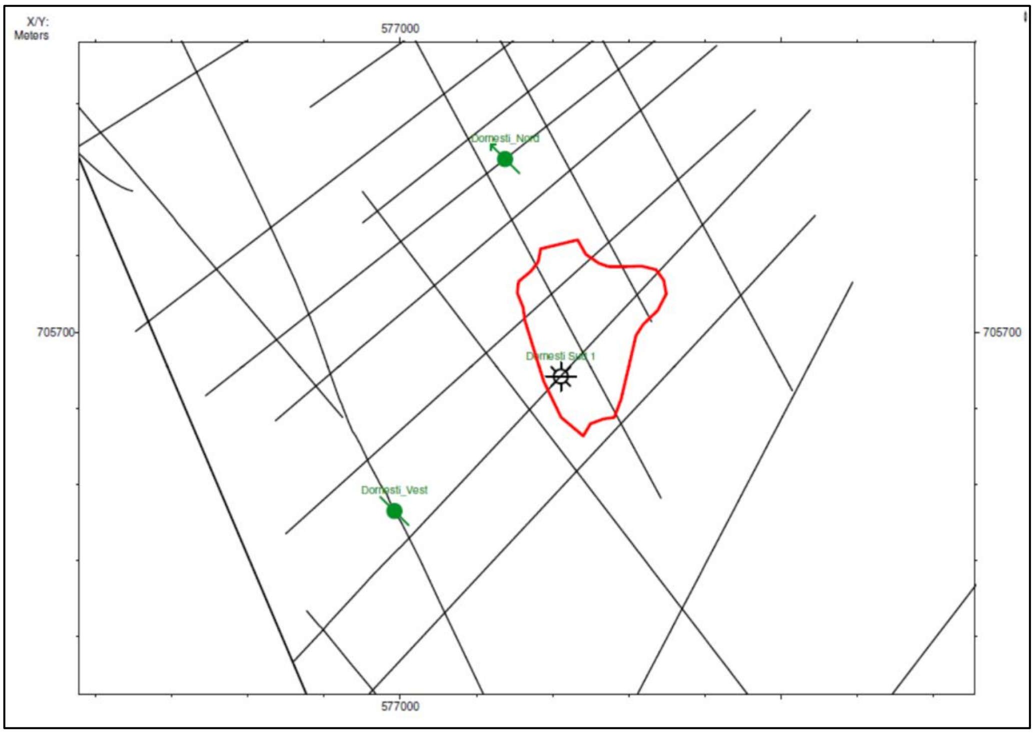


Figure 2-5 Proposed Dornesti Sud production area (not yet awarded)

2.3. Geological interpretation

Exploration across the Moldovan Platform has targeted several stratigraphic intervals including Tertiary sandstones, Cretaceous cherts and Cambro-Ordovician quartz reservoirs. However, material discoveries have been predominantly shallow biogenic gas accumulations within the Sarmatian (Miocene) age fluvial/deltaic sequences that cover the area.

The Sarmatian interval is dominated by claystones with interbeds of unconsolidated siltstones and sandstones. Seismically, the Sarmatian section is typified by a series of clinoforms which prograde from north-west to south-east across the area above the ubiquitous Badenian Anhydrite, which provides a reliable seismic structural marker (Figure 2-6). Most of the Sarmatian sediments in the prospective zone appear to be “toesets” of the clinoforms, containing sands and silts that were developed as a series of very fine grained contourites and distal turbidites.

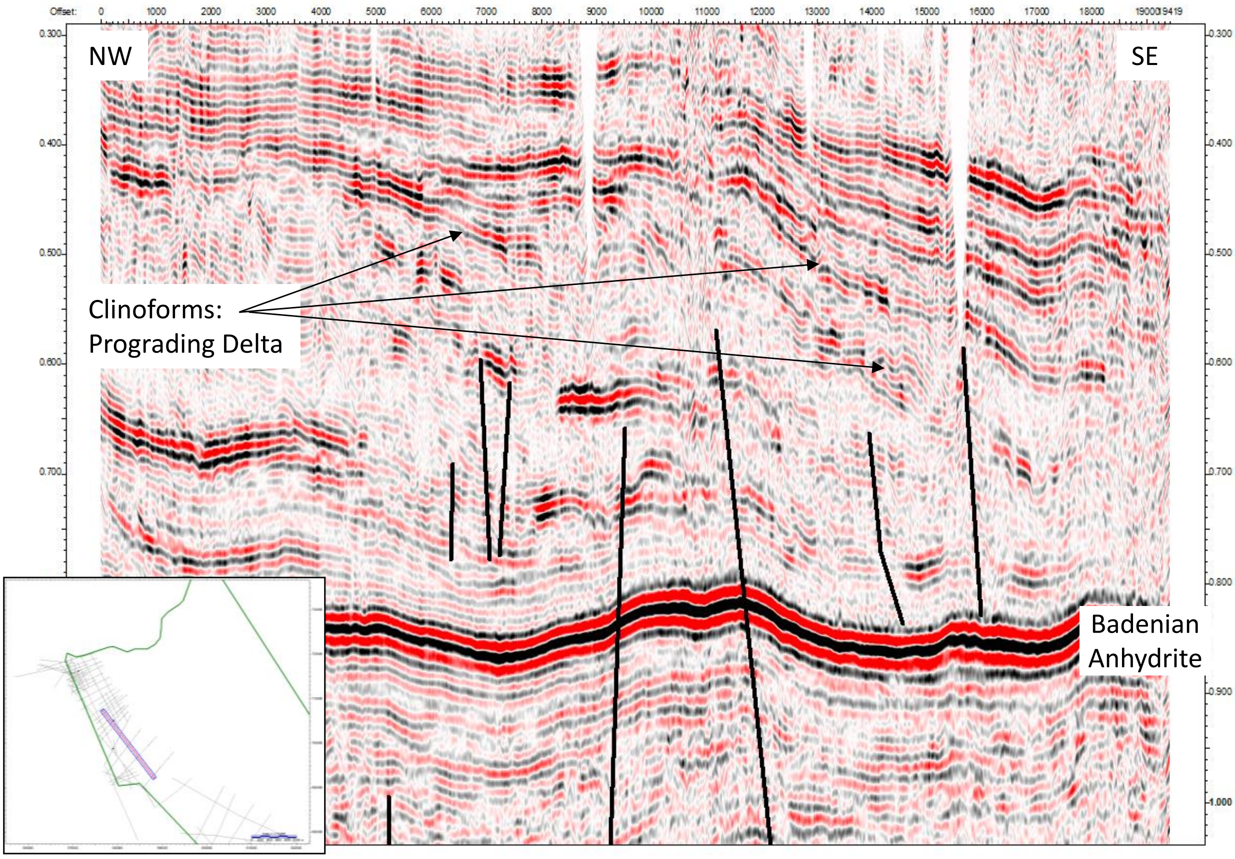


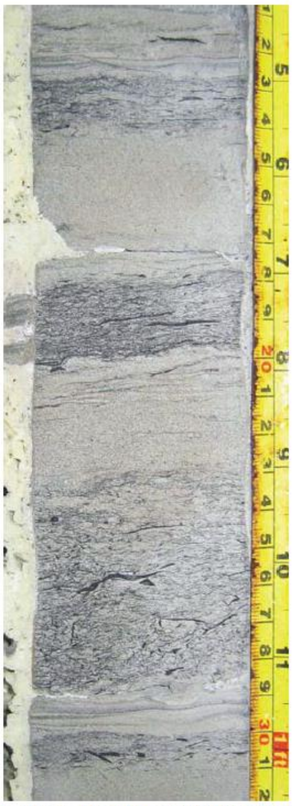
Figure 2-6 Example seismic line

A number of silt intervals are identified on mudlogs which are difficult to confirm on wireline logs; very shaley sands and thin interbedded sands and shales are petrophysically very similar to background shale deposition.

A core (Figure 2-7) taken from the reservoir interval of Dornesti Sud comprises thinly laminated, well sorted, very-fine to fine sandstones. Thin siltstone laminae interbedded with the sandstones and repeated sequences of upward fining and decreasing bed thickness are suggested to represent the distal expression of waning turbidite flows. This is supported by the presence of foraminifera and calcispheres within the sandstones which indicate a marine environment.

Consequently, the general interpretation is that the sediments were deposited in a basin floor setting some distance from a marine shelf to slope environment with the possibility that sand deposition was related to a marine lowstand during the early Sarmatian.

Finely flat laminated fine sandstones with thin siltstone drapes (534.6m MD)



Fine sandstone beds with concentrations of plant fragments (534.2m MD)

Fine sandstone beds exhibiting rippling and low angle cross stratification (538.1m MD)

Figure 2-7 Core photos from the reservoir interval in Dornesti Sud-1

2.4. Seismic Interpretation

The Suceava licence is partially covered by 2D seismic (Figure 2-2), most of which has been acquired since 2004, with a typical line spacing of 500-5000m in the area of interest. However, as each discovery is less than 5km^2 in area, they are only covered by 2 or 3 lines (Figure 2-8, Figure 2-9 and Figure 2-10).

Seismic data quality varies across the area, but the Sarmatian sequence is generally well defined, while the prominent Badenian Anhydrite reflector provides a consistent basis for structural interpretation (Figure 2-6). Individual reservoir units within the Sarmatian cannot be correlated across the entire licence area, but have sufficient coherency to provide definition around each discovery. This is probably a function of sand/silt deposition patterns, which is expected to occur in lenses within delta toe-sets rather than as widespread stratigraphic layers.

The relatively sparse data coverage leads to large potential uncertainty in the structural maps, but it is evident (Figure 2-11, Figure 2-12 and Figure 2-13) that, with the possible exception of Dornesti Sud, the discoveries do not correspond to structural highs. Instead, gas accumulations are probably stratigraphically limited within shale-encased sand/silt lenses.

There is some evidence to support the correlation between seismic amplitude and presence of hydrocarbons, although a number of other factors, including bed thickness tuning, net sand ratio and variations of shale properties, affect seismic amplitude. However, in the absence of structural closure, the strong seismic amplitudes associated with the Climauti, Dornesti Sud and Granicesti SE discoveries provide the best guide to the size of each accumulation.

There is very little velocity or depth information for the Sarmatian events so depth conversion cannot be undertaken with a high degree of confidence. However, the base case interpretation of gas-filled, stratigraphically limited, reservoirs that can be delimited by seismic amplitude mapping means that depth conversion is not a critical factor in determining the in-place volumes.

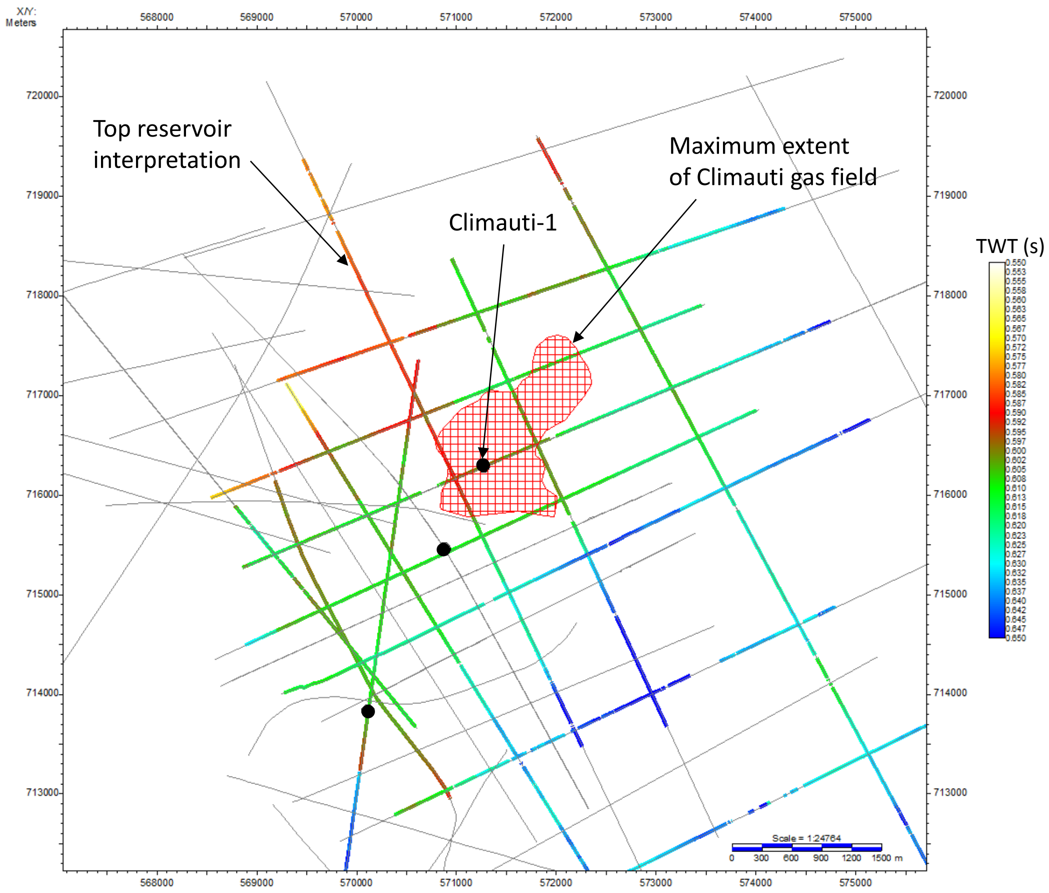


Figure 2-8 Climauti field: Seismic data coverage and interpretation

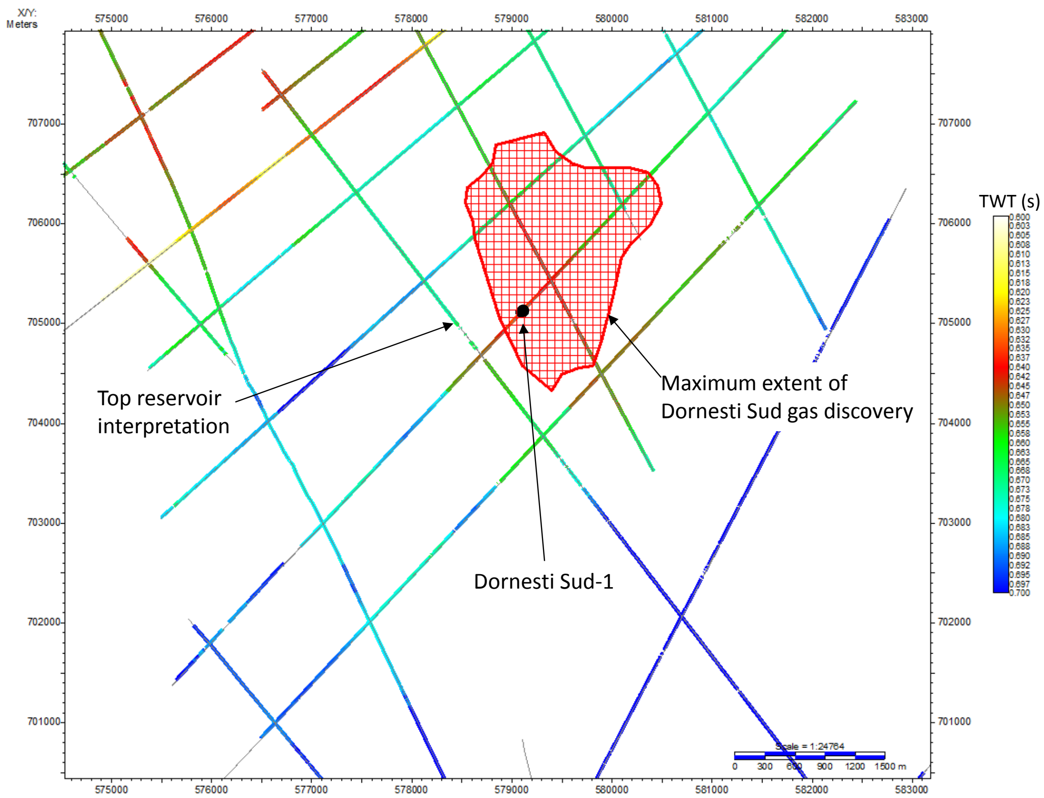


Figure 2-9 Dornesti Sud discovery: Seismic data coverage and interpretation

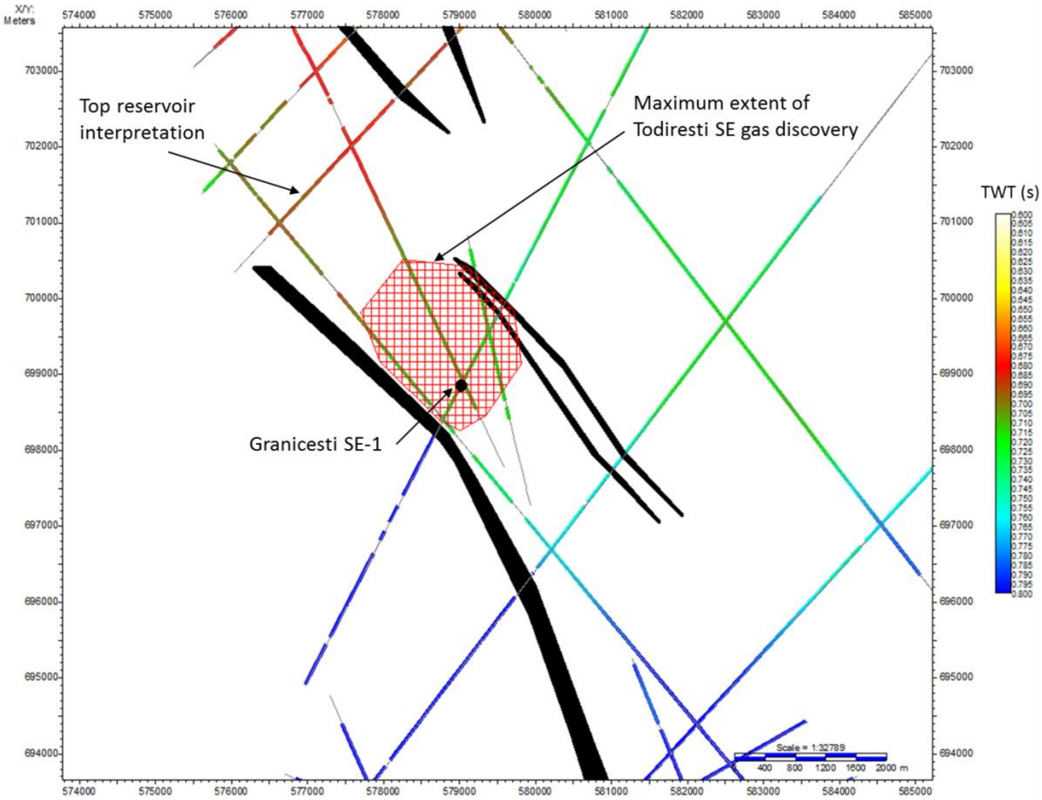


Figure 2-10 Granicesti SE-1 discovery: Seismic data coverage and interpretation

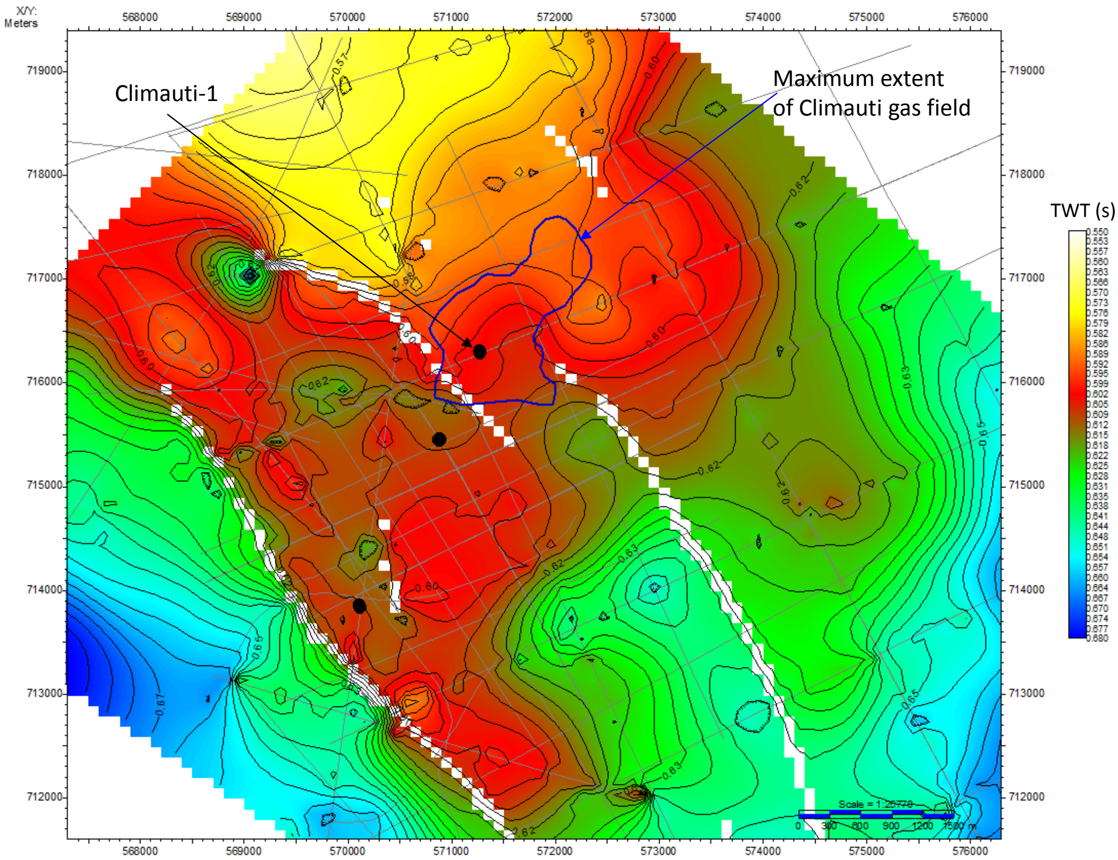


Figure 2-11 Climauti field: Gridded time interpretation

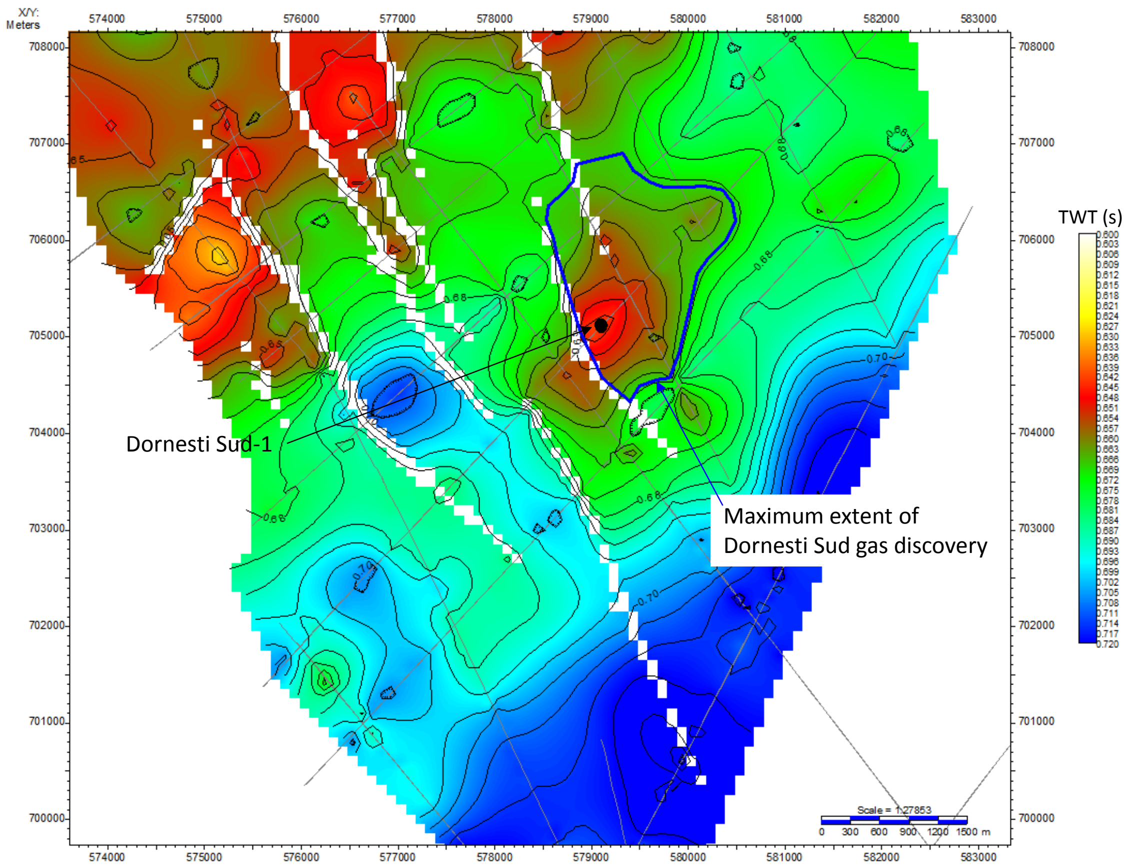


Figure 2-12 Dornesti Sud discovery: Gridded time interpretation

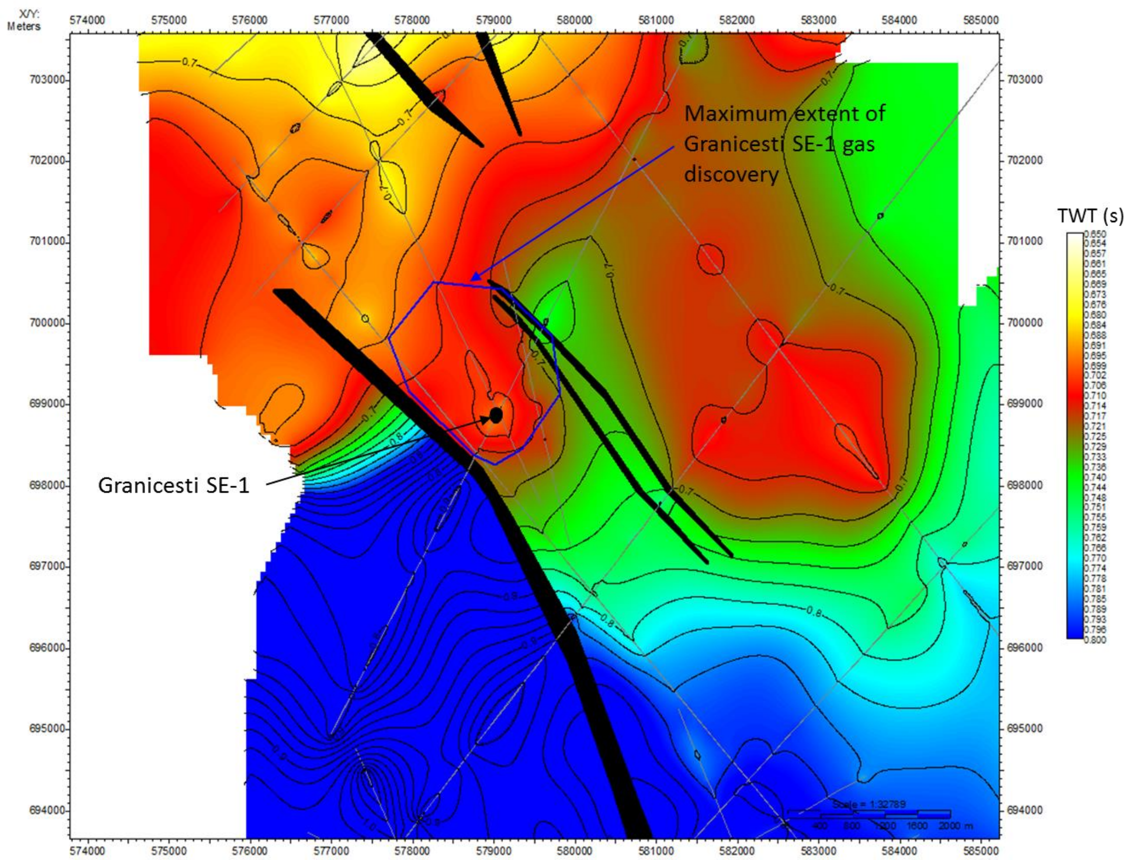


Figure 2-13 Granicesti SE-1 discovery: Gridded time interpretation

2.5. Petrophysical Interpretation

Digital wireline data were provided for 9 wells, although the log suite for 4 wells comprised SP and resistivity only. However, more comprehensive datasets were available for the wells in the three discoveries (Table 2-1).

Log Type	Climauti-1	Dornesti Sud-1	Granicesti SE-1
Gamma Ray	GRCOMP	GRDLLCOMP	GRCOMP
Neutron	NPRL	CNC	CNC
Density	DEN	DEN	DEN
Sonic	DTCOMP	DTCOMP	
Deep resistivity	RDCOMP	RDCOMP	RDCOMP
Shallow resistivity	RSCOMP	RSCOMP	RSCOMP
Micro resistivity		RMLL	
SP		SPCOMP	SPCOMP
Caliper		CAL	2_CAL

Table 2-1 Available log data

2.5.1. Climauti-1

Climauti-1 was drilled to a total depth of 590m. Two sands are interpreted from logs as being gas bearing, one of which was tested and produced gas (Figure 2-14):

- Main gas sand, tested gas from an approximately 7m thick sand at a depth of 456.6m MD (-51.5m TVDss).
- Upper gas sand, approximately 5m thick at a depth of 424.8m MD (-19.7m TVDss).

The well was converted to a gas producer.

2.5.1.1. Data

The only available data provided for Climauti-1 were the wireline logs (Table 2-1) and formation tops within the Kingdom project. No supporting information about the drilling of this well, e.g. end-of-well report, was provided.

2.5.1.2. Well evaluation

In the absence of Density Correction log or Caliper, the condition of the hole is difficult to determine and no Bad Hole flag was generated. However, the available logs appear to be of a reasonable standard.

The Clay Volume (VCL) was calculated from the Gamma Ray (GR) curve and also from the Neutron-Density separation, and the lower value was used to define final VCL (Figure 2-14). Hydrocarbon-corrected porosity was calculated from the Density log, assuming a sand grain density of 2.65 g/cc.

A standard Archie interpretation was used to determine water saturation. The temperature gradient was determined and plotted on the Computer Processed Interpretation (CPI) (Figure 2-14) based on two fixed points: the maximum recorded temperature in the Dornesti Sud-1 well of 91.4^{o}F at 909 m MD, and an assumed 50^{o}F temperature at surface.

Three salinity values of 10,000 ppm, 33,000 ppm and 40,000 ppm, based on regional values and Pickett plot results (Figure 2-15), have been used in this study to demonstrate the effect a varying Rw will have on Sw results, while unconsolidated Archie parameters have been assumed:

m= 1.7 n= 2 a= 1
Rw = 0.7, 0.24 and 0.2 Ohmm at 60^{o}F (10,000, 33,000 and 40,000 ppm respectively)

An Rmf of 0.1 at 60^{o}F has been assumed, and no fluid contacts were observed in the well. The results are presented in Figure 2-14.

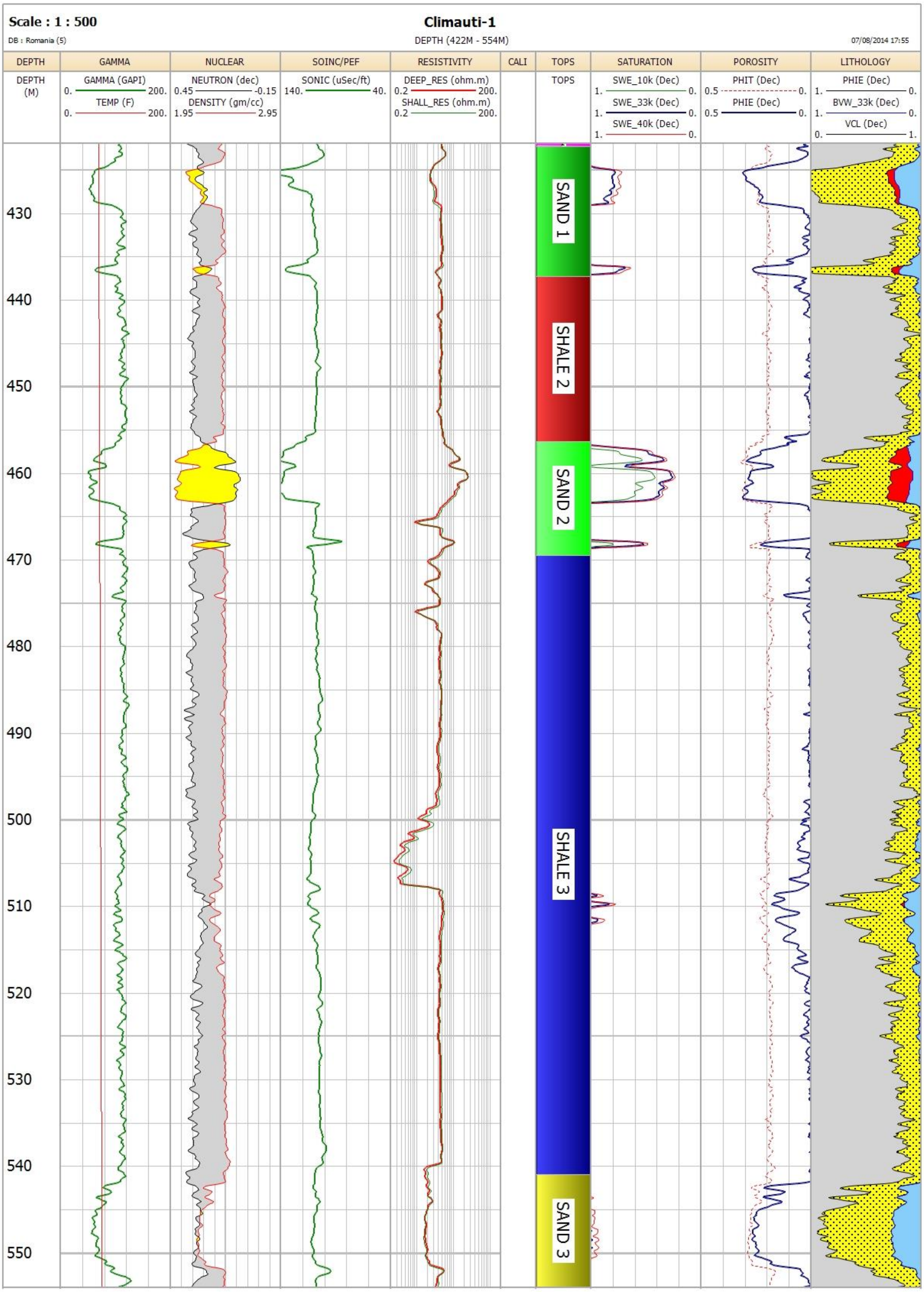


Figure 2-14 CPI plot for Climauti-1

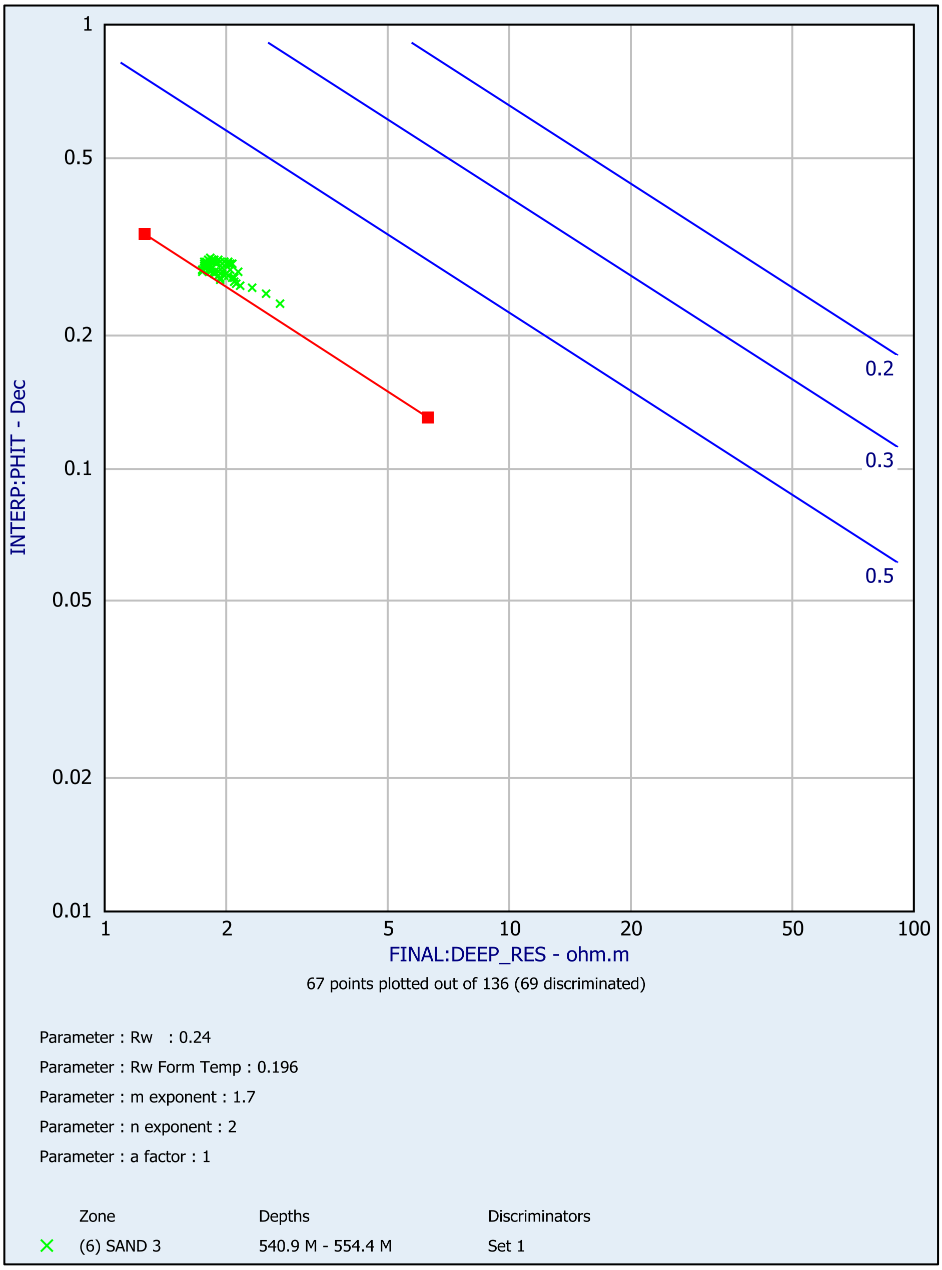


Figure 2-15 Pickett plot for Climauti-1

2.5.2. Ruda-1

Ruda-1 was spudded on 30th November 2014 by Raffles Energy, and drilled to a TV of 551mMD. Rotary Table elevation was 397.9m above mean sea level (MSL) and ground elevation was 394 m above MSL.

