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Competent Persons Report – Italian Assets

Australia's Po Valley Energy Limited, ("Po Valley" or "The Company") is pleased to provide the attached updated Competent Persons Report (CPR) on the Italian Assets held by its 100% owned subsidiary Po Valley Operations Pty Ltd.

MEDIA CONTACT:

Po Valley CEO, Michael Masterman (0418 951 792)

ABN 33 087 741 571
Registered Office: Suite 8, 7 The Esplanade, Mt. Pleasant WA 6153, Australia
Phone: +61 8 9316 9100 Fax: +61 8 9615 5475

CGG Services (UK) Limited

COMPETENT PERSONS REPORT

on the Italian assets of :-

Po Valley Operations Limited

Dated: 24th April 2019

CGG project no: BP526

CGG Services (UK) Limited
Crompton Way, Manor Royal Estate
Crawley, West Sussex RH10 9QN, UK
Tel: +44 012 9368 3000, Fax: +44 012 9368 3010

cgg.com

CGG GeoConsulting

DISCLAIMER AND CONDITIONS OF USAGE

Professional Qualifications

CGG Services (UK) Limited (CGG) is a geological and petroleum reservoir consultancy that provides a specialist service in field development and the assessment and valuation of upstream petroleum assets.

CGG has provided consultancy services to the oil and gas industry for over 50 years. The work for this report was carried out by CGG specialists having between five and 20 years of experience in the estimation, assessment and evaluation of hydrocarbon reserves.

Except for the provision of professional services provided on a fee basis and products on a licence basis, CGG and its employees who worked on preparation of this report, are independent of Po Valley Operations Limited (PVO) and their directors, senior management and other advisers; have no economic or beneficial interest (present or contingent) in the company or in any of the mineral assets being evaluated and is not remunerated by way of a fee that is linked to the admission or value of the issuer.

Data and Valuation Basis

In estimating petroleum in place and recoverable, CGG have used the standard techniques of petroleum engineering. There is uncertainty inherent in the measurement and interpretation of basic geological and petroleum data. There is no guarantee that the ultimate volumes of petroleum in place or recovered from the field will fall within the ranges quoted in this report.

In undertaking this valuation CGG have used data supplied by PVO in the form of geoscience reports, seismic data and engineering reports. The supplied data has been supplemented by public domain regional information where necessary.

CGG has used the working interest percentages that PVO has in the Properties, as communicated by PVO. CGG has not verified nor do CGG make any warranty as to PVO's interest in the Properties.

Within this report, CGG makes no representation or warranty as to: (i) the amounts, quality or deliverability of reserves of oil, natural gas or other petroleum; (ii) any geological, geophysical, engineering, economic or other interpretations, forecasts or valuations; (iii) any forecast of expenditures, budgets or financial projections; (iv) any geological formation, drilling prospect or hydrocarbon reserve; (v) the state, condition or fitness for purpose of any of the physical assets, including but not limited to well, operations and facilities related to any oil and gas interests or (vi) any financial debt, liabilities or contingencies pertaining to PVO.

CGG affirm that from 22nd March (the cut-off date for inclusion of data) to the date of issue of this report, 1) there are no material changes known to CGG that would require modifications to this report, and 2) CGG is not aware of any matter in relation to this report that it believes should and may not yet have been brought to the attention of PVO.

The report has been prepared and is presented in accordance with the requirements of the AIM Rules for Companies and the "Guidance Note For Mining and Oil & Gas Companies" issued by AIM in June 2009 ("AIM

Guidance Note"). This report conforms with the guidelines and definitions of the Petroleum Resources Management Systems (PRMS) (2007 and 2011) as published by the Society of Petroleum Engineers (SPE). Further details of these definitions are included in Appendix A of the CPR.

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If substantive new data or facts become available or known after the date of issue of this report, then this report should be updated to incorporate all relevant new information.

CGG has made every reasonable effort to ensure that this report has been prepared in accordance with generally accepted industry practices and based upon the data and information supplied by PVO for whom, and for whose exclusive and confidential use (save for where such use is for the Purpose), this report is made. Any use made of the report shall be solely based on PVO's own judgement and CGG shall not be liable or responsible for any consequential loss or damages arising out of the use of the report.

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The accuracy of this report, data, interpretations, opinions and conclusions contained within, represents the best judgement of CGG, subject to the limitations of the supplied data and time constraints of the project. In order to fully understand the nature of the information and conclusions contained within the report it is strongly recommended that it should be read in its entirety.

Created by
Andrew Webb, Manager, Petroleum Reservoir and Economics
Tel: +44 (0)1293 683000 – andrew.webb@cgg.com

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Date	Originator	Checked & Approved
Signed:		

Prepared for:	Prepared By:
Po Valley Operations Limited Via Francesco Crispi 90 00187 Rome, Italy	Andrew Webb CGG Services (UK) Limited Crompton Way, Manor Royal Estate Crawley, West Sussex RH10 9QN United Kingdom

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Created by
Andrew Webb, Manager, Petroleum Reservoir and Economics
Tel: +44 (0)1293 683000 – andrew.webb@cgg.com

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Created by
Andrew Webb, Manager, Petroleum Reservoir and Economics
Tel: +44 (0)1293 683000 – andrew.webb@cgg.com

Tables

1 EXECUTIVE SUMMARY

This Competent Persons Report (CPR) is an independent evaluation, prepared by CGG Services (UK) Ltd (CGG), for the Directors of:

Po Valley Operations Limited (PVO)
Via Francesco Crispi 90
00187
Rome, Italy

The CPR has been drafted in accordance with PVO's request dated 5th February 2019. The subject of the report is PVO's Italian licences located in the Po Valley and the Adriatic Sea.

The petroleum reserves and resources definitions used in the CPR are those published by the Society of Petroleum Engineers (SPE) and World Petroleum Congress (WPC) in 1998, supplemented by the Petroleum Resource Management System (PRMS), published by the SPE/WPC in 2007.

1.1 DETAILS OF LICENCES AND ASSETS

The principal licences and assets of PVO that have been evaluated in this report are:

1. The Podere Gallina Exploration Licence containing the Cembalina prospect and the Selva Malvezzi Production Concession. Within the Selva Malvezzi Production Concession are the Podere Maiar gas field, the gas prospects known as Fondo Perino, East Selva, Riccardina, Selva B North and Selva B South.
2. The AR94PY licence, located offshore Adriatic northern Italy, contains the d40ACPY Exploitation Concession with the Teodorico gas field and the PL3-C gas prospect.
3. The Torre del Moro licence containing the Torre del Moro oil prospect
4. The Cadelbosco licence containing the Zini (Qu-B), Zini (Qu-A), Canolo (Qu-A) and Canolo Pliocene gas prospects; the Bagnolo in Piano oil discovery and Bagnolo SW oil prospect
5. The Grattasasso Licence containing the Ravizza oil discovery

1.2 RESERVES

The following table presents the reserves on a gross and a PVO net attributable basis deriving from the licences.

Table 1.1 Summary of Reserves

Asset	Gross			Net attributable			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Gas MMscm (Bcf)							
Selva	117 (4.1)	379 (13.4)	846 (29.9)	74 (2.6)	239 (8.4)	533 (18.8)	PVO
Teodorico (outside 12 mile zone)	756 (26.7)	1034 (36.5)	1345 (47.5)	756 (26.7)	1034 (36.5)	1345 (47.5)	PVO
Total MMscm (Bcf)	873 (30.8)	1413 (49.9)	2191 (77.4)	830 (29.3)	1273 (44.9)	1878 (66.3)	

Note:-
1. *Reserves are the volumes estimated to be potentially recoverable from the proposed development schemes*
2. *Volumes are stated after the application of an economic cut-off*
3. *Proved, Proved & Probable and Proved, Probable & Possible categories account for the uncertainty in the estimates*
4. *Full definitions of the Reserve categories can be found in Appendix A*
5. *Totals may not add due to rounding errors*
6. *Conversion factor used for cubic metres to cubic feet is 35.31*

NPVs at the base gas price are tabulated below for a 100% field interest and PVO's respective net interest for each asset. It should be noted that the NPVs presented are not deemed to be the market value of the asset, and that the values may be subject to significant variation with time due to changes in the underlying input assumptions as more data becomes available and interpretations change.

Table 1.2 NPV10 for Reserves

Asset	Gross (€ MM)			Net attributable (€ MM)		
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible
Selva	10.2	28.8	49.3	6.4	18.2	31.0
Teodorico (outside 12 mile zone)	5.8	17.8	28.3	5.8	17.8	28.3

CGG's gas price assumption follows the forward Italian PSV spot gas price curve until 2024, and thereafter escalates at 2% per year.

1.3 CONTINGENT RESOURCES

The following table presents the contingent resources on a gross and a PVO net attributable basis deriving from the licences.

Table 1.3 Summary of Total Contingent Resources

Contingent Resources	Gross			Net Attributable		
	1C	2C	3C	1C	2C	3C
Gas MMscm (Bcf)	428.8 (15.1)	910.3 (32.1)	1742.8 (61.5)	361.6 (12.8)	730.8 (25.8)	1349 (47.6)
Oil MMbbl	9.4	43.4	122.2	9.4	43.4	122.2

Table 1.4 Summary of Contingent Resources by Asset

	Gross			Net attributable				
Asset	1C	2C	3C	1C	2C	3C	Risk factor	Operator
Gas MMscm (Bcf)								
Teodorico (inside 12 mile zone)	209.9 (7.4)	300.5 (10.6)	395.9 (14.0)	209.9 (7.4)	300.5 (10.6)	395.9 (14.0)	60%	PVO
Level B North	99.8 (3.5)	252.3 (8.9)	504.5 (17.8)	62.9 (2.2)	158.9 (5.6)	317.8 (11.2)	70%	PVO
Level B South	27.5 (1.0)	96.6 (3.4)	264.5 (9.3)	17.3 (0.6)	60.9 (2.2)	166.6 (5.9)	60%	PVO
Level A South	29.3 (1.0)	51.2 (1.8)	102.1 (3.6)	18.5 (0.7)	32.3 (1.1)	64.3 (2.3)	60%	PVO
Zini (Qu-B)	31.2 (1.1)	76.5 (2.7)	130.3 (4.6)	26.5 (0.9)	65.0 (2.3)	110.7 (3.9)	70%	PVO
Canolo (Qu-A)	19.8 (0.7)	31.2 (1.1)	48.1 (1.7)	16.9 (0.6)	26.5 (0.9)	40.9 (1.4)	70%	PVO
Canolo (Pliocene)	11.3 (0.4)	102.0 (3.6)	297.4 (10.5)	9.6 (0.3)	86.7 (3.1)	252.8 (8.9)	70%	PVO
Oil (MMbbl)								
Bagnolo in Piano	6.6	27.3	80.6	6.6	27.3	80.6	70%	PVO
Ravizza	2.8	16.1	41.6	2.8	16.1	41.6	70%	PVO

Notes:-
1. *Contingent Resources are the volumes estimated to be potentially recoverable if the appraisal well is successful and the opportunity is then fully developed.*
2. *Volumes are stated before the application of an economic cut-off*
3. *1C, 2C and 3C categories account for the uncertainty in the estimates and denote low, best and high outcomes*
4. *Full definitions of the Contingent Resource categories can be found in Appendix A*
5. *The risk factor means the estimated chance that the volumes will be commercially extracted*
6. *Conversion factor used for cubic metres to cubic feet is 35.31*

1.4 PROSPECTIVE RESOURCES

The following table presents the prospective resources on a gross and a PVO net attributable basis deriving from the licences.

Table 1.5 Summary of Total Prospective Resources

Prospective Resources	Gross			Net Attributable		
	Low	Best	High	Low	Best	High
Gas MMscm (Bcf)	1779.6 (62.8)	3080.4 (108.8)	6290.6 (222.1)	1207.5 (42.6)	2115.9 (74.7)	4240 (149.7)
Oil MMbbl	87.1	160.5	352	87.1	160.5	352

Table 1.6 Summary of Prospective Resources by Asset

	Gross			Net attributable				
Asset	**Low**	**Best**	**High**	**Low**	**Best**	**High**	**Risk factor**	**Operator**
Gas MMscm (Bcf)								
East Selva	824.1 (29.1)	985.6 (34.8)	1149.8 (40.6)	519.2 (18.3)	620.9 (21.9)	724.4 (25.6)	40%	PVO
Riccardina	367.2 (13.0)	1097.8 (38.8)	3651.5 (128.9)	231.3 (8.2)	691.6 (24.4)	2300.4 (81.2)	21%	PVO
Cembalina	59.5 (2.1)	93.5 (3.3)	133.1 (4.7)	37.5 (1.3)	58.9 (2.1)	83.9 (3.0)	51%	PVO
Fondo Perino	288.9 (10.2)	413.5 (14.6)	580.6 (20.5)	182 (6.4)	260.5 (9.2)	365.8 (12.9)	34%	PVO
Zini Qu-A	16.2 (0.6)	39.7 (1.4)	67.6 (2.4)	13.8 (0.5)	33.7 (1.2)	57.5 (2.0)	30%	PVO
PL3-C (Teodorico)	223.7 (7.9)	450.3 (15.9)	708 (25.0)	223.7 (7.9)	450.3 (15.9)	708 (25.0)	17%	PVO
Oil (MMbbl)								
Torre del Moro	65	106	240	65	106	240	11%	PVO
Bagnolo SW	22.1	54.5	112	22.1	54.5	112	34%	PVO

Notes:-

1. *Prospective resources are the volumes estimated to be potentially recoverable from undiscovered accumulations through future development projects*
2. *Prospective resources have both an associated chance of discovery and a chance of development*
3. *Volumes are sub-divided into low, best and high estimates to account for the range of uncertainty in the estimates*
4. *Prospective Resources are stated before the application of a risk factor and an economic cut-off*
5. *Full definitions of the Prospective Resource categories can be found in Appendix A*
6. *The risk factor means the estimated chance of discovering hydrocarbons in sufficient quantity for them to be tested to the surface*
7. *Conversion factor used for cubic metres to cubic feet is 35.31*

1.5 CONCLUSION

CGG have reviewed the information provided by PVO on their Italian assets, and conclude that the estimates of the reserves and resource volumes, and costs contained in this report are reasonable and reflect the potential for the fields and prospects, given current knowledge.

It should be noted that the reserves classification in this report for Selva Malvezzi and Teodorico (d40ACPY) assumes that full Production Concessions will be awarded. Preliminary approval by the Italian regulatory authorities has been given for both fields; final approval will be granted after the EIA decree. CGG understands that the government decree of February 11th 2019, related to review of upstream oil and gas activities in Italy does not affect Production Concessions officially requested before the decree date.

CGG have chosen to maintain the reserves classification at this point in time, but to revisit the classification again once the results and impact of the new law and the review become clearer.

2 INTRODUCTION

This independent Competent Person's Report (CPR) was prepared by CGG at the request of Po Valley Operations Ltd (PVO). The report evaluates the reserves and resources associated with PVO's Italian licences located in the Po Valley and the northern Adriatic Sea.

2.1 DETAILS OF LICENCES

Details of the licences covered by this report are presented in Table 2.1 below.

Table 2.1 PVO licence details

Licence (field/prospect)	Operator	PVO Interest (%)	Status	Licence expiry date	Licence Area
Podere Gallina (Cembalina)	PVO	63%	Exploration	See note 1	506 km^2
Selva Malvezzi (Podere Maiar, East Selva, Selva B north/south, Riccardina, Fondo Perino)	PVO	63%	Development	See note 1	80.8 km^2
d40ACPY (Teodorico, PL3C)	PVO	100%	Development	See note 2	65.9 km^2
AR94PY (Rita, Azzurra, Ginevra)	PVO	100%	Exploration	8th January 2023	526 km^2
Torre del Moro (Torre del Moro)	PVO	100%	Exploration	3rd February 2023	111 km^2
Cadelbosco - gas (Zini, Canolo)	PVO	85%	Exploration	21st September 2024	512.8 km^2
Cadelbosco - oil (Bagnolo in Piano, Bagnolo SW)	PVO	100%	Exploration	21st September 2024	512.8 km^2
Grattasasso (Ravizza)	PVO	100%	Exploration	7th June 2024	34.1 km^2

1. *PVO lodged the application for the first 3-year extension of the exploration period in July 2016, but as a result of changes in hydrocarbon law in Italy in February 2019, the administrative procedures related to the grant of exploration licences are currently suspended. The separate application for a Production Concession to develop the Selva Gas Field was submitted by PVO to the Italian authorities in May 2018. Although the Production Concession was granted preliminary approval in January 2019, the award of a full concession is subject to environmental and other approvals, which may be affected by the recent changes in hydrocarbon law. The EIA has been submitted to the Authorities for approval on April 19th 2019.*

2. *A sub-area of the AR94PY licence containing the Teodorico field was granted preliminary approval for a Production Concession in August 2015. However, the award of a full concession is subject to environmental and other approvals, which may be affected by the recent changes in hydrocarbon law.*

The location of PVO's licences are shown in the map below.