The reservoir section was logged with a conventional GR-SP-CALI-DDL-DSLL-NDEN wireline log across the 8.5" hole using Weatherford as the logging contractor.

An interpretation was made available by Zeta, and compared to the nearby Climauti-1 well, some 700 metres away. The correlation is shown in Figure 2-16, and the reservoir section shows an almost identical character to the Climauti-1 well.

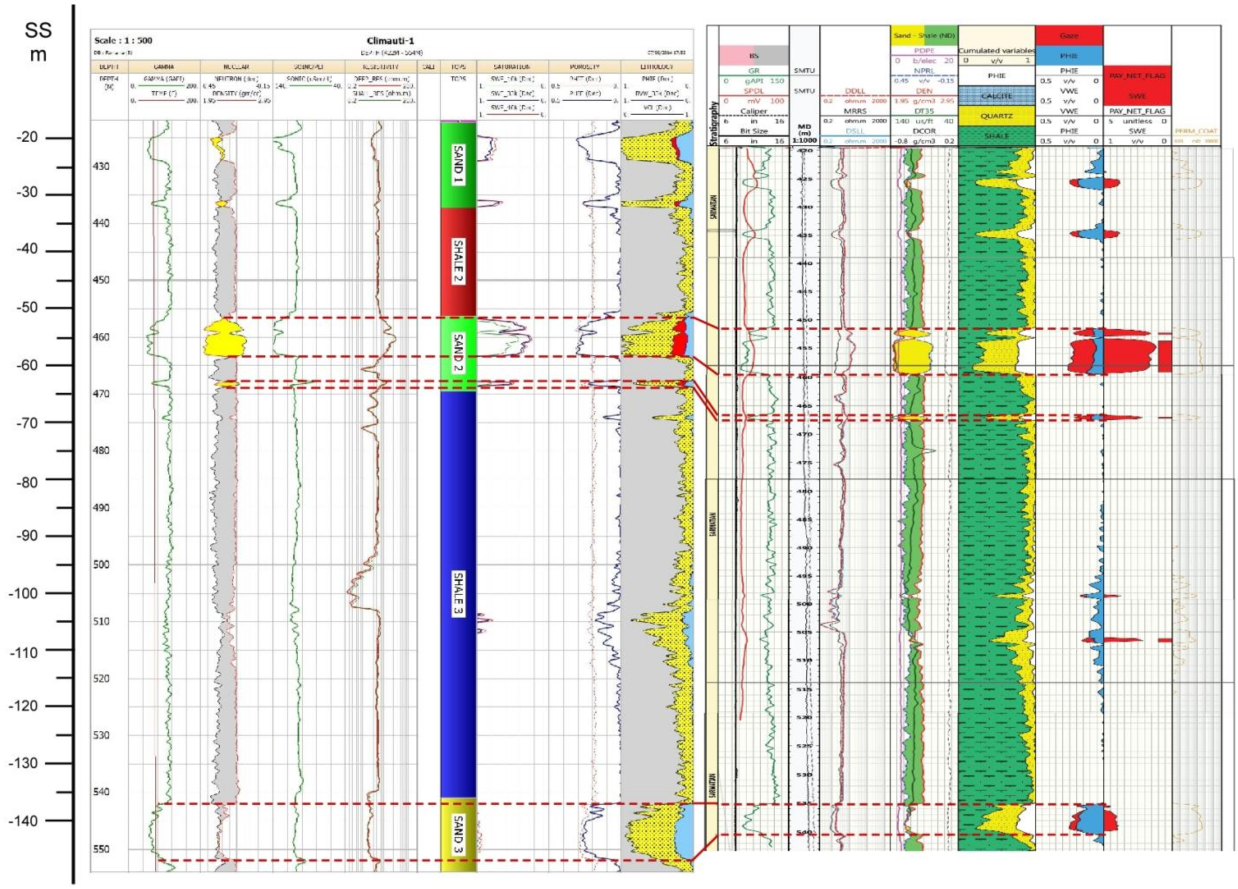


Figure 2-16 CPI for Climauti-1 and Ruda-1

2.5.3. Dornesti Sud-1

Dornesti Sud-1 was spudded on 18th November 2007 by Aurelian Oil and Gas and was drilled to a TD of 915 m MD (-504m TVDss). Rotary Table elevation was 410.9 m above mean sea level (MSL) and ground elevation was 406.6 m above MSL.

The objective of the well was to determine the potential of gas bearing sands in the Sarmatian formation and the well was suspended as a potential gas producer.

2.5.3.1. Well Data

Dornesti Sud-1 was logged by ATLAS/GIP (PLOIESTI) AND EASTERN GEOPHYSICA, yielding a basic suite of curves (Table 2-2). Digital data and field prints of logs were available (Figure 2-17).

Hole Size (in)	Date	Run No	Tool String	Logged Interval (m)	Contractor
12 1/4	23/11/2007	W_101	DLL-SP-GR	45-305	Atlas/GIP
12 1/4	23/11/2007	W_102	BHC-GR	BHC 45-305 GR 0-305	Atlas/GIP
12 1/4	23/11/2007	W_103	CALXY-GR	45-305	Atlas/GIP
8 1/2	04/12/2007	W_201	DLL-SP-GR	395-910	Atlas/GIP
8 1/2	04/12/2007	W_202	BHC-GR	395-910	Atlas/GIP
8 1/2	04/12/2007	W_203	CD-CN-GR	395-910	Atlas/GIP
8 1/2	04/12/2007	W_204	MLL-GR	395-910	Atlas/GIP
8 1/2	04/12/2007	W_205	CALXY-GR	395-910	Atlas/GIP

Table 2-2 Wireline logs run in Dornesti Sud-1

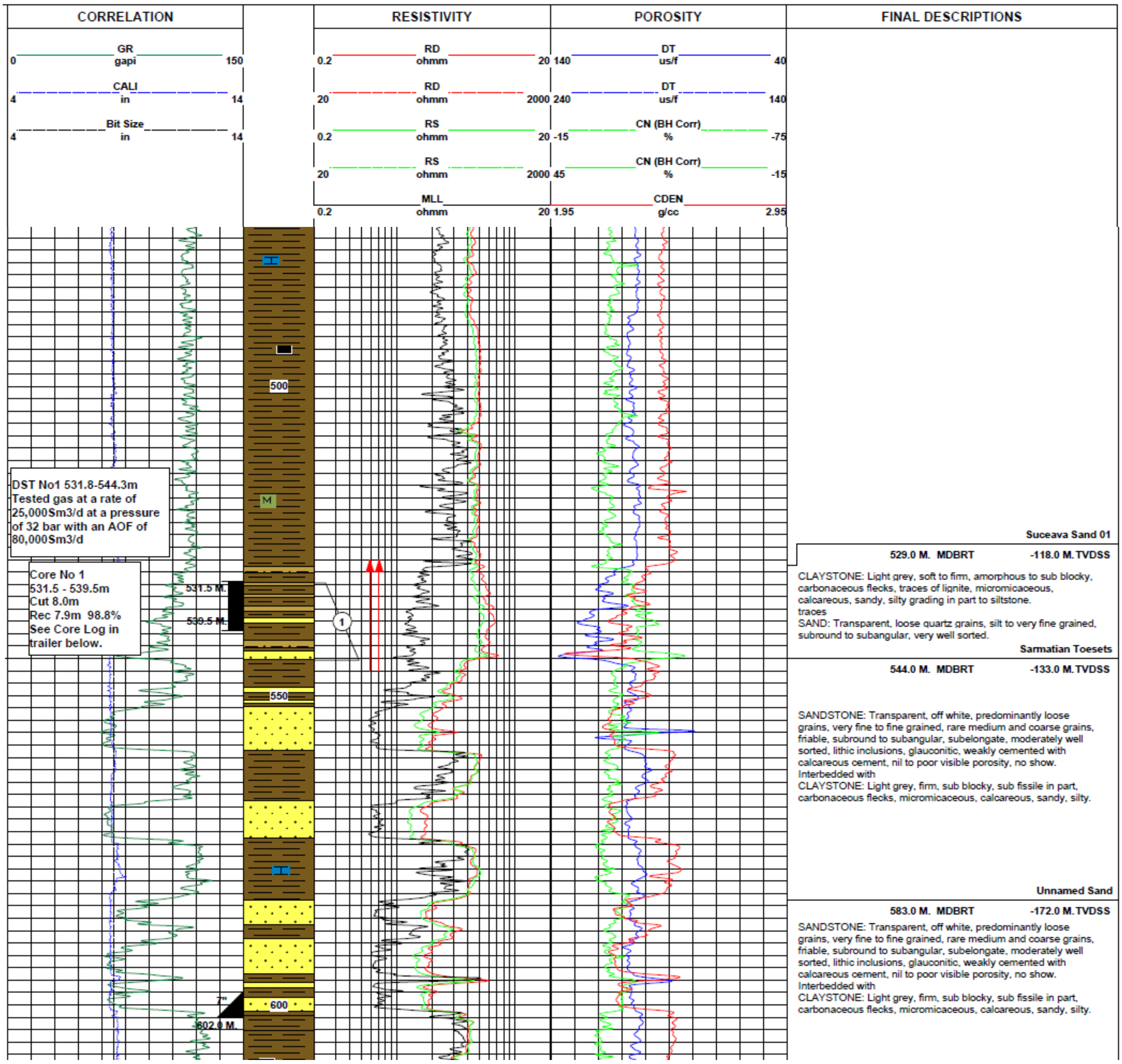


Figure 2-17 Completion log for Dornesti Sud-1

A gas kick was observed at 531.5m MD and kill mud was required to bring the well under control; at the same interval gas shows rose to 2.00% against a background of 0.66%. No shows were recorded in the cuttings. Once the well was under control, an 8m core was cut; the cored interval comprised thinly laminated, well sorted, very-fine to fine sandstones (Figure 2-7) that are interpreted as distal turbidites. No core analysis results were available, however it was stated that the core was sent to Core Lab Aberdeen for SCAL measurements.

2.5.3.2. Well evaluation

A Bad Hole flag was generated from the Calliper log; the Density Correction log is very spikey throughout most of the zones of interest and consequently is not a good indicator of hole condition.

VCL was calculated from the GR curve and also from the Neutron-Density separation, and the lower value was used to define final VCL apart from two zones (617.7-623.3 and 631.2-691.6 m MD) where the GR-derived value was used in preference. The resultant curve was checked against the Lithological log (Figure 2-17), and showed reasonable correspondence.

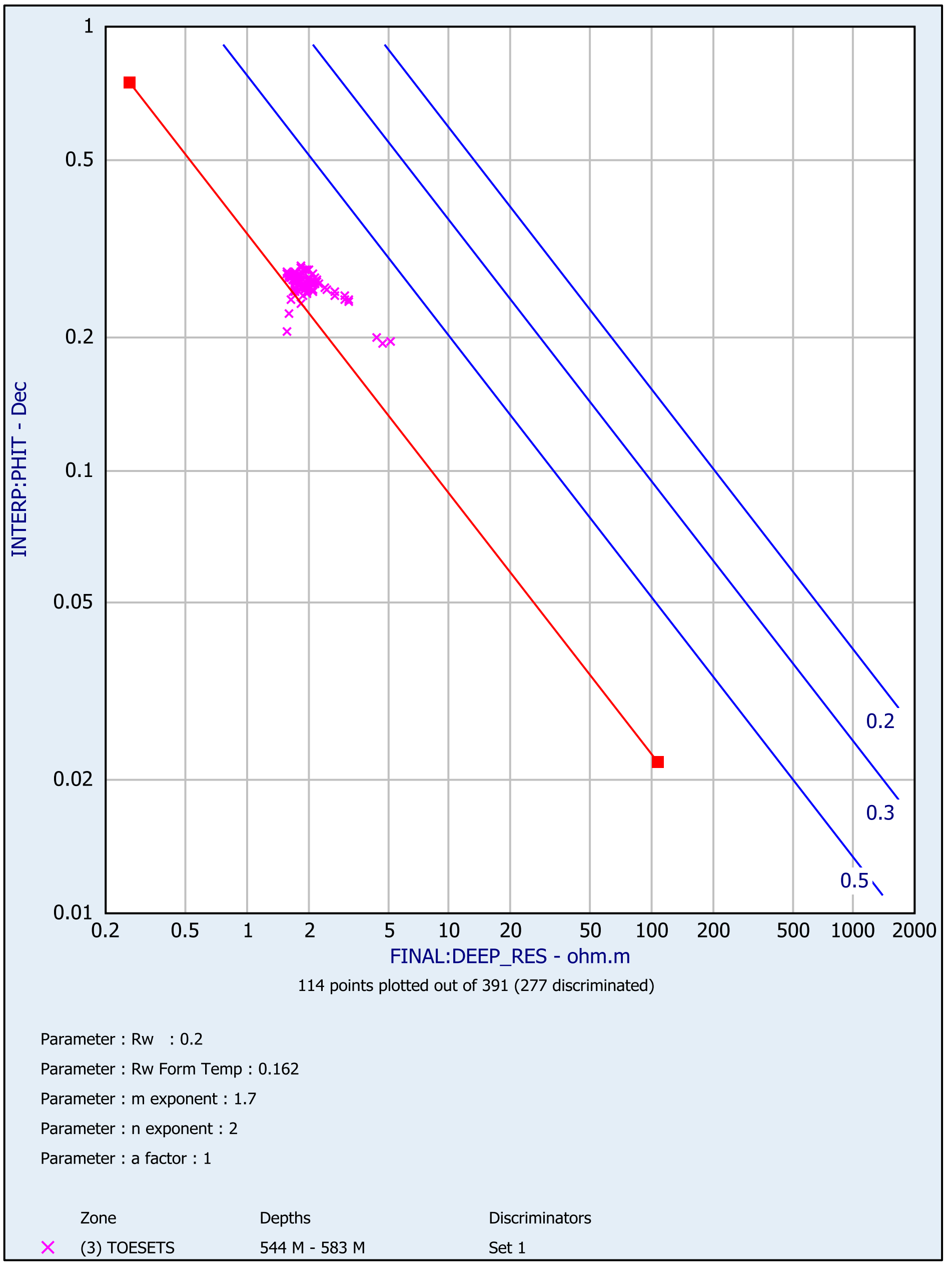


Figure 2-18 Pickett plot for Dornesti Sud-1

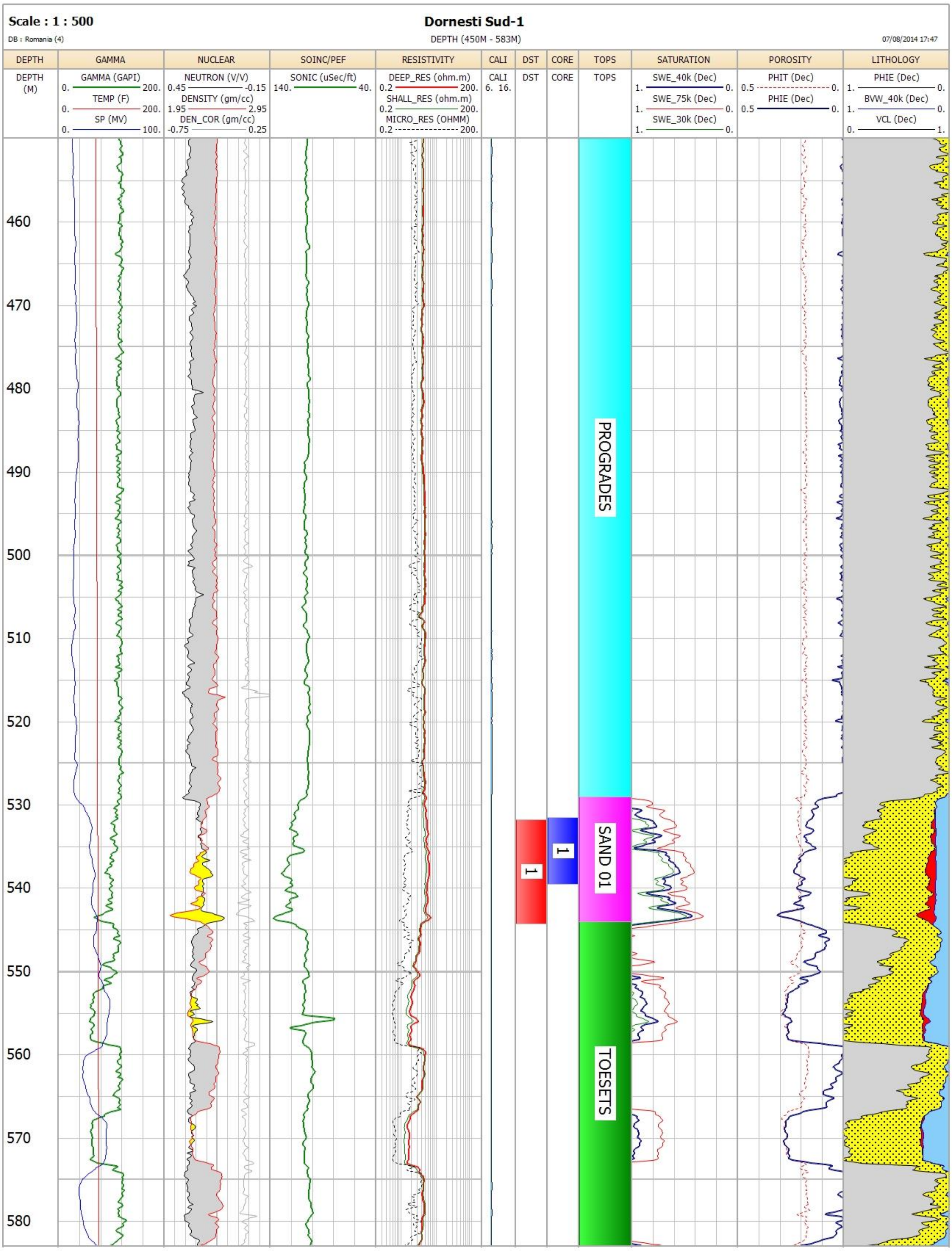


Figure 2-19 CPI plot for Dornesti Sud-1

For most of the well, hydrocarbon-corrected porosity was calculated from the Density log, assuming a sand grain density of 2.65 g/cc. Where Bad Hole conditions were flagged, the Sonic Log was used instead.

A standard Archie interpretation was used to determine water saturation. The temperature gradient was determined and plotted on the CPI based on two fixed points: 91.4°F at 909 m MD (the maximum recorded temperature from four logging runs), and an assumed 50°F temperature at surface.

A spreadsheet 'water analysis' was provided which contained formation water property data. The indicated salinity displays a range of 46.3-77.7 g/l NaCl, which very approximately equates to 45,000 to 75,000 ppm. The data have not been QC'd.

Three salinity values of 30,000 ppm, 40,000 ppm and 75,000 ppm, based on log data, DST results, the water analysis data and low quality Pickett plot results (Figure 2-18), have been used in this study to demonstrate the effect a varying Rw will have on Sw results, while unconsolidated Archie parameters have been assumed:

m = 1.7
n = 2
a = 1
Rw = 0.26, 0.2 and 0.115 Ohmm at 60°F (30,000, 40,000 and 75,000 ppm respectively)

An Rmf of 0.14 at 68°F has been assumed from Wireline logging QC sheet, and no fluid contacts were observed in the well. The results are presented in Figure 2-19.

2.5.4. Granicesti SE-1

Granicesti SE-1 was spudded on 17th December 2004 by a previous operator and was drilled to a TD of 2296m MD (-1934m TVDss) within Ordovician quartzite. Rotary Table elevation was 362.0m above mean sea level (MSL) and 5.4m above ground level.

Four conventional cores were taken and 6 drill stem tests attempted ranging from the Cretaceous up to the shallow Sarmatian intervals, yielding gas and water from the Sarmatian intervals. The current study has only evaluated the Sarmatian section of the well.

2.5.4.1. Well Data

Well was logged by Atlas GIP (Table 2-3), and the digital wireline log data were provided. However, mud log data (including gas curves), were only available as a digital image (Figure 2-20).

RUN #	TOOL STRING	INTERVAL (M.)
1A	DIFL-BHC-GR	0-199
1B	MMT-CAL XY-GR	0-199
2A	DLL-GR	190-1117
2B	BHC-DIFL-GR	190-1117
2C	CDL-CNL-GR	190-1117
2D	MLL-CAL	190-1117
2E	MMT-CALXY-GR	190-1117
3A	DLL-GR	2101-1060
3B	DIFL-BHC-GR	TOOL FAILURE
3C	CDL-CN-GR	TOOL FAILURE
3D	CBL-VDL-CCL	1116-10
3E	XMAC	2101-450
4A	GR-DLL-SP	TOOL FAILURE
4A2	GR-DLL-SP	2296-1116
4B	GR-DIFL-AC	2296-1116
4C	GR-CNL-CDL	STUCK IN HOLE

Table 2-3 Wireline logs run in SE-1

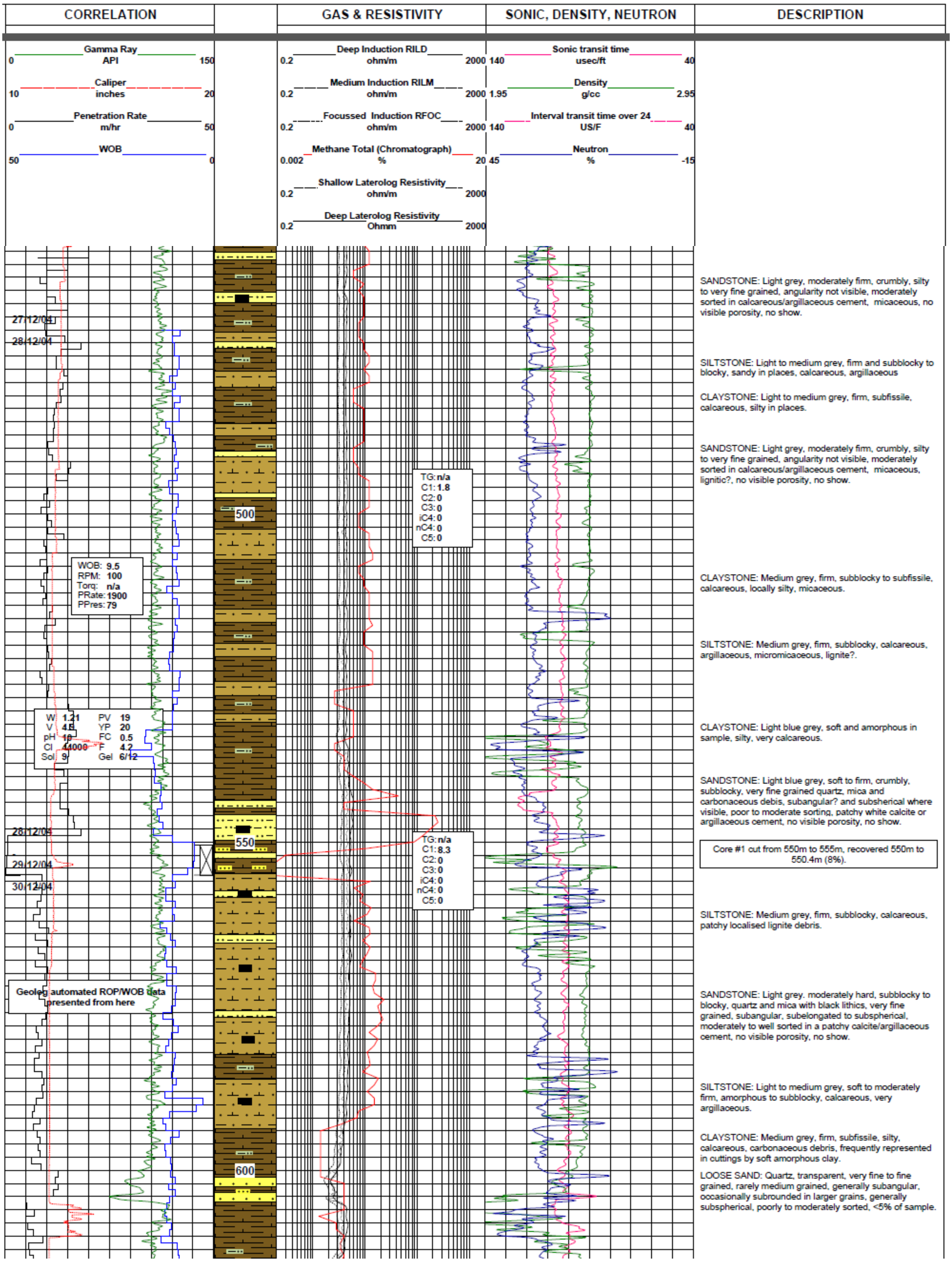


Figure 2-20 Completion log for Granicesti SE-1

Hydrocarbon shows were observed in the Sarmatian: background methane in the Sarmatian was 0.8%. This rose to a peak of 8.3% (C1 only) in sandstones at 547m MD. There were no shows from the samples. The gas value remained high to 594m averaging 1.1% in sandy siltstones. It remained low for the remainder of the Sarmatian averaging 0.4%.

2.5.4.2. Well evaluation

Only data for the Sarmatian section of the well above the Badenian Anhydrite have been interpreted in the current study. The interpretation of this section is highly complex due to the nature of the Tertiary sediments and the fact that the well is affected by bad hole conditions with fairly severe washouts. The results contain several contradictions and the generated VCL, porosity and saturation logs should be used with extreme caution. For example:

1. DST's at 542m MD and 387m MD produced gas and proved the presence of gas respectively, and yet the log interpretation shows a silty clay at best that is water bearing. Thin beds are assumed which are different enough to have an effect on the SP, Resistivity logs and to a stronger degree the Sonic logs but not the Nuclear logs.
2. The upper section of shale (~210-250 m MD) has some reasonable sands, with good porosity and calculated gas saturations if the Rw parameters from lower sections are used (~40,000 ppm salinity), but there are not the expected gas effects on the logs, there are no oil shows in the cuttings so this section may contain fresh water; to obtain a high water saturation in these logs a salinity of approximately 7,000 ppm would have to be assumed. This is a large change in Salinity over a short interval.

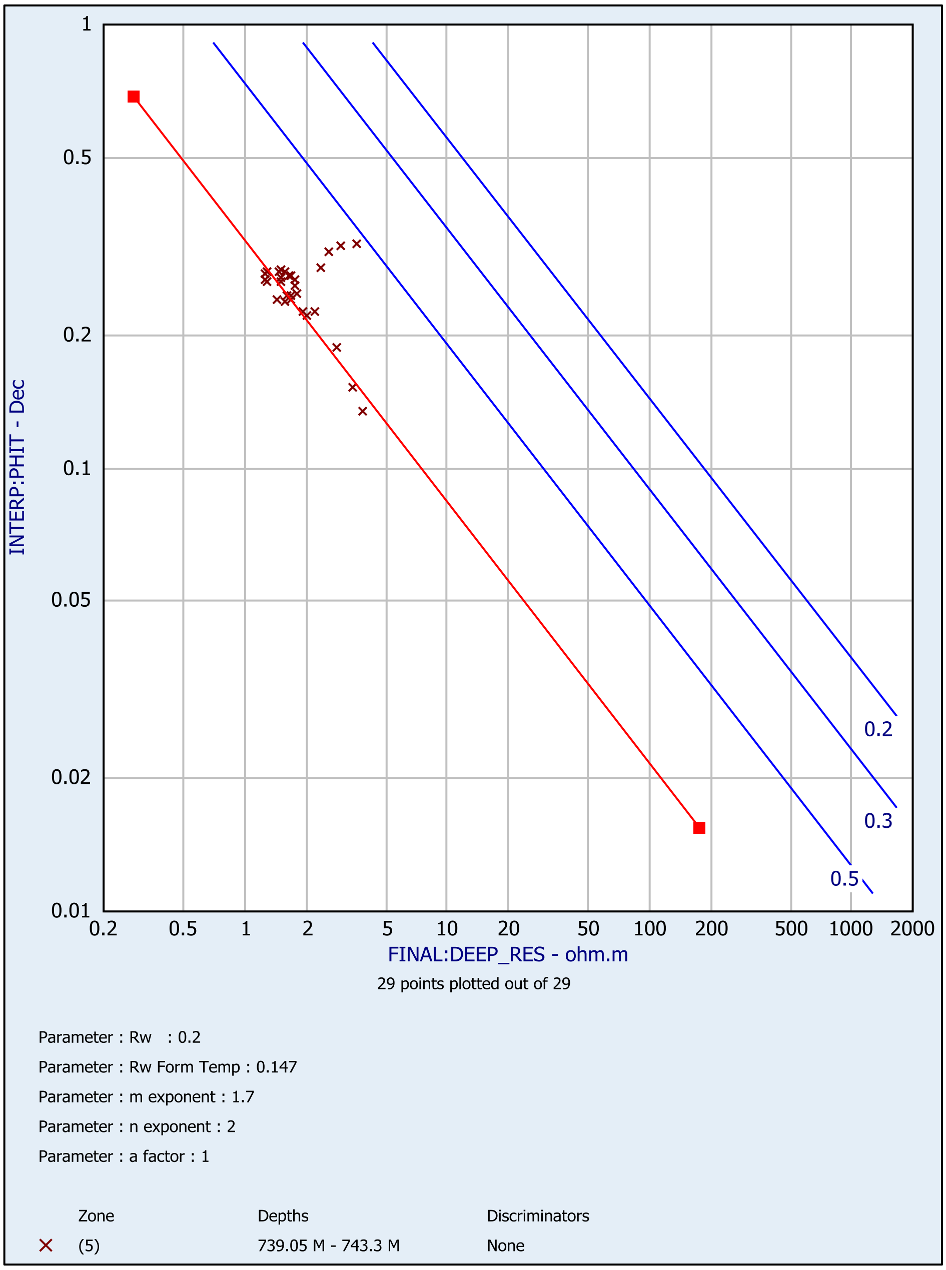


Figure 2-21 Pickett plot for the lower Sarmatian section in Granicesti SE-1

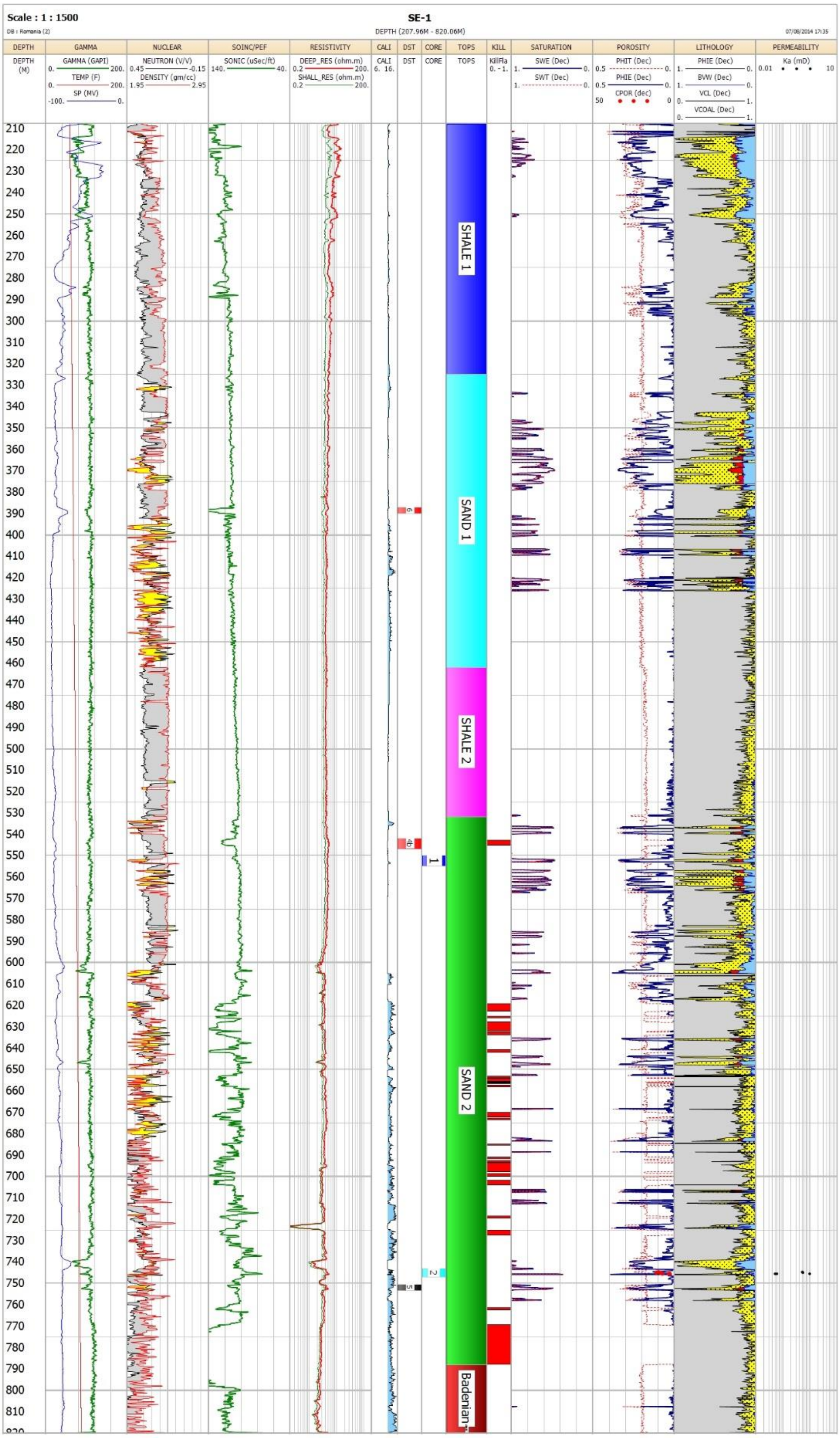


Figure 2-22 CPI plot for the Sarmatian section in Granicesti SE-1

Consequently, the best indicator for hydrocarbon presence in the Granicesti SE-1 well is the Completion Log (Figure 2-20).

The logs are of poor quality for over 50% of the Sarmatian section of the well with washouts and thin beds causing either erroneous logs or logs which do not have the resolution to resolve the geology.

VCL was calculated from the GR curve and also from the Neutron-Density separation; the lower value was used to define final VCL and the resultant curve was checked against the Lithological log (Figure 2-20). Between 425-460 m MD the amount of VCL that has been calculated appears to be too high (if the thin bed characteristics of the Sonic and GR are true). However, this is not to say that there is missed pay here as there is very little character on the SP or Resistivity logs and the Composite Log describes “Mudstones and Siltstones” rather than sands.

For most of the well, hydrocarbon-corrected porosity was calculated from the Density log, assuming a sand grain density of 2.65 g/cc. Where Bad Hole conditions were flagged, the Sonic Log was used instead.

A standard Archie interpretation was used to determine water saturation. The temperature gradient was determined and plotted on the CPI based on two fixed points: the maximum recorded temperature in the Dornesti Sud-1 well of 91.4°F at 909 m MD, and an assumed 50°F temperature at surface. However, determining Saturation and Pay in these thin bedded sands is very complex.

Based on the assumption that there is water in the upper section of the well and gas in the lower sections at different points, based on DST results, two very different Rw’s have been used respectively. The first uses a salinity of 7,000 ppm and the second uses 40,000 ppm, based on Pickett plot analysis (Figure 2-21) and regional well data. Unconsolidated Archie parameters have been assumed:

m = 1.7
n = 2
a = 1
Rw = 1 Ohmm at 60°F in the upper section and 0.2 Ohmm at 60°F below
(7,000 and 40,000 ppm respectively).

An Rmf of 0.1 at 60°F has been assumed, and no fluid contacts were observed in the well. The results are presented in Figure 2-22.

2.5.5. Average Reservoir properties

Climauti-1 shows evidence of gas in two sands, the Upper Sand and the Main Sand (Figure 2-14). The Main Sand is 7.0m thick at the Climauti-1 location, and is clearly gas-bearing. However, the Upper Sand, which is 4.4m thick in the well, displays much lower gas saturation values, and if the salinity is assumed to be 10,000 ppm (see section 3.5.1.2), then the unit is shown to be water-bearing. It is unlikely that the Upper Sand forms a viable gas reservoir. Average reservoir properties were calculated for each unit, using a range of VCL cut-off’s to provide an estimate of the possible range in each parameter (Table 2-4 and Table 2-5). It should be noted that the range presented does not consider lateral variation within the reservoirs.

Max VCL (cut-off)	Net-to-gross	Effective porosity	Effective Sw for given salinity		
			10,000 ppm	33,000 ppm	40,000 ppm
1.0	100%	25%	68%	46%	43%
0.5	91%	26%	65%	42%	39%
0.3	71%	28%	58%	36%	34%
0.2	61%	29%	55%	35%	32%
0.1	41%	29%	53%	33%	31%

Table 2-4 Average properties for the Main Sand in Climauti-1

Max VCL (cut-off)	Net-to-gross	Effective porosity	Effective Sw for given salinity		
			10,000 ppm	33,000 ppm	40,000 ppm
1.0	100%	26%	100%	83%	78%
0.5	10%	26%	100%	83%	78%
0.3	98%	26%	100%	82%	77%
0.2	95%	26%	100%	82%	76%
0.1	89%	27%	100%	82%	76%

Table 2-5 Average properties for the Upper Sand in Climauti-1

Dornesti Sud-1 shows evidence of gas in a single sand at a depth of 529.5-544.5m MD (Figure 2-19). The unit is 15.0m thick at the Dornesti Sud-1 location, and is clearly gas-bearing, as proven by a drill-stem test. The unit displays a fining-up profile, and the upper part may not form viable reservoir. There are two further sands below the main accumulation, but the petrophysical evaluation indicates that they are most-likely water-bearing unless the water salinity is excessively high (i.e. 75,000 ppm or more). Average reservoir properties have been calculated for the main reservoir unit, using a range of VCL cut-off's as for Climauti-1 (Table 2-6). Once again, it should be noted that the range presented does not consider lateral variation within the reservoirs.

Max VCL (cut-off)	Net-to-gross	Effective porosity	Effective Sw for given salinity	
			40,000 ppm	75,000 ppm
1.0	100%	18%	74%	57%
0.3	81%	19%	69%	53%
0.2	65%	21%	65%	50%
0.1	49%	22%	61%	47%

Table 2-6 Average properties for the main sand in Dornesti Sud-1

As discussed in section 3.5.3.2, the reservoir parameters for the hydrocarbon accumulation in SE-1 are extremely difficult to evaluate due to the thin interbedded nature of sands, silts and shales. The interval (542-547m MD) that was tested and flowed gas does not show up as net pay in the petrophysical evaluation (Figure 2-22). Consequently, average petrophysical parameters have not been calculated for this well, and a wide range of uncertainty must be assumed.

2.6. Fluid properties

Climauti has been on production since March 2011. No PVT analysis was available for review, but the composition has been given in various reports, and is recorded in Table 2-7. Three gas samples were taken and analysed from Dornesti Sud, and the data was available. Some samples were taken during testing of the Granicesti SE-1well, but no PVT reports were available. In each case, the gas contains >99% methane, and so remaining uncertainty in the fluid properties is considered to be limited. Fluid properties have been derived from Stand and Katz correlations, and are summarised is in Table 2-7.

Property	Units	Climauti	Dornesti Sud	Granicesti SE-1
Methane	mol%	99.4	99.25	99.4
Nitrogen	mol%	0.26	0.57	N/A
CO2	mol%	0.108	0.04	N/A
Initial Reservoir Pressure	psia	654	595	610
Reservoir Temperature	°F	70	76	70
Formation Volume Factor	rb/stb	0.02085	0.02345	0.02247
Gas Expansion Factor	stb/rb	48.0	42.6	44.5

Table 2-7 Fluid Properties for Climauti, Dornesti Sud and Granicesti Gases

2.7. Historical Production and Testing

2.7.1. Climauti

The Climauti field has been on production since 2011 via a single well, and has been tied into the local low pressure gas infrastructure. The production history is shown in Figure 2-23, and demonstrates a typical decline and has produced 0.722 Bcf to 31st December 2014. The well has produced no significant amounts of water to date. The recent reduction in rate in November-December 2014 was due to abnormally low temperatures which affected maximum capacity at the host facility at Bilca, and is expected to be temporary.

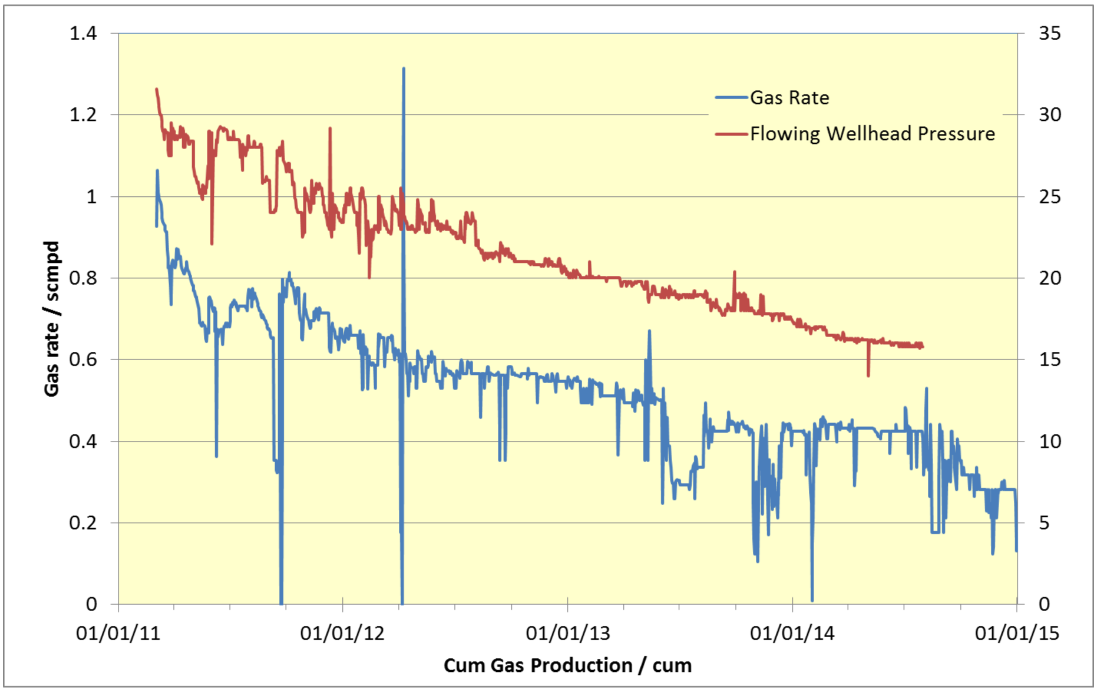


Figure 2-23 Historical production for Climauti

2.7.2. Ruda

The Ruda-1 well was drilled in December 2014 and reached target depth of 551 metres on 5 December. One gas bearing zone was found at 454 – 458 which was tested for 3 days with flow rates of up to 25,000m3/day (880,000scf/d) on a 12.0mm choke. The gas (containing over 98% methane) was discovered in a good quality Sarmatian sandstone reservoir. Dornesti Sud

Dornesti Sud was tested both shortly after the well was drilled in December 2007 and in June 2013.Both times the well was flowed at rates of up to around 0.9 MMscfpd for a limited number of hours. The well head pressure data for the test in June 2013 is shown in Figure 2-24, and does not show any indications of depletion although it is noted that the flow was of a limited duration.

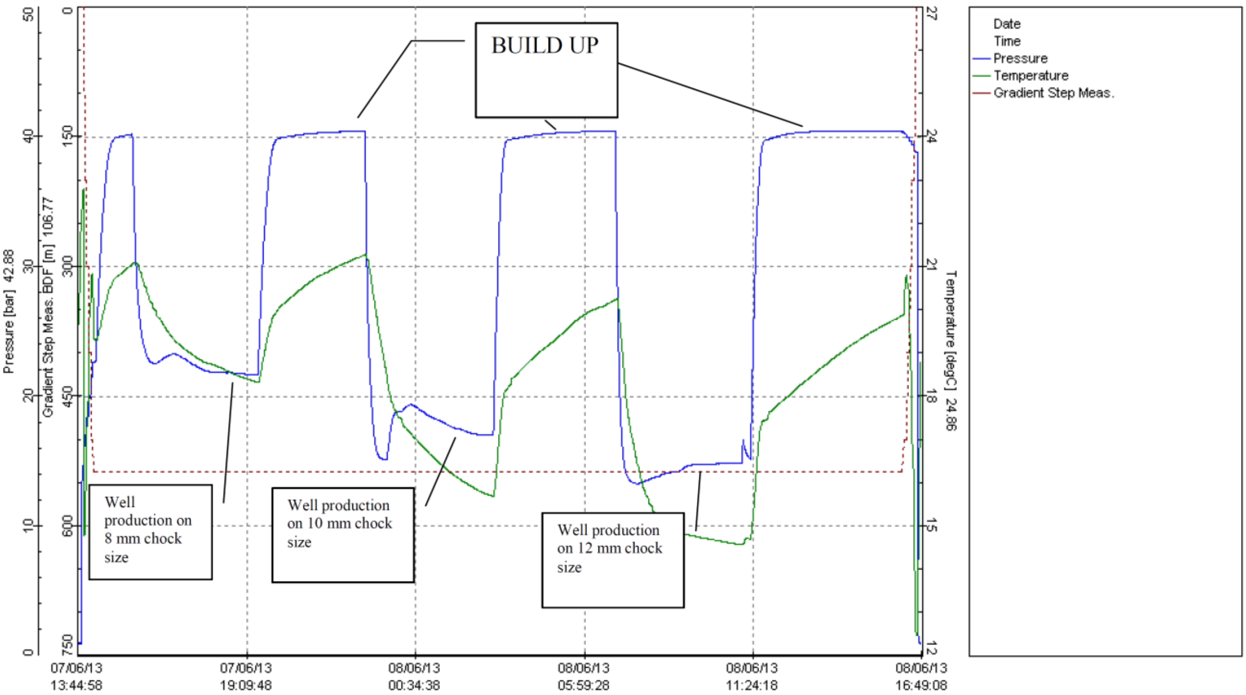


Figure 2-24 Wellhead Pressure and Temperature during test of Dornesti Sud in June 2013

2.7.3. Granicesti SE

Granicesti SE-1 was drilled in 2005 as an exploration well to test multiple objectives down to the Palaeozoic. The well found and tested gas in the Sarmatian over the interval 542-547m. The test was recorded with a Down Hole Pressure Gauge (DHPG) and the analysis report was reviewed. There were four main pressure build ups recorded, two before, and two after an acid wash and small scale hydraulic fracture stimulation. The treatment was beneficial and improved the k.h and skin from 148 mD.ft and 11 to 257 mD.ft and 6. The rate prior to the frac was 0.4 MMscfpd/d, before reaching a rate of 1.2 MMscfpd/d after the stimulation treatment. No depletion was evident from the test, and it is noted that the flow periods were of a short duration. This was because the well

Figure 2-25 Downhole Rate and Pressure data during test of Granicesti SE-1

2.8. Hydrocarbon Volumes

2.8.1. GIIP

The Climauti, Dornesti Sud and Granicesti SE discoveries appear to be stratigraphically trapped gas accumulations. Consequently, any estimate of the in-place volumes must assume that the reservoir is defined in terms of area and thickness, effectively a thin package, or lobe, of sand and silt encased in shale. The extent of each lobe must be defined by the mapped extent of the increased seismic amplitudes associated with each discovery (e.g. Figure 2-26 & Figure 2-27). The limited dataset and uncertainty over the exact limits of “increased amplitudes” results in a large range in the estimate of the field area. A low case, base case and high case area has been defined for each discovery based on different amplitude cut-offs and assumed sand lobe shape.

Similarly, low case, base case and high case reservoir thickness and petrophysical properties have been defined based on well data (section 3.5.4). Full sets of parameters are presented in Table 2-8, Table 2-9, Table 2-10 and Table 2-11.

A probabilistic estimate of GIIP can be calculated for each well based on the established ranges (Table 2-12). However, production data for Climauti provides an additional source of data regarding the size of the field. The field has already produced 0.66 Bcf, and decline analysis indicates that the connected volume of gas is in the range of 1.4-1.65 Bcf (see section 2.7.1). The produced volume provides an absolute minimum GIIP volume, while the decline curve results yield a good indication of the most-likely GIIP; larger in-place volumes are possible if compartments are invoked that isolate areas of the field from the Climauti-1 well.

When the results of the decline analysis are factored into the volume calculations, it is clear that the smallest possible mapped areas, based on the brightest amplitudes, are invalid. Instead, the field must cover a larger area (Figure 2-27), with a range based on lower amplitude cut-offs. The revised areas produce larger GIIP volumes, with P90 and P50 estimates that are more in-line with the production data results. However, it is worth noting that all such scenarios include the area that the proposed Ruda exploration well will assess (section 2.8.2). The implication is that the volumes being targeted by the Ruda well are already under development via the Climauti-1 well. This is consistent with the Ruda-1 well results which suggest that the reservoir encountered similar sands to the Climauti-1 well, but it is noted that this is not proof that the two wells are in communication, it is considered likely. This minor point will become largely irrelevant, once the Ruda-1 is tied-back, and production is secured from both wells, whether in communication or not. The Ruda-1 petrophysical results are consistent with the ranges used in Table 2-8 for the Climauti Main Sand.

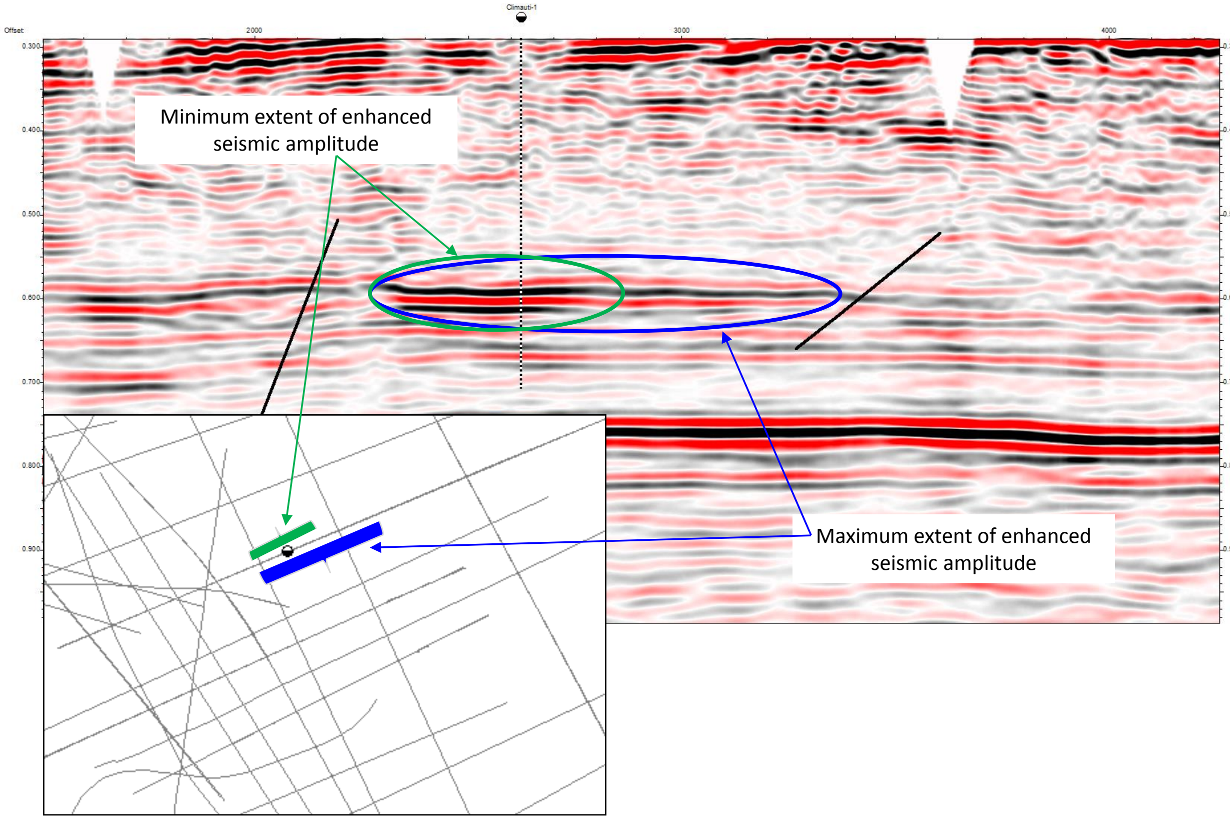


Figure 2-26 Example of increased amplitude strength around Climauti-1 gas discovery

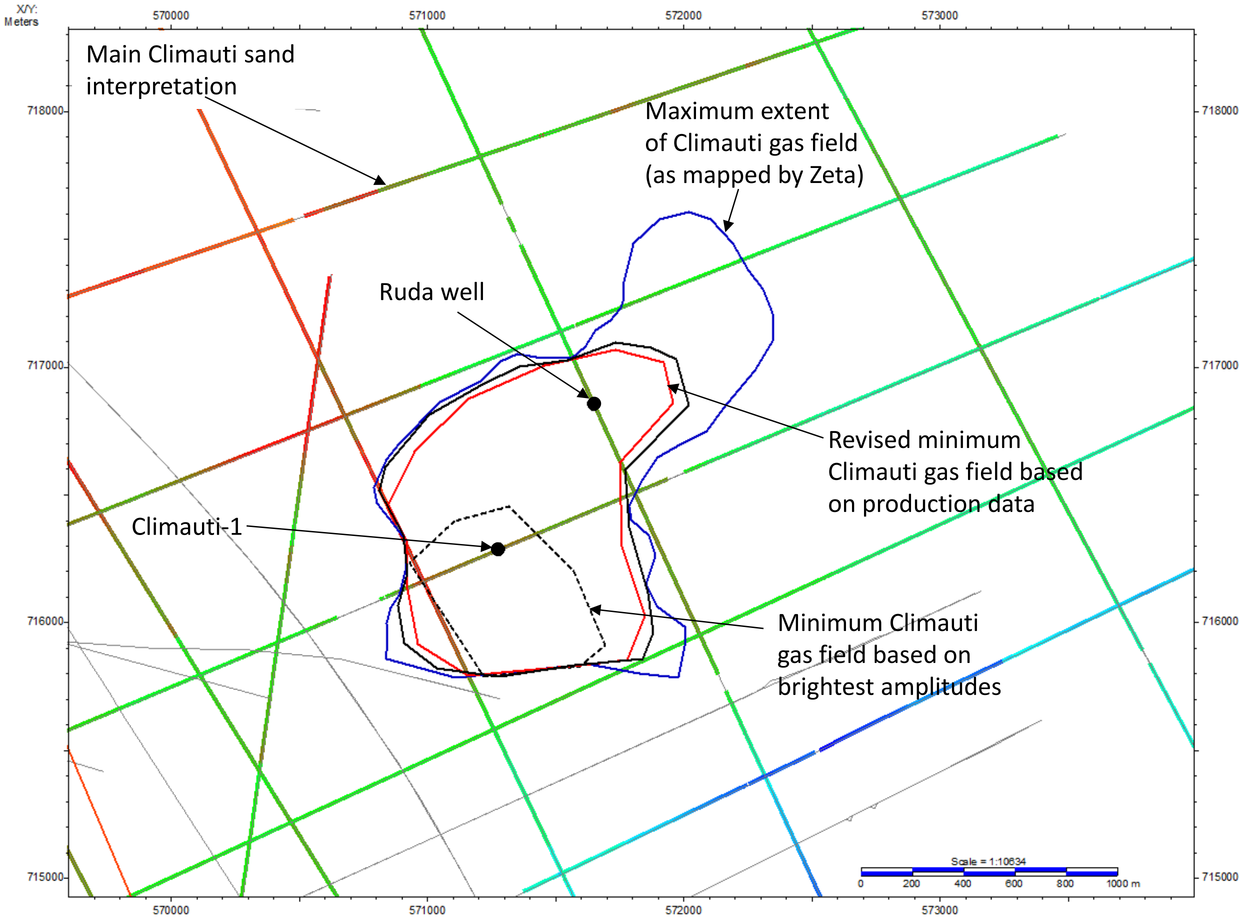


Figure 2-27 Area of the Climauti gas field

Parameter	Low	Base	High
Area (km^2)	1.0	1.1	1.55
Gross thickness (m)	5	7	9
Shape factor	0.8	0.9	1.0
Net-to-gross (%)	60	75	90
Porosity (%)	26	28	30
Water saturation (%)	30	35	45
Gas expansion factor (scf/rcf)	45	48	51

Table 2-8 Probabilistic ranges assumed for calculating GIIP volumes in Climauti (Main sand)

Parameter	Low	Base	High
Area (km^2)	0.30	0.5	0.75
Gross thickness (m)	2	4.5	7
Shape factor	0.8	0.9	1.0
Net-to-gross (%)	70	95	100
Porosity (%)	25	26	27
Water saturation (%)	75	85	100
Gas expansion factor (scf/rcf)	45	48	51

Table 2-9 Probabilistic ranges assumed for calculating GIIP volumes in Climauti (Upper sand)

Parameter	Low	Base	High
Area (km^2)	0.6	1.5	3.0
Gross thickness (m)	10	15	20
Shape factor	0.8	0.9	1.0
Net-to-gross (%)	50	65	80
Porosity (%)	19	21	23
Water saturation (%)	45	55	70
Gas expansion factor (scf/rcf)	40	42.6	45

Table 2-10 Probabilistic ranges assumed for calculating GIIP volumes in Dornesti Sud

Parameter	Low	Base	High
Area (km^2)	1.6	2.6	4.5
Net thickness (m)	2.5	5	15
Shape factor	0.8	0.9	1.0
Porosity (%)	25	30	35
Water saturation (%)	30	50	60
Gas expansion factor (scf/rcf)	42	44.5	47

Table 2-11 Probabilistic ranges assumed for calculating GIIP volumes in Granicesti SE-1 (Main sand)

GIIP (Bcf)	P90	P50	P10
Climauti (Upper sand)	0.0	0.1	0.2
Climauti (Main sand)	1.3	1.6	2.1
Dornesti Sud	1.1	1.8	2.9
Granicesti SE	1.6	2.9	5.5

Table 2-12 Probabilistic GIIP estimates for Suceava discoveries

2.8.2. Ruda Area Opportunity

The operator had defined an area close to the Climauti field, and proposed to drill an appraisal well approximately 700m northeast of Climauti-1 (Figure 2-27). Decline analysis from the Climauti-1 well indicated a minimum GIIP volume connected to the producing Climauti well, and all mapped scenarios for such a volume include the Ruda area (section 3.7.1). Consequently, it is our opinion that the Ruda-1 appraisal well has encountered an extension to the Climauti field, and is likely to accelerate recovery from the Climauti accumulation. This assumption is consistent with the recent well results, and so no additional GIIP volumes have been assigned to the Ruda Area.

2.8.3. Recoverable Volumes

2.8.3.1. Climauti

Recoverable Volumes for Climauti were based on Decline Curve Analysis from the existing production history. The production data has been plotted in Figure 2-28. A reasonable linear trend seems to have developed, excluding the influence of shutdowns, suggesting an exponential decline trend. Three lines have been drawn to give low, mid and high estimates for the Estimated Ultimate Recovery (EUR). It is noted that the downside EUR of 1.395 Bcf is greater than the P90 estimate within Table 2-12. This is not unusual, given that 0.772 Bcf has been produced to date, and shows reasonable consistency, but in this case, more reliance is given on the DCA result than on the probabilistic range in GIIP from a Monte Carlo Analysis. The Mid and High Case EURs were 1.479 and 1.647 Bcf, respectively. Note that the EUR from DCA will be truncated by the economic cut-off. It is expected that the Ruda-1 well would accelerate these produced volumes.

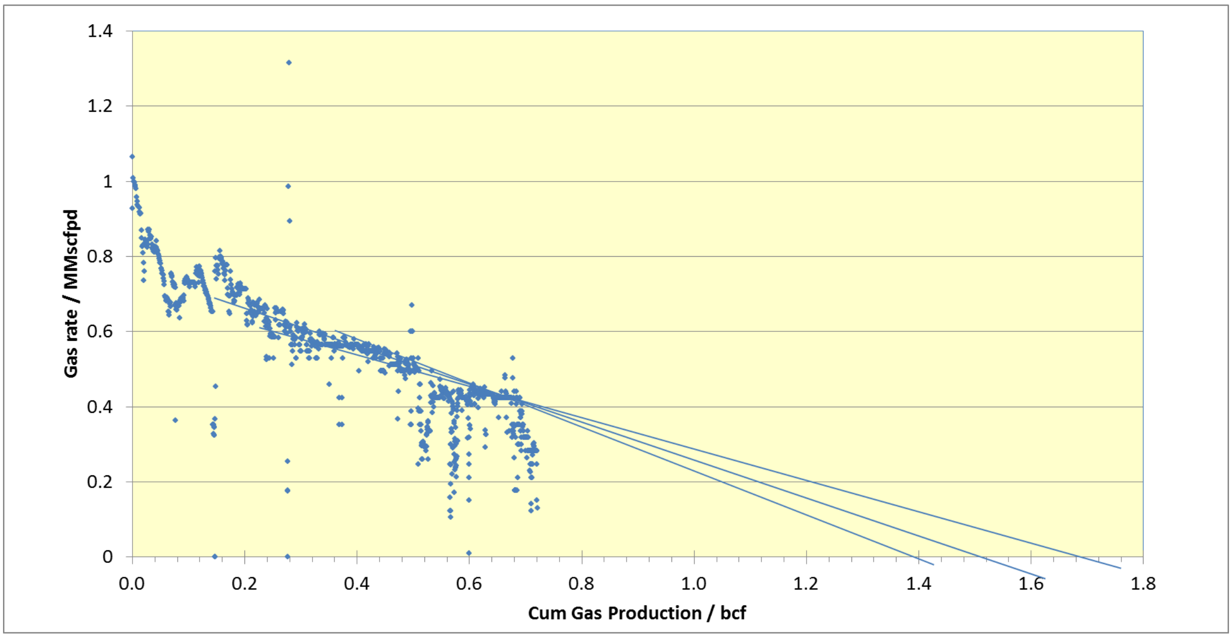


Figure 2-28 Decline Curve Analysis for Climauti-1

2.8.3.2. Dornesti Sud

Dornesti Sud started production on 5th December 2014, and there is insufficient production history data to determine reserves from decline analysis so EUR was based on the range in GIIP in Table 2-12, multiplied by a recovery factor. The recovery factor was estimated to be 77.1% by assuming depletion of the reservoir to 10 bara. An additional range was not considered as the biggest likely impact on recovery will be connected GIIP, which is considered within the GIIP range.

	P90	P50	P10
GIIP (Bcf)	1.1	1.8	2.9
EUR (Bcf)	0.818	1.399	2.187

Table 2-13 Range in GIIP and Estimated Ultimate Recovery for Dornesti Sud

2.8.3.3. Granicesti SE-1

Similarly, there is no production history for Granicesti SE-1, and so EUR was based on the range in GIIP in Table 2-12, multiplied by a recovery factor. The recovery factor was estimated to be 77.8% by assuming depletion of the reservoir to 10 bara. An additional range was not considered as the biggest likely impact on recovery will be connected GIIP, which is considered within the GIIP range.

	P90	P50	P10
GIIP (Bcf)	1.6	2.9	5.5
EUR (Bcf)	1.211	2.237	4.278

Table 2-14 Range in GIIP and Estimated Ultimate Recovery for Granicesti SE-1

2.9. Development Plans

2.9.1. Climauti

Climauti is already on production via the Climauti-1 well which is tied back to third party facilities at the Bilca gas processing plant operated by Raffles Energy. Zeta has no ownership interest in the gas plant. The Bilca gas field was discovered in 2000 and started production in 2006. The facilities are therefore relatively new. Zeta has informed us, and it appears from photographs supplied, that the facilities are in good condition (e.g. Figure 2-30) and are operating normally. There has been no site visit or data provided to ascertain the facilities condition or operability. The gas is then exported to the national gas grid. A second well in the Ruda area was drilled in December 2014. It is planned to develop this well by installing a 750m pipeline to the Climauti well, and from there export the gas to the Bilca gas plant via the existing Climauti pipeline, commencing in May 2015. As discussed in Section 2.8.2, this well would appear likely to produce from the amount of connected volume within the Climauti Field, and will be capable of accelerating production.

The initial rate for the Ruda well is taken to be the same as the projected rate for the Climauti well, assuming the current rate of decline. The same EUR has been used as in Section 2.8.3.1.

Figure 2-29 Climauti-1 well head

Figure 2-30 Bilca gas processing plant

Picture Courtesy of Raffles Energy, the facility owner.

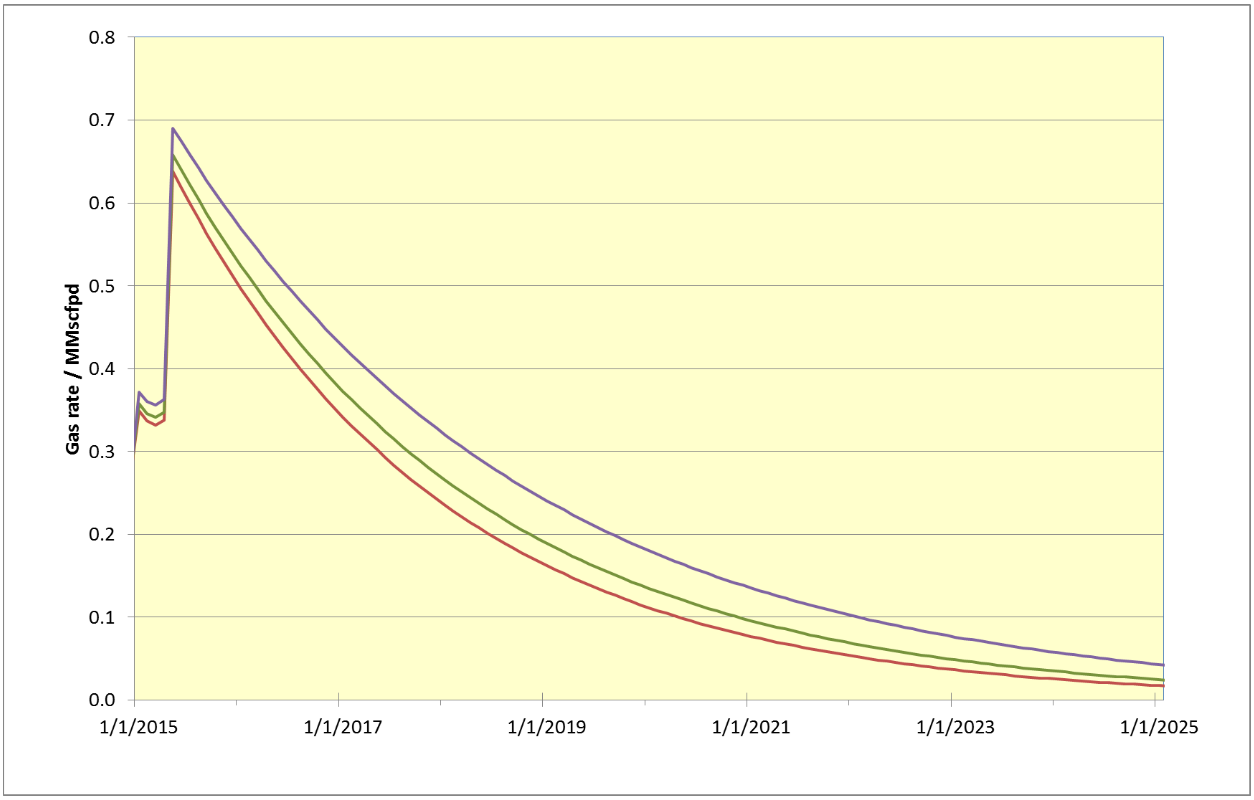


Figure 2-31 Climauti Forecast Production

	Average Rate (MMscfpd)		
Date	Low	Mid	High
2015	0.476	0.492	0.519
2016	0.434	0.464	0.513
2017	0.299	0.330	0.385
2018	0.206	0.235	0.288
2019	0.141	0.167	0.216
2020	0.097	0.119	0.162
2021	0.067	0.085	0.122
2022	0.046	0.060	0.091
2023	0.032	0.043	0.068
2024	0.022	0.031	0.051
2025	0.015	0.022	0.038
2026	0.010	0.015	0.029
2027	0.007	0.011	0.022
2028	0.005	0.008	0.016
2029	0.003	0.006	0.012
2030	0.002	0.004	0.009
EUR (Bcf)	1.393	1.476	1.640

Table 2-15 Untruncated Climauti Forecast based on two wells

2.9.2. Dornesti Sud

Dornesti Sud was developed in 2014 as a gas-to-power project with an onsite generator to produce electricity. The 0.9 MW facilities are constrained to 0.283 MMscfpd (8000 Sm3/d), which is less than the tested rate of 0.9 MMscfpd (Section 0). A range in plateau from an assumed start date of 1st November 2014 to 2020, 2024 or 2030 for the low, mid or high cases is possible. Given the length of plateau in the upside case, it would be possible to install a second generator at some point in the future, bringing capacity up to 2.5 MW, but this has not been factored into the profiles shown in Figure 2-32 and Table 2-16.

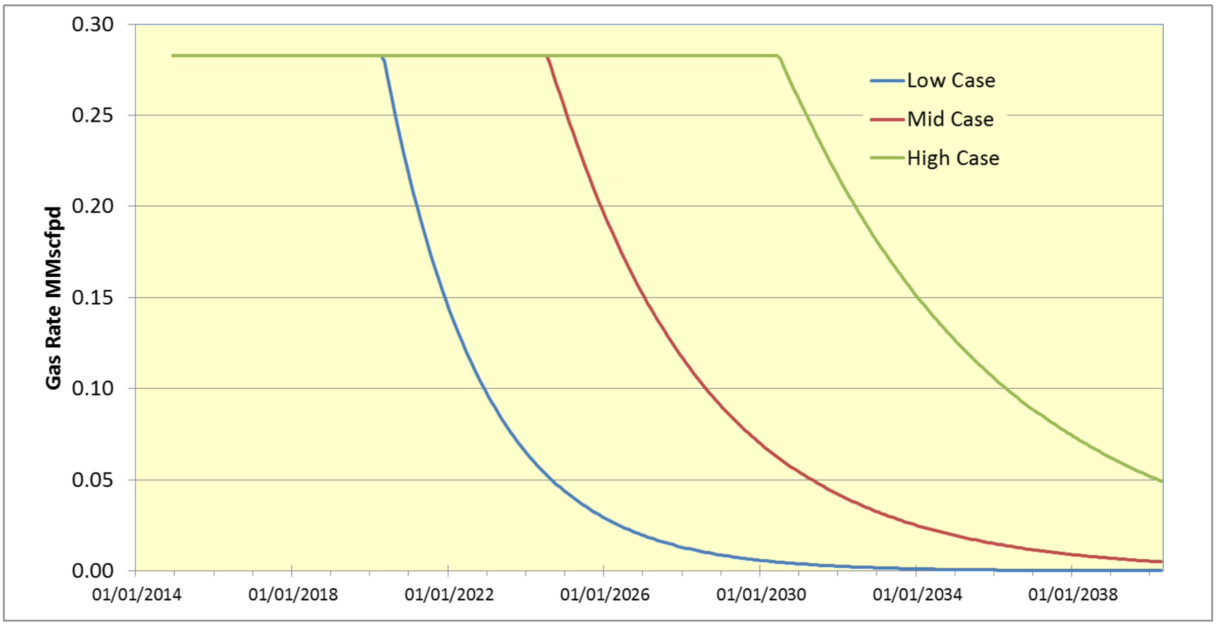


Figure 2-32 Dornesti Sud Forecast Production

	Average Rate (MMscfpd)		
Date	**Low**	**Mid**	**High**
01/12/2014+	0.283	0.283	0.283
2015	0.283	0.283	0.283
2016	0.283	0.283	0.283
2017	0.283	0.283	0.283
2018	0.283	0.283	0.283
2019	0.283	0.283	0.283
2020	0.260	0.283	0.283
2021	0.179	0.283	0.283
2022	0.120	0.283	0.283
2023	0.080	0.283	0.283
2024	0.054	0.276	0.283
2025	0.036	0.223	0.283
2026	0.024	0.173	0.283
2027	0.016	0.134	0.283
2028	0.011	0.104	0.283
2029	0.007	0.080	0.283
2030	0.005	0.062	0.276
2031	0.003	0.048	0.237
2032	0.002	0.037	0.198
2033	0.001	0.029	0.166
2034	0.001	0.022	0.139
2035	0.001	0.017	0.116
2036	0.000	0.013	0.097
2037	0.000	0.010	0.081
2038	0.000	0.008	0.068
2039	0.000	0.006	0.057
EUR (Bcf)	**0.818**	**1.391**	**2.081**

Table 2-16 Untruncated Dornesti Sud Forecast

2.9.3. Granicesti SE-1

The development plan for Granicesti SE-1 is to be confirmed after well testing. Zeta hope to test the well in August 2016. Testing is currently awaiting completion of negotiations with local landowners. Subject to successful testing, Zeta intend to develop the field for gas export using a small liquids separator at the wellhead to process the gas, and then export directly to the local Transgaz low pressure gas pipeline infrastructure which is within 1km of the well. Initial rates of 1.2, 1.4 & 1.6 MMscfpd have been assumed, with a start-up date of 1st December 2016. An exponential decline curve has been used. The resulting profiles are shown in Figure 2-32 and Table 2-16. In case the test results prove disappointing, a fall back option would be considered to develop the gas via an electricity generator at the well head, like Dornesti Sud.

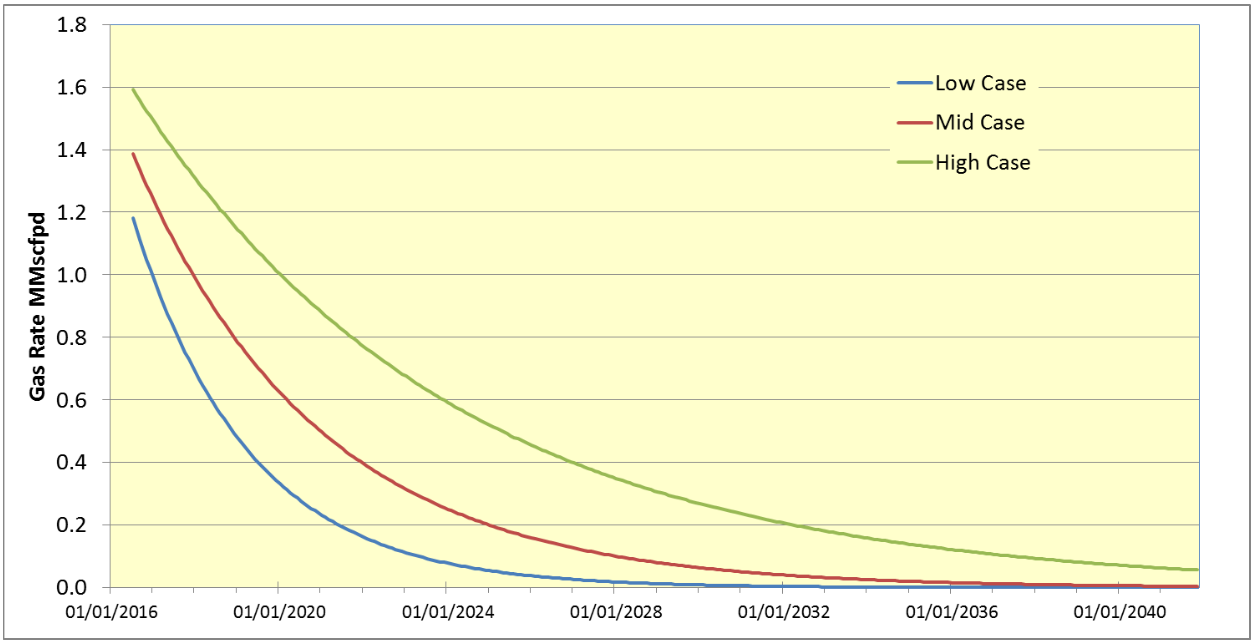


Figure 2-33 Granicesti SE-1 Forecast Production

	Average Rate (MMscfpd)		
Date	**Low**	**Mid**	**High**
1/7/2016+	0.553	0.667	0.781
2017	0.840	1.117	1.403
2018	0.585	0.889	1.230
2019	0.407	0.708	1.078
2020	0.283	0.564	0.945
2021	0.197	0.449	0.828
2022	0.137	0.357	0.726
2023	0.096	0.284	0.636
2024	0.067	0.226	0.558
2025	0.046	0.180	0.489
2026	0.032	0.144	0.429
2027	0.022	0.114	0.376
2028	0.016	0.091	0.329
2029	0.011	0.072	0.289
2030	0.008	0.058	0.253
2031	0.005	0.046	0.222
2032	0.004	0.037	0.194
2033	0.003	0.029	0.170
2034	0.002	0.023	0.149
2035	0.001	0.018	0.131
2036	0.001	0.015	0.115
2037	0.001	0.012	0.101
2038	0.000	0.009	0.088
2039	0.000	0.007	0.077
2040	0.553	0.006	0.068
EUR (Bcf)	**1.211**	**2.237**	**4.235**

Table 2-17 Untruncated Granicesti SE-1 Forecast

2.10. Development and Production Costs

The Suceava licence is operated by Raffles Energy. In addition to direct operating costs for each field, Raffles currently charges overhead costs to the licence at a rate of $7300 per month. This is expected to increase to $8500 per month when Granicesti SE-1 comes on-stream in 2016.