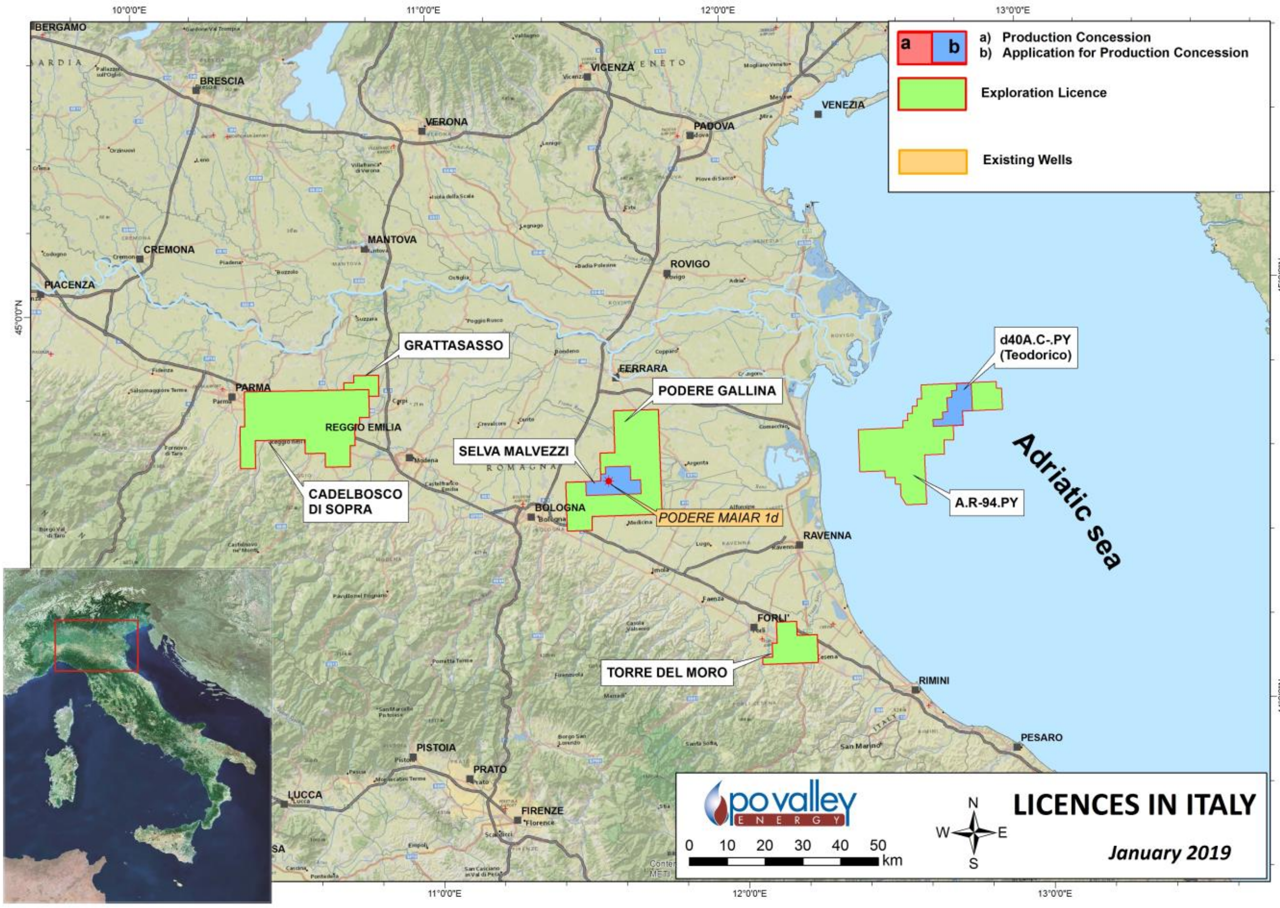


Figure 2.1 PVO Licences, Italy

2.2 SOURCES OF INFORMATION

In completing this evaluation, CGG have independently reviewed information and checked the validity of interpretations provided by PVO, as well as utilising complementary information from the public domain.

CGG have produced a number of CPRs on the assets over the last six years for PVO, and as a result are familiar with the geology. Much of the data supplied by PVO for this report was in the form of updates to existing data previously provided to and reviewed by CGG. The key previous PVO CPRs that CGG have used in compiling this report are:-

- CPR dated 3rd May 2013 (Cadelbosco/Grattasasso)
- CPR dated 15th February 2018 (Teodorico)

- CPR dated 6th February 2019 (Selva)

In conducting their evaluation, CGG have accepted the accuracy and completeness of data supplied by PVO, and have not performed any new interpretations, simulations or studies.

Data utilised by CGG in the preparation of this CPR included:-

- Location maps
- Geological and reservoir reports
- Well logs of drilled wells
- Seismic workstation projects and associated interpretations
- Historical production and pressure data
- AFE's and budgets
- Well logs
- Well testing reports
- Field Development Plans

As the assets in question are yet to be developed or are in the exploration phase, no site visits have been conducted by CGG.

2.3 EVALUATION METHODOLOGY

In estimating the reserves and resource volumes, CGG has used the standard techniques of geological estimation to develop the technical sections of this CPR. Reserve and resource ranges have been determined using deterministic methods. For prospective resources the associated chance of geological success (GCoS) has also been independently estimated.

PVO staff demonstrated and reviewed the seismic workstation interpretations during CGG visits to PVO in 2013 and 2015. At the same time, maps and geological issues were discussed face to face with senior PVO staff. The seismic picks, reservoir structure and gross rock volume, according to these interpretations, was demonstrated to CGG. CGG followed the assessment and drilling of the Podere-Maiar-1 well in late 2017. Prospects worked up after 2015 (Riccardina, Selva South B and North A+B levels and Torre del Moro) have been fully reviewed by CGG. Independently derived prospective resource assessments are provided in this document.

CGG has independently constructed development profiles, and validated estimates of capital and operating costs provided by PVO. For those assets that have been categorised as reserves, the NPV (Net Present Value) of the cash flows derived from exploiting those reserves has been calculated using industry standard discounted cash flow techniques based on forecasts of costs and production rates.

In estimating cash flows, CGG has extrapolated economic parameters based upon recent and current market trends. Estimates of these parameters (notably the future price of gas and oil) are uncertain, and cash flows at low and high price scenarios have therefore also been determined. It should be noted that there is no guarantee that the outturn economic parameters will be within the ranges considered.

2.4 PRINCIPAL CONTRIBUTORS

CGG employees and consultants involved technically in the drafting of this CPR have between five and 20 years of experience in the estimation, assessment and evaluation of hydrocarbon reserves.

CGG confirms that itself and the authors of this report are independent of PVO, its directors, employees and advisers, and has no interest in the assets that are the subject of this report.

The following personnel were involved in the drafting of the CPR.

Andrew Webb

Has supervised the preparation of this CPR. He is the Manager of the Petroleum Reservoir & Economics Group at CGG, having joined the company as Economics Manager in 2006. He graduated with a degree in Chemical Engineering and now has over 30 years' experience in the upstream oil and gas industry. He has worked predominantly for US independent companies, being involved with projects in Europe and North Africa. He has extensive experience in evaluating acquisition and disposals of asset packages across the world. He has also been responsible for the booking and audit of reserves both in oil and gas companies, but also as an external auditor. He is a member of the Society of Petroleum Engineers and an associate of the Institute of Chemical Engineers.

Dr. Arthur Satterley

Has a BSc 1st Class in Geology, University College of Wales and a PhD from the University of Birmingham on Upper Triassic reef limestones and a post-doctoral research experience on platform carbonate margins. He has 20 years' experience of petroleum geological evaluations and resource assessments for both oil and gas fields throughout the exploration and development life cycle. He has experience of carbonate and clastic reservoirs in most major petroleum provinces including onshore northern and southern Italy.

Toni Uwaga

Has an MSc from Heriot Watt University, Edinburgh, in Petroleum Engineering. He has 22 years' industry experience. Over the years he has worked on oil and gas projects spanning the North Sea, East Irish sea, Gulf of Guinea, Middle East, India, Malaysia, North America and the Caribbean Sea. He functioned as Reserves Coordinator for Shell Petroleum Development Company, Nigeria. He has participated as Lead Reservoir Engineer in several CPRs across the various regions he has worked. He is a member of the Geological Society of Trinidad and Tobago (GSTT) and the Society of Petroleum Engineers (SPE). He has several technical papers, published by GSTT and SPE.

Peter Wright

Has an MA in Engineering from Cambridge University and an MBA from Cranfield University. He has over 20 years' experience in the economic evaluation of upstream oil and gas assets including exploration prospects, development projects and producing assets. His career has included working as a director of specialist economics focussed consulting companies, and has covered a variety of asset types both onshore and offshore in Europe and the rest of the world. He also regularly delivers training courses on petroleum economics and risk analysis at various centres around the world. He is a member of the Society of Petroleum Engineers.

2.5 ITALIAN OIL AND GAS INDUSTRY

Italy is one of the major gas producers in southern Europe, although in global terms represents only a small percentage of total gas production. Gas is produced from onshore fields predominantly in the north of Italy (Po Valley) and offshore fields in the Adriatic Sea, with some production from Sicily. Gas has been produced in the Po Valley since the Second World War, initially exclusively by ENI.

The domestic gas markets were liberalized in 1998, which saw the end of the ENI monopoly over production, and the opening up of licences to independent oil and gas companies. Gas production is currently about 6.2 billion cubic metres per year, which satisfies about 10% of domestic demand. The remaining demand is met by imports from Russia, Algeria, Norway, Qatar and Libya. Italy is the third largest gas consumer in Europe after Germany and the UK.

The mainland of Italy is extensively served by national and local gas pipeline networks, facilitating the export and sale of production. A sophisticated market has also developed within the country for all aspects of servicing exploration and production activities, including well drilling and logging, process plant design and fabrication, and maintenance/operations.

On 11th February 2019 the Italian government issued a decree relating to the exploration and production of hydrocarbons in Italy, both onshore and offshore. The decree introduced an 18 month (extendable up to 24-month) suspension of the processing of permits for exploration licences and new exploitation concessions a substantial increase in rental fees. The objective of the suspension is to determine those areas of the country that are suitable, from an environmental and social economic perspective, for hydrocarbon activities going forwards. In areas deemed unsuitable, exploration licences will be withdrawn, and new production licences will not be granted or renewed. It is understood that compensation will be payable to companies in relation to past costs incurred on any exploration licences that are withdrawn. CGG understands that the suspension does not affect Selva Malvezzi and Teodorico Concessions.

2.6 REGIONAL GEOLOGICAL CONTEXT

The Po Basin is a major hydrocarbon province which was estimated by the US Geological Survey to have approximately 16 TCF of ultimately recoverable gas (Lindquist, USGS, 1999, on-line review paper). The basin occurs on the margins of the Alpine mountain chain to the North and the Apennine chain to the South. The basin opens into the Adriatic Sea to the East. Compression associated with the building of these mountain belts created a large deep basin (or "foredeep") into which large thicknesses of sediment were shed from the surrounding uplands. As the basin deepened, turbidite sands were created and the high sediment supply began to fill the basin. Many of these turbidite sands are now gas-bearing, including long-established reservoirs discovered and developed by ENI, as well as thin-bedded reservoirs that are becoming new targets at the present time. Pliocene reservoirs include marine sands of significant lateral extent, which are folded over faulted structures that were formed during the compressional phases. At least 6km of Pliocene sediments were deposited in the foredeep, and as this was filled, the Po River drainage system became established, depositing marine sands in a delta-front environment. These may be overlain by fluvial sands as subsidence slowed and the basin filled.

The source of the gas is Miocene and Pliocene shales that are interbedded with turbidites and other sediments; the gas is predominantly biogenic rather than associated with deep burial of the shales. Biogenic gas may be generated at shallower depths than is required for the generation of gas by burial, and is related to the activity of bacteria acting on organic matter buried with the shales. However, the deepest known bacterial gas generation is recorded in the Po Basin at a depth of 4500 metres. As such, the process can generate large gas volumes throughout a basin, and the source may continue to be active at the present time. These aspects have led directly to the hydrocarbon richness of the Po Basin. Many structures and many reservoirs have proven to be gas-bearing, which explains the 263 developed fields in the Po Basin. Much potential for new discoveries remains, as do many opportunities for field re-development (missed pays and remaining gas in old fields).

The assets under consideration here include Miocene and Pliocene reservoir sands, stacked vertically, and including both thick, good quality gas sands and thin-bedded gas reservoirs. Reservoir sands are interbedded with shaley and marly fine-grained sediments. In many cases, the sands are pressure isolated from each other and may be drained in succession according to well designs and completion strategies employed.

3 GEOPHYSICS AND GEOLOGY

3.1 PODERE GALLINA LICENCE

3.1.1 Selva

The Selva Stratigraphic redevelopment represents a part of the former ENI-operated Selva gas field. The extension of the Selva Field was interpreted by Po Valley Operations Ltd. mainly using depth maps derived from seismic interpretation and well data at Upper Mid Pliocene level. Recent modelling (DREAM 2013) was based on the conservative assumption that the initial GWC of the Selva Field at 1336m TVDSS had risen to 1235m (top level C in the Selva-6 well) leaving a potential undrained updip gas volume.

Seismic and well data show the Selva Stratigraphic redevelopment to be an Upper Middle Pliocene onlap to a Lower Pliocene thrust-bounded anticline. However, interpretation of seismic lines suggests the reservoir is also displaced by reactivated thrust splays which detach onto the main thrust fault. Although the depth structure map is quite well constrained by existing well penetrations, the 2D seismic (in terms of line spacing and vintage) is imperfect for imaging small features and part of the Operator's plan is to revise the structure mapping using additional data in the near future. The Podere Maiar-1 well was drilled in late 2017 and tested in early 2018. It targeted the updip volume based upon a new interpretation of the position of the lapout edge towards the Selva-3 well. The latest interpretation of the well test and its implications are fully incorporated into this CPR and into CGG's consideration of Reserves.

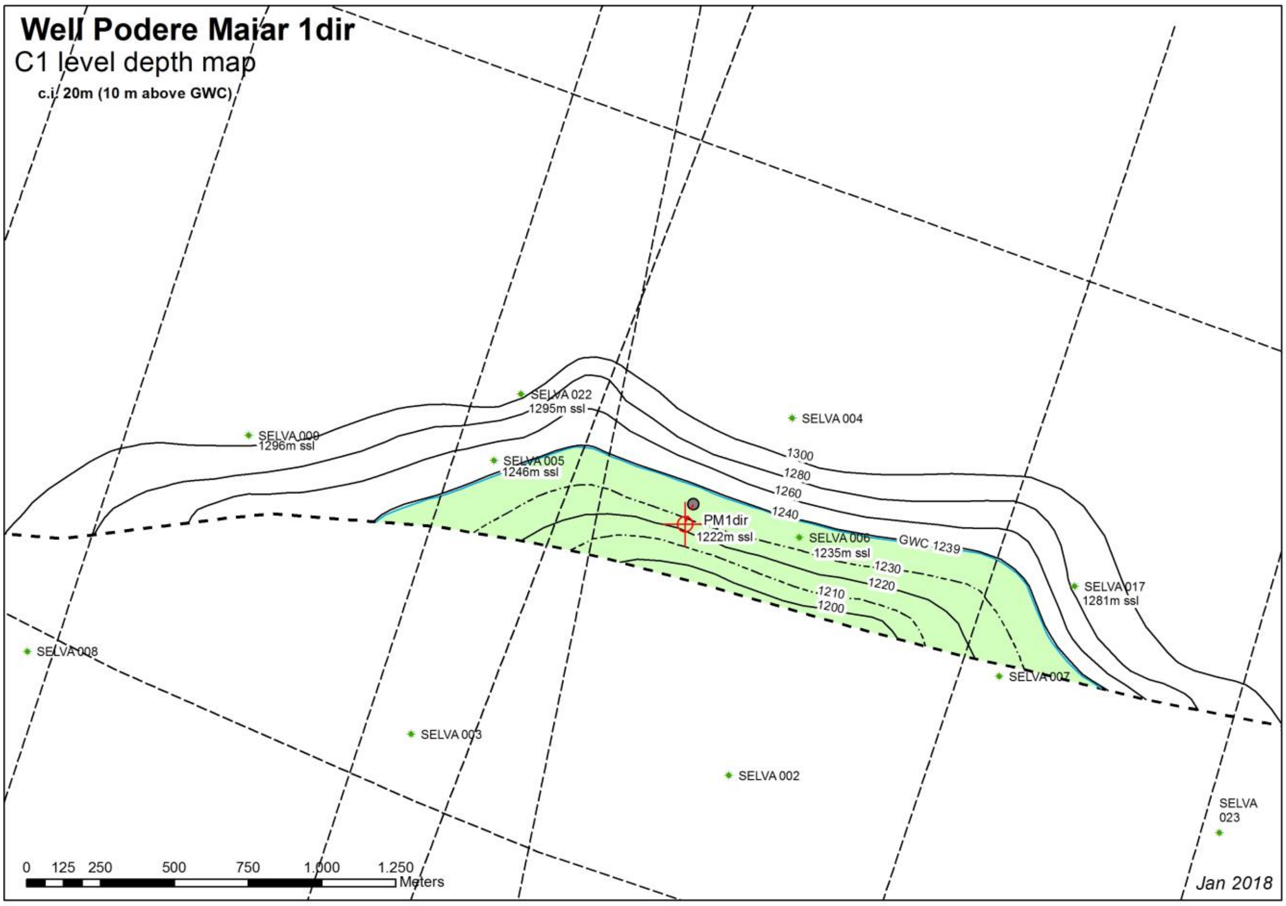


Figure 3.1 Selva stratigraphic structure map (Podere Maiar Gas FIeld)