2.10.1. Climauti

The Climauti Field is already in production from the Climauti-1 well which cost $1.875 million. The well is operated by Raffles Energy as a satellite to their Bilca Field. A second well, Ruda-1 was drilled in December 2014 at an estimated cost of $1.18 million. A flowline will be installed to tie in the well at an estimated cost of $268,000. No further CAPEX is anticipated.

Climauti pays processing costs (€38.5/1000Sm^3) to Raffles Energy for operating the field.

It is currently anticipated that Climauti (including Ruda-1) will continue producing up until end 2021. Abandonment costs are estimated to be €40,000 per well ($107,000 total).

2.10.2. Dornesti Sud

The Dornesti Sud-1 well started production in December 2014. Costs are derived from the operator's investment proposals. Capital costs of $0.723 million have been incurred to date. No further CAPEX is expected, except for a contingent $0.335 million for a major overhaul of the generator after 64,000 hours service (after every 8 years use).

Operating costs for the well and generator maintenance and running costs are estimated to be €15 per hour. It is estimated that after the production goes off plateau, the well will continue to produce at declining rates until the economic limit is reached at 90,000 Sm3 per month (about 35% of generator capacity), in which case the field life would last until 2022, 2028 or 2035 in the P90, P50 and P10 cases.

Abandonment costs are estimated to be €40,000 ($53,000).

2.10.3. Granicesti SE-1

It is assumed that Granicesti will be developed for gas production to the NTS grid, as currently planned. The Granicesti SE-1 well was drilled in 2004 by a previous operator. The only CAPEX costs incurred by the current partners are expected to be $0.536 million for testing in March 2016, and $1.34 million hook-up costs anticipated in Q2 2016, plus $0.27 million in 2018 to install compression.

Operating costs are anticipated to be on a similar basis to Climauti, and processing costs of €38.5/1000Sm^3 payable to Raffles Energy for operating the field have been assumed.

It is estimated that after the production goes off plateau, the well will continue to produce at declining rates until the economic limit is reached at around 100,000 Sm3 per month in which case the field life would last until 2022, 2027 or 2030 in the P90, P50 and P10 cases. The P10 case is cut-off at 2030 on the basis of greater uncertainty on maintenance costs for facilities integrity after 15 years.

Abandonment costs are estimated to be €40,000 ($53,000).

2.11. Economics

2.11.1. Romanian Petroleum Fiscal System

The Romanian Fiscal Regime applicable to oil and gas extraction is a Tax and Royalty system comprising the following elements:

Royalty payable on gross production volumes on a sliding scale according to quarterly production rates as follows:

Oil Royalty Rate	Oil Production Rate per Quarter Year	Gas Royalty Rate	Gas Production Rate per Quarter Year
2.5%	0-10,000 tonnes	3.5%	0-10 million m^3
5%	10-20,000 tonnes	7.5%	10-50 million m^3
7%	20-100,000 tonnes	9%	50-200 million m^3
13.5%	>100,000 tonnes	13.5%	>200 million m^3

Table 2-18 Royalty Rates (Hydrocarbon law 238/2004)

Due to the production rates anticipated, the Royalty rate applicable to Suceava licence will be 3.5%. The gas produced for the Dornesti Sud gas to power project is also subject to the 3.5% Royalty.

Corporate Income Tax (CIT) 16%. In the case of the Suceava licence, there are significant accumulated past costs of around $6 million which are carried forwards as tax losses against future income.

Supplementary Income Tax of 60% of additional sales revenue derived from deregulation of gas prices in Romania. Additional tax due = 60% x (additional income – royalty x additional income – investment depreciation allowance). Additional income is defined as income gained from sales prices above the ANRE reference price of 495 RON/1000m^3.

ANRE Electricity production tax is levied at 0.08% of revenues.

Construction Tax of 1.5% of book value of any oil and gas facilities including infrastructure and wells, paid annually.

Oil production levy of €4 per tonne. This is not applicable to the Suceava licence which produces only gas.

Transmission Tax on gas and electricity of 0.1 – 0.85 RON per MWhr. This is applicable to gas and electricity distributors, but is not applicable to the Suceava licence. The gas is sold to Wintershall who are subject to this tax when the gas is transported.

There have been press reports about government plans to revise the oil and gas fiscal regime in Romania, with possible implementation in 2015. Details of the new fiscal regime are not yet available. However, the prime minister stated on 4th June 2014 that the focus would be on revising taxation for the offshore sector, and that the new tax system would not affect current contracts.

2.11.2. Gas and Electricity Prices

Gas prices for gas produced in Romania are regulated by the Regulatory Authority for Energy (ANRE). Previously gas prices were constrained far below international market prices, but there is an IMF, World Bank and EU supported programme of gradual liberalisation of gas prices which is expected, over an extended period to result in full market prices being achieved. Prior to deregulation, in 2013, the ANRE regulated gas price was 495 RON/1000m^3. Using a calorific value of 10.828 MWh/1000m3, the regulated price was 45.71 RON/MWh. This price is the reference price against which any Supplementary Income Tax is compared.

Following partial deregulation of the gas price, the current regulated price for domestic gas sales is 53.30 RON/MWh (=577.13 RON/1000m^3). Gas sales to industrial users are subject to a higher regulated price of 89.4 RON/MWh or 968 RON/1000m^3. The ANRE calculates the ratio of sales to industrial and domestic users and informs gas producers on a monthly basis (typically 70-80% industrial). For modelling purposes, we have used an average of 75% industrial sales.

Additional Income Tax is levied on the difference between the reference price and the regulated price.

The deregulation programme was intended to fully deregulate industrial prices by 2015 and domestic prices by 2018. However, the Romanian government has slowed the pace of deregulation since mid-2014, and it is currently unclear when the deregulation will be completed. It is currently expected that the current regulated price will persist throughout 2015, and we have used the current average regulated price 870 RON/1000m^3 (25% x 577 RON + 75% x 968 RON) for 2015. This is equivalent to $6.69/mmscf. Romania imports 20% of its total gas supply, from Russia, at prices around $10.5-11.3/mcf, which we consider to be the current market price for imported gas. (see http://www.naturalgaseurope.com/romania-gas-price-increased http://www.eia.gov/countries/country-data.cfm?fips=ro).

There is pressure from the IMF to continue the deregulation programme which would result in a gradual increase in gas prices, particularly for domestic users, and it is reasonable to expect the programme implementation to be continued at some point. For valuation, we have run sensitivities using the following reference price profiles:

Case	Description		2015	2016	2017	2018	2019	2020
Minimum	Current regulated (below market) price fixed.	RON/m3	870	870	870	870	870	870
		$/mcf	6.70	6.70	6.70	6.70	6.70	6.70
High	Deregulation to current market price +25%	RON/m3	870	1529	1629	1706	1706	1706
		$/mcf	6.70	11.77	12.54	13.13	13.13	13.13
Mid	Deregulation to current market price	RON/m3	870	1223	1274	1365	1365	1365
		$/mcf	6.70	9.41	9.80	10.5	10.5	10.5
Low	Deregulation to current market price -25%	RON/m3	870	968	993	1024	1024	1024
		$/mcf	6.70	7.45	7.64	7.88	7.88	7.88

Table 2-19 Reference Price scenarios

We are informed by Zeta that electricity is sold at the price of €40 per MW hr from Dornesti Sud, and this price has been used for this analysis.

2.11.3. Macroeconomic Assumptions

NPV valuations have been calculated with an effective date of 31st December 2014 using the following macroeconomic parameters: Inflation rate 3%, Discount Rate 10%, 3.6873 RON per US$ and 4.4752 RON per € exchange rates.

2.11.4. Suceava Valuation

The Suceava licence reserves valuation comprises the joint cashflows from the 2 fields (Climauti and Dornesti Sud) and joint overhead costs and taxation. As Zeta hold their 50% interest in the licence through a dedicated subsidiary company, Corporation tax is effectively levied on the licence as a standalone entity. Due to tax losses carried forward from past costs, and depending on the continued price deregulation, the Suceava licence will not pay CIT until 2017 (high case) or 2018 (low case).

Reserves Bcf	Project 100% Gross			Zeta 50% Net		
Operator: Raffles Energy	P90	P50	P10	P90	P50	P10
Climauti	0.622	0.685	0.801	0.311	0.342	0.400
Dornesti Sud	0.682	1.198	1.937	0.341	0.599	0.968
Suceava Total	1.303	1.883	2.737	0.652	0.941	1.369

Table 2-20 Suceava Reserves

Reference Price	Project 100% Gross			Zeta 50% Net		
NPV10 US$ MM	P90	P50	P10	P90	P50	P10
High: Deregulation to market price +25% ($13.13/mcf)	6.75	5.57	6.75	3.38	2.79	3.38
Mid: Deregulation to current market price ($10.5/mcf)	3.97	4.59	5.58	1.98	2.30	2.79
Low: Deregulation to market price -25% ($7.88/mcf)	3.20	3.72	4.53	1.60	1.86	2.27
Min: Current regulated price ($6.70/mcf)	2.87	3.36	4.09	1.44	1.68	2.05

Table 2-21 Suceava Reserves Valuation

The Suceava licence also contains Contingent Resources in the Granicesti SE-1 discovery which is awaiting testing and subsequent development. It is planned to develop the field with the existing single well, either for gas export or for a gas to power project. Permitting negotiations are currently ongoing with landowners, subject to successful outcomes, well testing may then commence. We consider there is a 90% chance the project will go ahead. As the Climauti and Dornesti Sud Fields already carry the Suceava licence overhead costs, the incremental value of adding a third producing field to the licence is significant. The Granicesti valuation shown below is the incremental value for the field as part of the Suceava licence, not a standalone value.

Contingent Resources (Gas)	Gross Bcf			Net Attributable Bcf			
Operator: Raffles Energy	Low	Mid	High	Low	Mid	High	Risk Factor
Granicesti SE-1	1.097	2.059	3.78	0.549	1.029	1.89	90%

Table 2-22 Suceava Contingent Resources

Reference Price	Project 100% Gross			Zeta 50% Net		
NPV10 US$ MM	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
High: Deregulation to market price +25% ($13.13/mcf)	3.80	11.08	19.12	1.90	5.54	9.56
Mid: Deregulation to current market price ($10.5/mcf)	3.98	7.98	13.89	1.99	3.99	6.95
Low: Deregulation to market price -25% ($7.88/mcf)	2.28	5.04	8.86	1.14	2.52	4.43
Min: Current regulated price ($6.70/mcf)	1.46	3.69	6.62	0.73	1.84	3.31

Table 2-23 Suceava Contingent Resource Valuation

3. Bobocu

3.1. Bobocu Overview

The Bobocu gas field is located approximately 20 km northeast of Buzau in eastern Romania (Figure 3-1). It was discovered by Romgaz in 1966 and produced from 1977 to June 1995 when most wells had died due to water loading and/or sand production. It was again briefly produced from December 2000 until November 2001. A total of 31 wells have been drilled in the area and gas has been produced from 14 Upper Miocene sandstone reservoirs located from 2500m to 2700m depth.

Figure 3-1 Bobocu licence map

The current Bobocu Licence was signed with NAMR on the 27th March 2007 and ratified by the government on 19th December 2007. Zeta has a 100% working interest in the permit. During 2010 Zeta acquired and processed a 75.25km^2 3D seismic survey. Zeta subsequently drilled 1 well, Bobocu-310, targeting remaining gas resources in the central portion of the field.

Zeta has undertaken a comprehensive interpretation of seismic and well data at Bobocu and has delineated 17 separate gas accumulations. In addition, they have delineated a further 12 prospects around the margins of the licence. The Rockflow evaluation of the resources associated with these accumulations and prospects consisted of the following:

- A review of the Zeta seismic interpretation to assess accuracy and consistency of horizons picked.
- The interpretation of additional horizons to create seismic anomaly maps to check and if necessary independently pick a range of reservoir limits for the various accumulations.
- An independent petrophysical evaluation for Bobocu-310 to confirm reservoir properties and compare with properties obtained from vintage wells
- A probabilistic estimate of initial in-place gas volumes for Bobocu.
- A probabilistic estimate of initial in-place gas volumes (gross and within licence) for the prospects around the margins of Bobocu

- An estimate of the probability of success for the prospects.

3.2. Database

There was a fairly comprehensive database available for Bobocu of which the following were used as the basis of the evaluation:

- Kingdom seismic project containing 75km2 3D survey with interpreted horizons, grids and 39 wells within and adjacent to the Bobocu licence (Figure 3-2).
- 31 wells with limited electric log suites predominantly consisting of SP and resistivity plus a comprehensive set of logs and reports for Bobocu-310.
- Average core porosity measurements over 5 reservoir zones.
- Bobocu Field Study September 2011.
- ISIS Competent Persons Report January 2012.

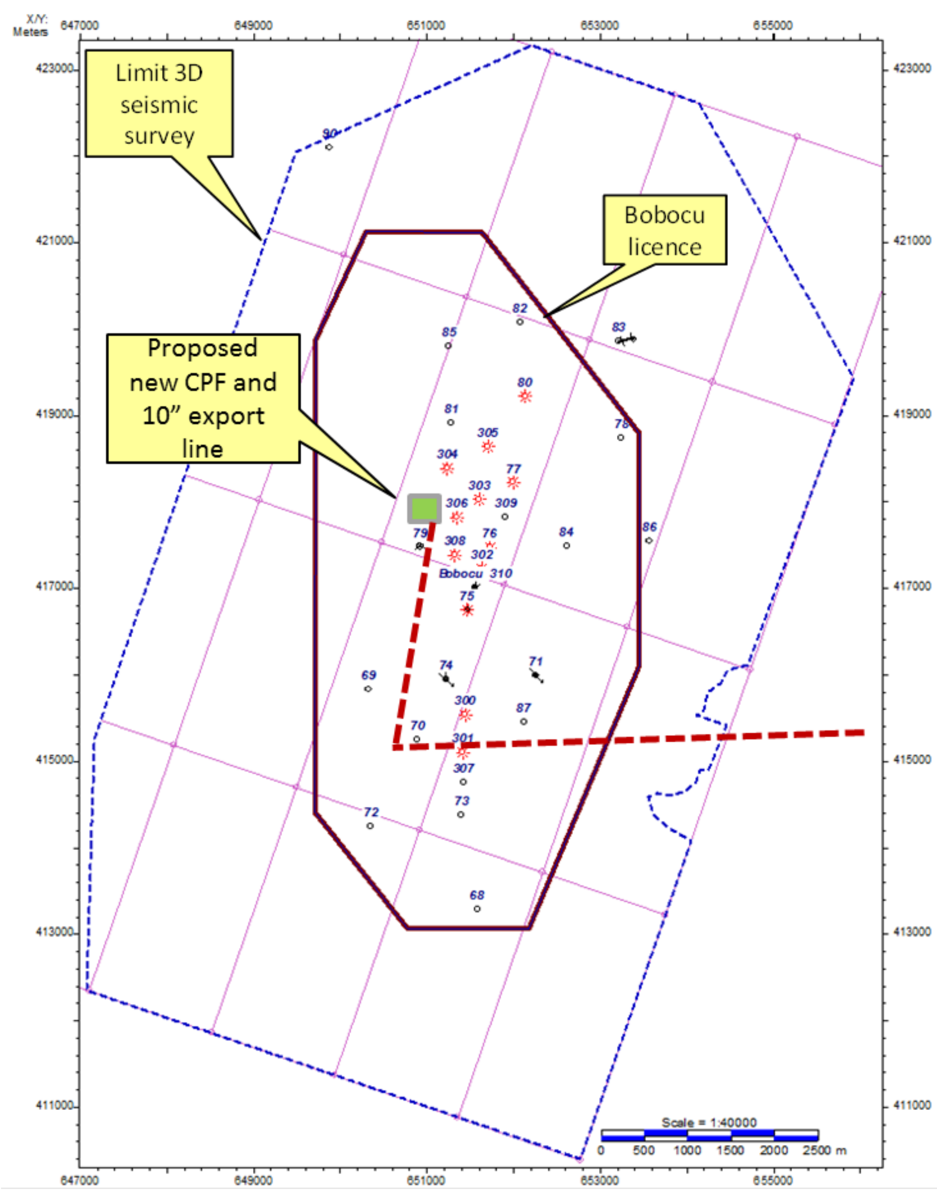


Figure 3-2 Bobocu database

3.3. Geological interpretation

Geologically, the Bobocu field lies on the northeast part of the Moesian Platform, near the margin of the Focsani Basin. This represents the deepest part of the entire Romanian outer Carpathian Neogene foreland basin and is locally 6000m thick (Figure 3-3). Sediments of the Middle to Upper Miocene largely comprise sandstone siltstone marl and claystone. A number of source rock intervals are present within the Neogene section including the Badenian supra-anhydrite and intra-anhydrite marly series and Sarmatian shales. In both of these units the source intervals were deposited interbedded with reservoir sequences. The Badenian and Sarmatian pelitic sequences contain type II and III kerogens with Total Organic Content (TOC) ranging from 1.3 to 2.5 wt %.

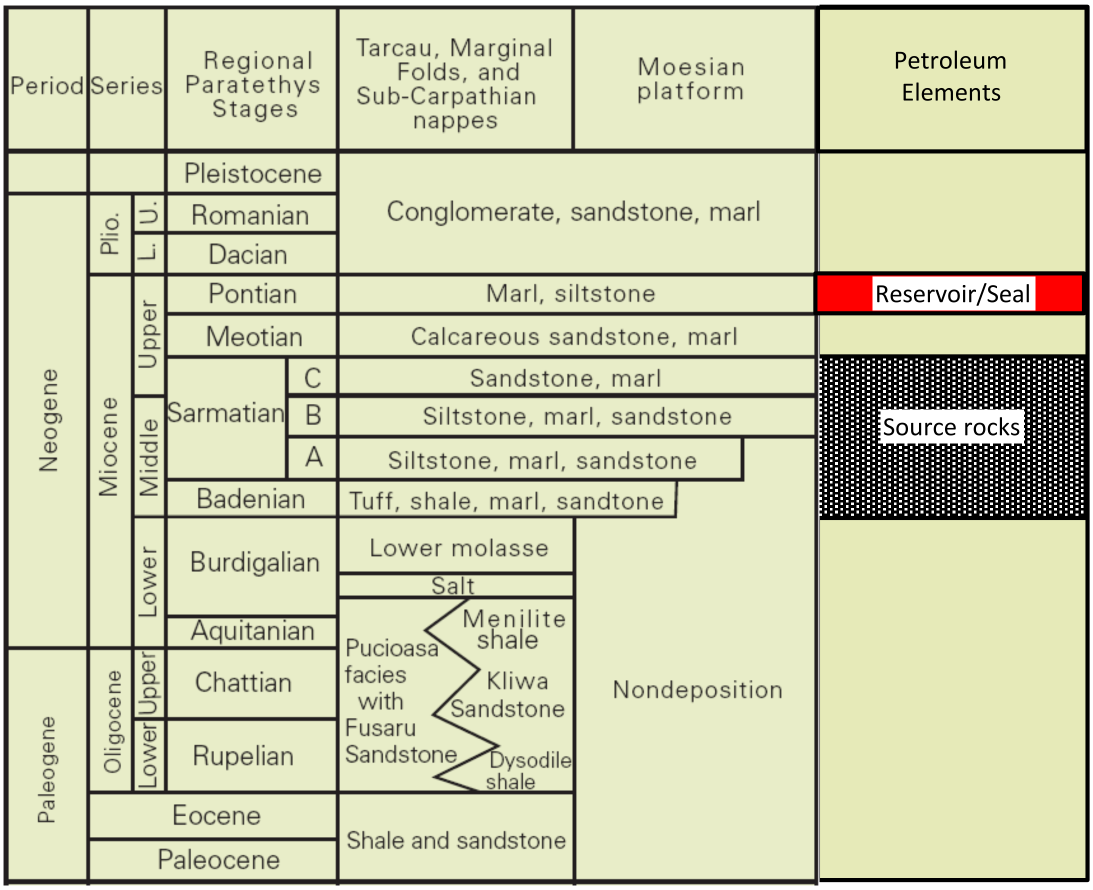


Figure 3-3 Simplified Stratigraphic Column of the Moesian Platform

The Pontian (Upper Miocene) sediments form the reservoirs at Bobocu (Figure 3-3), are believed part of a lacustrine delta sourced from the north and northeast and prograding in a southerly direction. This is supported by the log motif for the wells which shows a series of coarsening upward sequence typical of deltaic sediments. Subsequently these sediments were folded due to strike slip movements. At Bobocu these have created a gentle southward plunging anticline (Figure 3-4). Closure along the axis of the anticline is very limited and usually cannot explain the level of gas seen in the wells. As a result, it is believed that there is an element of stratigraphic trapping present consisting of pinch-out of sands to the north. Overall, the reservoirs are believed deposited in a number of deltaic lobes which form the basis of the traps in the field.

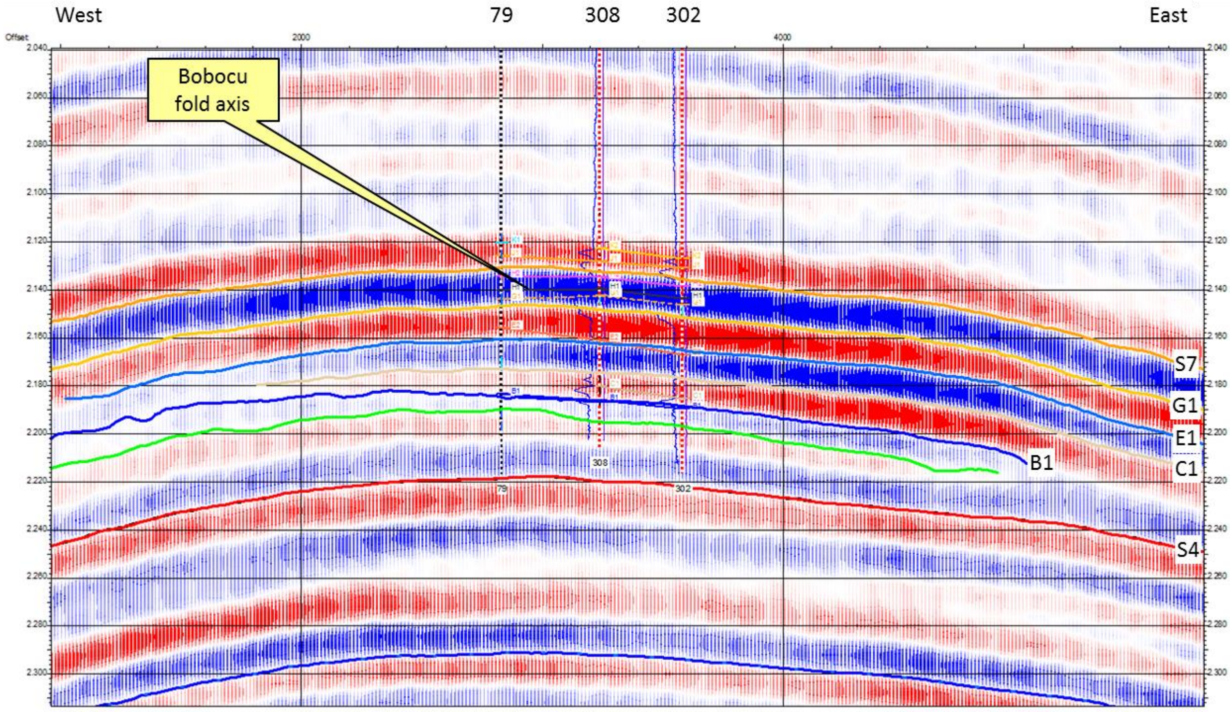


Figure 3-4 Dip line (203) through Bobocu showing anticline

Using a combination of the seismic data and well log character, Zeta produced a detailed reservoir correlation. This divides the reservoir into 14 separate gas sands (Figure 3-5). Overall, the correlation appears reasonable although it was noted there were some differences in dip between the correlated sands in depth and dip seen on the seismic mapping in time.

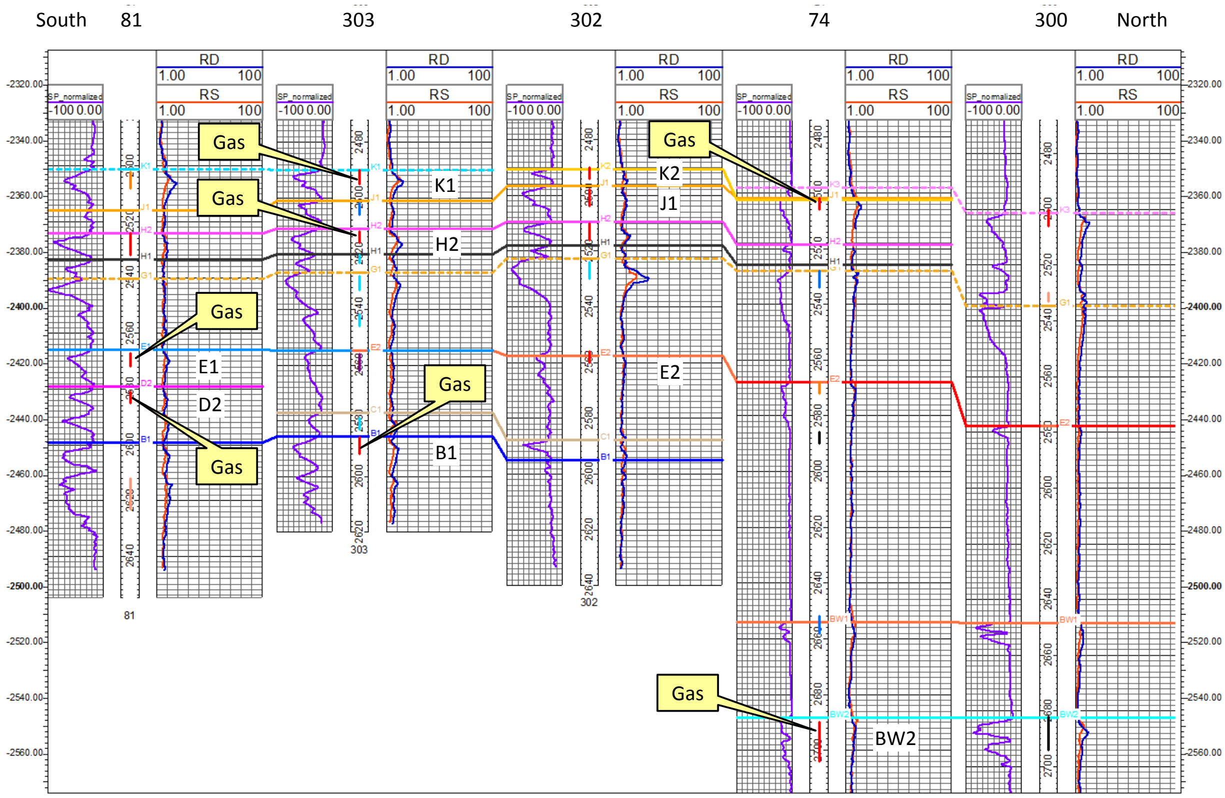


Figure 3-5 Example of reservoir correlation at Bobocu

3.4. Seismic Interpretation

The seismic interpretation produced by Zeta was examined for pick accuracy and consistency. The accuracy of seismic event recognition was checked using a synthetic seismogram which showed the horizons to be correctly identified (Figure 3-6). The quality of the 3D seismic survey at the level of the Pontian reservoirs is good giving a high degree of confidence in structural interpretation. To a lesser extent it shows a number of broad stratigraphic features. The Pontian reservoir architecture has been delineated by the interpretation of 8 horizons picked on zero crossings. These show the overall structure of the field and delineate stratigraphic features such as delta lobes (Figure 3-7). However, the seismic generally lacks the temporal resolution to delineate the thin individual sandstone beds that form the Bobocu reservoirs. As an indicator for the distribution of the sands within the delta lobes and possible extent of gas reservoirs, amplitude maps were produced on peaks and troughs over productive intervals. However, it should be noted that a number of factors affect seismic amplitude in addition to the presence of hydrocarbons including bed thickness tuning, net sand ratio and variations in shale properties.

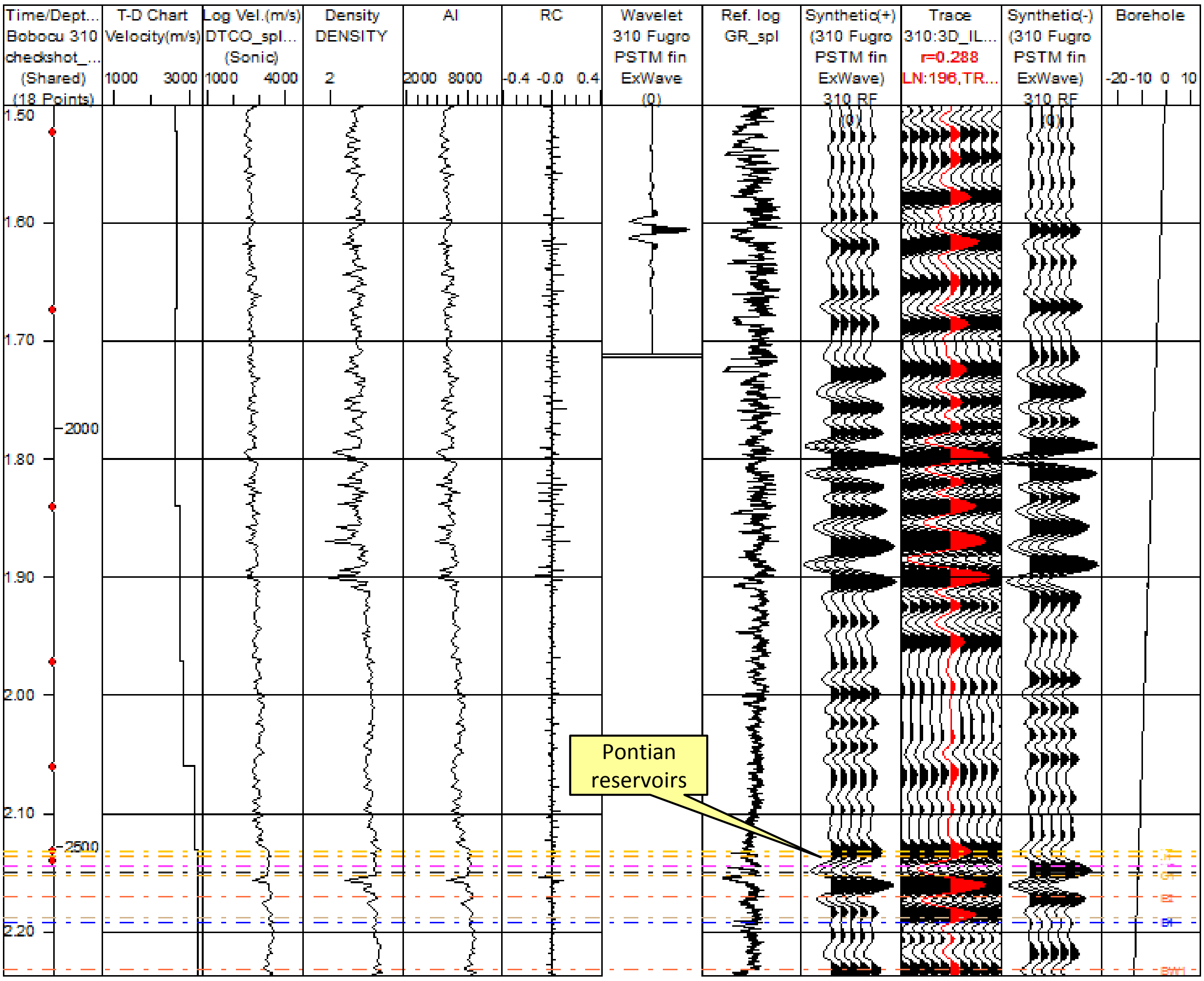


Figure 3-6 Synthetic seismogram Bobocu-310

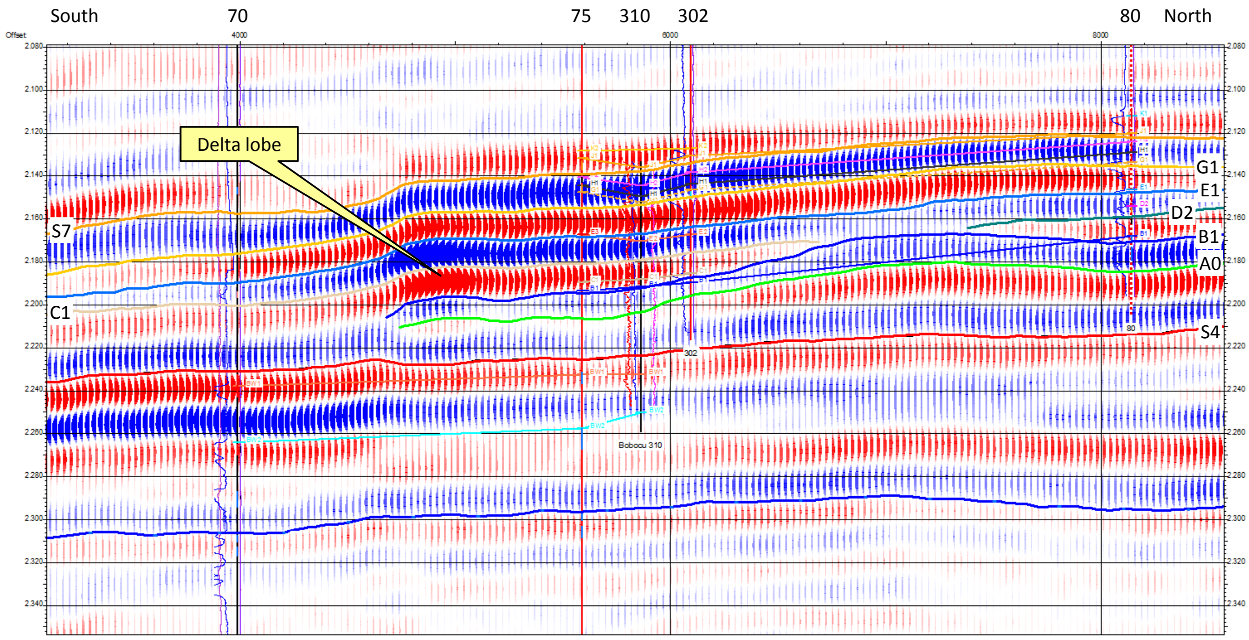


Figure 3-7 Seismic cross-line 227 along Bobocu fold axis showing delta lobes

3.5. Petrophysical Analysis

3.5.1. Zeta Analysis

Petrophysical analysis of 31 wells was initially undertaken by Zeta. The majority of these wells had a very limited log suite generally consisting of a SP and resistivity log. For 3 wells a gamma ray and sonic log was incorporated in the analysis. The Zeta output consisted of the following:

1. V-shale log calculated from a normalised SP with GR log used when available.
2. Porosity log calculated using the Wyllie Time Average equation for the 3 wells with a sonic log. For wells without a sonic log, a porosity log was produced using a relationship generated from a cross plot of the V-shale log and the sonic derived porosity.

Zeta attempted to calculate water saturation but found the resistivity log response over a zone was inconsistent with the recovery of gas or water on test. As a result, no water saturation curve was produced.

Net reservoir was determined for each reservoir in each well using a porosity cut-off of 5% which equates to a permeability of 0.01 mD as derived from the core poroperm data. Zeta produced a set of tables where gross thickness, net thickness and average porosity were calculated for each reservoir zone in each well. Overall it is considered that the net thickness and average porosity calculated by Zeta for each reservoir was reasonable considering the limited poor quality of the log data.

3.5.2. Rockflow Analysis of Bobocu-310

As a QC for the previous Zeta analysis Rockflow undertook an analysis of Bobocu-310. This well was spudded on 23rd July 2012 and drilled to a TD of 2704m. It was drilled in order to confirm the geological model of the area and to test the delta lobes identified as gas bearing. The well has a comprehensive suite of modern logs.

3.5.2.1. Wireline data

Bobocu-310 was logged by Schlumberger and the data use for the analysis is given in the table below:

Borehole Diameter	Open/Cased Hole	Run	Logs
12 ¼”	Open	1	GR, SP, Calliper X-Y, Dev, Shallow & Deep resistivity, P-sonic
	Cased	1	CBL, VDL, CCl, GR
8 ½”	Open	1	GR, SP, Bit size, Resistivity, Calliper X-Y, Dev, P-Sonic, Shear Sonic.
		2	Litho-density, density correction, compensated neutron, GR, Calliper, MCFL
		3	CMR, GR
		4	MDT
	Cased	1	CBL, VDL, CCL, GR
Checkshot survey 200, 500, 1000, 1400, 1600, 1800, 2000, 2220, 2400, 2526, 2650m MD			

Table 3-1 Wireline logs run in Bobocu 310

Pressure tests

An MDT was run to understand the current pressures in the reservoirs (Table 3-2), not to establish fluid gradients, due to the extensive production that has already taken place within the field. Mobilities are plotted on the CPI as point data and good mobilities are present over the ‘cleaner’ sand sections.