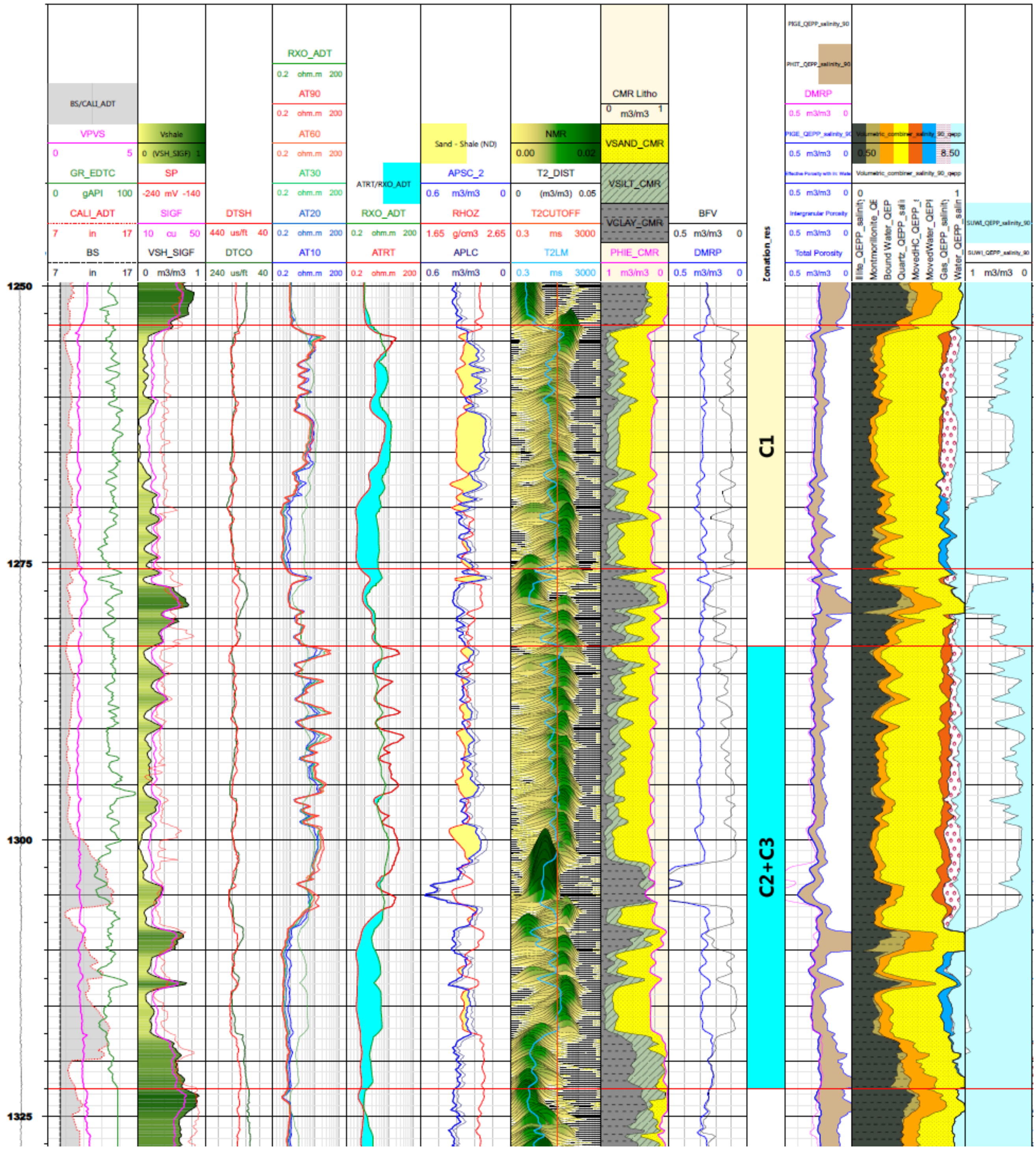


Figure 3.2 Podere Maiar-1: C1 and C2 Sand Reservoirs, Extract from ELAN Interpretation Plot

The ELAN log and interpretation plot is provided as Figure 3.2, above.

Podere Maiar-1 penetrated a gross thickness of 62.5 metres of Lower Pliocene (C1 and C2) gas sands of the old Selva field. Petrophysical analysis has indicated average properties in each sand as follows:

<u>C1 Sand</u>

22 metres gross thickness, 70% net-to-gross, 22-26% porosity and 65% gas saturation. A recovery factor of 60-70% is assumed across the P90 to P10 case.

<u>C2 Sand</u>

40.5 metres gross thickness, 63% net-to-gross, 21-25% porosity and 70% gas saturation. A recovery factor of 60-70% is assumed across the P90 to P10 cases.

The logging tools deployed for the assessment of the reservoirs were high quality and comprehensive, including a CMR (Figure 3.2). Porosity estimation is considered reliable as the CMR-Density technique was used (ideal for gas-filled shaly sandstones), and the CMR also clearly distinguishes sand from shale. The ELAN interpretation has been checked and appears to be reliable, showing long reservoir sections with good gas saturations. The quality of the reservoir section encountered by the well appears good and reliably defined.

Pressure data taken over the reservoir section has established a separate gas-water-contact in C1 and C2 sands which are separated by a shale. In both sands, the contact derived from pressure data points falls close to the GWC identified on the petrophysical interpretation plot. The location of the water, therefore, is quite well established from independent evidence.

Gas initially in place estimates have been reviewed and the following parameters are considered fair estimates:

Table 3.1 Parameters used in the estimation of gas-initially-in-place (GIIP)

Sand	Case	GWC	NtG	Phi	Sg	Bg	GIIP (MMscm)
C1	min	1,237.0	0.66	0.22	0.65	140	81
C1	max	1,239.6	0.75	0.26	0.65	144	299
C2	min	1,274.5	0.58	0.21	0.7	140	261
C2	max	1,277.8	0.68	0.25	0.7	144	910
Total	min						342
	max						1,208

The mid-case GIIP is taken as the average of low and high.

As a proposed re-development of an old field, this appears relatively low risk; the major geological risk component is the location of the reservoir zero thickness line (pinch-out) and the shape of the pinch-out as drawn on the structure map (currently the zero line is drawn as a smooth, straight line which could be correct or could be substantially incorrect). Lack of high-resolution structural definition means Gross Rock Volume remains the greatest geological uncertainty. At this stage, post appraisal well but prior to production start-up, there is remaining uncertainty regarding the interpretation of the well test, in particular the meaning and significance of the "boundaries" seen in C1 and C2 sands. These boundaries are the result of non-unique interpretations of well test data, although the slope of the derivative is a clear reservoir signature for both sands. At the present time, CGG considers that the derivative signature from the C2 sand flow test may be significant in terms of a geological feature that limits the contacted gas volume or accelerates water coning.

The major risk to recoverable gas volumes is considered to be the timing of water breakthrough. In the Po Valley region, accurately predicting the timing of water breakthrough in comparable reservoirs has been a source of uncertainty in the past. The well test and production risks will be discussed in Chapter 4.

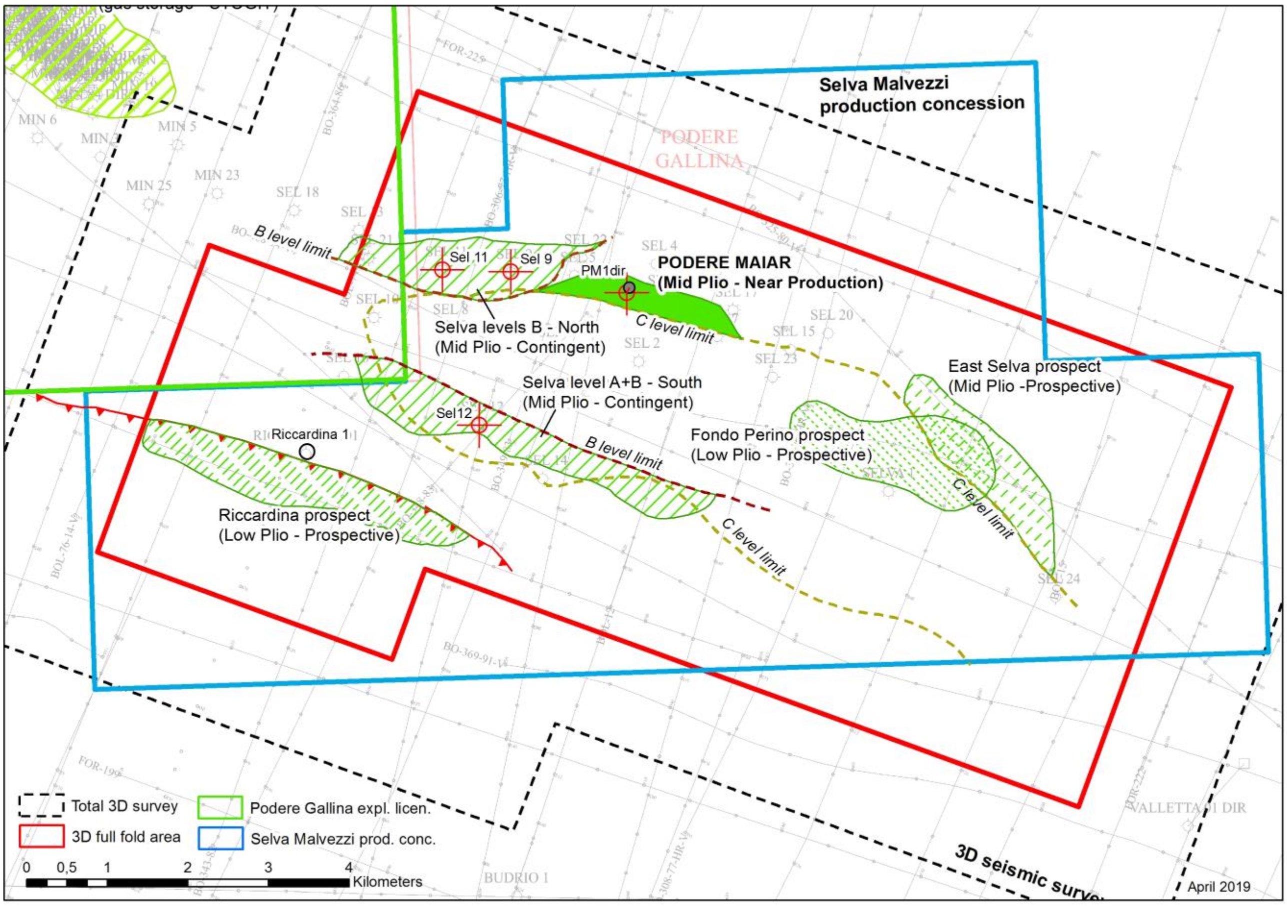


Figure 3.3 Selva Malvezzi Production Concession, Podere Maiar Gas Field and Associated Prospects

3.1.2 Selva North and South Prospects

Following the successful Podere Maiar-1 well drilled in late 2017, PVO have firmed up a further two prospects on the North and South crest of the old Selva gas field (Figure 3.4). Both prospects rely on the same stratigraphic pinch-out concept successfully proved viable by the Podere Maiar-1 well.

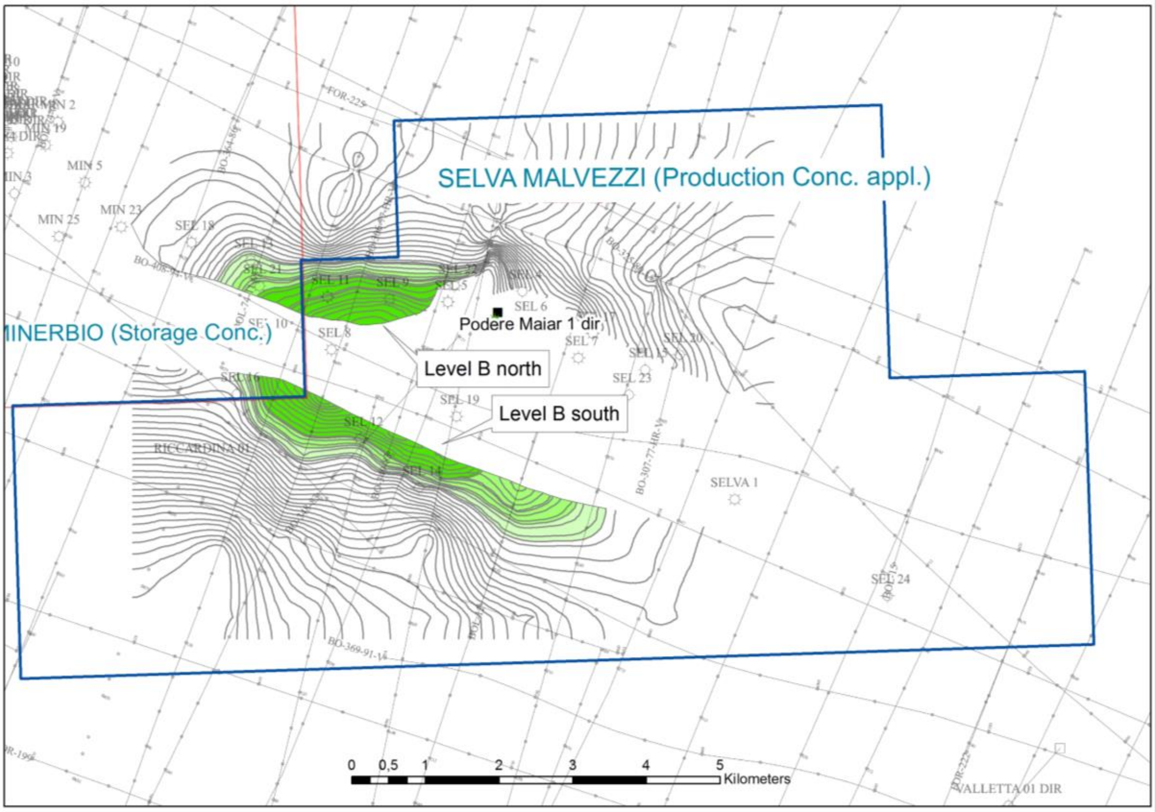


Figure 3.4 Level B North and South Prospects, Selva Malvezzi Production Concession

Although these are named as Prospects by PVO, they fall into the Contingent Resource category because they have already produced gas to surface in commercial quantities leaving a remaining updip gas volume.

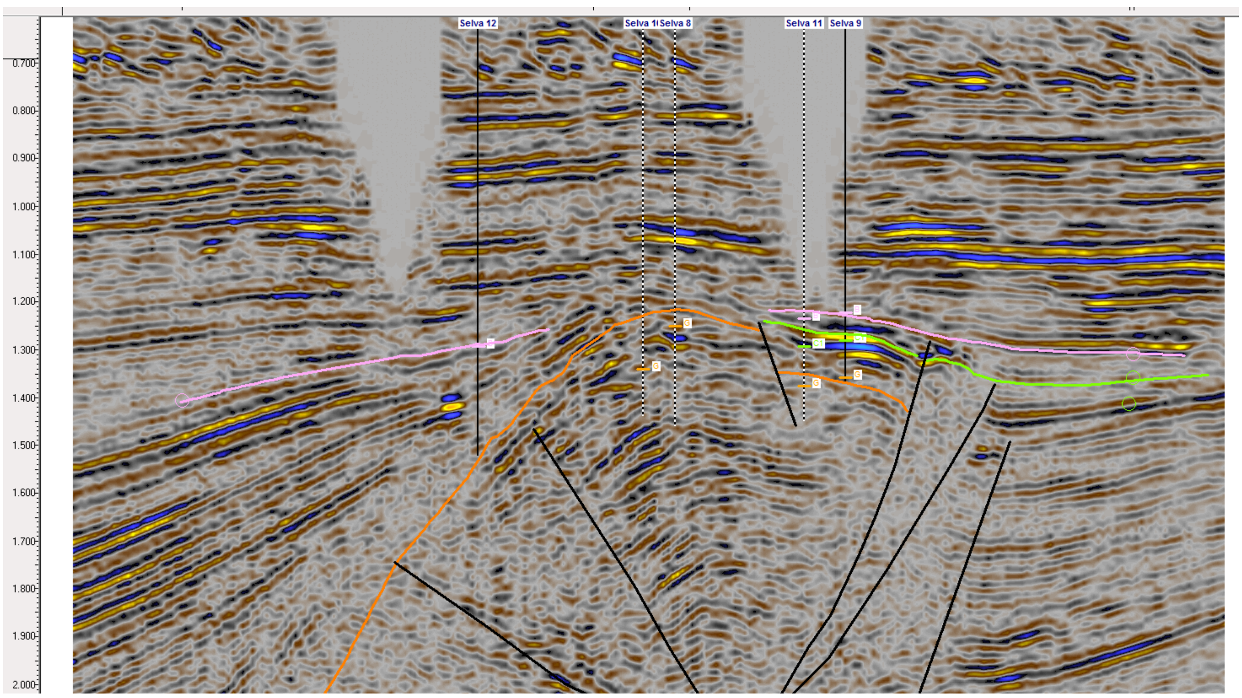


Figure 3.5 Seismic line BO327-80 showing Selva Level B North and South Prospects

After proof of concept was established by means of the successful Podere Maiar-1 well, similar updip pinch-out prospects have been worked up by PVO. The Level A and Level B sands, productive in the main Selva gas field, pinch out onto the underlying thrust fold structure in the same way that Level C sands do (drilled and proven to be good quality sands and gas-bearing by PM-1 well). Comparable reservoir properties are anticipated, and the sand thickness is known from some of the old Selva producing wells, particularly Selva-9 for North Prospect and Selva-12 for South Prospect. For the North Prospect, only Level B sand is expected, whereas for the South Prospect Level B plus slightly shallower Level A sands are taken into account.

PVO have used eleven reprocessed 2D seismic lines and information from old Selva gas wells to work up these prospects. CGG has reviewed the information supplied by PVO and have validated their presence. Level B sands were formerly exploited by ENI in Selva gas field in the period from 1959 to 1971 and 1977 to 1982. During this time, Level B in the north flank produced 248 MMScm of gas and 0.94 MMScm from the south flank leaving undrained gas updip from these producers.

The definition of the potential volumes remaining in the updip pinchout is dependent upon the location of the pinch-out (zero sand thickness) line, which is difficult to determine using the available 2D seismic lines. Nevertheless, CGG believes that there is good potential for success in pursuing the concept in this area.

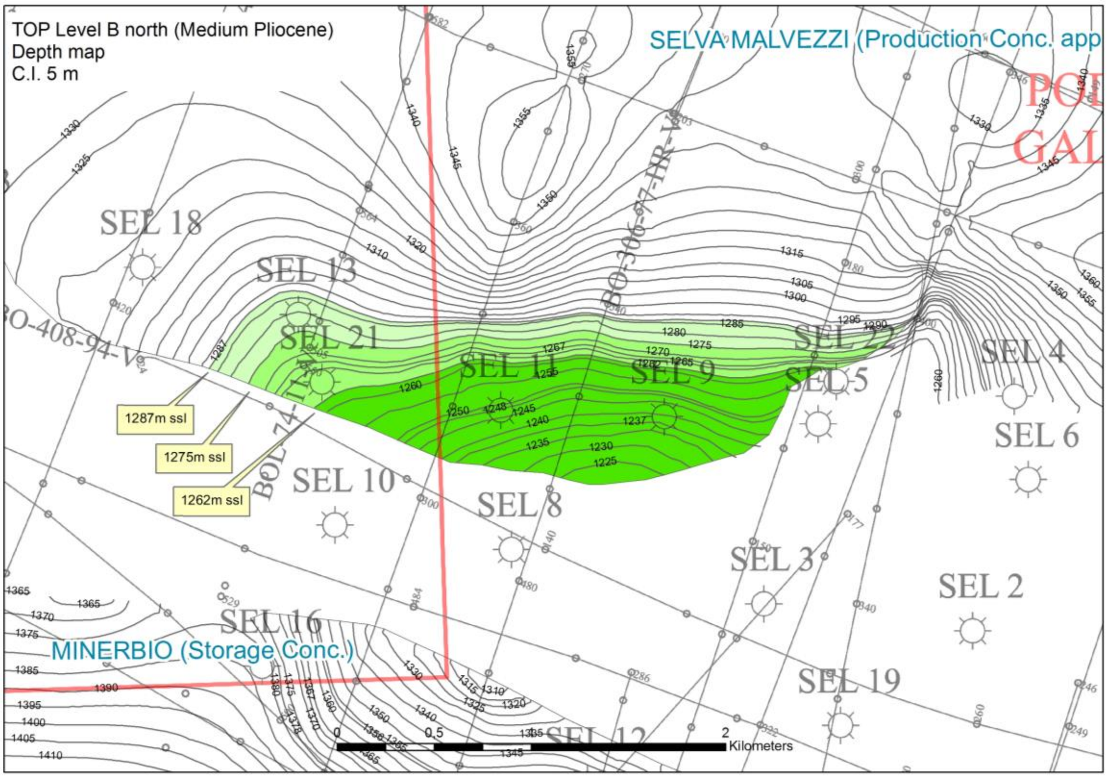


Figure 3.6 Level B North Prospect, Depth Structure Map showing Low, Mid and High Case contacts

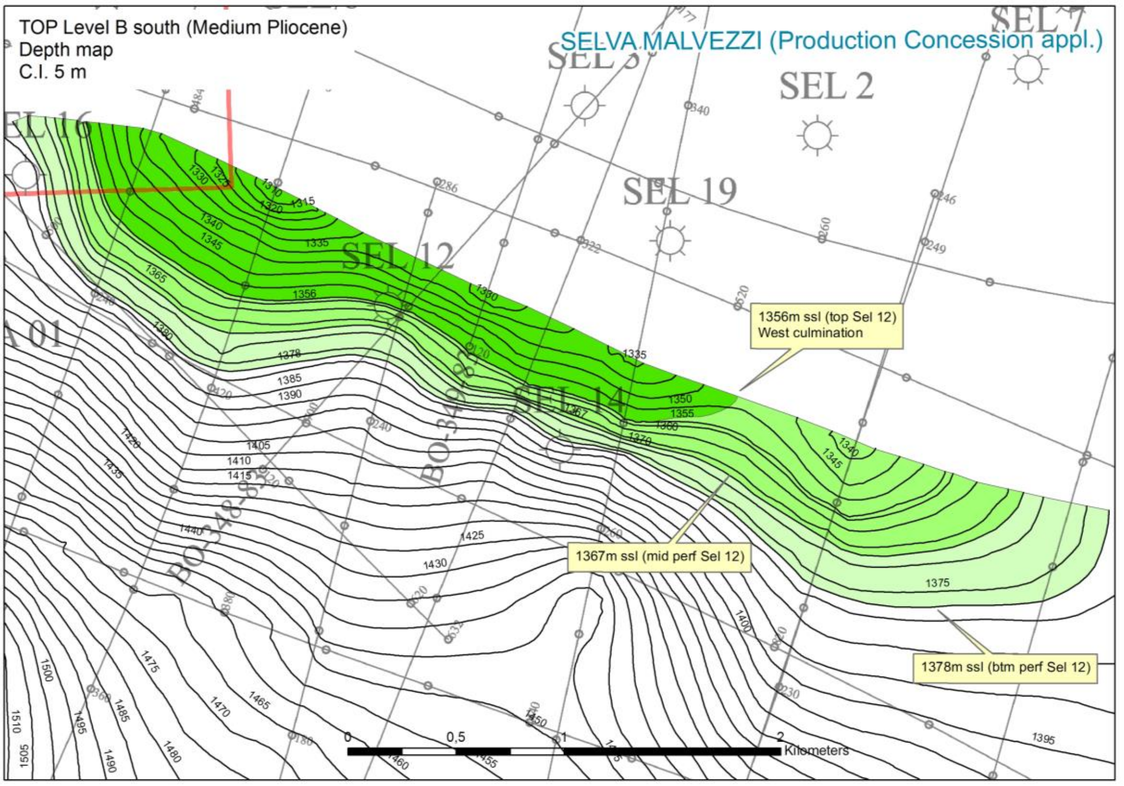


Figure 3.7 Level B South Prospect, Depth Structure Map showing Low, Mid and High Case contacts

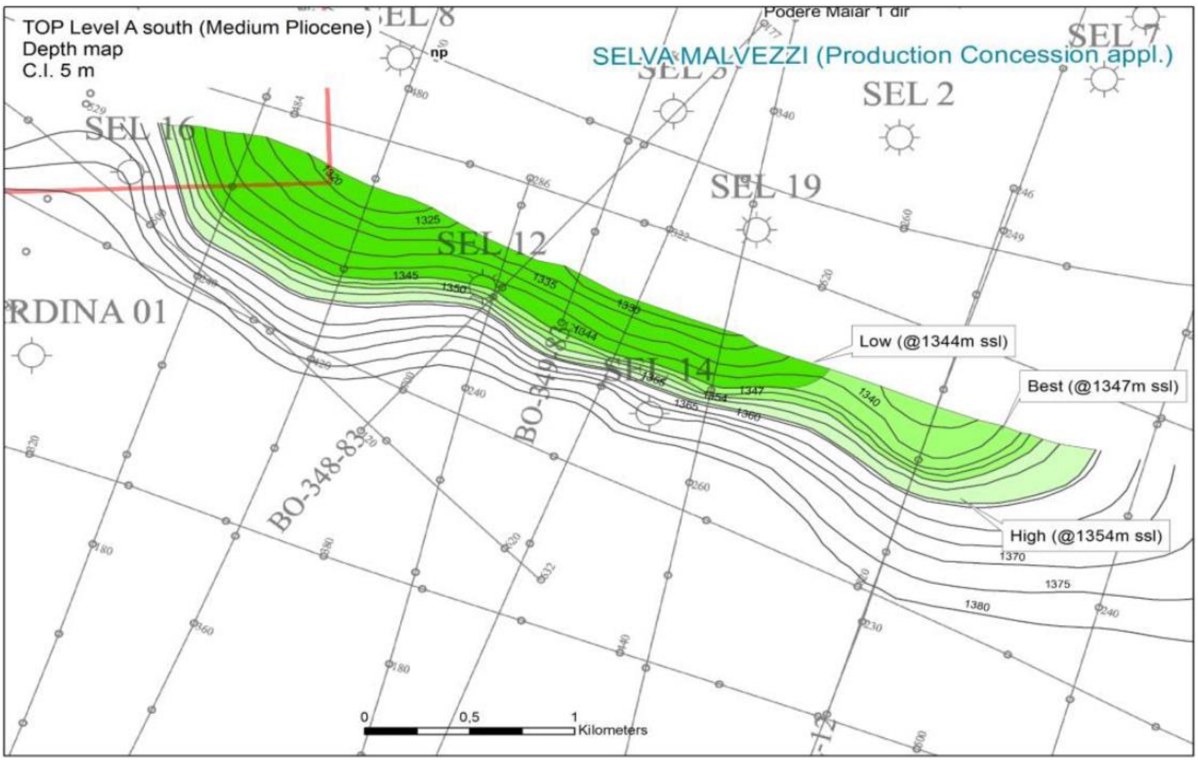


Figure 3.8 Level A South Prospect, Depth Structure Map showing Low, Mid and High Case contacts

Information from nearby wells is limited to old log plots and very limited log coverage (SP and resistivity). In spite of this, a thick sand package appears to be present on the Northern side of the structure. The assessment presented by PVO appears to present a reasonable reflection of the available data. CGG consider that the values presented in Table 3.2 below provide a balanced view of uncertainty range and likely resource potential:

Table 3.2 Level B North Contingent Resource; Parameters used in the estimation of gas volumes

LOW CASE	GBV MMscm	NtG frac	Phi frac	Sw frac	Bg	GIIP MMscm	RF %	Resource MMscm
GWC -1262	18.0	0.55	0.2	0.40	0.008333	143	70	99.8
BEST CASE	**GBV MMscm**	**NtG frac**	**Phi frac**	**Sw frac**	**Bg**	**GIIP MMscm**	**RF %**	**Resource MMscm**
GWC -1275	35.0	0.6	0.22	0.35	0.008333	360	70	252.3
HIGH CASE	**GBV MMscm**	**NtG frac**	**Phi frac**	**Sw frac**	**Bg**	**GIIP MMscm**	**RF %**	**Resource MMscm**
GWC -1287	55.0	0.65	0.24	0.30	0.008333	721	70	504.5

Concerning Level B South Prospect, available well data suggests a much thinner sand package, having an estimated thickness range of 4 – 6.5 – 9 metres. CGG has used these and the area-thickness method to estimate volume and applies the reservoir parameters in Table 3.3 below. The Level A sand package is also evaluated from sand thickness information in the Selva-12 well where it appears to be a little over 3 metres thick and of good quality. An average thickness range of 2.5 – 3.25 – 4 metres for the whole area is assumed, with the reservoir parameters shown in Table 3.4.

Table 3.3 Level B South Contingent Resource; Parameters used in the estimation of gas volumes

LOW CASE 1C	GBV MMscm	NtG frac	Phi frac	Sw frac	Bg	GIIP MMscm	RF %	Resource MMscm
GWC -1356	5.6	0.55	0.2	0.40	0.008065	46	60	27.5
BEST CASE 2C	**GBV MMscm**	**NtG frac**	**Phi frac**	**Sw frac**	**Bg**	**GIIP MMscm**	**RF %**	**Resource MMscm**
GWC -1367	14.0	0.6	0.22	0.35	0.008065	149	65	96.6
HIGH CASE 3C	**GBV MMscm**	**NtG frac**	**Phi frac**	**Sw frac**	**Bg**	**GIIP MMscm**	**RF %**	**Resource MMscm**
GWC -1378	27.9	0.65	0.24	0.30	0.008065	378	70	264.5

Table 3.4 Level A South Contingent Resource; Parameters used in the estimation of gas volumes

LOW CASE	GBV MMscm	NtG frac	Phi frac	Sw frac	Bg	GIIP MMscm	RF %	Resource MMscm
GWC -1344	2.75	1	0.22	0.35	0.008065	49	60	29.3
BEST CASE	**GBV MMscm**	**NtG frac**	**Phi frac**	**Sw frac**	**Bg**	**GIIP MMscm**	**RF %**	**Resource MMscm**
GWC -1347	4.06	1	0.23	0.32	0.008065	79	65	51.2
HIGH CASE	**GBV MMscm**	**NtG frac**	**Phi frac**	**Sw frac**	**Bg**	**GIIP MMscm**	**RF %**	**Resource MMscm**
GWC -1354	7	1	0.24	0.30	0.008065	146	70	102.1

A risk factor has been estimated for these two opportunities (the risk factor is the estimated chance that the volumes will be commercially extracted). Level B North Prospect is the better prospect having a project risk factor of 70% whereas the less well defined South Prospect is assigned a project risk factor of 60%. The main uncertainties exerting an effect on project risks are the current situation in terms of gas water contact elevation and sand architecture, both of which can be established by the drilling and flow testing of a well.

3.1.3 Riccardina Prospect

The prospect lies within the Selva Malvezzi Production Concession approximately 5km distant from the Podere Maiar-1 well. Already identified by ENI, the Riccardina-1 well tested the prospect in 2004 but encountered water-bearing sands and was abandoned. PVO have re-interpreted the available seismic data (ten 2D lines) and have come to the opinion that this well just missed the prospect, coming in on the wrong side of a thrust fault and lying outside of the high amplitude area that is interpreted to signify gas presence. Target reservoirs are sands of the lower Pliocene Canopo Formation, which is a silty-sandy succession offering some 250m of section in the target area. PVO are planning to acquire a small 3D survey over the area.

The structure is reasonably well defined by means of the available 2D seismic lines (Figure 3.9, Figure 3.10).

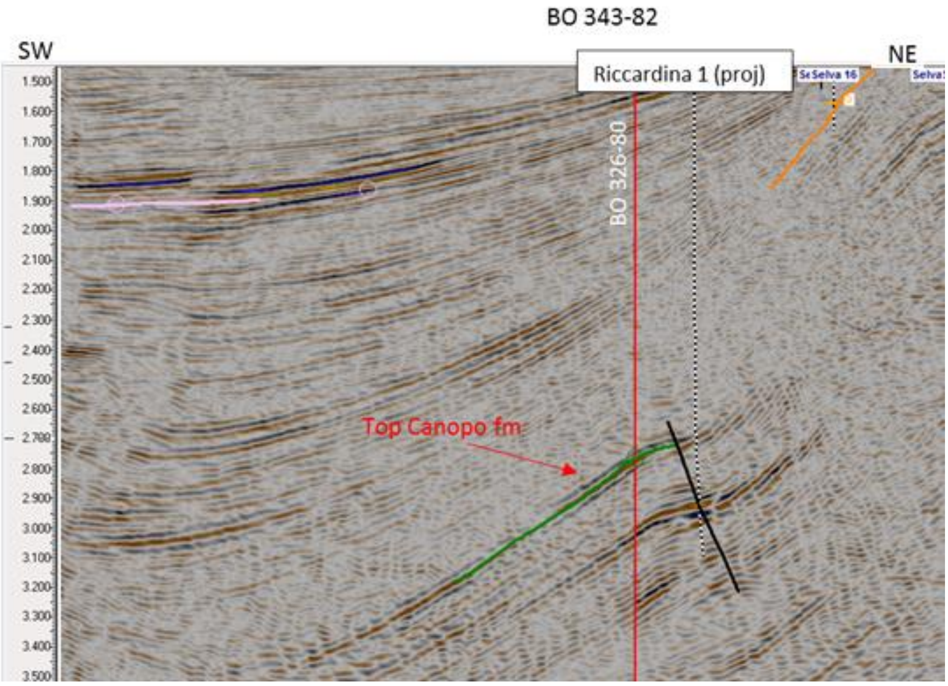


Figure 3.9 Riccardina Prospect: Seismic Line BO343-82 shows gas prospect in Canopo Formation

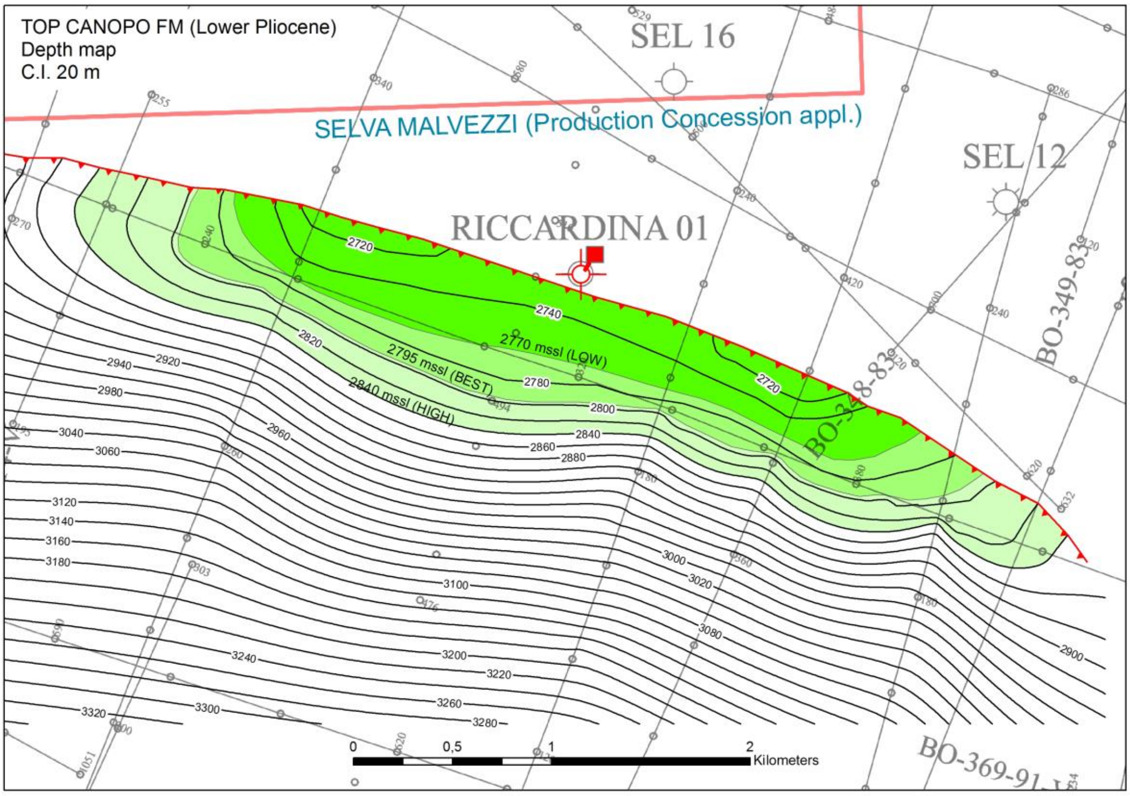


Figure 3.10 Riccardina Prospect; PVO depth structure map at top Canopo Formation (metres subsea)

CGG has inspected the Riccardina-1 well logs. The Upper Canopo Formation consists of alternating sands-silts with fairly thick and permeable sands ranging from 1 – 10 metres. There is separation between shallow and deep resistivity logs indicating invasion and SP suggests permeable formation. Resistivity readings confirm the presence of saline formation water in this well. The reservoir geology appears positive but there is chance of encountering sand of less than 20% porosity at this depth. CGG has made an independent assessment of reservoir parameters based on evidence provided by PVO (Table 3.5).