Test #	File #	Depth MD m.	Depth MD ft	Buildup Pressure Psi	psi/ft	Mud Before Psi	Mud After Psi	Mobility mD/Cp	Fluid Identification	Remarks
4	26	2499.8	8201.9			4165.2	4158.9			tight
5	27	2537.6	8325.7	3587.05	0.431	4237.4	4225.0	113.8		
6	28	2536.0	8320.7	3584.13	0.431	4217.9	4218.2	115.7	WATER	
7	29	2534.3	8315.1	3580.8	0.431	4209.9	4210.5	31.7	WATER	sample bottle 1
8	30	2532.9	8310.6	3613.65	0.435	4203.4	4200.8	0.1		slightly supercharged
9	31	2531.3	8305.3	3597.59	0.433	4199.0	4196.7	5.6		
10	33	2532.9	8310.6	3599.08	0.433	4199.7	4200.4	2.6		
11	34	2532.8	8310.2	3611.25	0.435	4200.0	4197.6	0.1		slightly supercharged
12	35	2532.9	8310.4	3593.94	0.432	4198.2	4195.3	1.5		lost seal during pumpout
13	36	2532.9	8310.4	-		4195.1	4194.3	-		No seal
14	37	2531.3	8305.2	3600.55	0.434	4194.1	4193.5	2.1		lost seal during pumpout
15	38	2520.6	8270.1	2332.01		4170.4	4169.0	0.2		not stabilized
16	39	2519.5	8266.3	-		4167.3	4165.4	0.0		tight
high confidence point										
medium confidence point										

Table 3-2 MDT pressures, Well Bobocu 310

3.5.2.2. Well Tests

Three separate DST's were taken (Table 3-3) all produced water with no gas indication. Further review of DST 1 in the G lobe identified that the best sand interval was not perforated, and so insufficient gas flowed into the well to lift water in the wellbore.

Perforation Interval	Top Depth m MD	Bottom Depth m MD	Unit	Fluid
1	2530.6	2534.6	Pontian G lobe	Water with no gas indication
2	2518.5	2522.0	J Main lobe	Water with no gas indication
3	2168.5	2172.0	Pontian	Water with no gas indication

Table 3-3 DST test intervals for Well Bobocu 310

3.5.2.3. Hydrocarbon shows

The gas curves on the mud log show mainly C1 with 'trace' C2 over some of the carbonaceous/coal intervals (2020-2220 m MD) and over the main Pontian sands from 2500m to 2610m. There are clear gas 'kicks' recorded on the chromatograph at all mud log and wireline log interpreted sands.

3.5.2.4. Porosity Permeability relationship

Digital CMR results were not available and so the derived permeability curve could not be plotted on the CPI. However, it should be noted that permeability derived from NMR results are unreliable for a quantitative value unless calibrated to core or local empirical poroperm relationships are understood. That said the MDT mobility and CMR permeability curves show the same pattern over the limited interval where both data are present, which gives confidence to both sets of data.

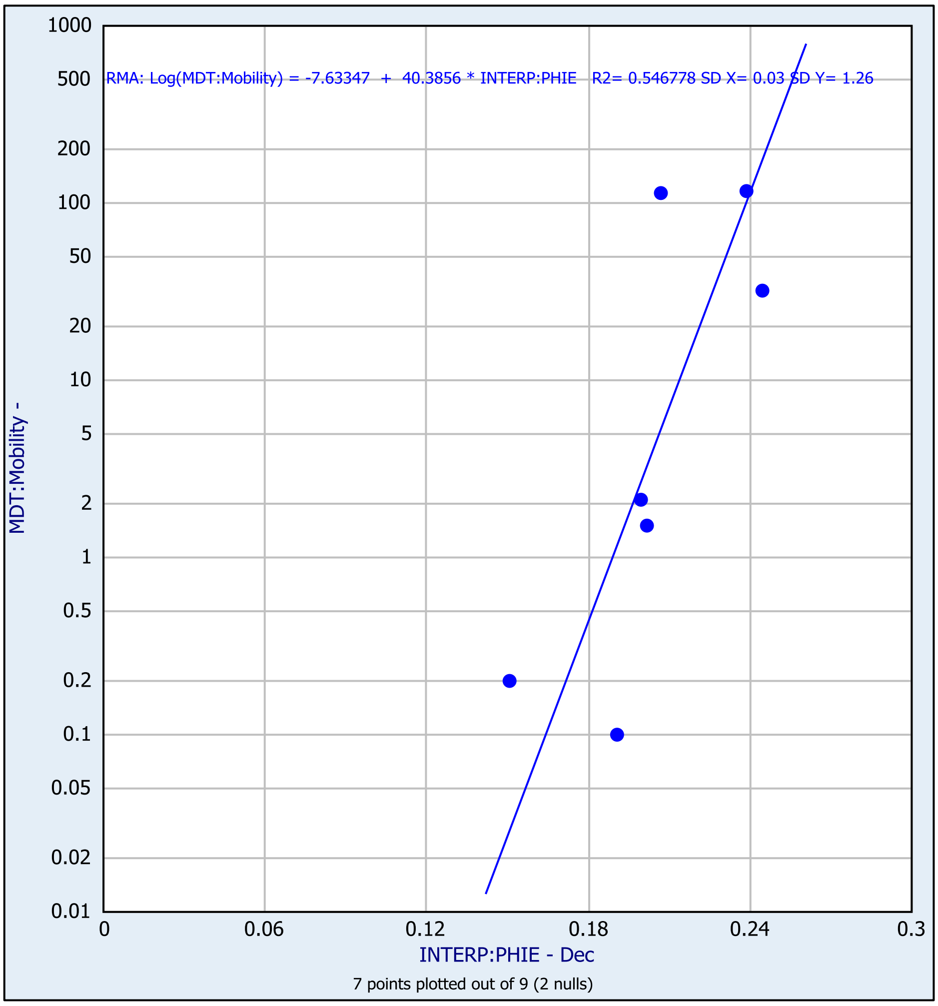


Figure 3-8 Cross plot of MDT mobility against interpreted PHIE

3.5.2.5. Volume of Clay

A minimum of linear VCL from Gamma and Density-Neutron separation has been used to define final VCL, the resultant curve was checked against the Lithological log.

3.5.2.6. Porosity

A hydrocarbon corrected porosity log has been calculated from the Density log, assuming a sand grain density of 2.65 g/cc. In the absence of Density Correction log or Caliper the condition of the hole is difficult to determine and no Bad Hole flag was generated.

3.5.2.7. Water Saturation

The three well tests and the two MDT samples were recorded as recovering water (although MDT assumed to be drilling fluid). The gas chromatograph shows gas in the wells and the logs do interpret Hydrocarbons (HC). A standard Archie interpretation has been used.

Temperature gradient: A temperature gradient was calculated and plotted on the CPI based on two fixed points the BHT (bottom hole temperature) of 152.6°F at 2704m MD taken from a CPI thought to have been made by Schlumberger and assuming 50°F at surface.

Formation water salinity and saturation exponents: The MDT sample results equate to salinities of 3,304 to 4,305 ppm which are similar to the salinity of the mud used during drilling, these samples are therefore interpreted to be contaminated with drilling mud and have not been used further during the analysis.

The test water samples were analysed by ANPM Suceava, Table 3-4 shows a summary of the results which translate to a salinity range of 7,638 ppm to 12,213 ppm. This salinity is fresher than expected but still within the historic data. Historic data lead Zeta to use a salinity of 30,000 ppm and Weatherford used a salinity of 35,000 ppm over the reservoir during their initial analysis from offset fields and historic data

Sample	Depth (m MD)	pH @ 19.8°C	Suspended Solids (mg/l)	Conductivity (µS/cm)	Chlorine (mg/l)
1	2168.5-2172	7.3	47000	20500	7630
2	2518.5-2522	8.8	640	36020	12200
3	2530.6-2534.6	7.4	11000	29600	9840

Table 3-4 Test water sample analysis Bobocu 310

Two Rw values based on 10,000 ppm and 30,000 ppm salinities have been used in this study to demonstrate the effect a varying Rw will have on Sw results (SWE_10k and SWE_30k respectively).

Weatherford used Archie parameters of a=0.62, m=2.15, n = 2 based on data from offset fields unavailable to Zeta. These values have not been adopted here as there is no way of checking their origin.

No Pickett plot has been determined and Archie parameters have been assumed:

m = 2
n = 2
a = 1
Rw = 0.6 and 0.26 Ohmm at 60°F

An Rmf of 0.98 at 79°F - taken from Schlumberger CPI log.

3.5.2.8. CPI plot

The CPI plot over the Pontian (Figure 3-9) shows significant gas saturations in the G1 Pontian sands over the interval 2530 to 2540m where depending on the Rw used they range from 40% to 60%. In addition there are 4 other thin sands that may contain gas.

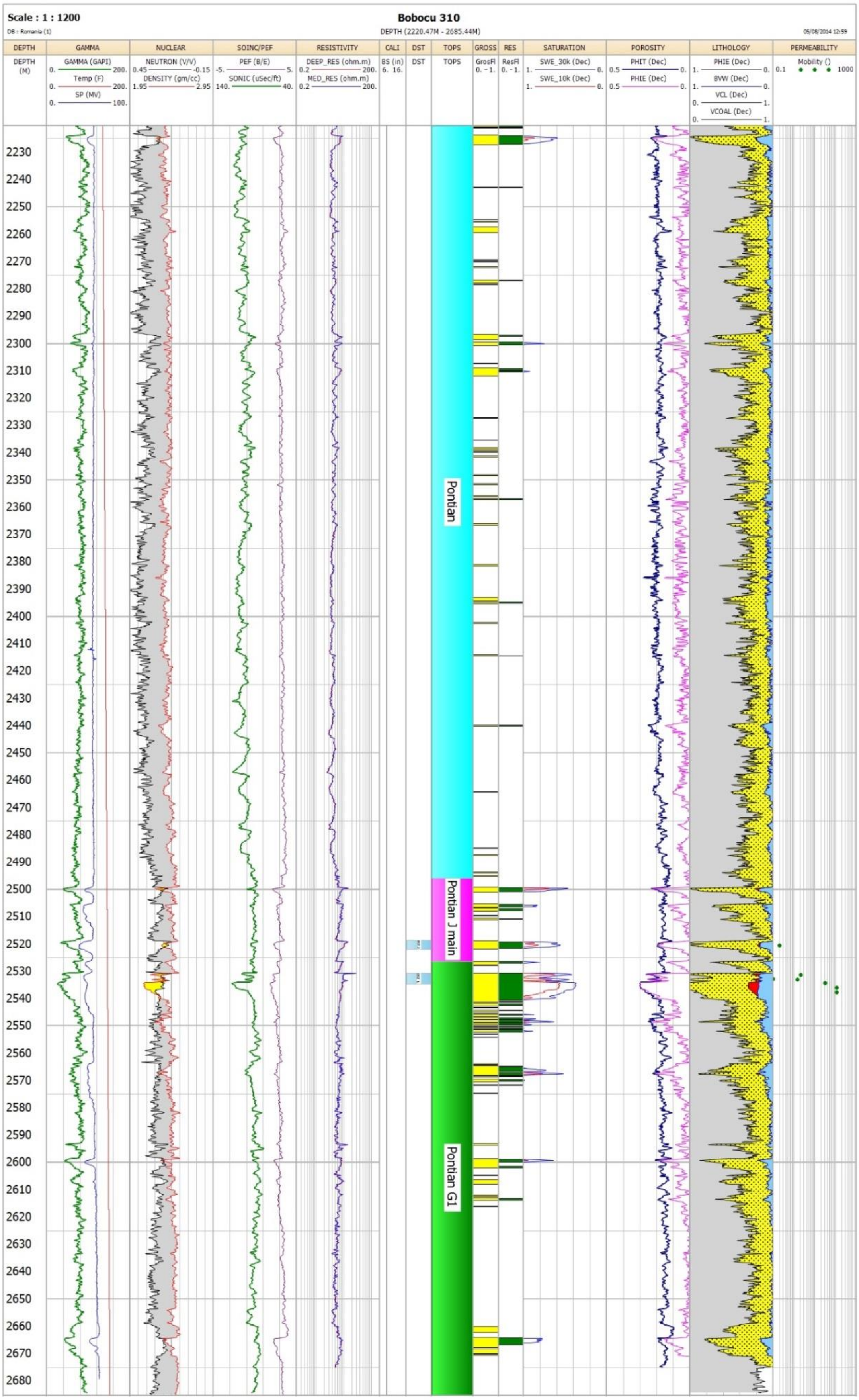


Figure 3-9 CPI plot of Pontian Bobocu-310

3.5.3. Average reservoir properties

Comparison of petrophysical averages calculated by Zeta and those obtained from Bobocu-310 for the same zone in nearby wells were comparable. It was therefore decided to use both analyses to calculate average reservoir properties for each delta lobe. These averages were based on productive wells in the lobe and relevant nearby wells. Due to the poor quality of the original logs and the depleted nature of the reservoirs in Bobocu-310, it was not possible to obtain initial gas saturation. Therefore the reservoir averages were restricted to net reservoir thickness and porosity.

Lobe	Net m				Porosity fraction			
	Min	Mean	Max	Standard deviation	Min	Mean	Max	Standard deviation
BW2	3.63	5.10	6.00	0.949	0.17	0.23	0.27	0.039
BW1	2.63	4.52	6.88	1.545	0.18	0.24	0.30	0.059
B1	4.88	5.38	5.88	0.5	0.22	0.243	0.28	0.035
C1	0.38	1.22	2.00	0.902	0.16	0.185	0.22	0.03
D2	0.50	2.25	3.38	1.032	0.06	0.077	0.1	0.015
E1	2.00	4.80	8.75	2.664	0.08	0.096	0.11	0.013
E2 South 2	3.38	7.06	11.25	3.652	0.07	0.097	0.14	0.021
E2 South 1	1.25	7.00	11.25	3.652	0.09	0.097	0.14	0.021
G1	7.25	10.19	13.00	2.067	0.190	0.230	0.280	0.033
H1 Main	2.75	4.50	5.50	1.208	0.14	0.158	0.19	0.022
H1 North	4.504	5.63	6.756	1.208	0.088	0.11	0.132	0.022
H2 main	2.74	4.88	7.88	1.487	0.14	0.177	0.22	0.026
H2 main N	5.88	6.84	7.88	1.487	0.16	0.176	0.2	0.026
J	1.75	4.49	8.25	2.204	0.07	0.121	0.15	0.031
K1 North	1.63	3.86	5.00	1.164	0.170	0.205	0.260	0.033
K2 East	0.38	1.27	2.63	1.096	0.150	0.175	0.220	0.031
K3 North	5.63	7.88	9.00	2.29	0.09	0.13	0.17	0.057

Table 3-5 Reservoir average for productive lobes

3.6. Fluid properties

Historical production has shown that the gas from Bobocu is ~99.4% methane. Fluid properties have been derived from Stand and Katz correlations, and are summarised is in Table 3-6.

Property	Units	Value
Methane	mol%	99.4
Nitrogen	mol%	0.26
CO2	mol%	0.108
Initial Reservoir Pressure	psia	4365
Reservoir Temperature	°F	144
Formation Volume Factor	rb/stb	0.00375
Gas Expansion Factor	stb/rb	266.7

Table 3-6 Fluid Properties for Bobocu Gas

3.7. Estimation of hydrocarbon resources

3.7.1. Bobocu GIIP

Zeta divided the 14 gas reservoirs at Bobocu into 17 productive lobes. The extent of the lobes was delineated primarily using seismic attributes (Figure 3-10). To confirm these extents, additional seismic horizons were picked on the relevant peaks and troughs and amplitudes extracted. Polygons were produced to delineate each productive lobe taking into consideration the seismic amplitude, well test, production data and structural dip (Figure 3-11 & Figure 3-12). Areas of the polygons were measured and classified as either a low, mid or high case. Due to the complex nature of the traps at Bobocu, net rock volume for the productive part of the lobe was calculated using area, net thickness and a shape factor. The net thickness used is given Table 3-5 while due to the thin nature of the reservoir, the shape factor varies between 0.9 and 1. The areas calculated for each lobe with comments on their delineation are given in Table 3-7 below.

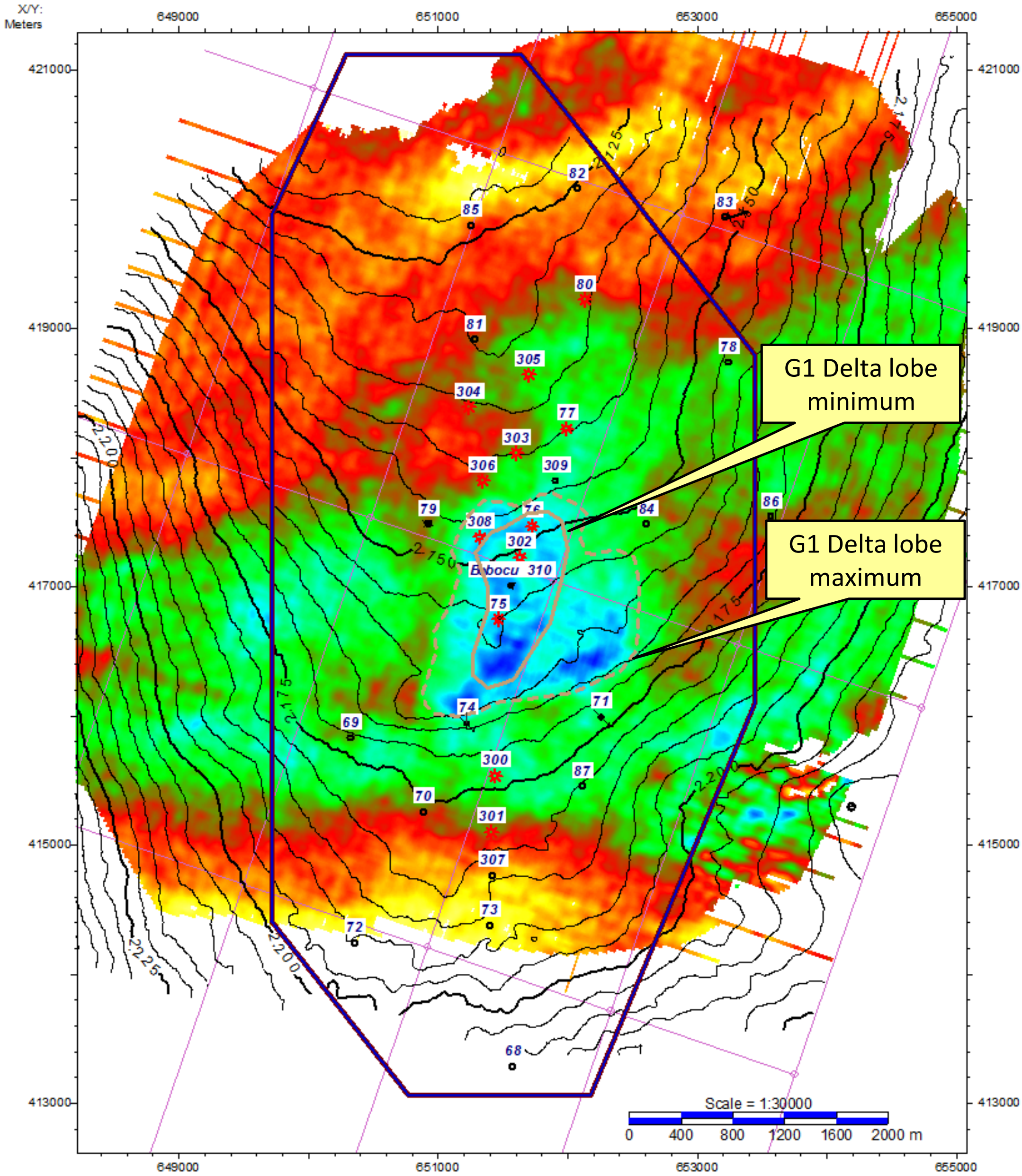


Figure 3-10 Reservoir G1 seismic amplitude with time structure contours

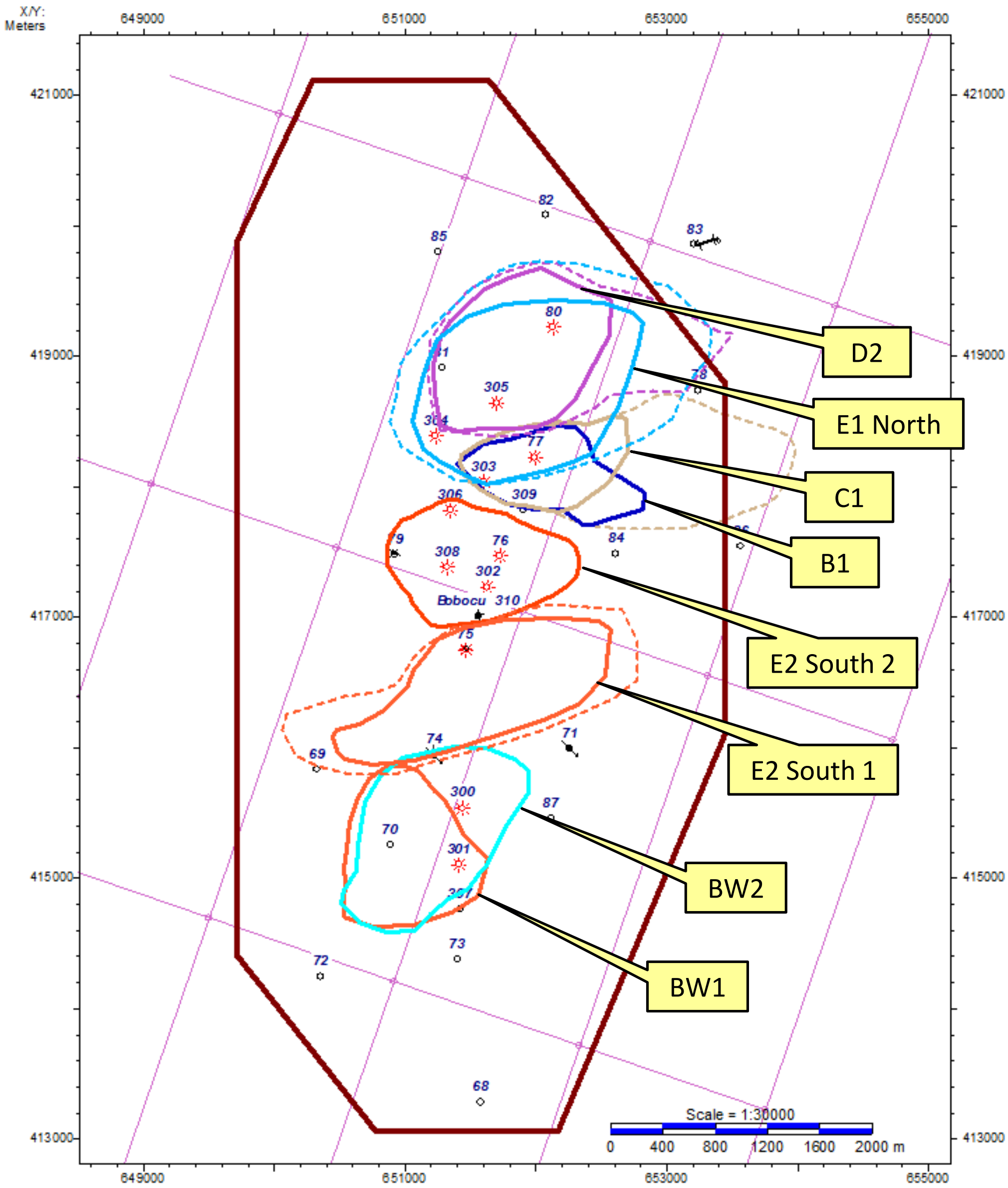


Figure 3-11 Bobocu lower reservoirs (BW2 to E2)

Note: Dashed polygons are maximum polygons for the same colour solid polygons

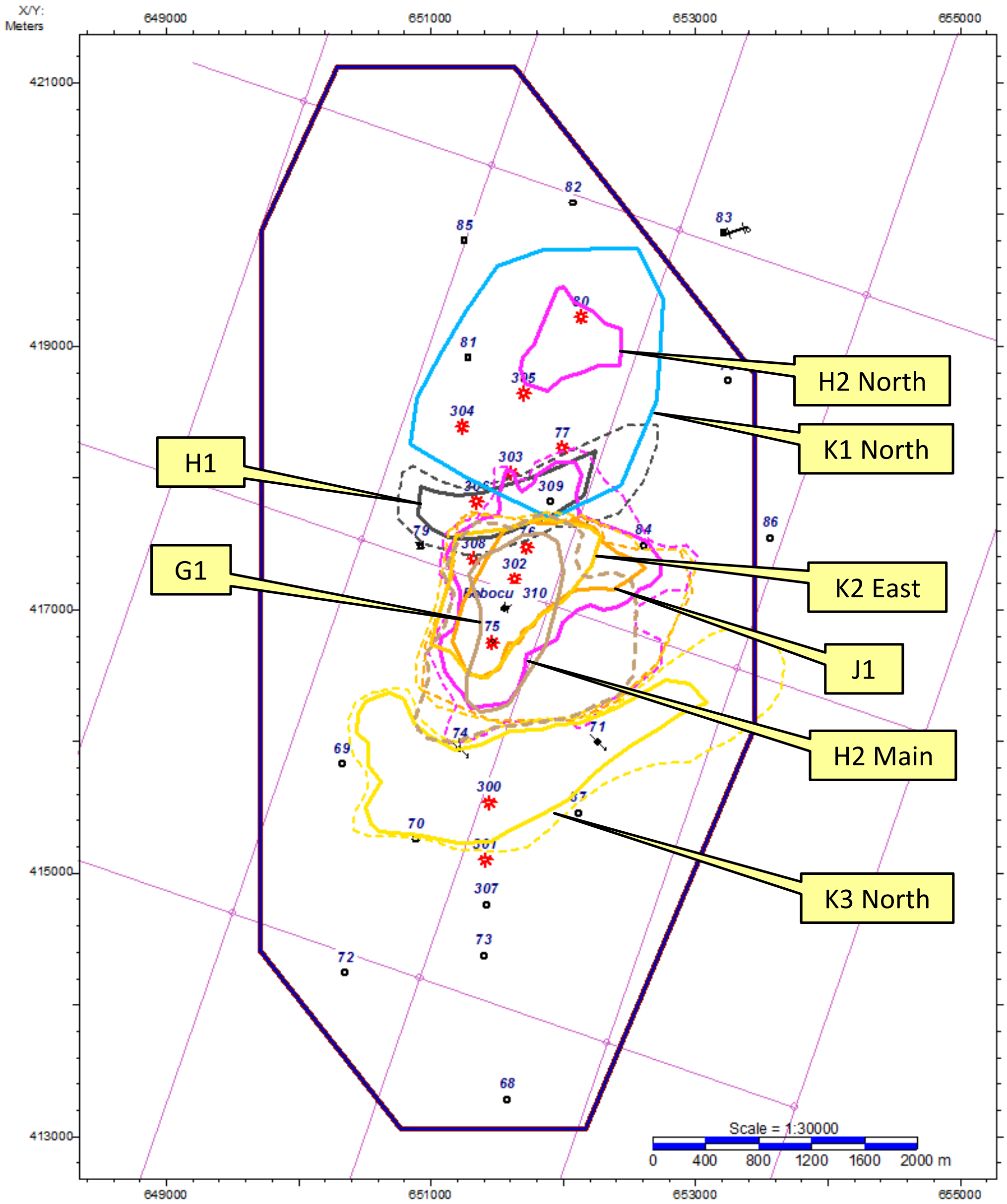


Figure 3-12 Bobocu upper reservoirs (G1 to K3)

Lobe	Area km^2			Comments
	Low	Mid	High	
BW2	1.064	1.330	1.596	Defined on amplitude decrease to north & southerly dip. Range: Mid case polygon +- 20%.
BW1	0.790	0.987	1.184	Based on 70. 73 to south is wet, & deeper in time but not depth. Range: Mid case polygon +- 20%.
B1	0.508	0.635	0.762	Defined on amplitude & time contours. Range: Mid case polygon +- 20%.
C1	0.655	1.243	1.831	Defined on wavelet pinch-out & time contour. Range: Low and high case polygons defined.
D2	1.259	1.648	2.036	Defined on D2 amplitude + time contours. Range: Low and high case polygons defined.
E1	1.857	2.446	3.034	Defined on amplitude + time contours. Range: Low and high case polygons defined.
E2 South 2	0.802	1.002	1.202	Based on wells. Range: Mid case polygon +- 20%.
E2 South 1	1.378	1.708	2.037	Defined on amplitude + time contours. Range: Low and high case polygons defined.
G1	0.673	1.360	2.046	Defined on G1 amplitude + time contours. Range: Low and high case polygons defined.
H1 Main	0.426	0.722	1.017	V poorly defined area. Range: Low and high case polygons defined.
H1 North	0.366	0.458	0.550	V poorly defined area. Range: Mid case polygon +- 20%.
H2 main	1.627	2.247	2.867	Defined on H amplitude + time contours. Range: Low and high case polygons defined.
H2 main N	0.273	0.341	0.409	Defined on H amplitude + time contours. Range: Mid case polygon +- 20%.
J	0.818	1.614	2.410	Defined on K amplitude anomaly & time contour. Range: Low and high case polygons defined.
K1 North	2.286	2.858	3.430	No amplitude anomaly; defined on wells & contours. Range: Mid case polygon +- 20%.
K2 East	0.910	1.730	2.550	Defined on K amplitude anomaly & time contour. Range: Low and high case polygons defined.
K3 North	1.540	2.071	2.601	Defined on K amplitude anomaly & time contour. Range: Low and high case polygons defined.

Table 3-7 Delta lobe areas used for estimate of GIIP

A probabilistic estimate of GIIP was calculated for each of the 17 delta lobes shown in Table 3-7. The inputs for the GIIP forecast were as follows:

1. Area: Range from Table 3-7 using a normal distribution with low as P90 and high as P10.
2. Shape factor: Triangular distribution, minimum=0.9, mid=0.95 maximum=1.0
3. Net reservoir thickness: Normal distribution with values from Table 3-5.
4. Porosity: Normal distribution with values from Table 3-5.
5. Gas saturation: Normal distribution with mean=0.58, standard deviation=0.03
6. Bg: Triangular distribution, minimum=0.00350, mid=0.00375 maximum=0.00400

The forecasts using the above input parameters for the GIIP in the discovered reservoirs at Bobocu are given in the Table 3-8 below.

Lobe	P90 Bcf	P50 Bcf	P10 Bcf
BW2	5.40	7.50	10.10
BW1	3.53	5.51	8.23
B1	3.38	4.36	5.48
C1	0.60	1.36	2.59
D2	0.67	1.36	2.22
E1	3.16	5.90	9.71
E2 South 2	2.04	3.57	5.71
E2 South 1	2.74	6.18	10.06
G1	8.13	16.27	26.43
H1 Main	1.52	2.55	3.94
H1 North	1.06	1.44	1.92
H2 main	6.13	9.97	15.40
H2 main N	1.65	2.16	2.74
J	1.97	4.25	8.21
K1 North	6.89	11.00	15.83
K2 East	0.92	2.21	4.34
K3 North	6.77	10.09	14.58
Total	**85.83**	**99.17**	**113.67**

Table 3-8 Bobocu discovered GIIP forecast

3.7.2. Near field prospects

Zeta has delineated a number of prospects based on seismic amplitude anomalies adjacent to the Bobocu field. All of them extend out of the Bobocu licence area and two in the east are almost entirely outside it and hence not reviewed. Zeta had proposed creating separate prospects for the H1, H2 and J reservoirs. However, due to the seismic temporal resolution it is not possible to separate these reservoirs so for this analysis they were combined into the HJ reservoir. This resulted in a total 5 prospects being assessed:

1. HJ Southwest
2. HJ West
3. J South
4. J North
5. K2 west

Two amplitude maps, HJ trough amplitude (Figure 3-13) and K peak amplitude (Figure 3-14), were used to delineate the extent of the prospective lobes. Low and high case polygons were produced to calculated a range of areas for the complete prospect and the areas within the Bobocu licence (Table 3-9).

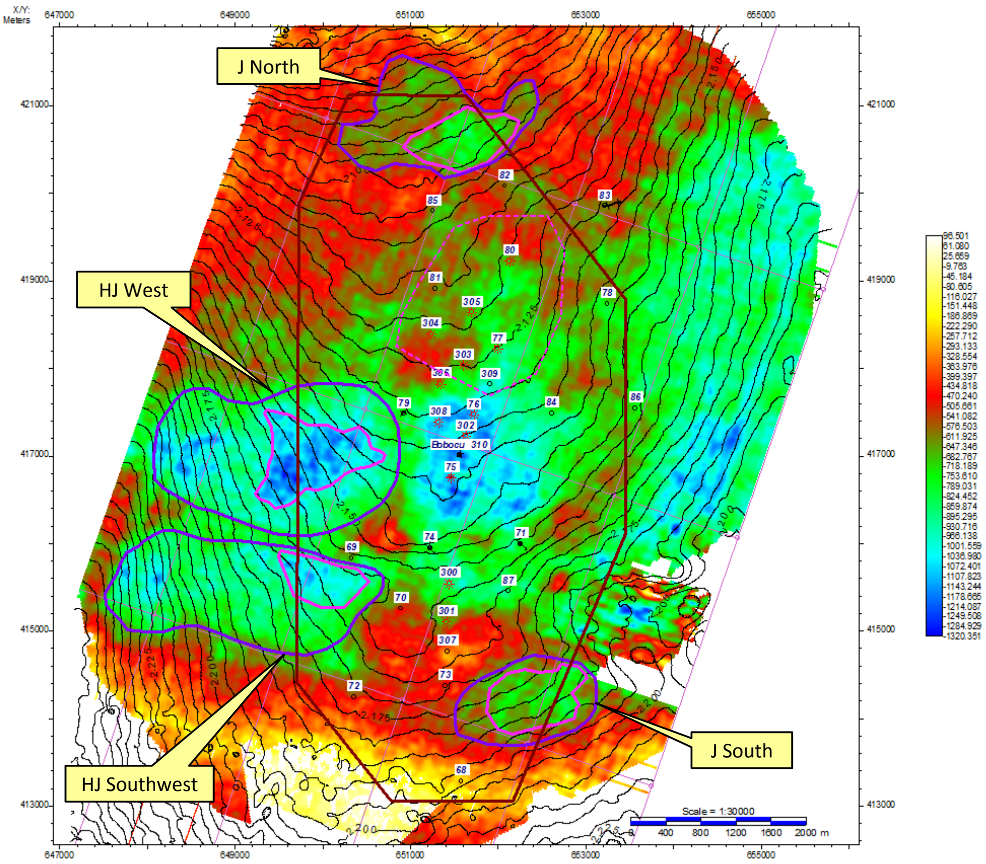


Figure 3-13 HJ Trough Amplitude Map

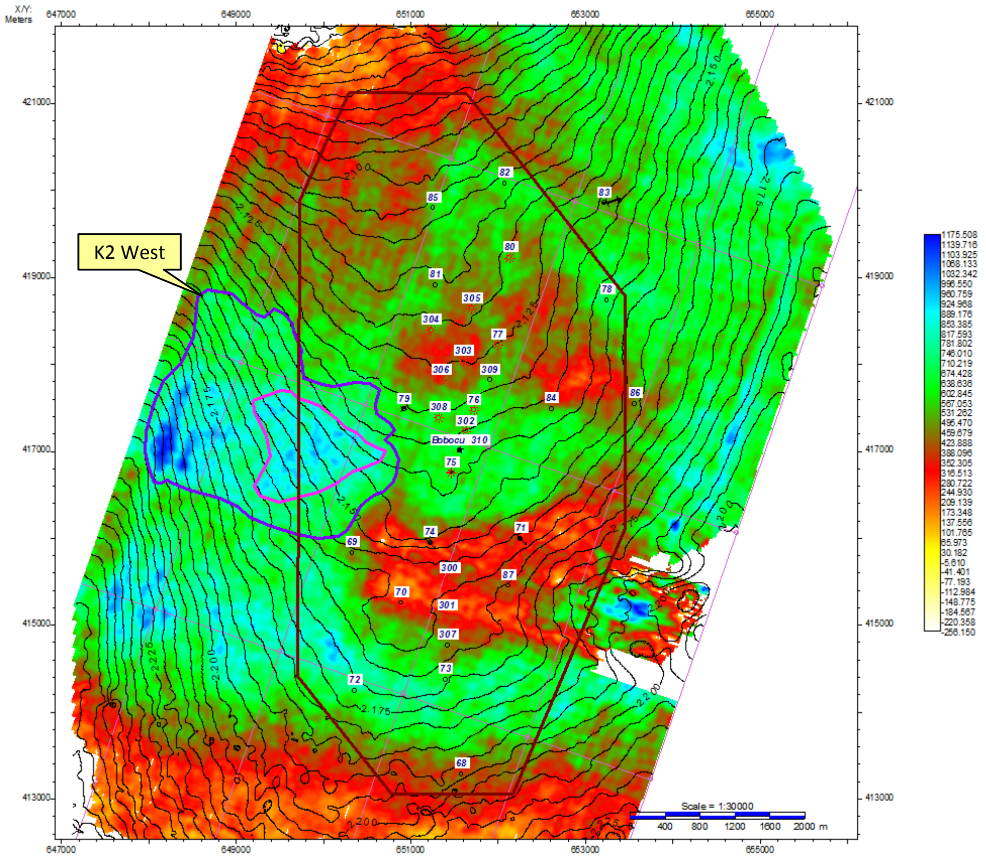


Figure 3-14 K Peak Amplitude Map

Lobe	Reservoir	Area Total km^2				Area Licence km^2			
		Min	P90	P10	Max	Min	P90	P10	Max
HJ Southwest	H J	0.139	0.416	3.068	9.204	0.139	0.347	0.795	2.385
HJ West	HJ	0.293	0.879	3.879	11.637	0.293	0.521	1.698	5.094
J South	J	0.214	0.643	1.264	3.792	0.214	0.492	0.936	2.808
J North	J	0.197	0.590	1.864	5.592	0.197	0.513	1.282	3.846
K2 West	K2	0.384	1.153	5.162	15.486	0.384	0.634	1.644	4.932

Table 3-9 Prospect areas

Net thickness and porosity for each reservoir were recalculated on combining the H1, H2 and J reservoirs into the HJ reservoir (Table 3-10).

Lobe	Reservoir	Net m				Porosity fraction			
		Min	Mean	Max	Standard Deviation	Min	Mean	Max	Standard Deviation
HJ Southwest	H J	2.25	9.80	18.38	5.15	0.07	0.148	0.22	0.038
HJ West	HJ	2.25	9.80	18.38	5.15	0.07	0.148	0.22	0.038
J South	J	2.00	4.78	10.50	2.57	0.07	0.131	0.17	0.030
J North	J	2.00	4.78	10.50	2.57	0.07	0.131	0.17	0.030
K2 West	K2	0.38	1.27	2.63	1.096	0.15	0.175	0.22	0.031

Table 3-10 Net reservoir thickness and porosity input for prospects

For the calculation of GIIP the same assumptions of shape factor, gas saturation and Bg used for Bobocu were retained. The resultant probabilistic forecast of gross GIIP for the prospects are given in Table 3-11 and the GIIP within the Bobocu licence in Table 3-12.