PVO have made the following assumptions regarding gas fill for this prospect:

- Low: contact at 2770 m ssl
- Best: contact at 2795 m ssl
- High: contact at spill point of the structure (@2840 m ssl)

Table 3.5 Selva Riccardina Prospect; Parameters used in the estimation of gas-initially-in-place (GIIP)

LOW CASE	GBV MMscm	NtG frac	Phi frac	Sw frac	Bg	GIIP MMscm	RF %	Resource MMscm
GWC -2770	34	0.45	0.18	0.40	0.0027	612	60	367.2

BEST CASE	GBV MMscm	NtG frac	Phi frac	Sw frac	Bg	GIIP MMscm	RF %	Resource MMscm
GWC -2795	76	0.5	0.2	0.35	0.0027	1830	60	1097.8

HIGH CASE	GBV MMscm	NtG frac	Phi frac	Sw frac	Bg	GIIP MMscm	RF %	Resource MMscm
Spill Point -2840	194	0.55	0.22	0.30	0.0027	6086	60	3651.5

Table 3.6 Selva Riccardina Prospect; Risk Assessment

RISK ELEMENTS		RISK SCORE (probability)	
CLOSURE	Interpretation	0.9	0.85
	Depth Conversion	0.85	
SEAL	Top Seal	0.85	0.425
	Base / Side Seal	0.5	
RESERVOIR	Presence	0.8	0.8
	Quality	0.8	
CHARGE	Source Rock	0.85	0.7225
	Migration	0.85	
	RISK TOTAL		**0.21**

Risk score for closure and reservoir is the lowest of two assigned values but for seal and charge it is the product of the two assigned values.

The primary risk is considered to be the seal capacity of the fault that defines the northern margin of the trap. Overall chance of success for the Riccardina Prospect is estimated to be 21%.

3.1.4 East Selva

The East Selva structure is identical in concept in the Selva Stratigraphic structure but has not previously been drilled. PVO reinterpreted the mapped closure area of this structure using available seismic data and CGG review of this work indicates that it presents a fair and reasonable view of the prospect.

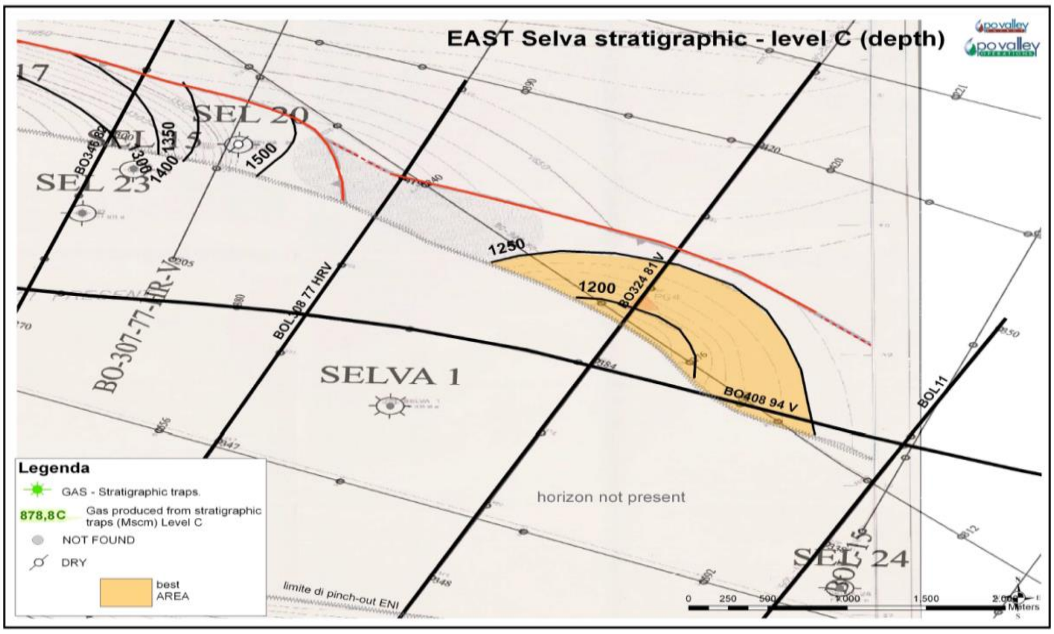
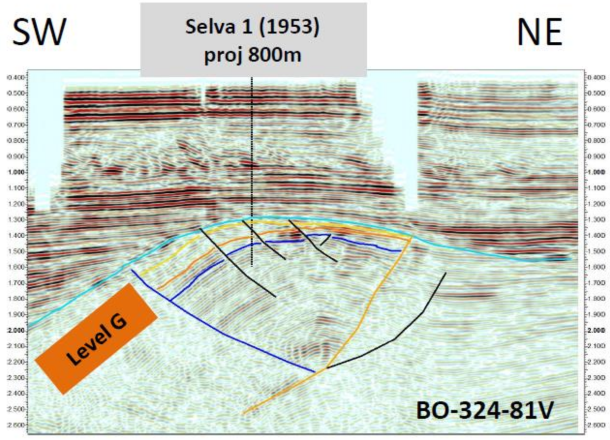


Figure 3.11 East Selva structure map

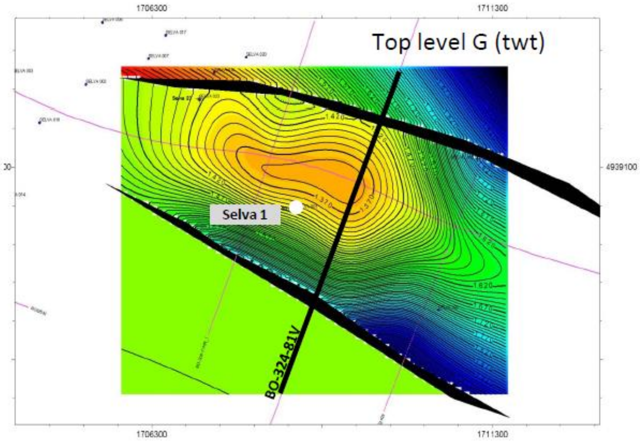
The East Selva reservoirs are expected to be as good as those in the Selva field itself. CGG's review of the Operator's work has concluded that the stated prospective resources are very reasonable. Given the proof of concept demonstrated by the success of the Podere Maiar-1 well, the Chance of Success at East Selva has been upgraded. The prospect could hold recoverable resources of 824, 986 and 1150 MMscm in Low, Best and High cases respectively. Since the drilling and successful outcome of the Podere Maiar-1 well, which proves the concept that Selva East is based upon, the CoS has been revised upward from 30% to 40%. The primary risk remains the definition of the gross rock volume based on only a small number of seismic lines, plus the presence of good quality reservoir sand (location of pinch-out).

3.1.5 Fondo Perino

The Fondo Perino prospect is the dip closed cap of a hanging-wall anticline located between the Selva-1 and Selva-23 wells. The trap is interpreted on two NNE-SSW oriented seismic lines located 1.3km apart and a WNW-ESE line. The limits of the prospect closure exist between smaller faults in the core of the anticline.



(A) Fondo Perino seismic cross-section



(B) Fondo Perino depth structure map

Figure 3.12 Fondo Perino structure

The reservoirs are Lower Pliocene sandstones of the Selva gas field; the prospect is the updip gas bearing level tested on Selva-1 well. The CoS is good at 34% for prospective resources of 289, 413 and 581 MMscm at P90, 50 and P10 cases respectively.

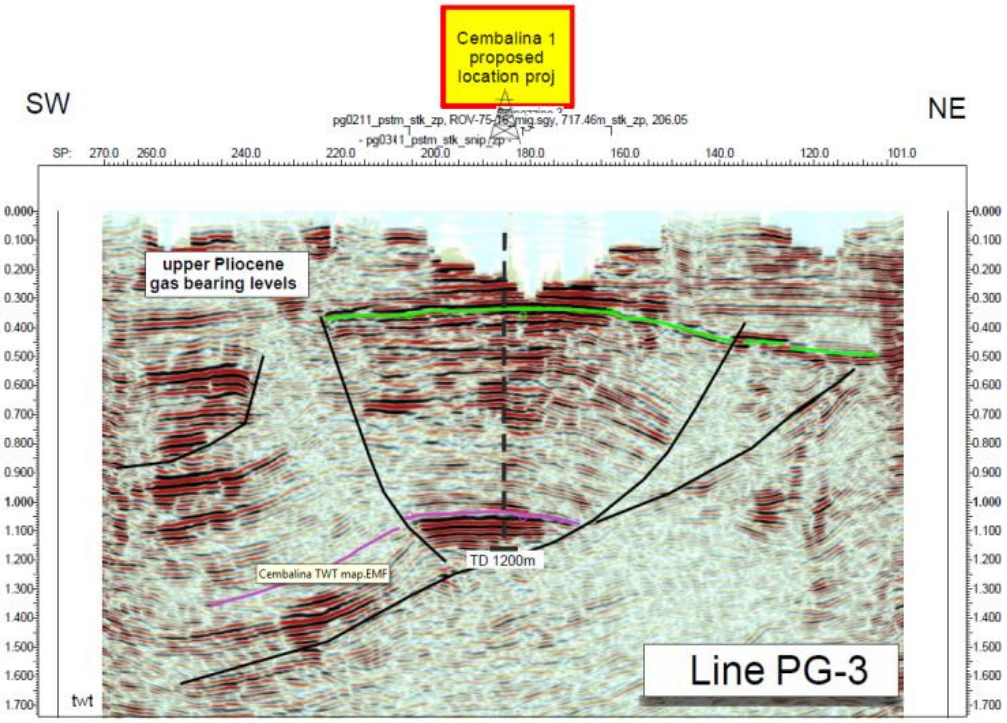
3.1.6 Cembalina

The Cembalina prospect, in the Podere Gallina exploration licence, is defined on five seismic lines at Upper Pliocene level. Lines are oriented NNE-SSW 1.2km to 3.4km apart and WNW-ESE 0.4km to 7km apart. The structure is a WNW-ESE oriented hanging-wall anticline with associated back thrust at Early Pliocene level with fold drape above the structure at Upper Pliocene level. The seismic interpretation of horizons has been checked and validated.

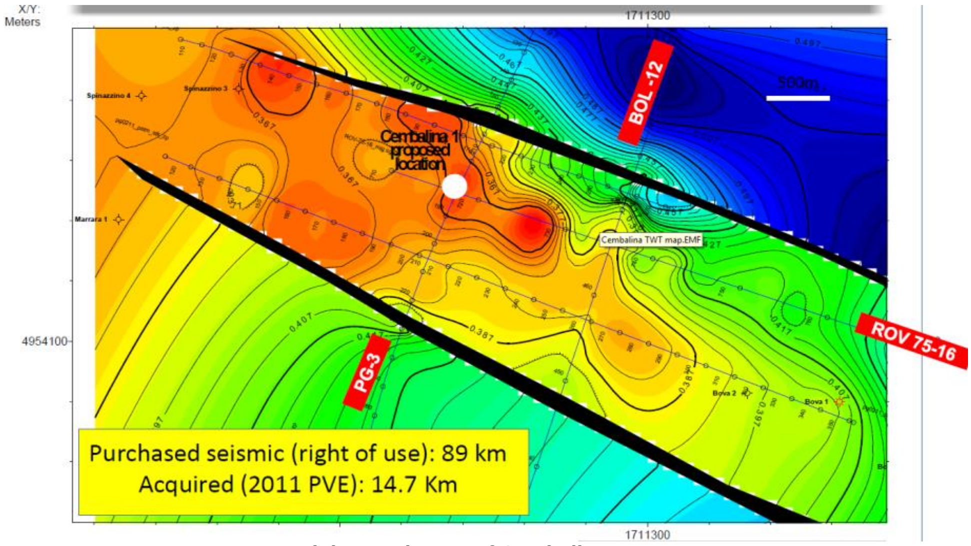
Additional seismic lines purchased by PVO in 2011 resulted in a revised structural interpretation which had the effect of increasing the size of the Cembalina prospect as compared to pre 2011.

Prospective reservoirs are the Early Pliocene marine sands which, in nearby wells, exhibit up to 30% porosity with 70% average gas saturation. The thickness of these sands is expected to be about 20 metres with a net-to-gross of about 50%.

In a success case, then, we concur with the prospective resource estimates given by PVO. These are a P90 of 60 MMscm, a P50 of 94 MMscm and a P10 of 133 Mscm. The CoS relating to these resources is 51% due to the proximity of gas fields producing from these Early Pliocene sands.



(A) Cross-section through Cembalina structure



(B) Depth map of Cembalina structure

Figure 3.13 Cembalina structure

Table 3.7 Summary of Gas Prospective Resource by Prospect (MMscm)

	Gross (MMscm)		
Prospect	**Low**	**Best**	**High**
Cembalina	59.5	93.5	133.1
Fondo Perino	288.9	413.5	580.6
East Selva	824.1	985.6	1149.8
Riccardina	367.2	1097.8	3651.5

There are currently no firm plans to drill wells on the Cembalina, Fondo Perino, Riccardina and East Selva prospects located within the licence area.

The 3D seismic that is planned across the Selva Field will also cover the East Selva, Riccardina and Fondo Perino prospects. It should help to de-risk these structures, and progress them towards drill-ready status.

3.2 AR94PY LICENCE

3.2.1 Description

This section concerns the AR94PY licence, which is located off the east coast of Italy, approximately 30 kilometres south-east of Venice in the Adriatic Sea. The AR94PY licence is 100% owned and operated by PVO, and contains the d40ACPY exploitation concession (undeveloped Teodorico gas discovery and the PL3-C gas prospect).

The location of the AR94PY offshore licence, and the d40ACPY Production Concession, with the 12 nautical mile development limit is shown in Figure 9.1.

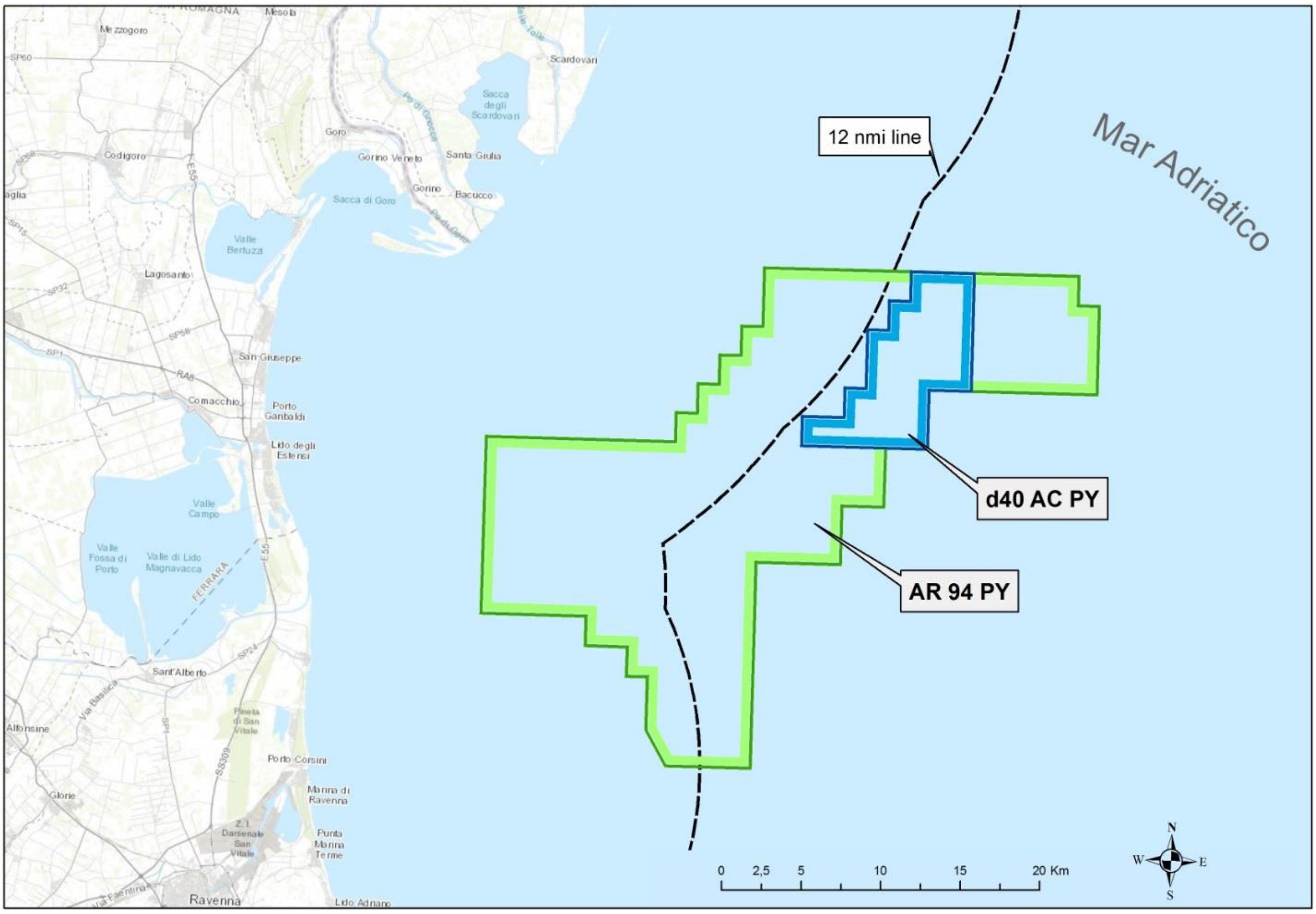


Figure 3-14 Location of the AR 94 PY original Exploration Licence and d40 AC PY Production Concession

3.2.2 Dataset

In completing this evaluation CGG has relied upon the data collected and reviewed at a data room in Rome in 2013 and a second review in 2017, as well as complementary information within the public domain. This data included, amongst others:

Power Point presentation for reserves and resources including general geological information.

Location maps, log intervals of the reservoir, and hydrocarbons in-place estimations made by PVO and independently by ourselves.

- Well logs of all drilled wells
- Seismic workstation projects, interpreted figures, time- and depth-structure contour maps
- Documents, graphs and tables of general geological and well data
- Portfolio summary and PVO interpretation
- Fiscal terms

CGG has relied upon PVO for the completeness of the data set provided.

CGG has independently reviewed in detail the volumetric estimates and reservoir parameters using the following workflow:

1. CGG spent a day with PVO technical staff (their senior geologist and senior geophysicist) at their workstations in Rome checking the interpretation of the reflections and depth conversion processes and assumptions made by PVO technical team. CGG were convinced that the work carried out by PVO was of a high standard, that the data used was of sufficiently high quality and the resulting Gross Rock Volumes (GRVs) computed are as accurate as possible.
2. The quality of the 3D seismic data used for delineating the gas field is very good and provides a very good basis for understanding the potential asset value range.
3. Areas of high amplitudes observed in the 3D seismic volume – often associated with gas presence in these relatively shallow and moderately consolidated reservoir sequences - were independently checked for each reservoir layer. CGG areas were higher than PVO areas, which were considered conservative. PVO areas were therefore taken forward in our evaluation.
4. A range of reservoir properties including thickness, net-to-gross, porosity, saturation and formation volume factor, all verified as reasonable and independently derived from well logs and from petrophysical interpretations, was then applied to the areas. CGG has developed independent parameter ranges based on our own observations made of the data and we have tested the assumptions used by PVO. Using PVO area data, CGG generated volumetric estimations that were comparable to or larger than PVO's.
5. A conservative estimation of water saturation (from 45% to 65%) in these gas sands, combined with conservative recovery factors of 40% to 55% were then applied to the GIIP estimates. The use of low recovery factor allows for the possibility of early water breakthrough and loss of well productivity as a result of liquid loading. The low relief of the structure suggests that water breakthrough could be the major factor in loss of production, water levels in the reservoir moving rapidly towards the well for small changes in depth of contact. No account has been taken of possible remedial actions that the Operator might take to maximise gas recovery once water has broken through to the perforations, and the Operator may be reasonably expected to take such mitigating action in due course.

Having checked PVO's methods and inputs, and found them to be fair and reasonable, we have carried forward PVO's stated gas-in-place estimates into our own, independently generated, production forecasts and economic assessments.

The basis of CGG's assessment has therefore been to check the technical, logical and interpretation basis for PVO's own assessments of the Teodorico Discovery, and CGG has found PVO's conclusions to be reasonable, given the data available.

3.2.3 Teodorico (Exploitation Concession d40ACPY)

3.2.3.1 Geological and Geophysical Assessments

The Teodorico Discovery (formerly Carola/Irma) consists of a low-relief four-way dip closure located in 30m of water in the northern Adriatic Sea. The well Ametista-1 was drilled in 1972 and today forms an important tie for structural definition and trap closure in the North. Four wells including the discovery well, Carola-1, were then drilled on the structure in the period 1986 to 2001. Gas was observed in several sands within the Pleistocene and Quaternary intervals, the sands with the largest potential volumes being the Pleistocene C, D and E sands, as well as the Quaternary QU-4 sand.

The discovery well, Carola-1, was drilled in 1986 to a depth of 2620 metres, and tested gas at a rate of up to 62,000 scm/d (1/4" choke) from sand PLQ-C2. This sand is partially within the 12 nautical mile limit and has not been considered as reserves in consideration of current Italian law. Sand QU-4 is very shallow and also extends within the 12 nautical mile limit; it was tested at a rate of up to 87,800 scm/d through a ½" choke.

Well Irma-1, drilled in 1988 to a depth of 2572 metres, tested gas at up to 131,000 scm/d from level PLQ-E2/F through a 5/16" choke and from PLQ-D1 at a maximum rate of 281,000 scm/d through a ½" choke.

The well Carola-2 was drilled in 1992 and showed very clear indications of gas on logs, similar to log indications in the previous two wells. Core was cut from Levels D and E of the Pleistocene "Carola Formation" in Carola-2, yielding porosity measurements in the range of 22.6% to 37.3% with permeabilities from 0.14mD to 174mD.

The final well, Irma-2X, drilled in 2001, showed water in the sands of interest, with traces of gas, and was categorised as "dry". All the aforementioned wells were plugged and abandoned.

Core data from Carola-2 indicates porosities of 22.6 – 37.3% and permeabilities of 0.14 – 174 mD.

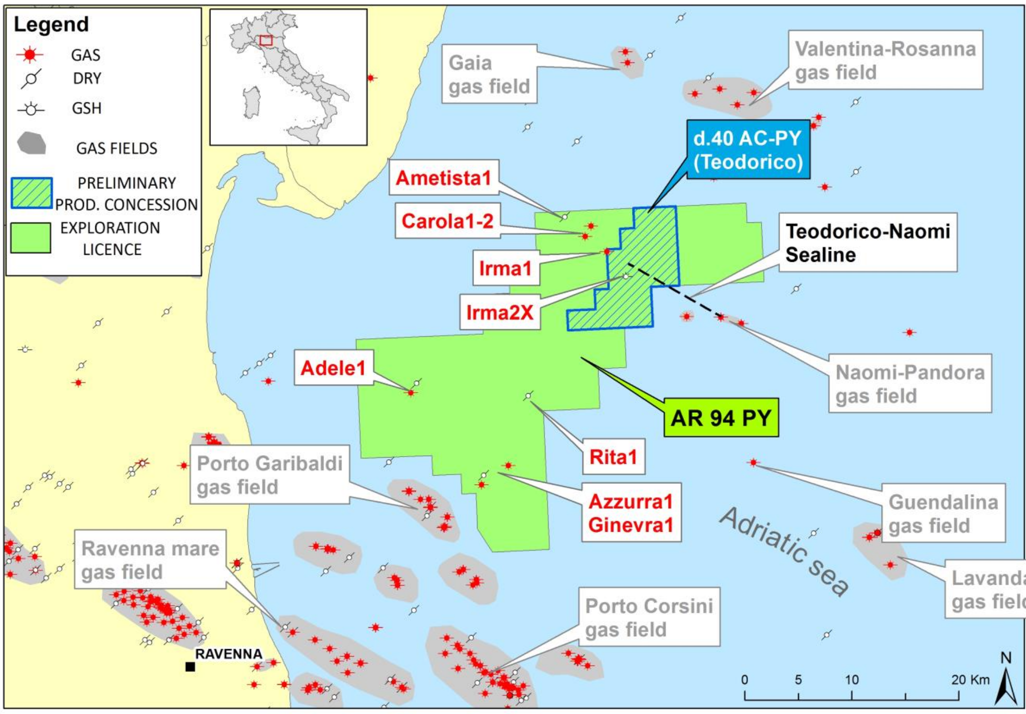


Figure 3-15 AR 94 PY License in Area of Producing Gas Fields

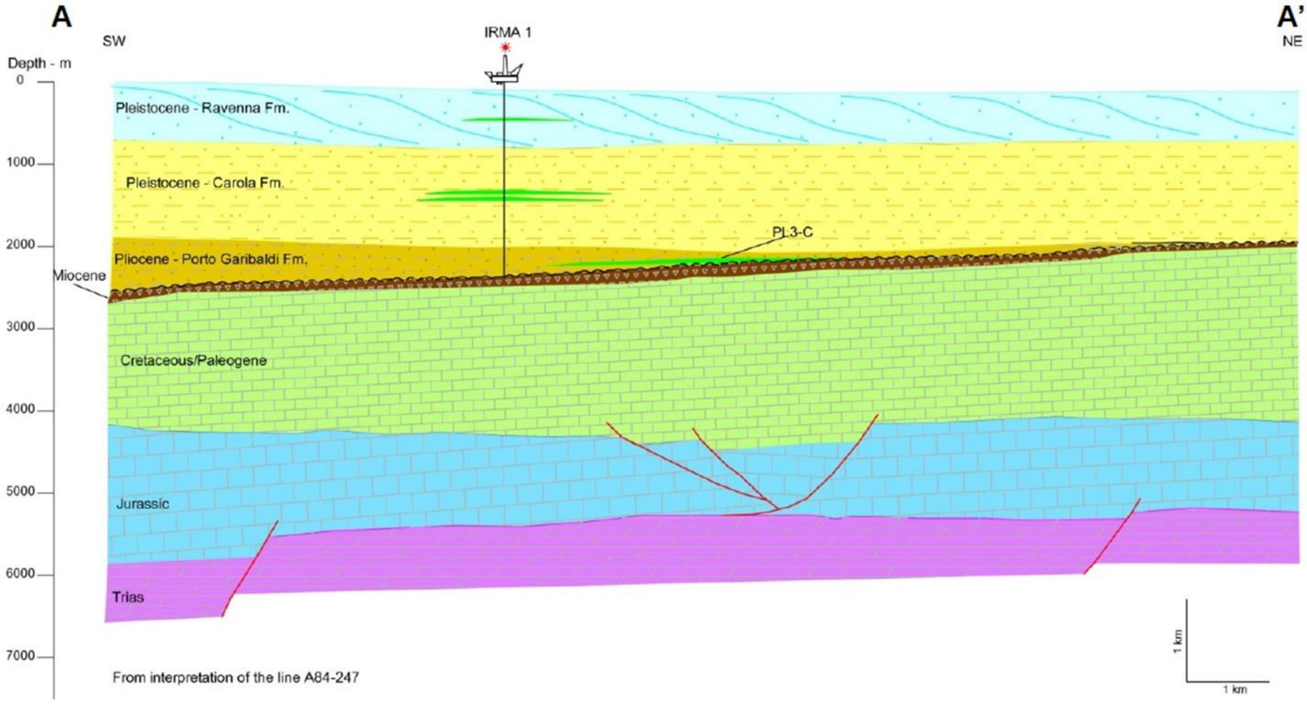
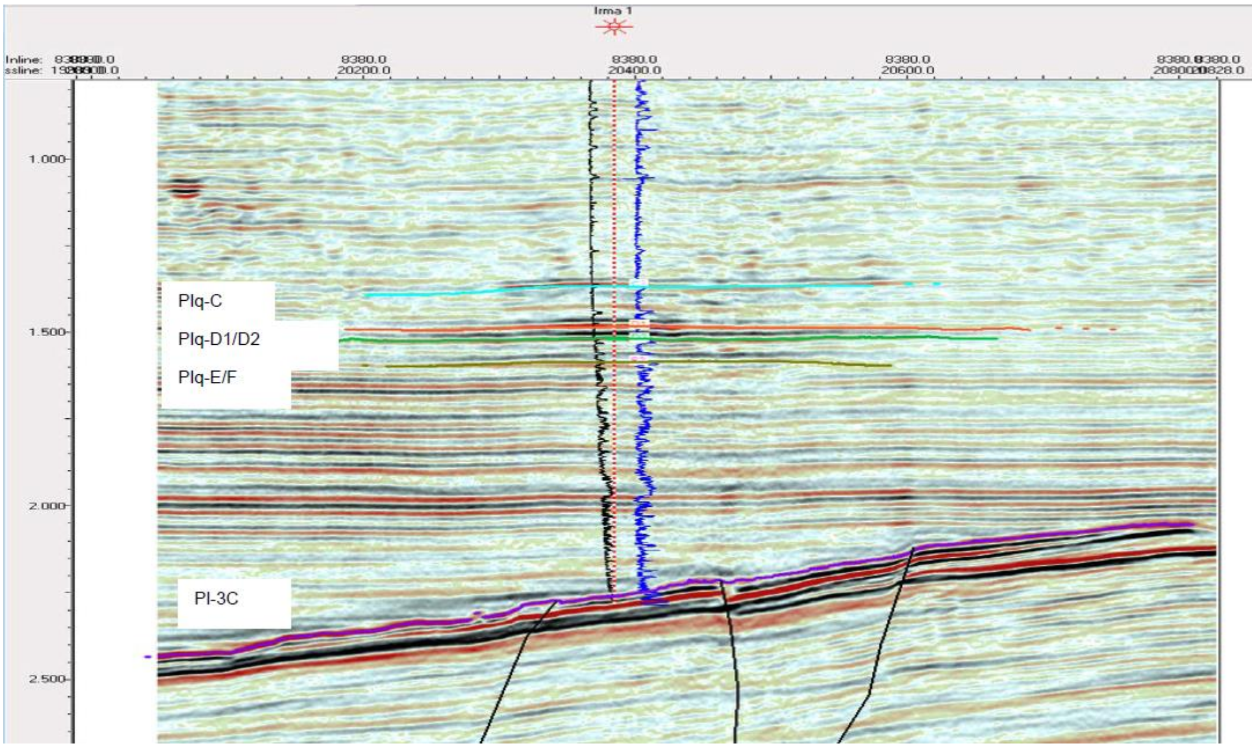


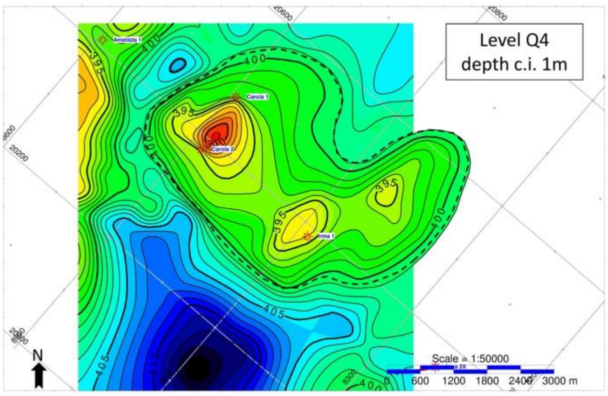
Figure 3-16 Schematic Cross-Section through well Irma-1 showing target reservoir zones

PVO has identified seven gas sands: two in Upper Pleistocene (QU-3, QU-4) and five in the Lower Pleistocene: PLQ-C, PL1-C2/C6, PLQ-D1, PLQ-D2 and PLQ-E2-F. Each forms a low-relief 4-way dip closure forming stacked reservoirs. The reservoirs are made up of turbidite sands, silts and shales; the source sediment being washed off the Alpine and Apennine mountain chains into subsiding basins.