Lobe	Reservoir	P90 Bcf	P50 Bcf	P10 Bcf
HJ Southwest	H J	3.60	11.93	28.21
HJ West	HJ	5.46	16.22	36.27
J South	J	1.48	3.05	5.67
J North	J	1.61	3.86	7.88
K2 West	K2	1.32	3.85	8.47
Total		**13.47**	**38.92**	**86.50**

Table 3-11 Gross prospect GIIP forecast

Lobe	Reservoir	P90 Bcf	P50 Bcf	P10 Bcf
HJ Southwest	H J	1.59	3.93	7.80
HJ West	HJ	2.95	7.64	16.23
J South	J	1.13	2.29	4.22
J North	J	1.30	2.86	5.59
K2 West	K2	0.58	1.41	2.79
Total		**7.54**	**18.13**	**36.63**

Table 3-12 GIIP within Bobocu licence

Recoverable volumes have been calculated using a probabilistic range of recovery factors of 50-65-80%, yielding the following prospective resources:

Lobe	Reservoir	P90 Bcf	P50 Bcf	P10 Bcf
HJ Southwest	H J	2.32	7.76	18.56
HJ West	HJ	3.50	10.40	23.44
J South	J	1.04	2.51	5.17
J North	J	0.95	1.97	3.71
K2 West	K2	0.85	2.47	5.51
Total		**8.66**	**25.12**	**56.38**

Table 3-13 Gross prospect recoverable resources

Lobe	Reservoir	P90 Bcf	P50 Bcf	P10 Bcf
HJ Southwest	H J	1.02	2.54	5.12
HJ West	HJ	1.90	4.92	10.55
J South	J	0.83	1.85	3.64
J North	J	0.72	1.48	2.76
K2 West	K2	0.37	0.91	1.83
Total		**4.85**	**11.70**	**23.91**

Table 3-14 Gross prospect recoverable resources within Bobocu licence

The estimated quantities of gas that may potentially be recovered by the application of a future development of these prospective resources relate to undiscovered accumulations. These estimates have both an associated risk of discovery and a risk of development. Further exploration, appraisal and evaluation is required to determine the existence of a significant quantity of potentially moveable hydrocarbons.

Based on the review of the seismic and well data, the probability of success for each prospect was assessed. Factors that were assessed comprised:

1. The presence of source rocks and whether the traps were accessible to charge.
2. The likelihood that the proposed reservoir facies would be developed at the prospect location with sufficient porosity and permeability to enable hydrocarbons to flow.
3. The chance that the delineated trap is present at the prospect location and will form an effective seal to contain hydrocarbons.

The presence and effectiveness of the trap is considered the primary risk for the above prospects. At Bobocu the traps are located on the southerly plunging nose of an anticline so that stratigraphic seal is only required to the north. However, four of the prospects are located on the flanks of the anticline so that stratigraphic seal is required in two directions consequently increasing seal risk. The probability of success for each prospect is given in Table 3-15 below:

Lobe	Source		Reservoir		Trap		Overall
	Presence	Migration	Facies	Properties	Presence	Seal	
HJ Southwest	1.00	0.80	0.80	0.90	0.60	0.50	0.17
HJ West	1.00	0.80	0.80	0.90	0.80	0.50	0.23
J South	1.00	0.80	0.80	0.90	0.60	0.60	0.21
J North	1.00	0.80	0.80	0.90	0.80	0.60	0.28
K2 West	1.00	0.80	0.60	0.90	0.60	0.50	0.13

Table 3-15 Probability of success for Bobocu prospects

There are no current plans to drill any of the prospects, most of which lie mainly outside Zeta's licensed area.

3.8. Dynamic Performance

Bobocu has been on production from March 1977 to October 2001. The well by well production is shown in Figure 3-15, and the cumulative production to date is 32.91 Bcf. Production ceased for various reasons, but usually water production and/or followed by sand production. No bottom hole pressure information was available at the end of the well or field life, so the amount of remaining gas in place has been estimated from the range of Initial in place gas volumes and the cumulative production by lobe.

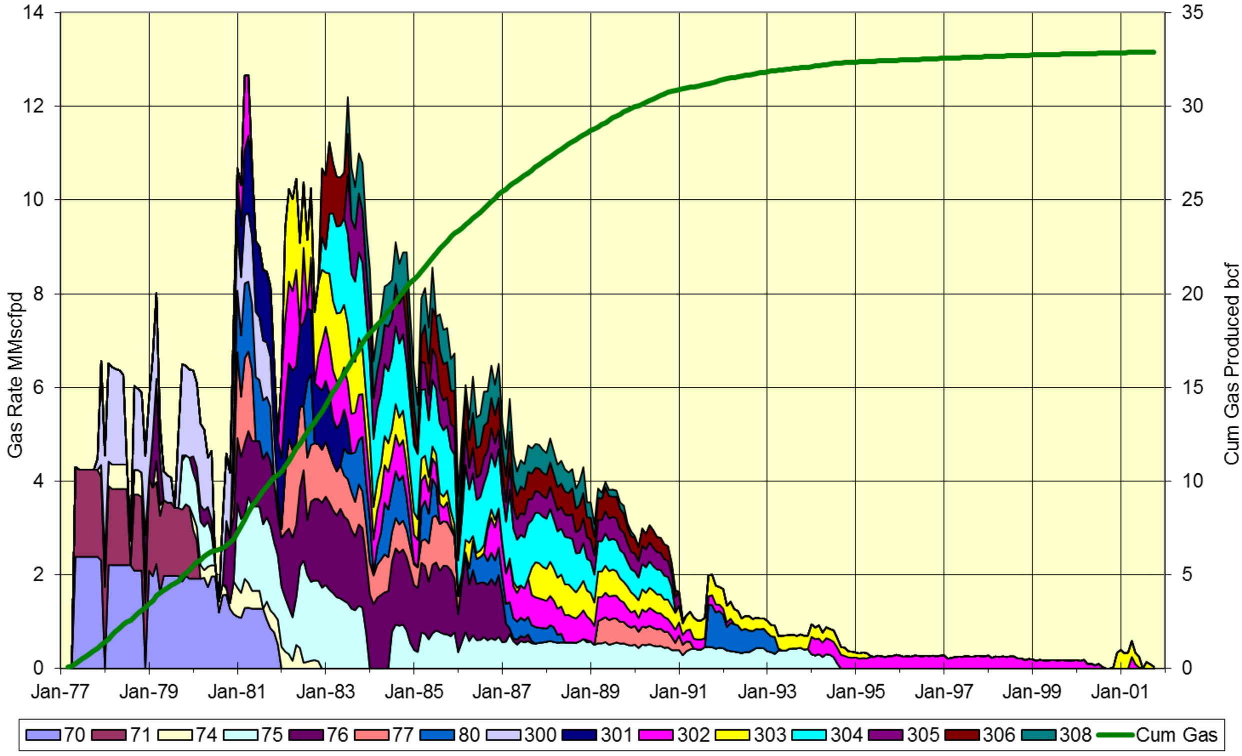


Figure 3-15 Production History by well for Bobocu

	GIIP (Bcf)			Produced	RF*		
Lobe	**P90**	**P50**	**P10**	**(Bcf)**	**P90**	**P50**	**P10**
BW2	5.40	7.50	10.10	3.29	61.0%	43.8%	32.5%
BW1	3.53	5.51	8.23	1.12	31.6%	20.2%	13.5%
B1	3.38	4.36	5.48	2.44	72.3%	56.0%	44.6%
C1	0.60	1.36	2.59	0.18	29.8%	13.2%	6.9%
D2	0.67	1.36	2.22	0.33	49.6%	24.3%	14.9%
E1	3.16	5.90	9.71	2.61	82.8%	44.3%	26.9%
E2 South 2	2.04	3.57	5.71	1.59	78.0%	44.6%	27.9%
E2 South 1	2.74	6.18	10.06	2.13	77.7%	34.4%	21.1%
G1	8.13	16.27	26.43	4.23	52.0%	26.0%	16.0%
H1 Main	1.52	2.55	3.94	1.19	78.1%	46.7%	30.2%
H1 North	1.06	1.44	1.92	0	0.0%	0.0%	0.0%
H2 main	6.13	9.97	15.40	4.21	68.6%	42.2%	27.3%
H2 main N	1.65	2.16	2.74	0.66	40.2%	30.8%	24.2%
J	1.97	4.25	8.21	0.95	48.3%	22.4%	11.6%
K1 North	6.89	11.00	15.83	3.81	55.3%	34.7%	24.1%
K2 East	0.92	2.21	4.34	0.51	55.9%	23.3%	11.8%

K3 North	6.77	10.09	14.58	3.66	54.1%	36.3%	25.1%
Probabilistic Sum	85.83	99.17	113.67		38.3%	33.2%	29.0%
Arithmetic Sum	56.55	95.67	147.51	32.91			
** RF is Historically Produced Volume divided by GIIP*							

Table 3-16 GIIP, Historical Production and Historical Recovery Factor of Bobocu by Lobe

3.9. Development Plans

3.9.1. Facilities

Bobocu Field previously produced gas from 1997 to 1995, and briefly from 2000 to 2001 by Romgaz, the Romanian state gas company. The field was exported by a 10 ¾" pipeline to the Rosioru field where the gas was dried before being piped to the Transgaz National Transportation System.

Wells were produced from three groups of surface locations. The facilities at each of the groups have mainly been removed. Roads connecting the various groups are still in place. The export gas pipeline is still in place and is now used as a low pressure (2.5 bar) gas distribution line. The line had previously operated at 10-30 bar when exporting gas to the Rosioru field.

In 2008 and 2009 Zeta prepared a conceptual re-development plan for Bobocu based on construction of new standalone processing facilities which would allow development without access to Romgaz facilities, although access to the Transgaz transportation system would still be required. Although Zeta have not yet committed to any re-development plan, the existing conceptual plan forms the basis for this review.

The development concept is based around having a new Central Processing Facility (CPF) located to the west of the location of the Group 2 abandoned facility (Figure 3-2). The location allows the facilities and the main field pipelines to be constructed well away from the operating gas distribution line.

The field is located in the midst of flat fields and construction of the CPF at this location should be feasible. There are already a number of roads from the previous field development and the only additional road would be a short access road to the new CPF site.

Based on the technical evaluation above, notional development plans comprising 4, 8 or 16 wells have been evaluated with 1, 2 or 3 well clusters, along the lines of the previous development, using existing civil works as much as possible. Gas would be collected at drill cluster manifolds by 4" flowlines, and transferred to the CPF via 6" flowlines. The CPF would provide processing and at a later stage compression.

Processing would comprise liquids separation and gas dehydration to avoid hydrate formation and to reach the sales specification. As the Bobocu gas is almost entirely methane, thereby meeting the entry specification, the main processing requirement is to remove water. Methanol would be sent from the CPF to each well to avoid hydrate precipitation. Hydrate formation was observed during previous production, and is likely to occur in future without mitigation. Separated water would be reinjected into well 302.

Facilities would include inlet manifold, gas/free water separation, test separator, heating, dehydration, metering, compression (future allowance) and export to the Transgaz gas transmission system via a new 12km 10" pipeline. Additional civil works and infrastructure would be required including electrical supply (from the national electricity grid), site lighting & landscaping, fire protection and office and maintenance buildings.

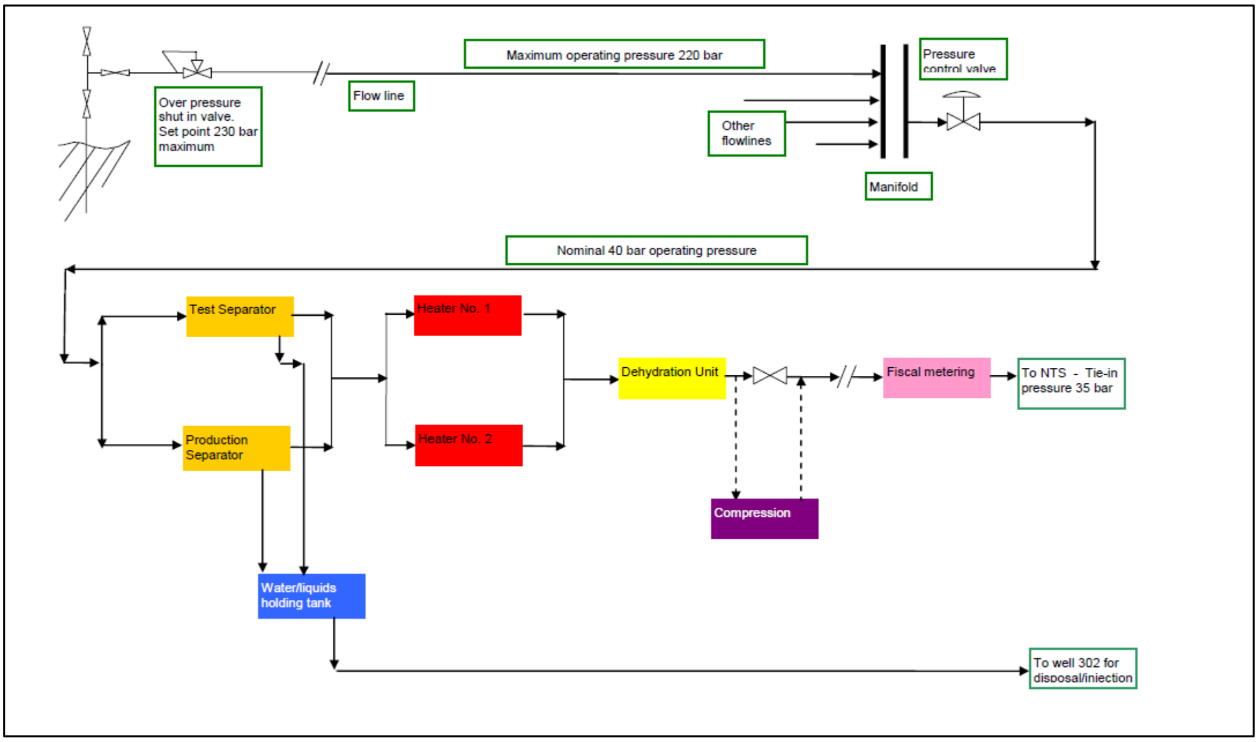


Figure 3-16 Proposed Bobocu Process System

3.9.2. Wells and Production Profiles

Three re-development scenarios have been developed based on 4, 8 and 16 well developments.

The recovery factors shown in Table 3-16 were calculated by taking the cumulative historical production per lobe, and dividing it by the P90, P50 and P10 GIIP. At the upper end, the best recovery of 78% may have been achieved, if the smallest GIIP values are assumed, and this was considered to be a maximum nominal recovery factor in each lobe, if sufficient wells are drilled to access the additional mapped GIIP and water does not halt production. Applying a 78% recovery factor to each lobe gave potentially recoverable volumes, shown in Table 3-17.

	GIIP (Bcf)			Prod	Potentially Recoverable (Bcf)		
Lobe	**P90**	**P50**	**P10**	**(Bcf)**	**P90**	**P50**	**P10**
BW2	5.40	7.50	10.10	3.29	4.21	5.85	7.88
BW1	3.53	5.51	8.23	1.12	2.76	4.30	6.42
B1	3.38	4.36	5.48	2.44	2.63	3.40	4.27
C1	0.60	1.36	2.59	0.18	0.47	1.06	2.02
D2	0.67	1.36	2.22	0.33	0.52	1.06	1.73
E1	3.16	5.90	9.71	2.61	2.46	4.60	7.58
E2 South 2	2.04	3.57	5.71	1.59	1.59	2.78	4.46
E2 South 1	2.74	6.18	10.06	2.13	2.13	4.82	7.85
G1	8.13	16.27	26.43	4.23	6.34	12.69	20.62
H1 Main	1.52	2.55	3.94	1.19	1.19	1.99	3.07
H1 North	1.06	1.44	1.92	0	0.83	1.13	1.50
H2 main	6.13	9.97	15.40	4.21	4.78	7.78	12.02
H2 main N	1.65	2.16	2.74	0.66	1.29	1.68	2.14
J	1.97	4.25	8.21	0.95	1.54	3.31	6.40
K1 North	6.89	11.00	15.83	3.81	5.37	8.58	12.35
K2 East	0.92	2.21	4.34	0.51	0.72	1.72	3.39
K3 North	6.77	10.09	14.58	3.66	5.28	7.87	11.37
Probabilistic Sum	85.83	99.17	113.67				
Arithmetic Sum	56.55	95.67	147.51	32.91	44.11	74.62	115.06

Table 3-17 Potentially Recoverable Volumes for Bobocu by Lobe

	Remaining Recoverable (Bcf)			Number of wells		
Lobe	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**
BW2						
BW1	1.64	3.18	5.30	1	1	2
B1						
C1						
D2						
E1						
E2 South 2						
E2 South 1			5.72			1
G1	2.11	8.46	16.39	1	2	4
H1 Main						
H1 North						
H2 main		3.57	7.81		1	2
H2 main N						
J			5.45			1
K1 North	1.56	4.77	8.54	1	2	3
K2 East						
K3 North	1.62	4.21	7.71	1	2	3
Total	6.94	24.19	56.93	4	8	16

Table 3-18 Nominal Development Plan by Lobe

The historically produced volumes were then subtracted from the potential ultimate recoverable volumes, to get a range in remaining recoverable volumes. To access these volumes, additional wells would have to be drilled, and some of the recoverable volumes are small, and so were not considered. In the low, mid and high cases, remaining recoverable volume cut-off of 1.5, 3 and 5 Bcf was considered, in order to prioritise the most lucrative lobes. This identified 4, 8 or 16 well locations in the low, mid and high cases that could recover some of the remaining gas.

Nominal locations were identified and are shown in Figure 3-17

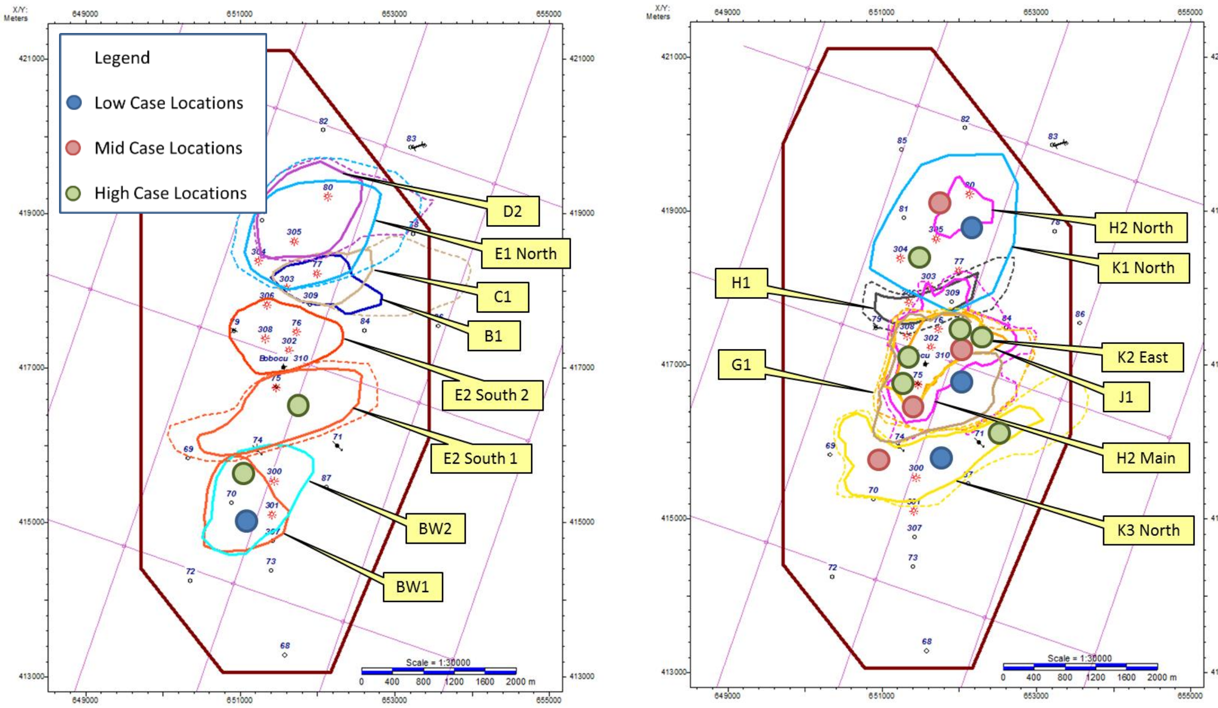


Figure 3-17 Nominal Well Locations for Low, Mid and High Case Development

Initial rates per well were based on historical production rates from other wells earlier in the field life and these are shown in Table 3-19.

	Initial Gas Rates (MMscfpd)		
Lobe	**Low**	**Mid**	**High**
BW1	1.6	2	2.4
E2 South 1	N/A	N/A	2.4
G1	1	2	2.4
H2 main	N/A	0.9	1.25
J	N/A	N/A	1.6
K1 North	1	1.5	2
K3 North	1.6	2	2.4

Table 3-19 Assumed initial Gas Rates for New Wells

Profiles were then generated using exponential declines and assuming that each well could be drilled or side-tracked from existing wells (subject to a well integrity review) and tied in once every two months, to give the profiles shown in Figure 3-18 to Figure 3-20. A start date of 2018 was assumed for this purpose, but the actual date may be revised.

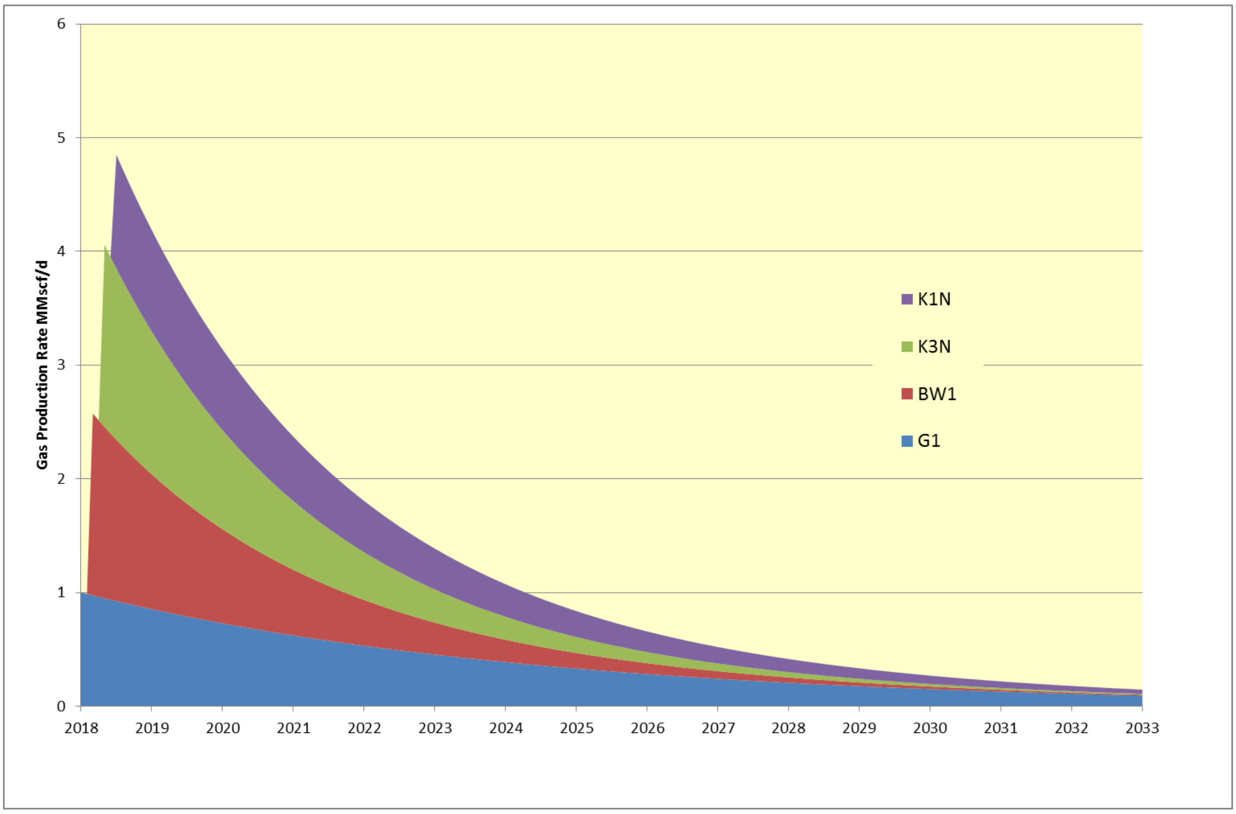


Figure 3-18 Untruncated Low Case Production Profiles

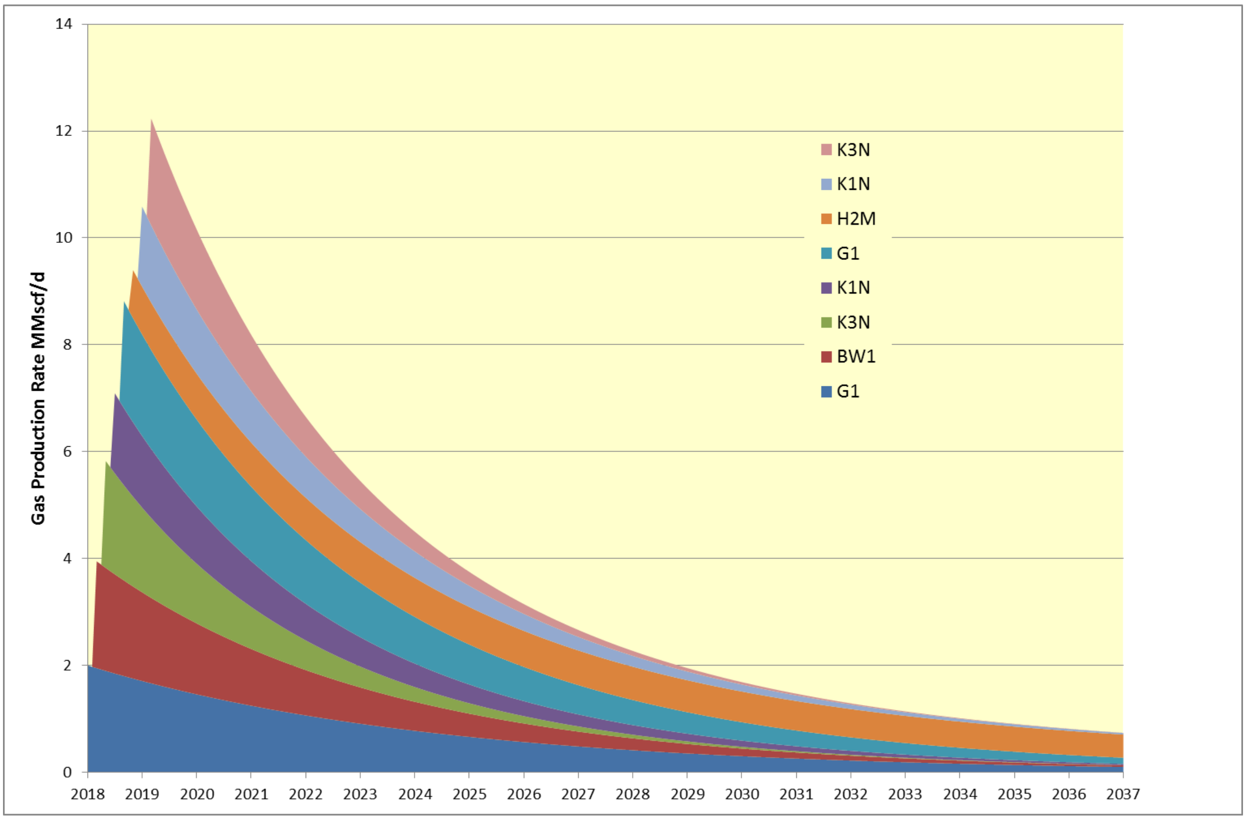


Figure 3-19 Untruncated Mid Case Production Profiles

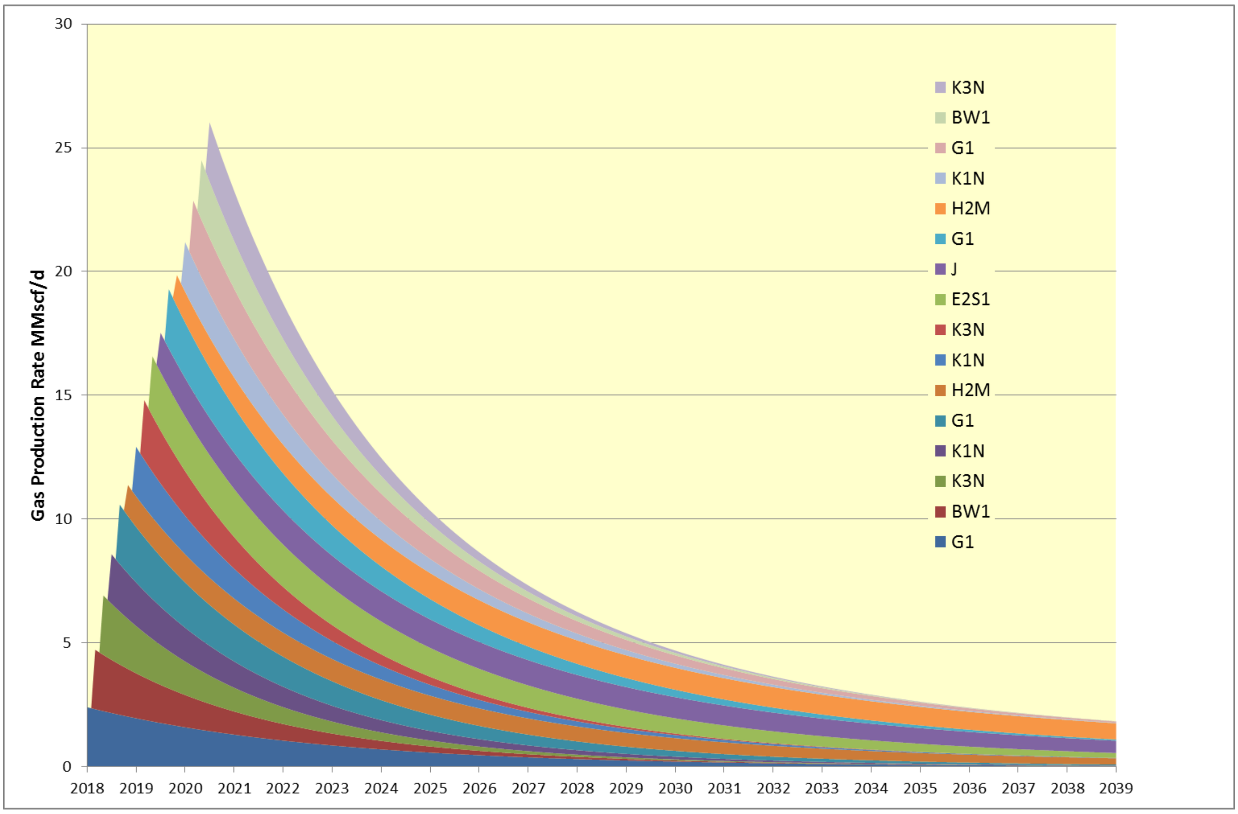


Figure 3-20 Untruncated High Case Production Profiles

	Daily Production Rate MMscfpd				Annual Production Bcf		
Year	**Low**	**Mid**	**High**		**Low**	**Mid**	**High**
2018	3.548	6.128	7.362		1.295	2.237	2.687
2019	3.649	11.020	16.578		1.332	4.022	6.051
2020	2.726	8.991	23.368		0.998	3.291	8.553
2021	2.049	7.160	20.378		0.748	2.614	7.438
2022	1.551	5.740	16.117		0.566	2.095	5.883
2023	1.183	4.631	12.834		0.432	1.690	4.684
2024	0.909	3.759	10.291		0.333	1.376	3.767
2025	0.702	3.068	8.304		0.256	1.120	3.031
2026	0.546	2.519	6.746		0.199	0.919	2.462
2027	0.428	2.079	5.516		0.156	0.759	2.013
2028	0.337	1.726	4.539		0.123	0.632	1.661
2029	0.267	1.439	3.756		0.098	0.525	1.371
2030	0.213	1.207	3.127		0.078	0.440	1.141
2031	0.171	1.016	2.617		0.062	0.371	0.955
2032	0.137	0.860	2.202		0.050	0.315	0.806
2033	0.111	0.731	1.862		0.040	0.267	0.680
2034	0.090	0.624	1.581		0.033	0.228	0.577
2035	0.073	0.535	1.349		0.027	0.195	0.492
2036	0.060	0.461	1.155		0.022	0.169	0.423
2037	0.049	0.398	0.993		0.018	0.145	0.362
2038	0.040	0.345	0.856		0.015	0.126	0.312
2039	0.033	0.300	0.741		0.012	0.110	0.270
Total					**6.892**	**24.194**	**56.930**

Table 3-20 Bobocu Untruncated Production Profiles.

3.10. Development and Operating Costs

Zeta currently plans to drill a new sidetrack in 2015 to test the development concept in one of the identified targets. If this is successful, the hope is to move towards a redevelopment plan with permitting and design in 2016, procurement and construction in 2017 and start of production in 2018. Compression would be added in 2019, or possibly later, as needed.

3.10.1. Wells CAPEX

The low case development would require 1 further sidetrack and 2 new wells to be drilled in 2017 (total 4 wells). The mid case would require an additional sidetrack plus 3 new wells to be drilled in 2018 (total 8 wells). The high case would require a further well and sidetrack in 2018 plus 2 sidetracks and 4 new wells in 2019 (total 16 wells).

Based on existing well designs, the estimated costs for a 2800m vertical well is $5.39 million, including a 15% contingency, and $2.695 million for a sidetrack. Total well costs are $16.2 million in the low case, $35.0 million in the mid case and $70.1 million in the high case.

3.10.2. Facilities CAPEX

Facilities cost estimates have been created for the 4, 8 and 16 well cases as described above. The base case is to construct a processing plant with a single train with capacity of 350,000 Sm^3/d (~12.4 MMscfpd). In the high case, a second train would be added in 2019. The project would have a 4 year schedule, with year 1 for design, year 2 for plant construction and initial wells, with additional wells and flowlines added in years 3-4.

Case	Low	Mid	High
Wells	2 new + 2 ST	5 new + 3 ST	10 new + 6 ST
Design Rate Sm3/d	350,000	350,000	700,000
Design Rate MMscf/d	12.4	12.4	24.8
Design	0.582	0.582	0.803
Site & Civil Eng.	0.460	0.471	0.541
Flowlines	2.706	2.909	3.385
Surface Facilities	4.641	5.527	8.441
Commissioning & NTS connection	0.360	0.360	0.412
Project Management	0.412	0.467	0.657
Local Authority Fee (1%)	0.082	0.093	0.130
Subtotal US$ MM	9.243	10.409	14.368
25% Contingency	2.042	2.317	3.250
Insurance	0.050	0.050	0.050
Total US$ MM	**11.334**	**12.776**	**17.668**

Table 3-21 Bobocu Facilities costs US$ Millions

Decommissioning costs are estimated to be $250,000 per well plus facilities abandonment costs as shown below:

	Low case	Mid Case	High Case
Facilities	1.927	2.172	3.003
Wells	1.0	2.0	4.0
Total	2.927	4.172	7.003

Table 3-22 Bobocu decommissioning costs US$ million

3.10.3. Development Capital Cost Schedule

Low Case	2015	2016	2017	2018	2019	Total
Facility CAPEX (US$MM)		0.582	8.444	0.120	2.188	11.33
Well CAPEX (US$ MM)	2.695		13.475			16.17
Total CAPEX (US$ MM)	**2.695**	**0.582**	**21.919**	**0.120**	**2.188**	**27.50**
Mid Case	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Facility CAPEX (US$MM)		0.582	8.749	0.272		12.78
Well CAPEX (US$ MM)	2.695		13.475	18.865	3.173	35.04
Total CAPEX (US$ MM)	**2.695**	**0.582**	**22.224**	**19.137**	**3.173**	**47.81**
High Case	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Facility CAPEX (US$MM)		0.582	9.082	1.201	6.801	17.67
Well CAPEX (US$ MM)	2.695		13.475	26.95	26.95	70.07
Total CAPEX (US$ MM)	**2.695**	**0.582**	**22.56**	**28.15**	**33.75**	**87.74**

Table 3-23 Total Bobocu CAPEX schedule US$ Million

3.10.4. Operating Costs

Annual Operating costs have been estimated for the three development scenarios based on the 2009 FDP, and updated to current costs. Key cost items are operating staff, methanol injection and compressor power and maintenance. The compressor would be phased in as necessary according to the rate of decline in well pressure.

US$, x 1000	Low	Mid	High
Production Manager	143.0	143.0	143.0
Operatives (4/8)	91.4	91.4	182.8
Accountant (1)	34.3	34.3	34.3
Methanol	139.3	278.6	557.2
Material and chemicals	8.0	15.9	31.8
Utilities including electricity	6.0	11.9	23.9
Transport facilities	6.0	11.9	23.9
Reservoir pressure testing	11.9	23.9	47.8
Other contractors	10.0	19.9	39.8
Total Processing Facilities OPEX	**449.8**	**630.9**	**1084.5**
Wells OPEX			
$150k/well every 5 years = $30k/well/year	120	240	480
Overheads OPEX RON 24000/year	7.3	7.3	7.3
Compression power & maintenance	150	300	600
TOTAL Annual OPEX	**727.1**	**1178.2**	**2171.8**

Table 3-24 Bobocu Annual Operating Cost Estimates US$ Thousands

3.11. Economics

The applicable fiscal system and macro-economic assumptions are described in Section 2.11. For valuation purposes, the same gas price assumptions are made - the current regulated price for domestically produced gas ($6.70/Mscf), and a range of +/-25% around the current market price for imported gas ($10.50 per Mscf). As production from Bobocu is not expected to start until 2018, it is reasonable to expect that further progress will be made towards full deregulation by the time production starts.

The Bobocu indicative valuation has been performed on a 100% gross basis assuming the project proceeds to appraisal in 2015, and fairly rapidly to development thereafter. However, it is the intention of Zeta to farm out a significant proportion of the equity, with the new partner carrying Zeta for at least some of the cost. The gross project economics would remain the same but Zeta's economic value would depend on the terms of the farm-out deal.