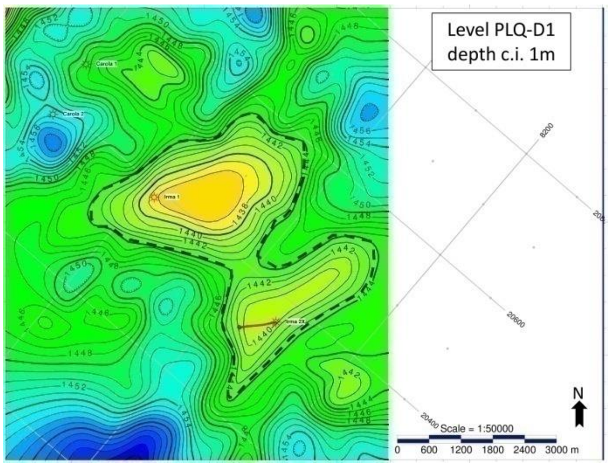
The area of interest contains five key wells: Ametista-1, Carola-1, Carola-2, Irma-1 and Irma-2X and is covered by the 3D ADRIA seismic survey, acquired and processed between 1993 and 1997 then reprocessed in 1998. PVO purchased and interpreted 118 sq. km of this 3D seismic volume. Depth conversion using VSP, check shot data and average velocity where no data is available in the well path confirms 4-way dip closure at each reservoir horizon. A velocity anomaly that exists between the Ametista-1 and Carola-1 wells is corrected using average velocities at QU-3 and QU-4 levels.



(A) Seismic section through Teodorico reservoirs and well Irma-1



(B) Top QU-4 depth map



(C) Top PLQ-D1 amplitude map

Figure 3-17 Teodorico structure and seismic attribute maps

CGG independently took the seismic data and calculated the area of the amplitude anomalies; CGG's computed areas were 20-40% larger than Po Valley "P50" areas, and a little larger than their "P10" areas. Po Valley had stated to CGG that they had taken a conservative approach to the areas, so Po Valley's smaller areas (constrained by depth structure mapping and the water in Irma-2X well) were therefore taken forward in our evaluation.

Table 3-8 Teodorico Field, PVO Calculated Areas versus Area of Amplitude Anomaly

RESERVOIR	PVO Area Calculations (sq.km)					Area of Amplitude Anomaly
	Min	P90	P50	P10	Max	(sq.km)
Q4	5.00	7.57	10.70	13.70	16.00	14.28
PLQ-C	8.00	8.64	11.20	13.80	14.40	14.29
PLQ-D1	4.47	4.63	5.25	5.87	6.03	6.35
PL3-C Prospect	2.00	2.46	3.03	3.64	4.13	4.21

Table 3-9 Teodorico Field: Parameters, Reserves and Contingent Resources for P90, P50 and P10 Cases

Sand	Area	Thickness	P90 Reservoir Parameters			GIIP	RF	Reserves	Contingent Resource
	km^2	(m)	NtG (%)	Phi (%)	Sw (%)	MMscm	%	MMscm	MMscm
QU-3	4.49	3.82	87.20	28.90	29.70	98.79	40%	-	39.6
QU-4	7.57	5.51	82.20	28.90	29.70	295.02	45%	-	133.1
PLQ-C	8.64	4.55	52.20	26.90	51.00	331.59	52%	181.3	-
PLQ-C 2-C6	2.40	2.22	62.20	26.90	51.00	70.26	52%	-	37.1
PLQ-D1	4.63	4.50	82.20	26.00	47.20	330.85	54%	184.1	-
PLQ-D2	4.69	2.67	52.20	25.10	42.20	171.81	46%	87.8	-
PLQ E2-F	10.30	5.50	45.00	26.00	45.00	574.80	55%	317.2	-

Sand	Area	Thickness	P50 Reservoir Parameters			GIIP	RF	Reserves	Contingent Resource
	km^2	(m)	NtG (%)	Phi (%)	Sw (%)	MMscm	%	MMscm	MMscm
QU-3	7.10	4.00	90.00	30.00	32.00	148.38	40%	-	59.5
QU-4	10.70	6.14	85.00	30.00	31.70	421.74	45%	-	189.8
PLQ-C	11.20	6.53	55.00	28.00	52.30	505.97	55%	277.5	-
PLQ-C 2-C6	3.16	2.50	65.00	28.00	52.30	94.72	55%	-	51.2
PLQ-D1	5.25	4.50	85.00	27.30	50.00	381.42	56%	212.4	-
PLQ-D2	6.66	3.50	55.00	26.50	45.00	257.45	53%	133.1	-
PLQ E2-F	13.20	5.50	56.00	28.00	55.00	755.99	55%	416.3	-

Sand	Area	Thickness	P10 Reservoir Parameters			GIIP	RF	Reserves	Contingent Resource
	km^2	(m)	NtG (%)	Phi (%)	Sw (%)	MMscm	%	MMscm	MMscm
QU-3	8.55	4.95	92.80	31.10	33.60	197.45	40%	-	79.3
QU-4	13.70	6.63	87.80	31.10	33.60	548.34	45%	-	246.4
PLQ-C	13.80	9.00	57.80	29.10	53.80	747.95	58%	413.5	-
PLQ-C 2-C6	4.07	2.78	67.80	29.10	53.80	124.84	58%	-	70.2
PLQ-D1	5.87	4.50	87.80	28.80	52.80	437.38	58%	243.6	-
PLQ-D2	7.90	4.33	57.80	28.50	47.80	355.03	58%	186.9	-
PLQ E2-F	15.40	5.50	16.00	29.10	60.50	950.88	55%	521.1	-

**GIIP, Reserves, and Contingent Resource are statically calculated*

3.2.4 Teodorico Late Pliocene (PL3-C)

During the appraisal phase, the well Irma-2X tested a water-wet Late Pliocene pinch-out structure against the Messinian unconformity which is named PL3-C (Figure 9.7, Figure 9.8). To the South East of the AR94PY licence the same reservoir horizon and structural configuration has tested gas in the nearby Naomi-Pandora gas field. PVO anticipates that the updip extension of PL3-C sand is a prospective structure which they propose to test with a well. After data review and volumetric QC, CGG agree with PVO that there could be prospective gas resources of 223.7, 450.3 and 708 MMscm in this structure with a chance of success (CoS) of 17% (Table 9.9). The greatest risks to this prospect are considered to be gas charge and trap integrity (fault seal). If successful, the gas could be treated using the Teodorico facilities.

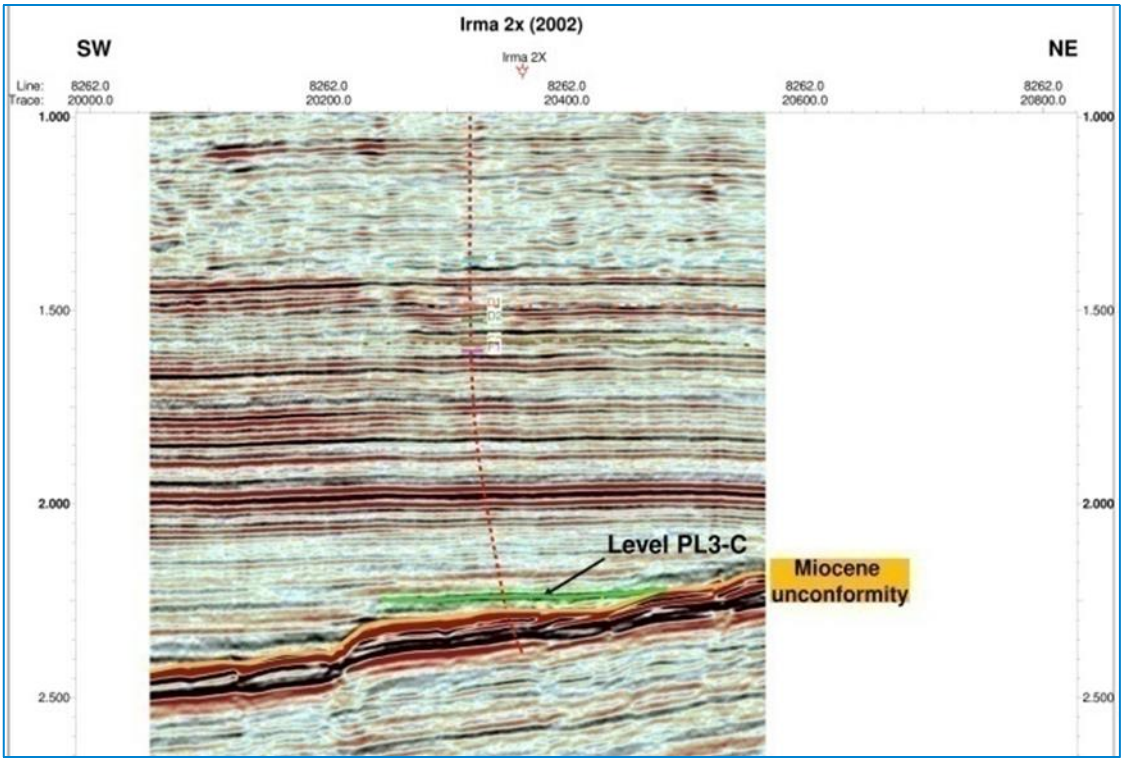


Figure 3-18 Seismic Line showing Late Pliocene pinch-out (PL3-C) NE of Irma-2X well

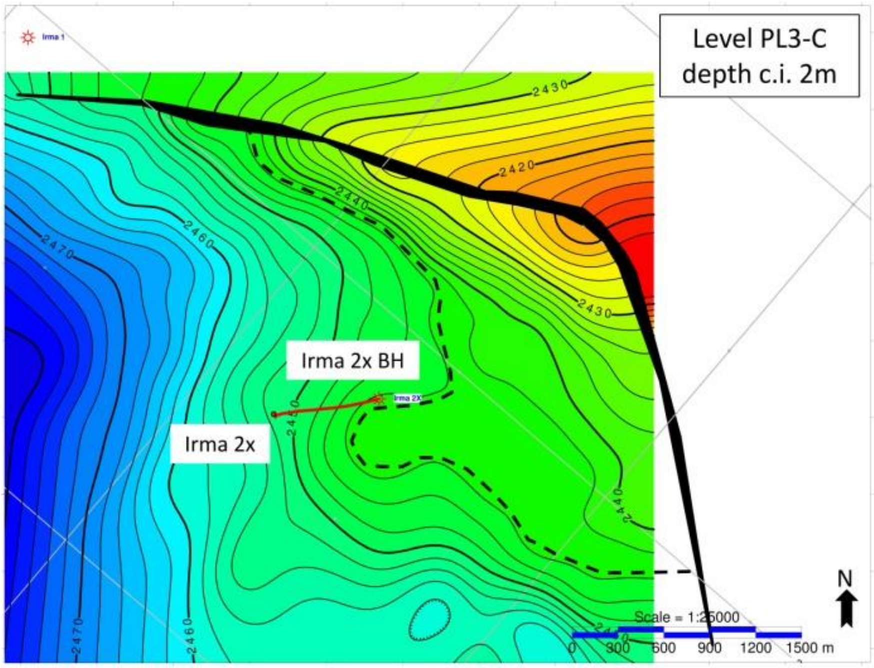


Figure 3-19 Depth Structure Map at Late Pliocene pinch-out (PL3-C) NE of Irma-2X well

Table 3-10 Gas Resource Estimation; Teodorico, PL3-C

Prospect	Prospective Resources (MMscm)			
	CoS	Low	Best	High
PL3-C	17%	223.7	450.3	708.0

3.2.5 The Rita Lead

Well Rita-1 was drilled by ENI in 1971 but was P&A as a dry hole (water-bearing). When drilling this well, ENI was exploring for gas in sands that pinch out against the underlying Miocene. Nearby, ENI discovered gas in the form of the Naomi-Pandora gas field. Prospectivity updip from the Rita well is indicated on seismic data inspected during a data room visit to ENI (CGG not present). PVO have stated that 3D seismic data clearly show the Rita well was drilled in the downdip portion of a positive seismic amplitude anomaly onlapping the Miocene. The geology and trap is closely analogous to the Naomi-Pandora gas field.

PVO has indicated that their future work program will be to purchase and interpret the seismic data around the Rita Lead in order to firm up a possible drilling target and location. For now, a technical evaluation is lacking and it is not possible to comment on potential gas volumes.

3.2.6 Adele and Azzura-Ginevre Discoveries

In addition to the Rita Prospect (which lies beyond the 12 mile nearshore limit) there are also the Adele and Azzurra-Ginevra gas discoveries. However, these cannot be appraised further or developed because they lie within the 12 mile limit.

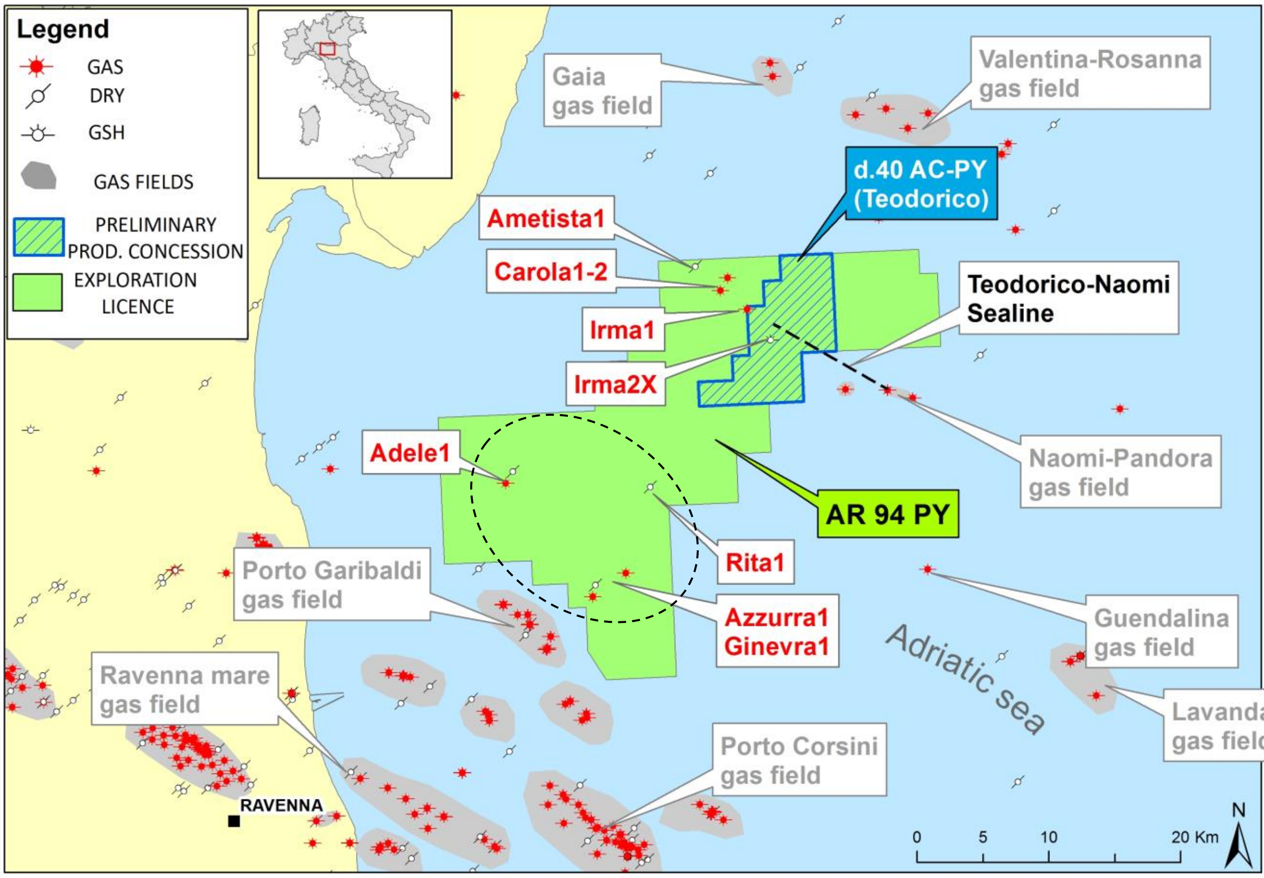


Figure 3-20 Rita Prospect, Adele and Azzura-Ginevra Discoveries within the AR 94 PY Licence Area

3.3 TORRE DEL MORO LICENCE

This Exploration Licence in the Emilia Romagna region of Northern Italy was awarded to PVO with a 100% working interest in February of 2017 (Figure 10.1).

In terms of underlying geology, the Licence encompasses an area on the Eastern margin of the Apennines, having Lower Jurassic carbonates of the Marmarone Formation at 3500 to 6000 feet depth or greater, buried by overlying Miocene to Pleistocene sediments. Oil shows were encountered in the target limestones in the Sarsina-1 well that was drilled some 16 km away on the lower flank of a large but much deeper thrust fold at about 5500m depth. The crestal part of the Torre del Moro fold remains undrilled, at about 3500-4000 metres depth; this being the main prospect in the Licence area (Figure 5.2).

Prospective reservoir targets are:

1. Primary target; the Lower Jurassic fractured limestones of the Calcare Massicciio
2. Secondary target, immediately underlying the primary target; Upper Triassic fractured and jointed dolomites

Source rocks are likely to be the oil-prone *Rhaetavicula contorta* limestone with possible contributions from the Triassic *Marne a Fucoidi* and the *Bonarelli* member. Sarsina-1 well, having oil shows, proves that a petroleum system has operated in the area.