Zeta has incurred past costs on the Bobocu licence which have accumulated tax losses $5.6 million which can be carried forward and offset against future Corporate Income Tax liabilities. It is understood from Zeta that these tax losses will be transferred with ownership of the asset from Zeta Petroleum SRL to Zeta Petroleum (Bobocu) SRL.

Due to the Royalties, Supplementary Taxes (which are levied on revenue, similar to a royalty) and operating costs, the production profiles (Table 3-20) are truncated at the economic limit which occur in 2031, 2033 and 2035 for the low, mid and high cases respectively at the assumed base case gas price of $10.5 per mcf.

	Project 100% Gross, and Zeta Interest		
Contingent Resources Bcf	**Low**	**Mid**	**High**
Bobocu	6.68	22.67	54.25

Table 3-25 Bobocu Contingent Resources

Reference Price	**Project 100% Gross**		
NPV10 US$ MM	**P90**	**P50**	**P10**
High: Deregulation to market price +25% ($13.13/mcf)	6.2	54.45	143.45
Mid: Deregulation to current market price ($10.5/mcf)	1.1	38.9	108.4
Low: Deregulation to market price -25% ($7.88/mcf)	-4.0	23.5	55.35
Min: Current regulated price ($6.70/mcf)	-6.35	16.65	57.8

Table 3-26 Bobocu Contingent Resources Valuation

The prospective resources identified in Table 3-14 are not considered to have any material value, and the operator has no current plans for exploratory drilling.

4. Jimbolia

4.1. Jimbolia Overview

The Jimbolia license area covers approximately 24 km^2 in the eastern part of the proven producing Pannonian Basin in western Romania (Figure 4-1). The license is operated by NIS Gazprom Neft (51% interest) with partners Zeta Petroleum (39%) and Armax (10%).

Two discoveries were made by Petrom SA in 1983:

- The Jimbolia Veche found several hydrocarbon accumulations within the Pliocene. One interval (Pliocene III) produced 2.89 Bcf gas and 13 MMstb of condensate between November 1985 and June 1998. A total of seven wells have been drilled on the field which is a three-way dip and fault closed anticline within the Lower Pliocene delta front reservoir sequence.
- Jimbolia Vest is located adjacent to the Serbian border and may be part of the same accumulation as the Serbian Crnja field. The reservoir sequence is formed of stacked pay with the majority of the pay intervals having high levels of impurities, in particular CO_2.

The Pliocene III interval in Jimbolia Veche is considered fully depleted, but a subsurface technical evaluation identified potentially commercially recoverable oil within the deeper Pliocene VIII interval. Jimbolia-100 was drilled in 2013 to appraise and test that interval. Oil was found with very high CO_2 content in its gas cap (73-79%), making development infeasible. In 2014 Jimbolia-100 was re-entered and gas with much lower CO_2 content was also tested in small quantities in the Pliocene V and VII.

The current study involved an independent assessment of the resources for the Jimbolia licence, and comprised of the following:

1. A review of the operator’s seismic interpretation.
2. A review of the geological environment and reservoir quality.
3. An independent petrophysical evaluation of Jimbolia-100.
4. A probabilistic estimate of initial in-place oil volume (STOIIP) for Jimbolia Veche.
5. A probabilistic estimate initial in-place gas volumes (GIIP) in Jimbolia Veche and Jimbolia Vest.
6. A recovery factor assessment & resource volume estimates

Figure 4-1 Jimbolia Location Map

4.2. Database

Zeta provided the following data to enable the evaluation:

- A Kingdom seismic project containing:
  - 13 2D seismic lines totalling 133km, with interpreted horizons and grids (Figure 4-2);
  - 33 wells within and adjacent to the Jimbolia licence, including the location of several wells in Serbia;
  - Log suites for 14 wells;
  - Formation tops for 15 wells.
- A field study report, including Zeta's assessment of hydrocarbon volumes (December 2011)
- Core, fluid and palaeontological data
- Well logs and end-of-well reports for Jimbolia-100
- The operator's analysis of geophysical well log data for Jimbolia-100
- Well test data

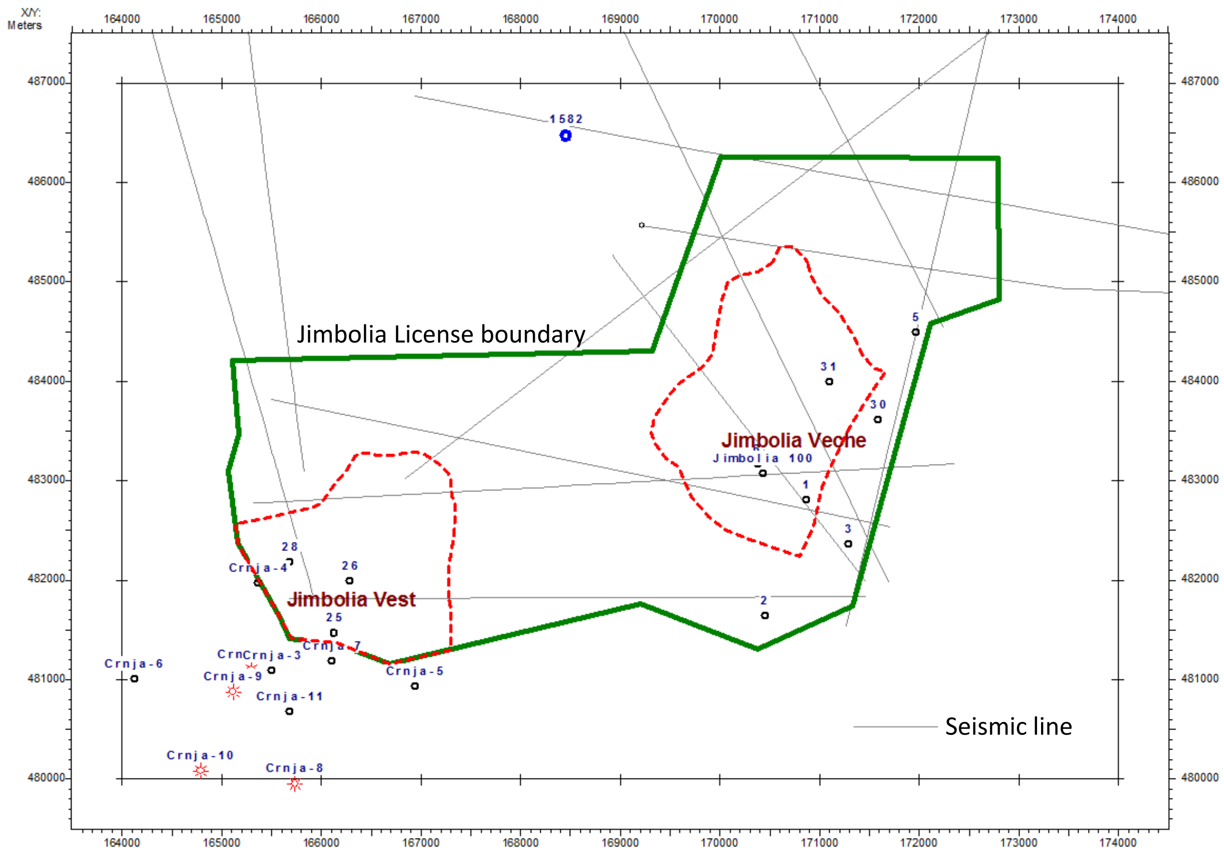


Figure 4-2 Jimbolia License: Seismic and well locations

4.3. Geological interpretation

The Jimbolia Licence is located in the Pannonian Basin, which is a Neogene extensional basin that lies between the Carpathian, Alpine and Dinaride thrust belts within the mega-suture zone of the African and European plates.

The Pannonian Basin system is a large, topographically low area characterised by a complex deformation history with a sequence of distinct structural episodes. A rapid and dramatic change in tectonic style started in the Early Miocene which initiated the formation of the current Pannonian

Basin, and within it, several small, deep basins. In places these basins contain as much as 7 km of Miocene to Quaternary sedimentary rocks.

Subsidence and infilling of the Pannonian basin occurred mainly during the Late Miocene and Pliocene when the area was part of an isolated brackish-water lake. The basin was filled by a large deltaic system originating from the rising Carpathians and Alps. The dominant controls on deposition were changes of basin subsidence rate and the high sedimentation rate.

The active petroleum system supplying the Jimbolia accumulations is sourced from the Lower Pliocene intra-formational shales and Badenian (Miocene) black shales.

Reservoir deposition within the Lower Pliocene was in a delta front environment with progradation into brackish waters. Eight reservoir intervals have been identified within the Lower Pliocene forming stacked pay zones within the Veche and Vest structures (Figure 4-3).

Jimbolia Veche is a 3-way dip faulted closure, with evidence of hydrocarbons in the Pliocene III, IV, VII and VIII. Jimbolia Vest contains two gas bearing intervals (Pliocene III and IV), but the structural closure is undefined, and it is probable that Jimbolia Vest is an extension of the Serbian Crnja Gas Field (Figure 4-2).

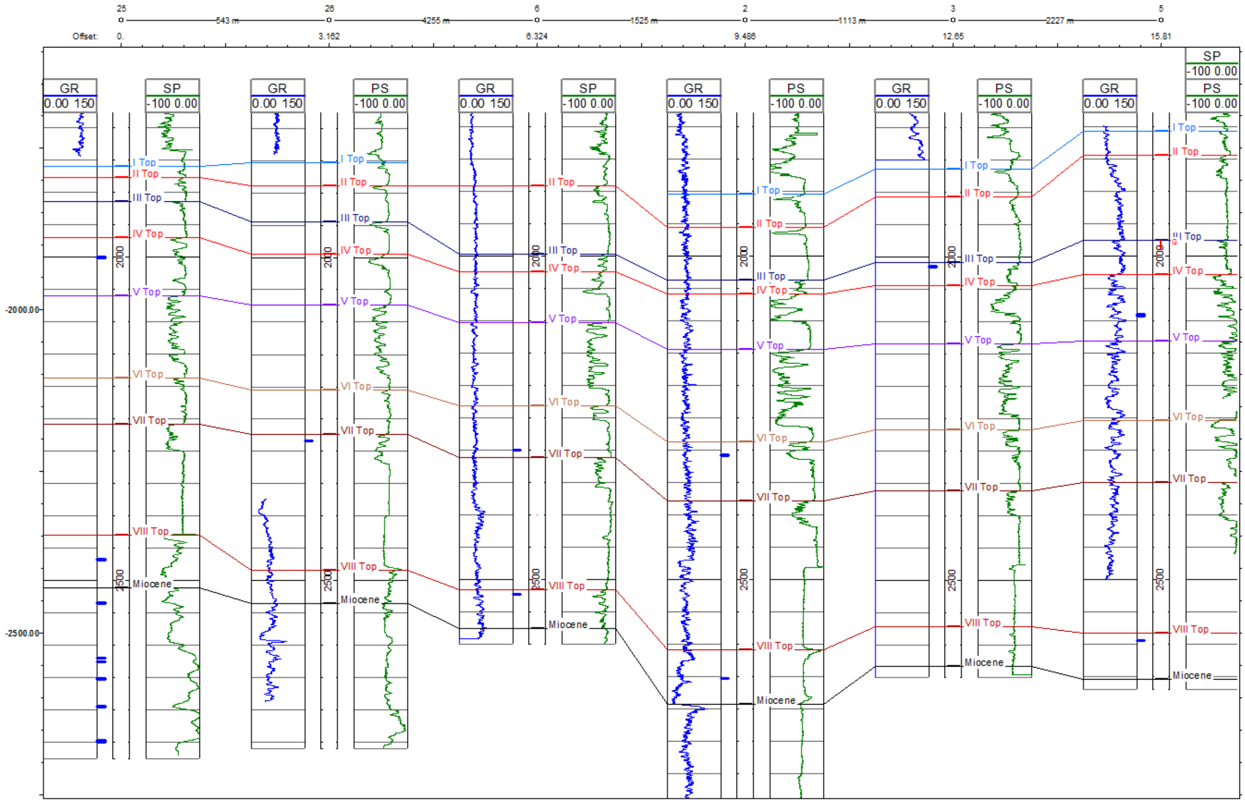


Figure 4-3 Correlation of Pliocene sands in Jimbolia

4.4. Seismic Interpretation

The Jimbolia licence is sparsely covered by 2D seismic acquired between 1975 and 1989. There are four seismic lines across the Jimbolia Veche structure (Figure 4-4); two were recorded in 1975 and two in 1984 and data quality is fair to good. However, only three seismic lines, which do not intersect, lie across the Jimbolia Vest structure with fair quality data (Figure 4-5).

Seismic data quality varies across the area, but the Pliocene sequence is generally well defined (e.g. Figure 4-6), and reservoir units can be correlated across large distances. However, the sparse data coverage leads to large potential uncertainty in the structural maps (Figure 4-7 and Figure 4-8).

There is very little velocity or depth information for the Sarmatian events so depth conversion cannot be undertaken with a high degree of confidence, although the number of well penetrations in Jimbolia

Veche reduces the error there. Combined with the uncertainty in structural gridding and depths of hydrocarbon contacts, this leads to a very large uncertainty in the gross rock volume estimates.

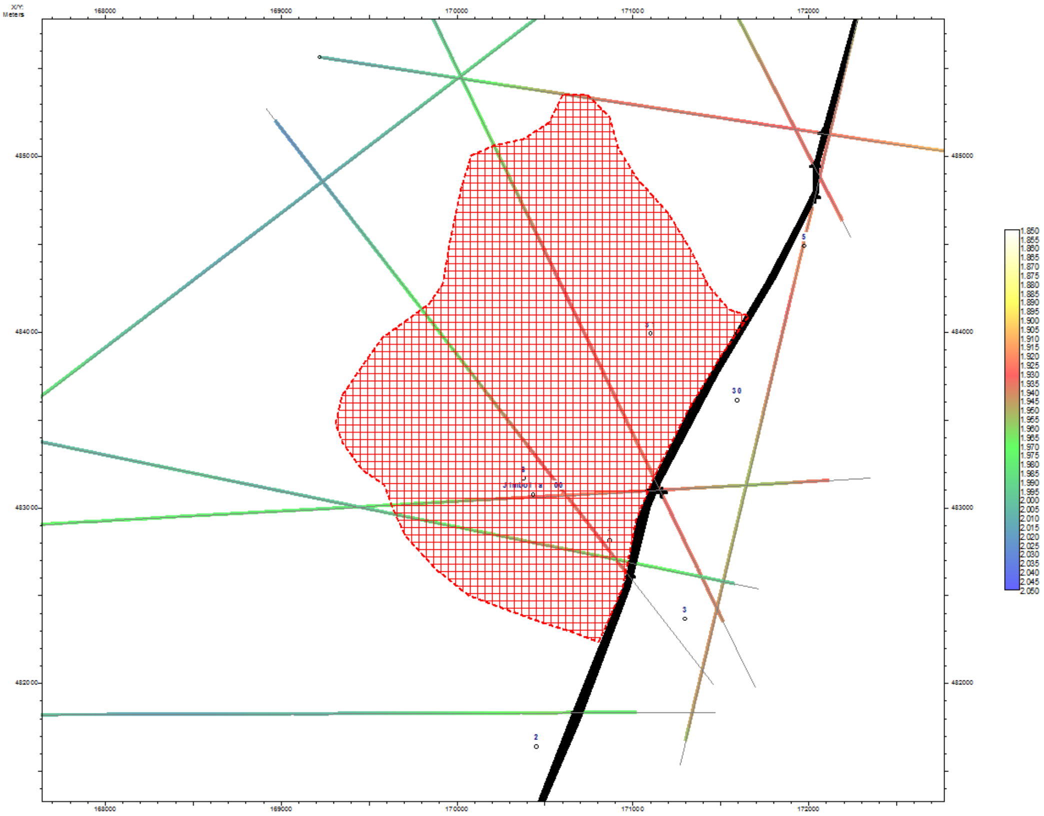


Figure 4-4 Jimbolia Veche structure: Seismic data coverage and Pliocene VIII interpretation

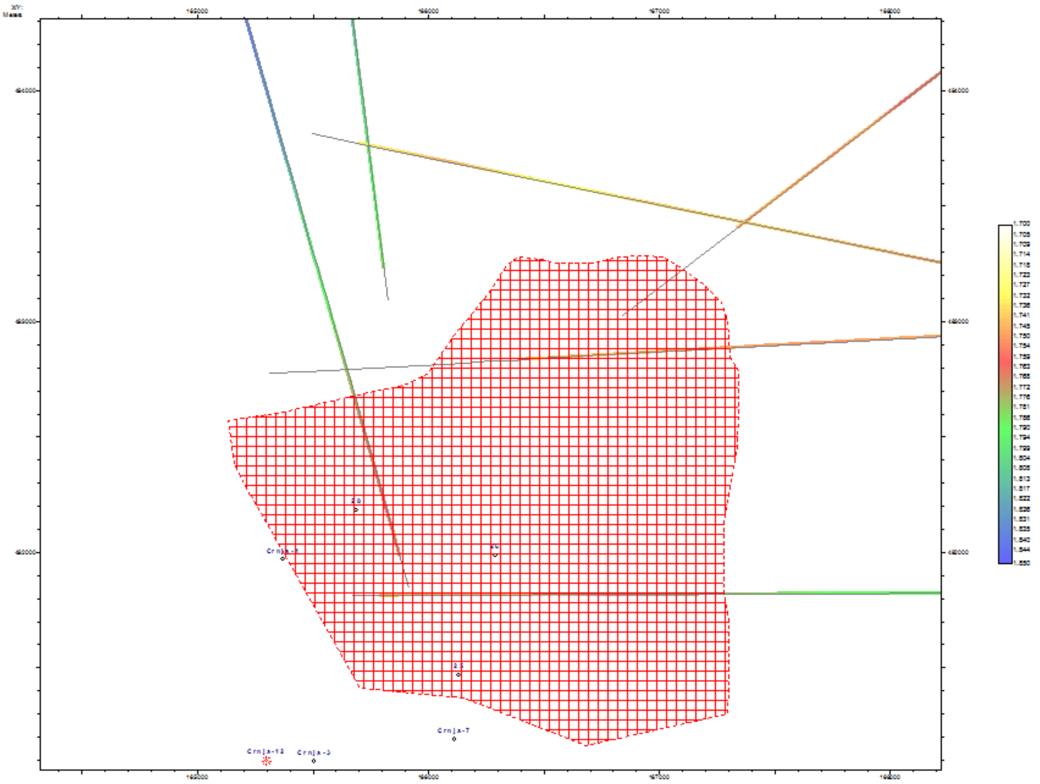


Figure 4-5 Jimbolia Vest structure: Seismic data coverage and Pliocene III interpretation

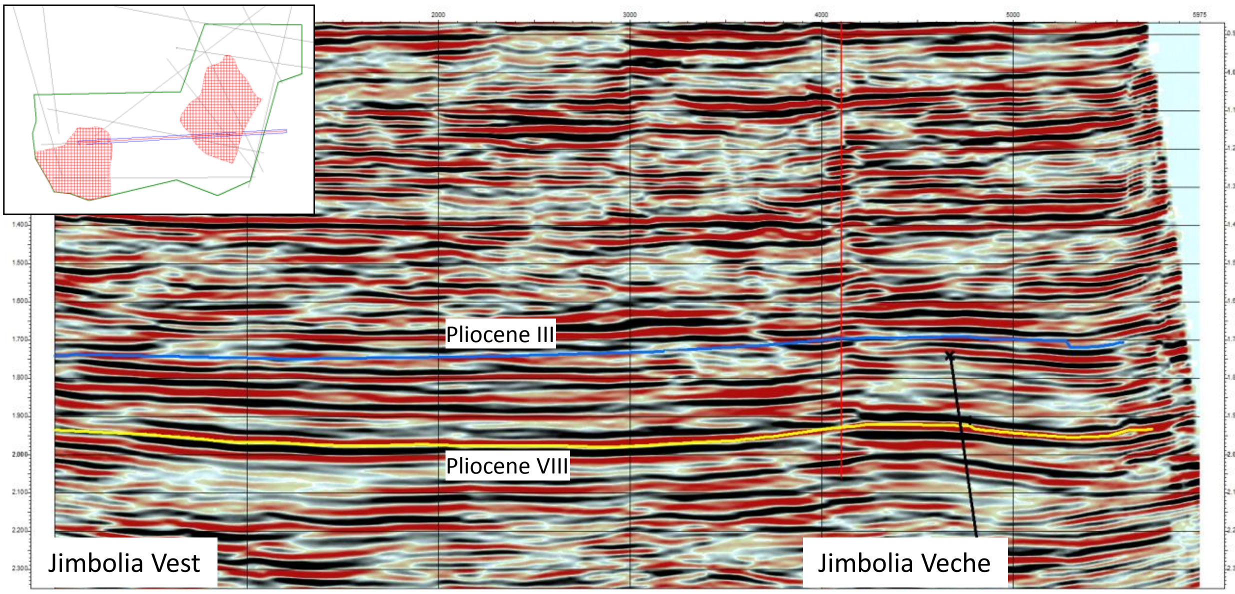


Figure 4-6 Seismic line 75-27-01

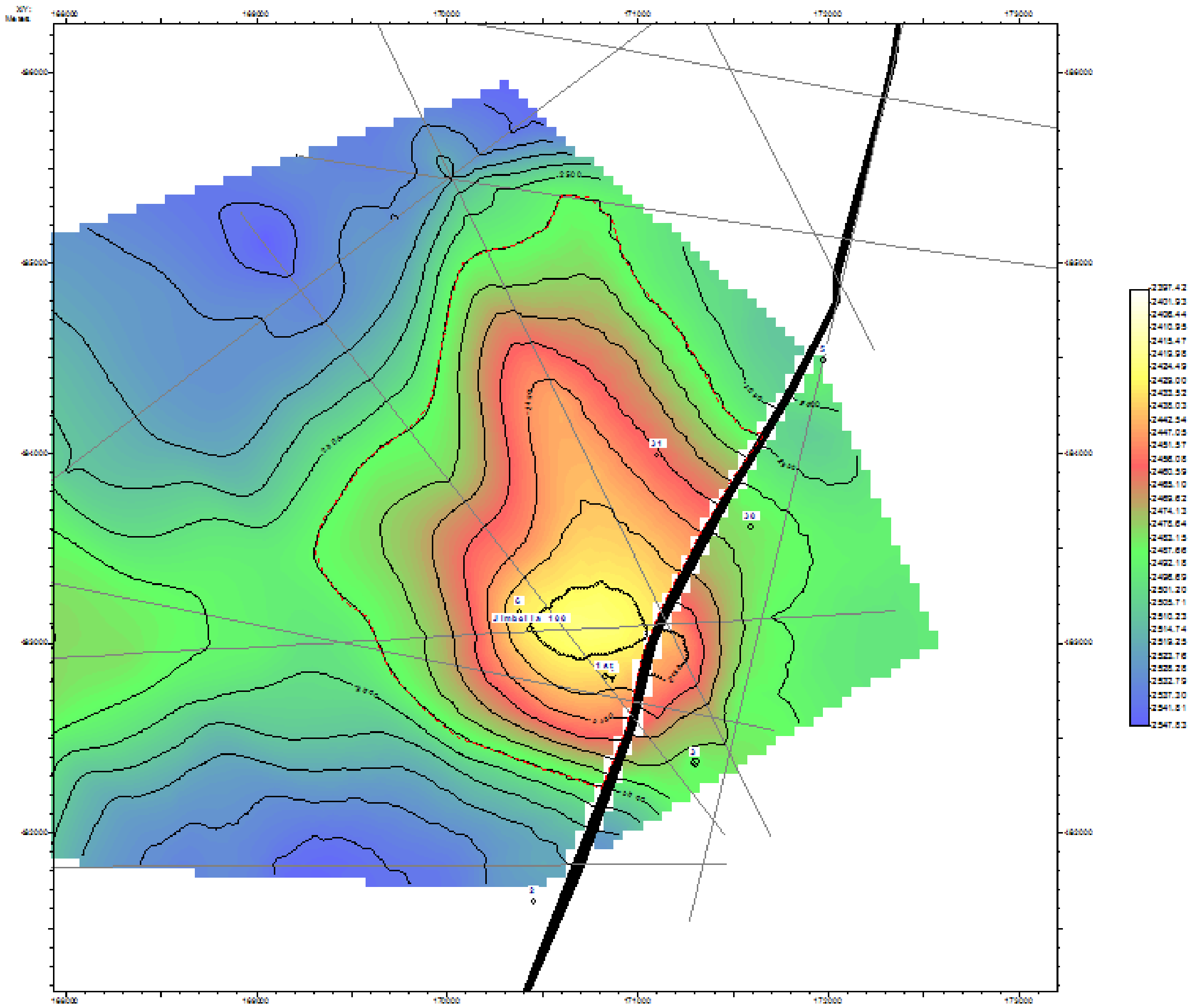


Figure 4-7 Jimbolia Veche structure: Depth structure map (Pliocene VIII)

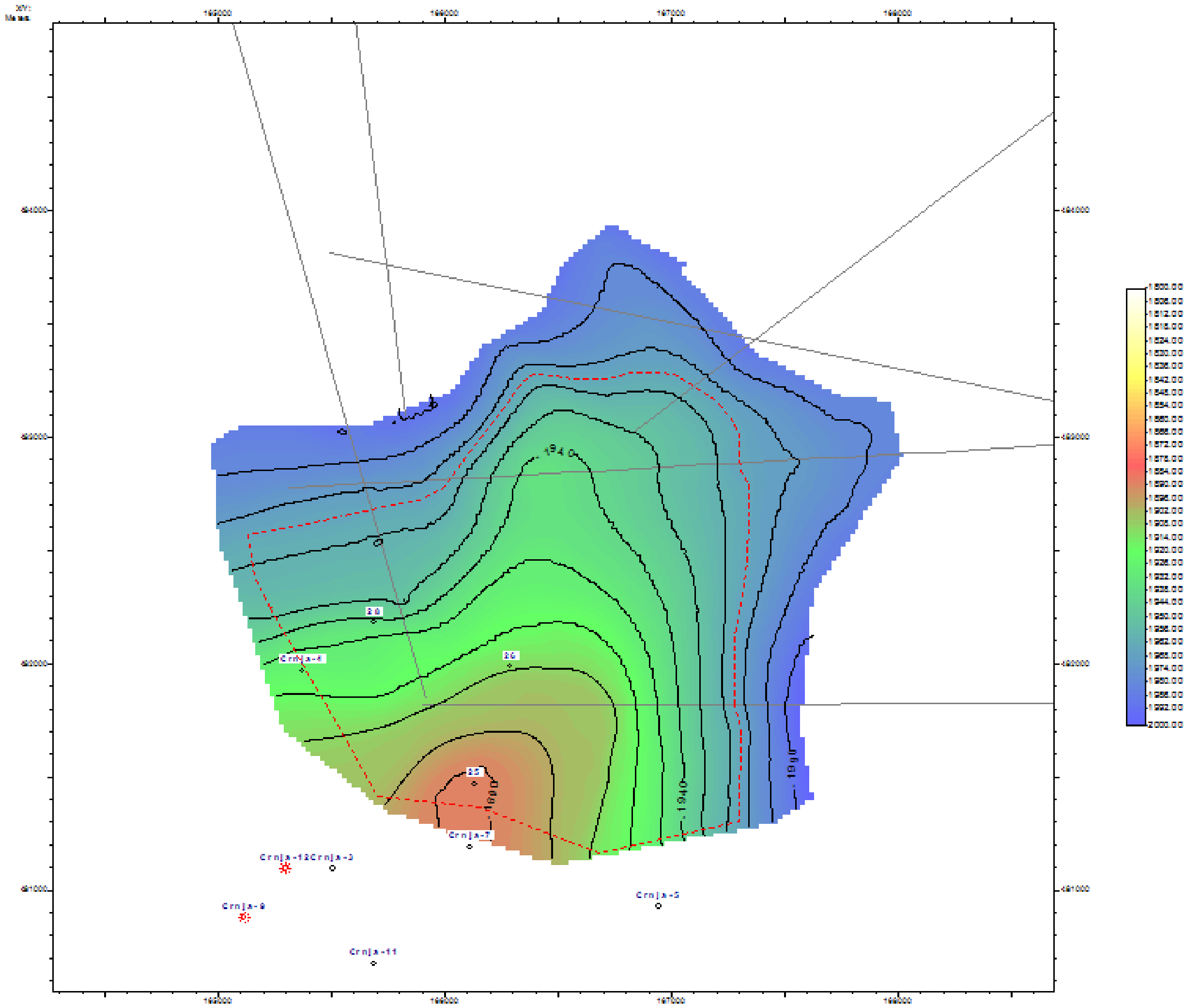


Figure 4-8 Jimbolia Vest structure: Depth structure map (Pliocene IV)

4.5. Petrophysical Interpretation

The well Jimbolia-100 was drilled in 2013 and reached a TD of 2593.0 m MD (-2510m TVDss) with a drill Floor elevation of 88.88 m above mean sea level (MSL). The well was intended to confirm the presence of commercial reserves of oil in Pliocene VIII reservoir of Jimbolia Veche structure.

Consequently, an independent evaluation of the Pliocene VIII in well Jimolia-100 was made, using offset well data including core. However, due to the poor well conditions and heavy barite mud, several of the logs were not fit for purpose and all logs had been affected in such a way that the results are very subjective.

4.5.1. Well Data

Table 4-1 shows what log data were acquired for each hole section of Jimbolia-100, while Table 4-2 details the tops that have been defined for the well. Jimbolia-100 had a maximum hole deviation of 1.15 degrees and can be considered to be vertical. An image of the mud log (including gas curves) was available (Figure 4-9), but digital data of the gas curves were not provided.

Phase 17 ½ in		Phase 12 ¼ in		Phase 8 ½ in	
Planned	Actual	Planned	Actual	Planned	Actual
Cased hole: 700-0m CBL, VDL, CCL, GR	Cased hole: CBL-VDL, GR	Open hole: 2400-700m; GR, SP, Caliper, P-Sonic, Resistivity shallow & deep, Bit Size Density, PEF, Density Correction, S-Sonic, Resistivity micro and medium Cased hole: 2400-0m: CBL,VDL,CCL,GR	Open hole: Unsuccesfull Cased hole 9 5/8": (2391-0m) CBL, VDL, CCL,GR (2391-1900): Neutron in cased hole	Open hole: 2590-2400m; GR, SP, Caliper, P-Sonic, Resistivity shallow & deep, Bit Size Density, PEF, Density Correction, S-Sonic, Resistivity micro and medium Cased hole: 2593-2200m: CBL,VDL,CCL,GR	Open hole: Resistivity 5 curves (HRLS). Density, GR, CAL, MSFL

Table 4-1 Well logs acquired in Jimbolia-100

Formation	Top Depth m MD	Base Depth m MD
III Top	1994	2024
IV Top	2024	2097
V Top	2097	2225
VI Top	2225	2314.25
VII Top	2314.25	2514
VIII Top	2514	2593

Table 4-2 Well tops for Jimbolia-100

4.5.2. Well Evaluation

The operator's analysis of the well log data summarised the data quality as follows: "The borehole diameter of Jimbolia-100 well is highly increased in some zones, whereas the borehole walls are mostly not smooth. Density of the mud is high (~1.67 g/cm3) and the mud contains high percentage of barite. Invasion of mud filtrate is deep (up to ~ 80 cm). Due to such conditions in the well, many GWL curves are not registered, and most of the recorded ones are useless (PS, PEF, CN...)."

A review of the data concurs with that opinion, and in particular, the Neutron porosity curve was unusable throughout the well.

VCL was derived from the Gamma Ray log, although the interpretation (picking of clay and sand points) was heavily based on the results provided in the Lithological log (Figure 4-9). Consequently, the lithological log is considered to be a more accurate representation of the reservoir quality.

The PEF log curve clearly shows the effects of the barite in the mud over the sand intervals. The hydrocarbon effect, if any, on the density log may be diminished due the effect of the barite mud. There is no useable Neutron curve from which to evaluate increasing or decreasing 'cross-overs' between the Neutron and Density curves which is a simple yet effective way of identifying a change from gas to oil to water in a sand with otherwise similar properties. There are no oil stains or odours on the cutting to indicate a heavier oil, but gas is clearly seen from the mud logger's results.

A hydrocarbon-corrected porosity has been calculated from the Density log, assuming a sand grain density of 2.72 g/cc and a fluid density of 0.8 g/cc; the high grain density of 2.72 g/cc was based on core data from Jimbolia-1 (Figure 4-10).

A histogram of Jimbolia-1 core data (Unit VIII) gave a mean average porosity of 12.7% (Figure 4-11) and a histogram of calculated porosity in Jimbolia-100 (Unit VIII) gave a mean average of 13.6% (Figure 4-12). This simple quality control check on the Density data used to calculate the porosity provides some confidence that the results are valid.

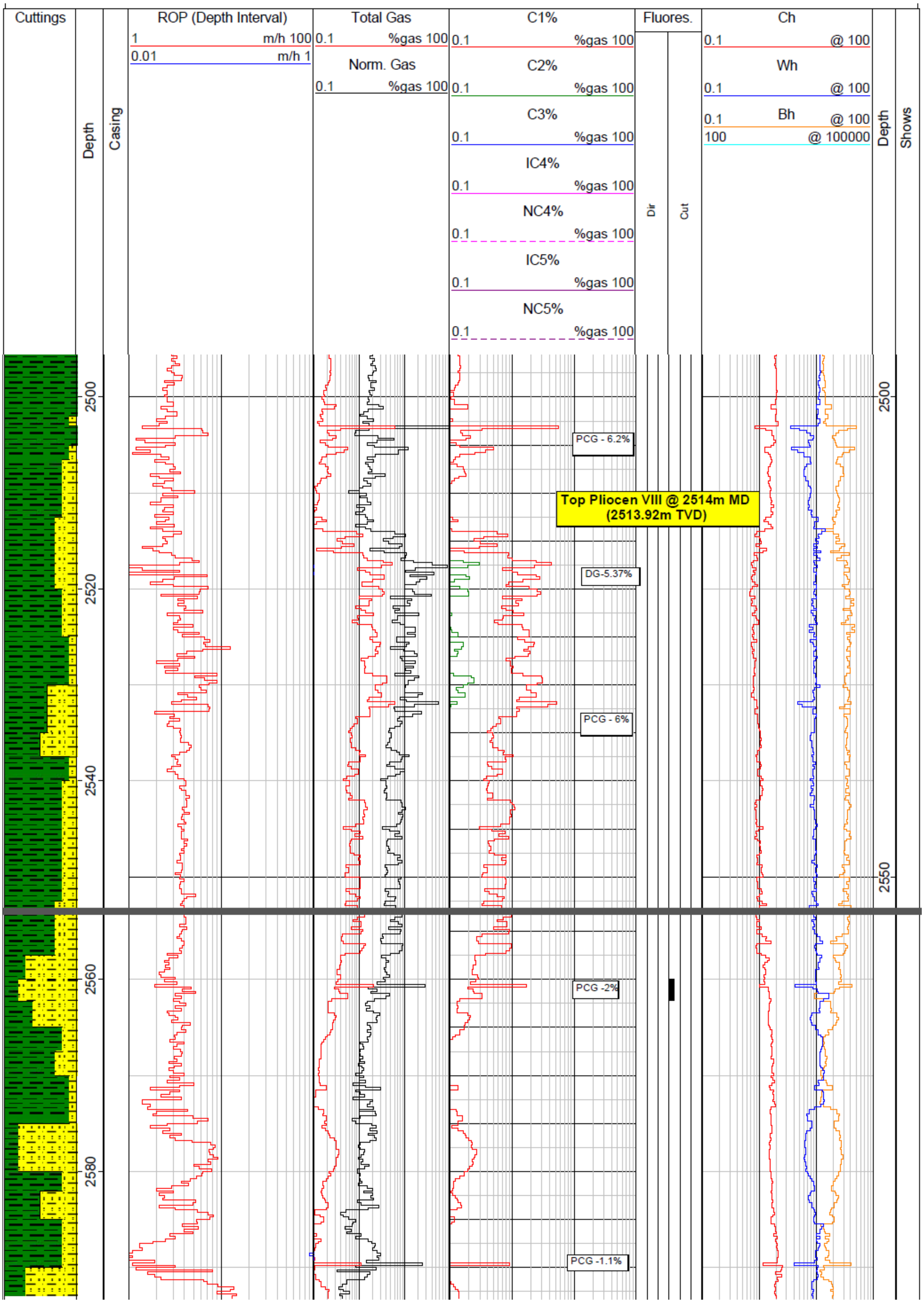


Figure 4-9 Gas log for Jimbolia-100 across the Pliocene VIII interval

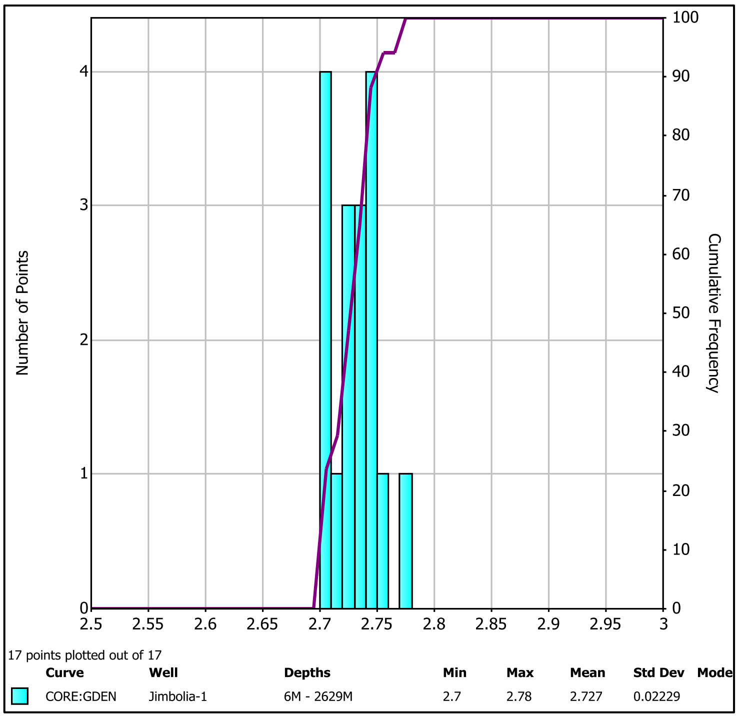


Figure 4-10 Histogram of core grain density for Jimbolia-1 over unit VIII

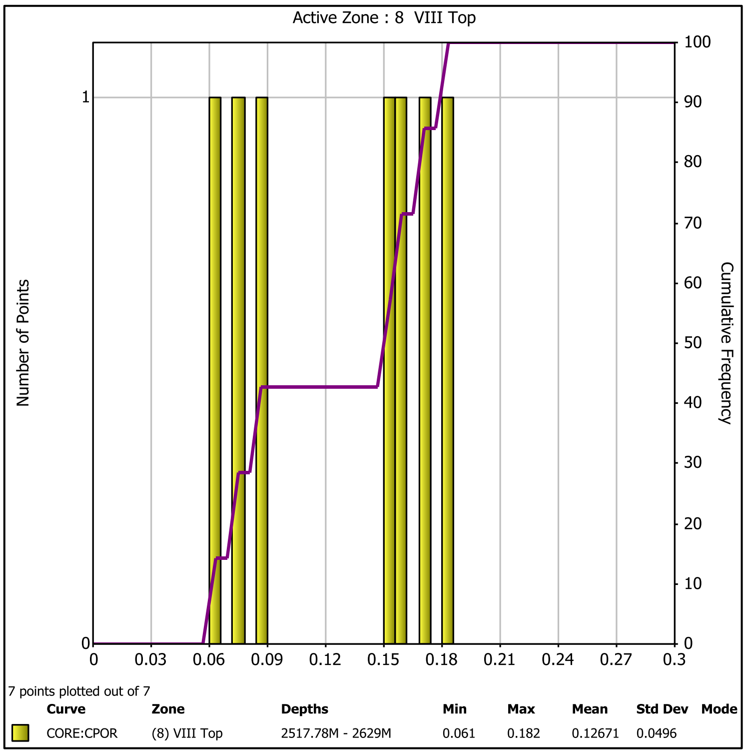


Figure 4-11 Histogram of core porosity for Jimbolia-1 over unit VIII

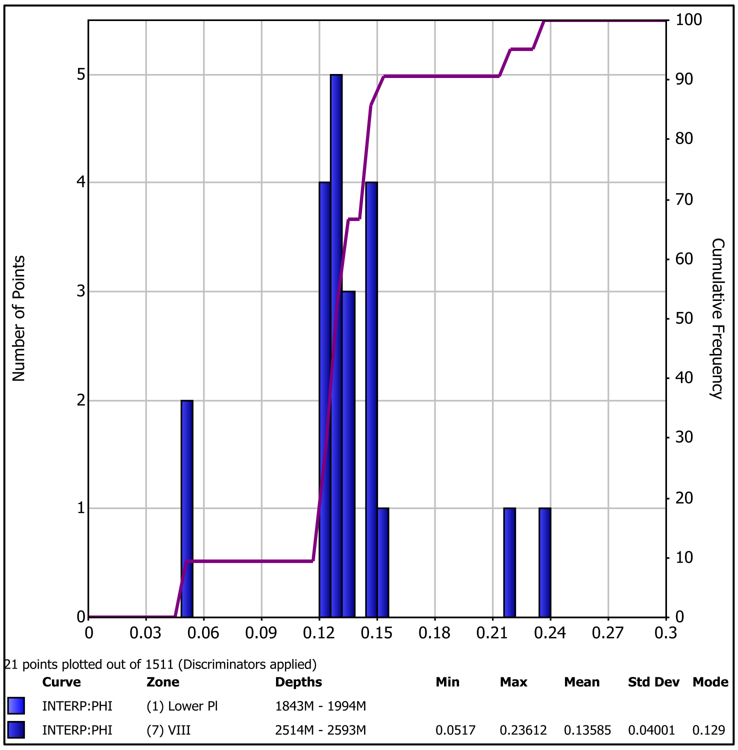


Figure 4-12 Histogram of log PHIE for well JIMBOLIA-100 over unit VIII; with a VCL<0.1

The Composite log records no hydrocarbon shows in the cuttings over the Pliocene VIII interval apart from at 2560 m MD where some cut fluorescence is observed. Between 1995-2115 (Unit III and IV) there is direct fluorescence (no oil stain, no odour, pinpoint, very pale, dark yellow, direct fluorescence) recorded on the Composite log.

Another way to look for HC's was to use the resistivity curves which have been reviewed with care, and any separation compared with the gas logs.

Water saturation has been estimated using a standard Archie interpretation with a fixed temperature of 248°F (for Unit VIII) based on well data (Table 4-3).

Structure	Productive objective	Initial pressure		Temperature	
		MPa	At	K	°C
Jimbolia Vest	Lower Pliocene – package III	19.6	200	369	96
Jimbolia Vest	Lower Pliocene – package IV	20.0	204	371	98
Jimbolia	Lower Pliocene – package III	19.6	200	369	96
	Lower Pliocene – package VIII	30.2	307	393	120

Table 4-3 Initial pressure and temperatures values

There are water analyses available from other wells in the region (Jimbolia-5 and -25) but the origin of the samples and the drilling fluids are unknown. For these reasons the well logs and gas shows on the mud logs were used to estimate a best estimate Rw. The 'best' Rw picked from a Pickett plot (Figure 4-13) based on data below 2578 m MD is 0.15 Ohmm (55,000 ppm). To show a spread of results salinities of 30,000 and 70,000 ppm have also been used (0.26 and 0.12 Ohmm at 60°F respectively) to calculate water saturation. The Archie parameters assumed are:

m	= 2
n	= 2
a	= 1
Rw	= 0.26, 0.15 and 0.12 Ohmm at 60°F (30,000, 55,000 and 70,000 ppm)
Rmf	= 0.1 at 60°F

Fluid contacts are a key point of interest in this well due to the presence of an oil accumulation in what is otherwise considered to be a gas structure. There is no pressure data, no useable Neutron data (to look at Density-Neutron separations), SP or Sonic data to help with this problem. The Lithological log shows no evidence of HC's in Unit VIII apart from a brief point of spot fluorescence mentioned at 2560m MD. The Resistivity curves do show a pattern change at 2524.5 m MD (Figure 4-14); there is a separation in curves above this point in the sand and less of a separation below this point which may indicate a change in fluid, although it may also be a change in rock parameters or invasion. However, test data from Jimbolia-1 and -6 indicate deeper gas, so there is little evidence to define a gas-oil contact in Unit VIII.

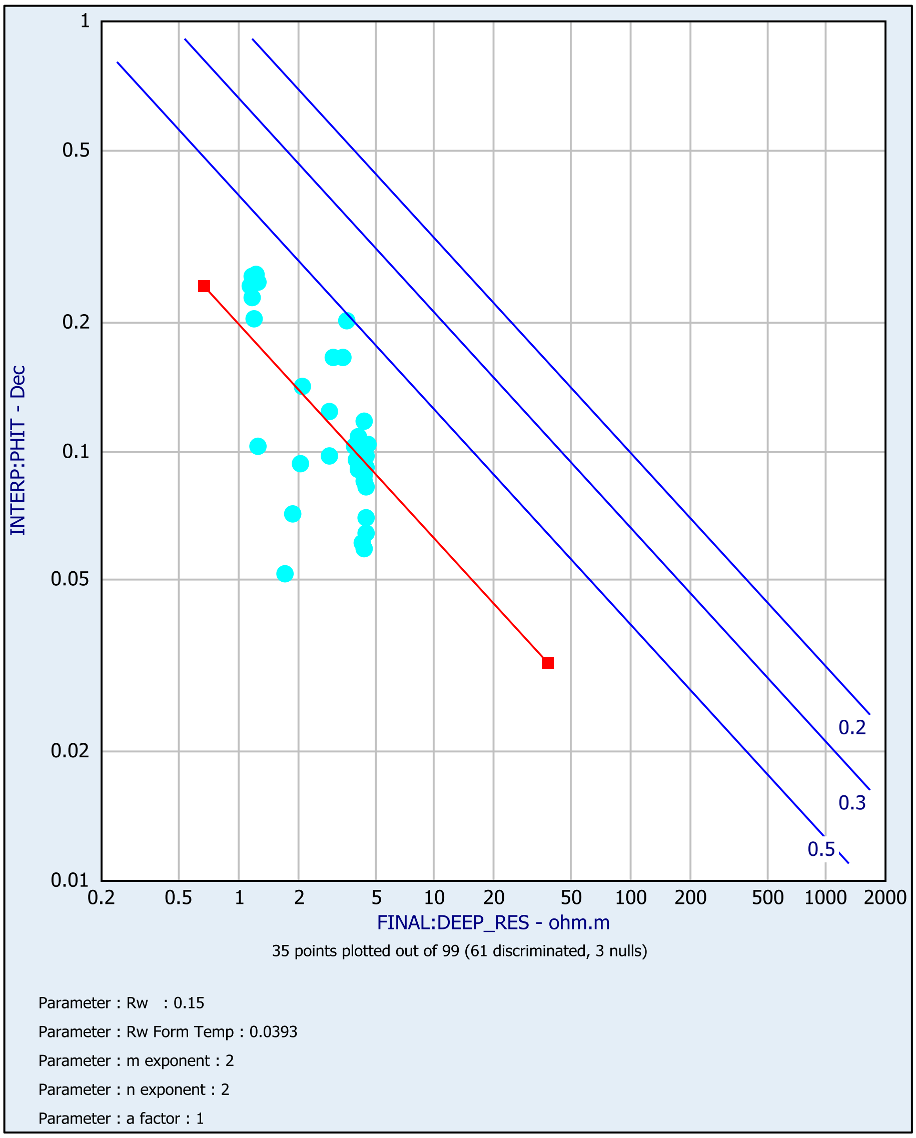


Figure 4-13 Pickett plot for Jimbola-100 in Unit VIII below 2578 m MD; VCL<0.3

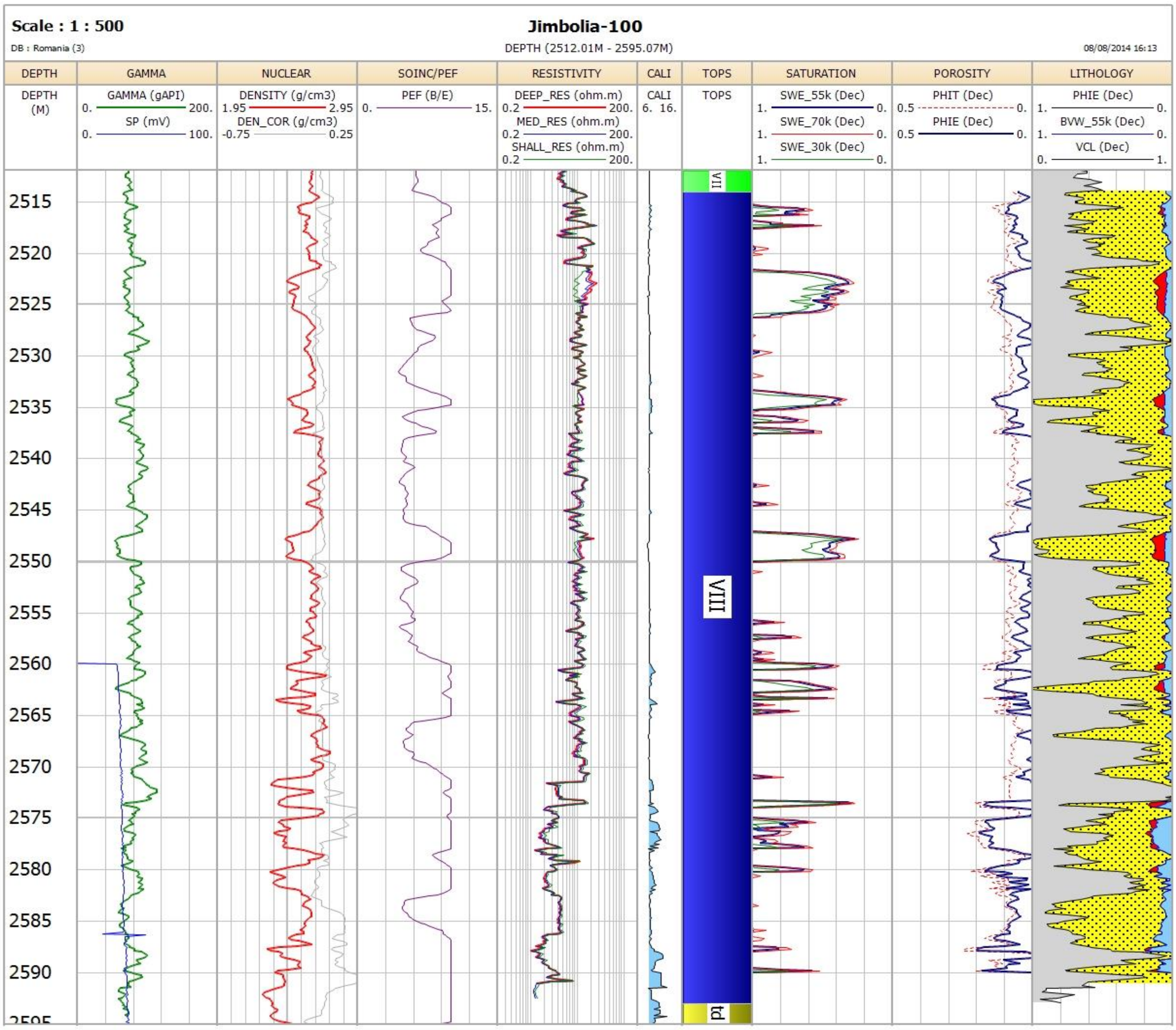


Figure 4-14 CPI over Unit VIII in Jimbolia-100

Well	Pliocene III	Pliocene IV	Pliocene VIII
1	24m	43m	55m
2	17m	44m	84m
3	31m	47m	62m
5	32m	57m	71m
6	20m	33m	60m
10	15m	44m	60m
25	30m	43m	82m
26	19m	36m	52m
28	40m	35m	-
30	25m	-	-
31	34m	46m	-
100	30m	53m	76m
Average	**26m**	**44m**	**67m**

Table 4-4 Pliocene unit thicknesses as encountered in Jimbolia wells

4.5.3. Average Reservoir properties

The Pliocene sequence has been penetrated by a number of wells (Figure 4-3), which show that each unit is widespread, with a reasonably consistent thickness (Table 4-4). However, there is considerable evidence of variation in the internal composition of the units, although the available log suites do not allow rigorous quantification. The only reasonable estimate of the average reservoir properties can be calculated for the Pliocene VIII unit in Jimbolia-100, using a range of VCL cut-off's (Table 4-5), keeping in mind the caveats outlined in section 4.5.2.

Max VCL (cut-off)	Net-to-gross	Effective porosity	Effective Sw for given salinity		
			30,000 ppm	55,000 ppm	70,000 ppm
1.0	100%	5%	92%	87%	85%
0.5	49%	8%	85%	77%	74%
0.4	32%	9%	78%	69%	65%
0.3	18%	10%	69%	58%	54%
0.2	8%	11%	59%	45%	41%
0.1	4%	13%	54%	42%	38%

Table 4-5 Average properties for the Pliocene VIII Unit in Jimbolia-100

4.5.4. Fluid Contacts

The fluid contacts within the Pliocene VIII unit are not well constrained. The interlayered nature of the reservoir sediments data (Figure 4-14) means that there is no clear indication from the limited log data available in the wells that penetrated the hydrocarbon-bearing structure. As discussed in section 4.5.2, the Resistivity curves in Jimbolia-100 show a separation at 2524.5 m MD (-2441m TVDss), which might indicate a change in fluid. However, the results of well tests in wells Jimbolia-1 and Jimbolia-6 contradict this and the preferred range for the gas-oil-contact (GOC) is between -2464m and -2474m TVDss.

Log data from Jimbolia-6 and Jimbolia-100 (Figure 4-14) indicates that the oil-water-contact (OWC) lies between -2492m and -2497m TVDss.

4.6. Fluid properties

Many samples were analysed for Jimbolia, and a summary of the results for the gas samples is shown in Table 4-6. Analysis to Heptane (C7) was also available, but is not shown here. The data shows that the gas in the Pliocene IV horizon, in both the Veche and Vest areas, contains significant amounts of CO2, which make the gas incombustible from this horizon. The Pliocene III gas in the Veche area is considered to be depleted.

In 2013 Jimbolia-100 sampled oil from the Pliocene VIII horizon which was reported as having a stock tank density of 0.78 g/cc (equivalent to a gravity of 49.9 °API) and a reported initial GOR of 179 m3/m3. A Vasquez and Beggs correlation was used to estimate bubble point and compressibility to give the fluid properties in Table 4-7. The gases associated with the oil production on test were found to be non-combustible due to the high CO2 content.

Following re-entry of Jimbolia-100 in October-November 2014, gas was tested from the Pliocene VII containing an average of 12.76% CO_2 and 4.60% N_2, whilst gas from the Pliocene V contained 3.86% CO_2 and 0.72% N_2.

Well	Area	Horizon	Interval m	Test Date	Nitrogen % vol	CO2 % vol	Methane % vol	C2+ % vol
5	Veche	P III	1990-1976	05/09/1988	12.68	0.7	79.01	7.61
1	Veche	P III	2002-1992	24/03/1983		0.52	88.75	10.73
1	Veche	P III	2002-1992	02/12/1985		0.56	83.93	15.51
1	Veche	P IV	2560-2542	22/09/1982		89.59	9.15	1.26
30	Veche	P III	2006-2002	06/10/1987	13.55	1.03	77.86	7.56
25	Vest	P IV	2014-1986	23/02/1985		33.22	60.88	5.9
25	Vest	P IV	2002-1986	02/12/1985		41.81	43.92	14.27
25	Vest	P IV	2002-1986	03/12/1985		50.51	42.87	6.62
25	Vest	P IV	2002-1986	05/12/1985		38.99	45.42	15.59
25	Vest	P IV	1978-1970	19/03/1985		5.31	86.75	7.94
28	Vest	P IV	2040-2032	29/04/1986		74.42	23	2.58
28	Vest	P IV	2040-2032	03/03/1986	4.33	77.46	15.6	2.61

Table 4-6 Gas Properties for Jimbolia

Property	Units	Value
Stock Tank oil density	g/cc	0.78
API Gravity	°	49.9
Initial Solution GOR	m3/m3	179
Bubble Point Pressure	psia	4482
Initial Reservoir Pressure	psia	4482
Reservoir Temperature	°F	248
Formation Volume Factor	rb/stb	1.7085

Table 4-7 Oil Properties for Jimbolia Pliocene VIII

4.7. Well Testing

The Jimbolia Veche Pliocene VIII interval was tested by two wells, Jimbolia-1 & Jimbolia-6. The maximum flow rate from each was 50 and 16 bpd, respectively. Both tests were accompanied by increasing gas oil ratios (GORs) during the test, and the oil is assumed to underlie a gas cap. As stated above, the gases were non-combustible due to the high CO2 content.

The overlying gas bearing intervals in Pliocene, III, V & VII were tested in Jimbolia-100 in Q4 2014. A summary of the tests is shown in Table 4-8. The Pliocene VI interval was not tested. The Pliocence III interval appeared to be fully depleted from earlier production.

Interval	Depth mMDbrt	Rate MMscf/day	Reservoir Pressure bar	Temperature Deg C
Pliocene VII	2304-08	0.2-0.76	218.9	109.5
Pliocene VI	Not tested - Fish in hole but logs suggest gas present			
Pliocene V	2123-25	0.2 - 0.49	201.2	104.8
Pliocene III	1992-94 & 1194-96	0	N/A	N/A

Table 4-8 Well test summary for Jimbolia-100

4.8. Hydrocarbon Volumes

4.8.1. Jimbolia Veche

Drilling results show evidence of hydrocarbons in the Pliocene III, IV, V, VII and VIII within the Jimbolia Veche structure. The Pliocene III unit produced 2.89 Bcf gas and 13 MMstb of condensate between November 1985 and June 1998, and is now considered fully depleted; no further volumes have been calculated during the current study.

Jimbolia-1 apparently recorded a weak gas trace from the Pliocene IV during testing, but there is no other evidence of gas within this interval. Consequently, commercial gas resources are not expected and no volumes have been calculated during the current study.

Jimbolia-100 tested gas in the Pliocene V at low rates (0.2 – 0.5 mmscf/d) and no volumes have been calculated during the current study.

Jimbolia-1ST recorded a gas deflection upon entering the Pliocene VII unit, and a well test across the interval in Jimbolia-1 produced a small amount of gas. However, a well test in the downdip well Jimbolia-3 only produced water, and an integrated review indicated that the Pliocene VII interval only holds a very small volume of gas that cannot be produced commercially. However, when Jimbolia-100 tested the Pliocene VII, it produced gas at 0.2 – 0.76 mmscf/d, although with significant CO_2 and N_2, and no volumes have been calculated during the current study.

Well tests across the Pliocene VIII interval produced oil and large volumes of associated gas, most of which was CO_2. The petrophysical evaluation of the interval (section 4.5.2) in Jimbolia-100 and the data from other wells and seismic allow low case, base case and high case reservoir volume and petrophysical properties to be defined (Table 4-9). From these, a probabilistic estimate of STOIIP was calculated and the results are presented in Table 4-10.

Parameter	Low	Base	High
GOC (m TVDss)	-2474	-2469	-2464
OWC (m TVDss)	-2492	-2495	-2497
Gas cap GRV (10^6 m^3)	30	45	60
Total GRV (10^6 m^3)	110	120	145
Net-to-gross (%)	10	20	30
Porosity (%)	9	10	11
Water saturation (%)	35	45	55
Formation volume factor (rb/stb)	1.6	1.7	1.9

Table 4-9 Probabilistic ranges assumed for calculating hydrocarbon volumes in Jimbolia Veche VIII

STOIIP (MMstb)	P90	P50	P10
Pliocene VIII	2.2	3.2	4.4

Table 4-10 Probabilistic STOIIP estimate for the Jimbolia Veche structure

Following testing in Q4 2014 of Jimbolia-100, the operator, NIS considers there is potential for gas to be produced from the Pliocene V, VI and VII units, subject to further testing of these units by re-entering Jimbolia-6. Although gas has not been produced from the Pliocene VI unit, log indications in Jimbolia-100 suggested the possible presence of gas. At present there are no plans to perform any further work in 2015. At present the potential volumes and commercial value for these three horizons appear to be immaterial, but this view could be revised if further testing is performed in future.

4.8.2. Jimbolia Vest

Jimbolia Vest contained two gas bearing intervals (Pliocene III and IV) when the wells were drilled in 1983, but the structural closure is undefined (Figure 4-5), and it seems most likely that Jimbolia Vest is an extension of the Serbian Crnja Gas Field. Consequently, gas volumes that might have been present in 1983 are unlikely to be present today. Further, the limited database (seismic coverage and well log suites) means that a robust quantitative volumetric assessment cannot be completed. However, broad ranges of reservoir extent, thickness and petrophysical properties can be assigned (Table 4-11 and Table 4-12) based on analogue information and the limited dataset. From these, indicative GIIP volumes can be estimated (Table 4-13), although production from Crnja means that the volumes cannot be expected to be present today.

Parameter	Low	Base	High
Area (km^2)	0.35	0.8	1.25
Gross thickness (m)	20	25	30
Shape factor	0.5	0.75	0.95
Net-to-gross (%)	10	25	40
Porosity (%)	10	15	20
Water saturation (%)	30	40	50
Gas expansion factor (scf/rcf)	150	155	160
Hydrocarbon content (%)	20	50	70

Table 4-11 Probabilistic ranges assumed for calculating hydrocarbon volumes in Jimbolia Vest III

Parameter	Low	Base	High
Area (km^2)	0.8	1.5	3.0
Gross thickness (m)	35	40	45
Shape factor	0.5	0.75	0.95
Net-to-gross (%)	10	30	40
Porosity (%)	10	15	20
Water saturation (%)	30	40	50
Gas expansion factor (scf/rcf)	150	155	160
Hydrocarbon content (%)	20	50	70

Table 4-12 Probabilistic ranges assumed for calculating hydrocarbon volumes in Jimbolia Vest IV

GIIP (Bcf)	P90	P50	P10
Pliocene III	1.0	1.9	3.3
Pliocene IV	1.6	3.2	6.0

Table 4-13 Indicative probabilistic GIIP estimates (in 1983) for the Jimbolia Vest structure

4.8.3. Recoverable Volumes

4.8.3.1. Jimbolia Veche Pliocene III

It has been assumed that the Pliocene III reservoir in Jimbolia Veche has been depleted from earlier production, and so no further recoverable volumes were estimated.

4.8.3.2. Jimbolia Veche Pliocene V, VI, VIII

Although testing in Jimbolia-100 demonstrated gas in the Pliocene V and VII, the rates were so low that recoverable volumes are currently considered to be economically immaterial, so no resource volumes have been calculated. It is noted however that there is a possibility, depending on possible future testing of Jimbolia-6, that volumes could be assigned to these horizons in future.

4.8.3.3. Jimbolia Veche Pliocene VIII

Recovery Factors were estimated by using a Material Balance Approach to a Low, Mid and High Case. It was assumed that the associated gas produced would be re-injected for disposal, as the gas in non-combustible. This results in partial pressure support. Additional assumptions on field abandonment pressure and average producing GOR were made and are summarised in Table 4-14. This gave a range in recovery factors from 15.1 to 33.6%, which was combined directly to give Low, Mid and High Scenarios with EUR ranging from 0.49 to 1.082 MMstb.

	Units	Low	Mid	High
STOIIP	MMstb	2.22	3.20	4.38
Abandonment Pressure	psia	1600	1200	800
GOR Average	scf/stb	6000	5000	4000
RF		15.1%	22.6%	33.6%
EUR	MMstb	0.490	0.746	1.082
Initial Oil Rate	bpd/well	70	90	110
Number of Producers		2	3	4
Number of Gas Injectors		1	1	1

Table 4-14 Recovery Factor Inputs and EUR

4.8.3.4. Jimbolia Vest Pliocene III/IV

As discussed in Section 0, the initial gas in place in Jimbolia Vest was downdip of the Crnja field in Serbia. Production from Crnja has probably led to either depletion or water ingress with the Jimbolia part of the field in Romania. No recoverable volumes have been estimated for this area.

4.9. Development Plans

4.9.1. Jimbolia Veche Pliocene VIII

There are no current development plans for Jimbolia. Venting of CO_2 will not be permissible, so any oil production would require gas separation and then disposal of the CO_2, probably by reinjection. This would add significantly to costs, and to date no economically viable plans have been proposed. Subject to the results of ongoing studies, work commitments for 2015 or relinquishment will be decided by the operator. In the current circumstances, we estimate there is a 50% chance of the field being developed in the foreseeable future.

The estimated Contingent Resource volumes for Jimbolia Veche Pliocene VIII are based on 2 to 4 oil producers and a single crestal gas injector well to dispose of all associated produced gas. Wells are assumed to take two months to drill, with one producer and the gas injector being available for first oil. A nominal start date of 1/1/2016 was assumed for the generation of indicative production profiles, but there is no current plan to achieve this start-up date. The GOR was expected to rise through time, reaching a maximum when approximately 50% of the EUR had been produced in each case.

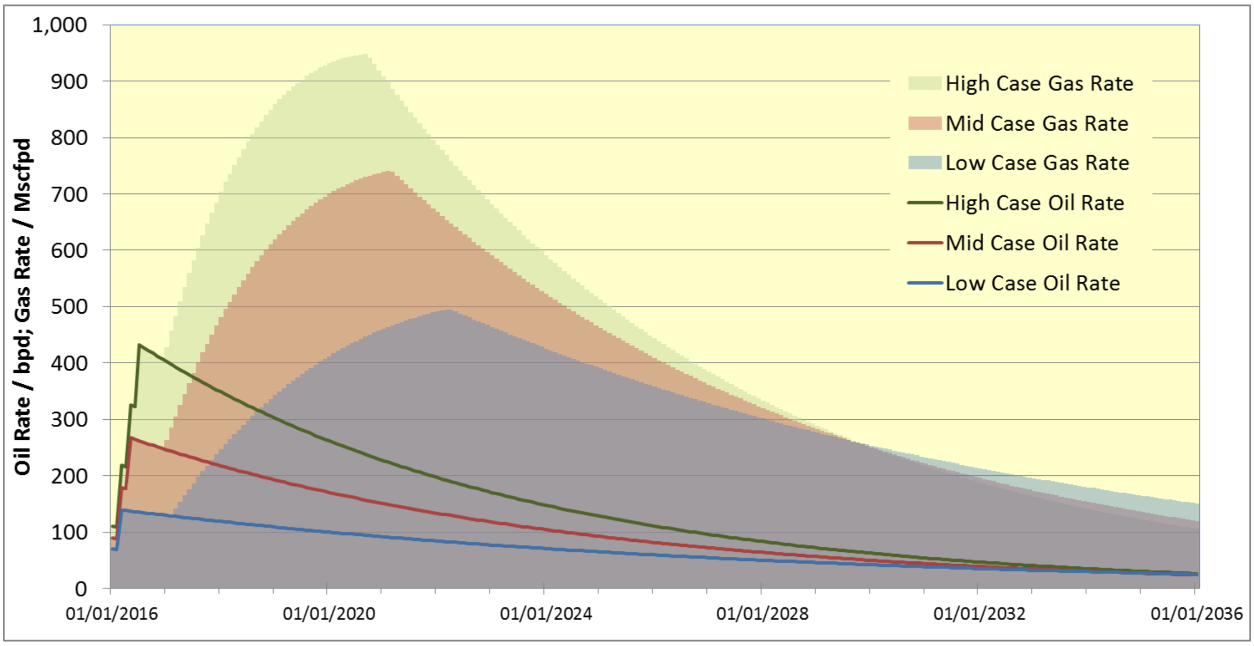


Figure 4-15 Jimbolia Veche Pliocene VIII Production Profiles

	Oil Rate (bpd)				Gas Rate (Mscf/d)		
Date	P90	P50	P10		P90	P50	P10
2016	124.4	217.1	319.2		125.0	218.1	320.8
2017	124.8	232.9	377.0		181.5	370.7	566.0
2018	114.5	206.1	326.8		293.3	550.2	782.7
2019	105.0	182.3	283.2		376.6	660.7	897.7
2020	96.3	161.3	245.5		436.0	720.9	938.5
2021	88.4	142.7	212.7		476.1	711.7	850.8
2022	81.0	126.3	184.3		484.2	631.3	737.3
2023	74.3	111.7	159.7		446.1	558.5	639.0
2024	68.2	98.8	138.5		409.2	494.2	553.8
2025	62.6	87.4	120.0		375.4	437.1	479.9
2026	57.4	77.3	104.0		344.3	386.7	415.9
2027	52.6	68.4	90.1		315.8	342.1	360.4
2028	48.3	60.5	78.1		289.7	302.7	312.4
2029	44.3	53.6	67.7		265.8	267.8	270.7
2030	40.6	47.4	58.7		243.8	236.9	234.6
2031	37.3	41.9	50.8		223.6	209.6	203.3
2032	34.2	37.1	44.1		205.1	185.5	176.2
2033	31.4	32.8	38.2		188.2	164.1	152.7
2034	28.8	29.0	33.1		172.6	145.1	132.3
2035	26.4	25.7	28.7		158.3	128.4	114.7
Total Oil MMstb	0.490	0.746	1.082	Total Gas Bcf	2.200	2.824	3.341

Table 4-15 Untruncated Indicative Jimbolia Veche Pliocene VIII Production Profiles

4.10. Development Costs

Development scenarios or costs have not been evaluated for Jimbolia. The Jimbolia 100 well cost €5.04 million, which is indicative of the costs which would be required for future wells.

4.11. Economics

No economic valuation has been performed for Jimbolia.

4.12. Contingent Resources

	Project 100% Gross			Zeta 39% Net		
Contingent Resources MMstb	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**
Jimbolia Veche Pliocene VIII	0.490	0.746	1.082	0.191	0.291	0.422

Table 4-16 Jimbolia Contingent Oil Resources

No contingent gas resources have been assigned.

5. Reconciliation with previous reporting

Zeta commissioned a CPR from ISIS Petroleum Consultants, dated 2nd March 2012 for the Australian Securities and Investments Commission (ASIC). This represents the latest previous reserves and resources report. Since that time, Zeta has made some acquisitions and divestments, and made operational progress with the assets in its portfolio. The following reconciliation explains the differences in reserves/resources since that publication.

5.1. Suceava

Zeta acquired its interest in the Suceava Licence in May 2012. It was not included in the previous CPR, and this is the first time Zeta has reported resource volumes for this asset.

5.2. Bobocu

ISIS previously reported Contingent and Prospective resources for Bobocu as follows:

Contingent Resources (Bcf)				Prospective Resources (Bcf)			
P90	P50	P10	Pmean	P90	P50	P10	Pmean
0.18	33.33	103.85	44.30	6.71	12.52	23.62	14.09

Table 5-1 ISIS 2012 CPR Contingent and Prospective Resources

Zeta acquired a new 3D seismic survey in 2010, and following extensive study drilled the Bobocu-310 well in 2012, which was unsuccessful. A detailed post-drill evaluation resulted in the following updated Contingent resources being reported in this report:

	Project 100% Gross, and Zeta Interest		
Contingent Resources Bcf	**Low**	**Mid**	**High**
Bobocu	6.68	22.67	54.25

Table 5-2 Rockflow 2015 CPR Contingent Resources

After truncating the prospects to the extent of the licence area, the following prospective resources are now reported. These volumes are comparable to ISIS volumes.

Lobe	Reservoir	P90 Bcf	P50 Bcf	P10 Bcf	PoS
HJ Southwest	H J	1.02	2.54	5.12	17%
HJ West	HJ	1.90	4.92	10.55	23%
J South	J	0.83	1.85	3.64	21%
J North	J	0.72	1.48	2.76	28%
K2 West	K2	0.37	0.91	1.83	13%
Total		**4.85**	**11.70**	**23.91**	

Table 5-3 Rockflow 2015 CPR Prospective Resources

5.3. Jimbolia

ISIS previously estimated Gross Prospective oil resources for Jimbolia Veche Pliocene VIII as follows:

Prospective Resources (MMbbl)			
P90	P50	P10	Pmean
0.63	1.51	3.13	1.72

ISIS considered the Jimbolia Veche Pliocene III to be a depleted gas reservoir with no further resources. ISIS considered Jimbolia Vest to be an extension of the Crjna field, but with no available data assigned no resources.

Since the ISIS report, Jimbolia-100 was drilled in 2013 which confirmed the presence of oil in the Jimbolia Veche Pliocene VIII. However, due to a CO_2 gas cap, it is not considered economically viable to produce the oil, hence the resources are now considered Contingent Resources. Our post-drill volumetric estimate is as follows:

	Project 100% Gross			Zeta 39% Net		
Contingent Resources MMstb	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**
Jimbolia Veche Pliocene VIII	0.490	0.746	1.082	0.191	0.291	0.422

In this report, we agree with ISIS conclusion that Jimbolia Veche Pliocene III is depleted and that Jimbolia Vest contains no resources due to depletion from Crjna field production.

5.4. Padureni

Zeta no longer holds any interests in the Padureni licence, and it therefore does not appear in this CPR.

APPENDIX 1 Glossary of Terms Used

\$	US Dollars	G & G	Geological and Geophysical
%	percent	GDT	Gas Down To
°C	Degrees Celsius	GIIP	Gas Initially In Place
°F	Degrees Fahrenheit	GOC	Gas Oil Contact
1P	Proved Reserves	GOR	Gas to Oil Ratio
2D	Two Dimensional	GR	Gamma Ray log
2P	Proved plus Probable Reserves	GRV	Gross Rock Volume
3D	Three Dimensional	GUT	Gas Up To
3P	Proved plus Probable plus Possible Reserves	GWC	Gas Water Contact
API	American Petroleum Institute	H_2S	Hydrogen Sulphide
AVO	Amplitude Variation with Offset	IRR	Internal Rate of Return
bbl	Barrels	JV	Joint Venture
Bcf	Billion standard cubic feet	K	Permeability
BHA	Bottom Hole Assembly	km	Kilometre
BHP	Bottom Hole Pressure	km^2	Square kilometres
boe	barrels of oil equivalent	m	metre
bopd	barrels oil per day	Mbbl	Thousand barrels
bpd	barrels per day	Mboe	Thousand barrels of oil equivalent
bwpd	barrels of water per day	Mbopd	Thousand barrels of oil per day
CALI	Caliper	Mscf	Thousand standard cubic feet
CAPEX	Capital Expenditure	Mscfpd	Thousand standard cubic feet per day
CO_2	Carbon Dioxide	MD	Measured Depth
cP	centipoise	mD	milli Darcies
CPI	Computer Processed Interpretation (of logs)	MDT	Modular Dynamics Tester
CT	Corporation Tax	MM	million
DCA	Decline Curve Analysis	MMbbl	million barrels of oil
DST	Drill Stem Test	MMstb	million stock-tank barrels of oil
DT	Sonic log	MMboe	million barrels of oil equivalent
E & A	Exploration & Appraisal	MMscf	million standard cubic feet
EOR	Enhanced Oil Recovery	MMscfpd	million standard cubic feet per day
EUR	Estimated Ultimate Recovery	MOD	Money Of the Day
FEED	Front End Engineering Design	MSL	Mean Sea Level
FDP	Field Development Plan	MW	MegaWatt
ft	feet	N_2	Nitrogen
FTHP	Flowing Tubing Head Pressure	N/G	Net to Gross
FWL	Free Water Level	NPV	Net Present Value

OBC	Ocean Bottom Cable
ODT	Oil Down To
OML	Oil Mining Licence
OPEX	operating expenditure
OPL	Oil Prospecting Lease
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
Phi	Porosity
Phie	Effective porosity
Phit	Total porosity
POOH	Pulled Out of Hole
POS	Probability 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
psig	pounds per square inch gauge
PV	Present Value
PVT	Pressure Volume Temperature
rb	Reservoir Barrels
RF	Recovery Factor
RFT	Repeat Formation Tester
RIH	Run in Hole
RROR	Real Rate of Return
Rw	Water resistivity
SCAL	Special Core Analysis
SG	Specific Gravity
SMT Kingdom	a PC-based interpretation workstation
SP	Spontaneous Potential log
SPE	Society of Petroleum Engineers
sq km	square kilometres
ss	subsea
stb	Stock Tank Barrels
STOIIP	Stock Tank Oil Initially In Place
Sw	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
USD	US Dollars
VCL	Clay Volume
WHP	Well Head Pressure
WHFP	Well Head Flowing Pressure
WI	Working Interest