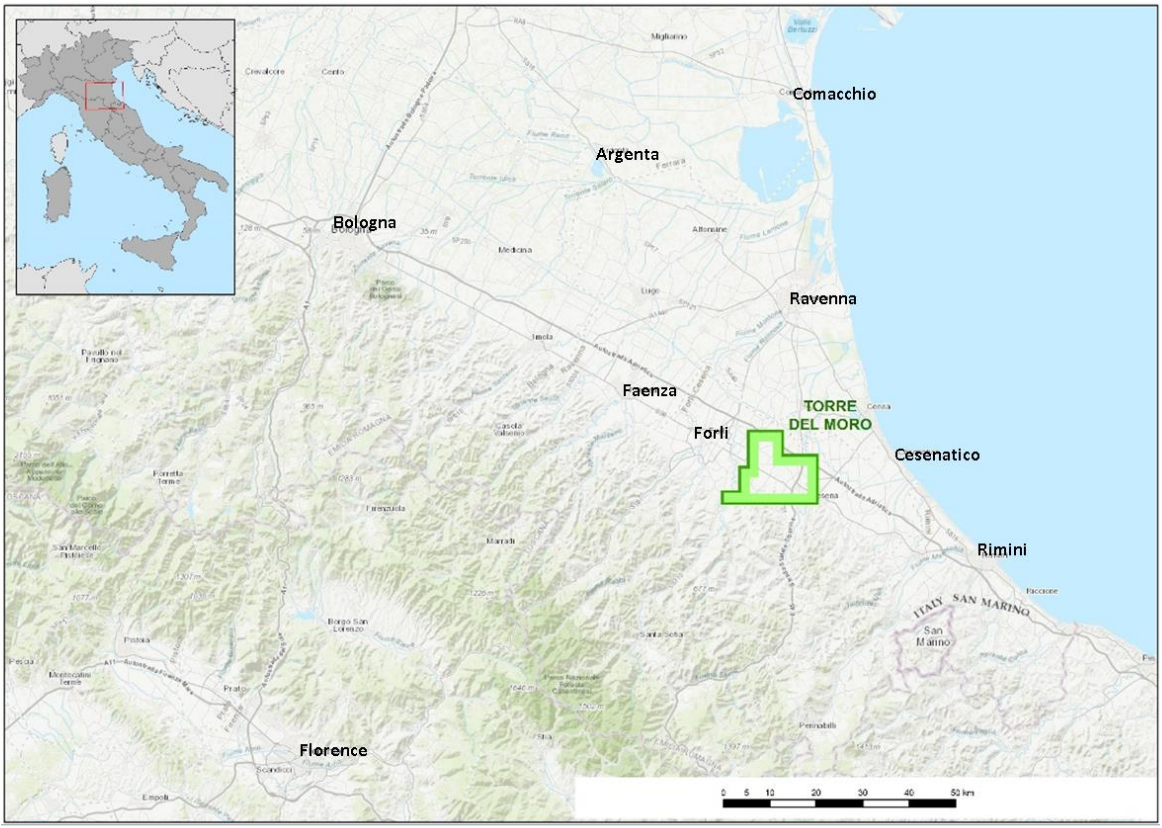


Figure 3-21 Map showing Location of the Torre del Moro Exploration Licence

For a top seal Torre del Moro relies upon Jurassic, basinal, limestone-shale sequences and fault seal at the thrust. Otherwise the structure has three-way dip closure. Perhaps the major trap risk is that the thrust fault seals effectively and that activity on this fault through the Tertiary has not allowed oil to leak upward.

PVO have obtained 2D seismic lines from ENI and have generated a structural interpretation in support of the gross rock volume of the structure and have reviewed publically available well log information relating to the Villafortuna oil field which is considered to be a good analogue for the Torre del Moro prospect. PVO have now performed the necessary technical work such that Torre del Moro can be regarded as a *viable drilling target*.

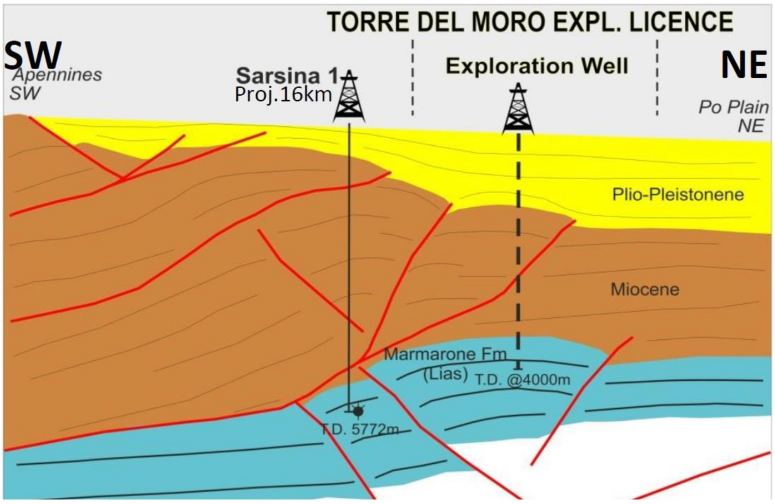


Figure 3-22 Schematic Cross-Section, Torre del Moro Prospect, showing notional exploration well location

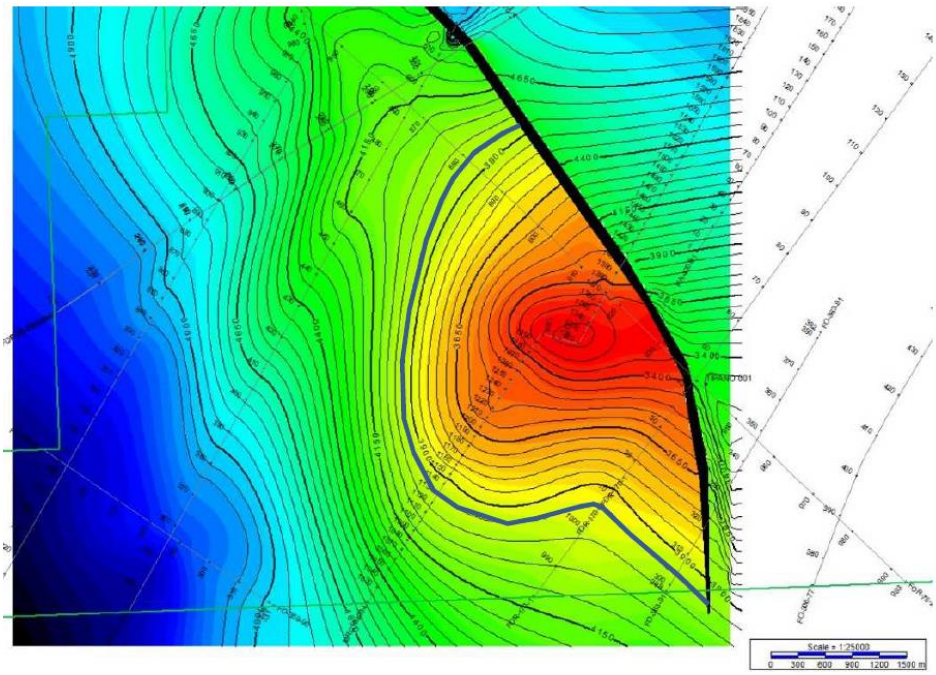


Figure 3-23 Depth Structure Map at top Corniola Formation, Torre del Moro Prospect

CGG has reviewed and adjusted the input reservoir parameters and uncertainty ranges, resulting in the following assessment of the potential range of reasonable outcomes for the Torre del Moro prospect:

Table 3.11 Torre del Moro Prospect: Oil-in-Place Assessment and Prospective Resource Potential

LOW CASE	GBV MMbbl	NtG frac	Phi frac	Sw frac	Bo	OOIP MMbbl	RF %	Resource (MMbbl)
Corniola	14243.4	1	0.01	0	1.3	110	20	22
Marmarone	2404.8	1	0.07	0.4	1.3	78	35	27
Massiccio Upr	716.4	0.6	0.15	0.35	1.3	32	35	11
Massiccio Lwr	3960	1	0.01	0	1.3	30	15	5
					Sum:	**250**		**65**

MID CASE	GBV MMbbl	NtG frac	Phi frac	Sw frac	Bo	OOIP MMbbl	RF %	Resource (MMbbl)
Corniola	15826	1	0.01	0	1.2	132	30	40
Marmarone	2672	1	0.07	0.35	1.2	101	40	41
Massiccio Upr	796	0.6	0.15	0.3	1.2	42	40	17
Massiccio Lwr	4400	1	0.01	0	1.2	37	25	9
					Sum:	**312**		**106**

HIGH CASE	GBV MMbbl	NtG frac	Phi frac	Sw frac	Bo	OOIP MMbbl	RF %	Resource (MMbbl)
Corniola	17584	1	0.015	0	1.09	242	40	97
Marmarone	2969	1	0.08	0.3	1.09	153	55	84
Massiccio Upr	884	0.6	0.15	0.25	1.09	55	65	36
Massiccio Lwr	4889	1	0.015	0	1.09	67	35	24
					Sum:	**517**		**240**

Uncertainty ranges have been increased and low case parameters decreased from PVO's view because of the high subsurface uncertainty regarding oil saturation and recovery factor from tight and fractured carbonates. This results in a low – mid – high range of 65 – 106 – 240 MMbbl prospective resource potential compared to PVO's assessment of 141 – 195 – 264 MMbbl.

Although there is a high resource potential, there are significant risks associated with the Torre del Moro prospect. This prospect relies on the presence of open and interconnected fracture networks which have not been infilled by cements. The active tectonic setting could work in PVO's favour although the circulation of fluids up the thrust faults could equally result in a largely cemented and closed fracture network. Fractures not only contain their own oil volume but serve to connect much greater volumes of oil in rock matrix (typically much lower permeability). In the absence of interconnected and open fracture networks, a well drilled into low porosity limestone will drain only a very limited volume around it and will substantially underperform with respect to the requirements of the High Case. The most significant risks to the prospect are reservoir quality, sealing capacity of the thrust fault and the possibility that recent movement along the thrust caused breach of trap and oil leakage. These risks may be seen in Table 3.12 below as the two values of 0.5.

The Chance of Success has therefore been independently assessed as 11% by CGG, where the risk score for closure and reservoir is the lower of two assigned values and for seal and charge is the product of two assigned values (Table 3.12):

Table 3.12 Torre del Moro Prospect: Risk Assessment

RISK ELEMENTS		RISK SCORE (probability)	
CLOSURE	**Interpretation**	0.7	0.7
	Depth Conversion	0.7	
SEAL	**Top Seal**	0.8	0.4
	Base / Side Seal	0.5	
RESERVOIR	**Presence**	0.7	0.5
	Quality	0.5	
CHARGE	**Source Rock**	0.85	0.8075
	Migration	0.95	
	RISK TOTAL		**0.11**

In CGG's experience, the chosen reservoir properties are comparable to those seen in other large limestone reservoirs in Italy (of which CGG staff have experience). The recovery factors proposed are lower than that obtained from some comparable producing fields but the risk involved in fractured reservoirs is high and such recovery cannot be guaranteed.

Created by
Andrew Webb, Manager, Petroleum Reservoir and Economics
Tel: +44 (0)1293 683000 – andrew.webb@cgg.com

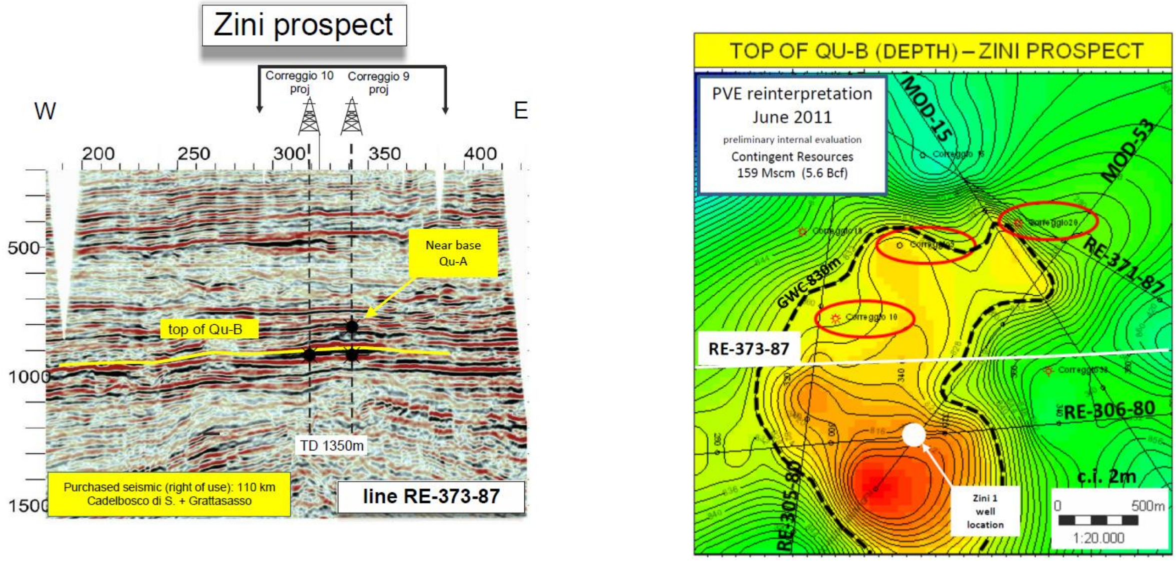
3.4 CADELBOSCO LICENCE

3.4.1 Zini (Qu-B) Contingent Resources

The Zini contingent resource represents a redevelopment of part of the old Correggio Field. The prospect is a Quaternary drape with possible north-easterly pinch-out over folded Pliocene rocks. Target reservoirs are updip Pliocene and Quaternary sands with proven production from the Correggio Field. Past production from Correggio amounts to 253 BCF from the Pliocene and another 1.9 BCF from the Quaternary sands.

The wells Correggio-9 and Correggio-20 demonstrate the current location of the gas-water contact at 830 metres tvdss. Mapping by PVE demonstrates a significant remaining untapped up-dip resource potential. The well Correggio-10 lies within this up-dip volume and proves the continued presence of gas-bearing sand by means of the SP and resistivity signature.

The seismic interpretation is reasonable; the TWT and subsequent depth contour maps have well control from several Correggio wells.



(A) Seismic cross-section of Zini Qu-B structure

(B) Depth map of Zini Qu-B structure

Figure 3.24 Zini Qu-B structure

PVO have estimated remaining recoverable gas by means of a reservoir simulation study carried out by DREAM consultants in 2010. CGG have reviewed the inputs and results of this work and conclude that the contingent resources indicated by this work are reasonable. They are 1.1, 2.7 and 4.6 BCF recoverable in the P90, P50 and P10 cases for the primary target sand Qu-B.

3.4.2 Zini (Qu-A) Prospective Resource

In addition, there is a prospective resource which may be added to the contingent resources specified above. An untested potential gas sand known as Qu-A, slightly shallower than Qu-B, could contain 39.7 MMscm of gas in a best case. Using the same parameter ranges as Qu-B, a Low Case of 16.2 MMscm and a High Case of

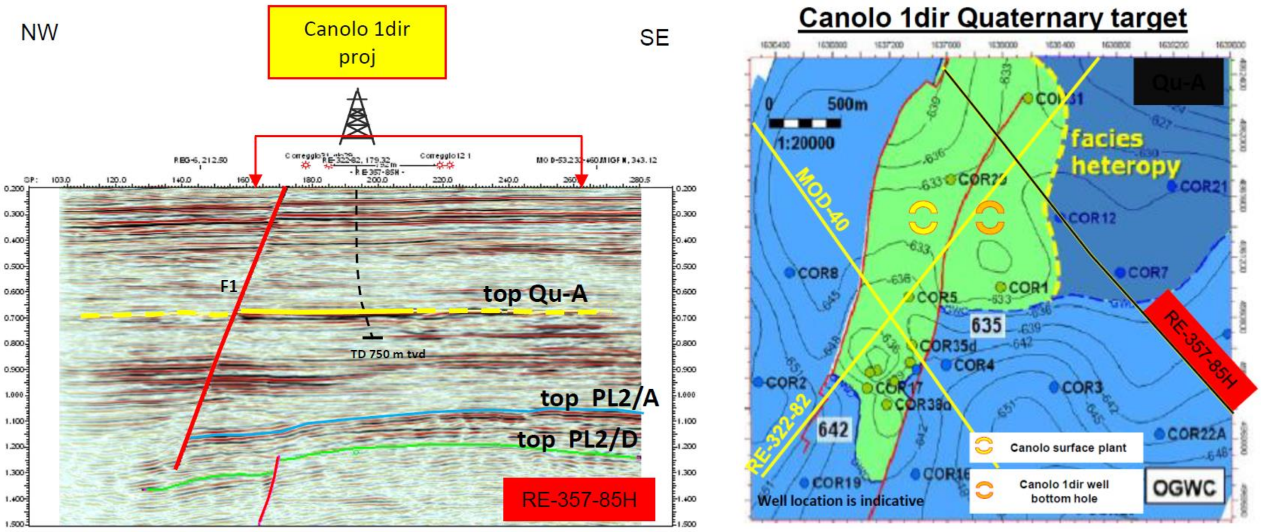
Created by
Andrew Webb, Manager, Petroleum Reservoir and Economics
Tel: +44 (0)1293 683000 – andrew.webb@cgg.com

67.6 MMscm may be derived. Being untested, PVO view this as a prospective resource category. CGG have independently estimated the CoS (probability of success) for this prospective Qu-A sand as 30% at this stage.

3.4.3 Canolo Qu-A Contingent Resources

The Canolo Qu-A contingent resource is located on the western flank of the Correggio Field. The top Qu-A reservoir exists as a Quaternary drape above folded Pliocene strata.

The interpreted trap is a combinational 3-way dip closed structure against an ENE-WSW oriented fault. All horizons were interpreted using the seismic data purchased from ENI.



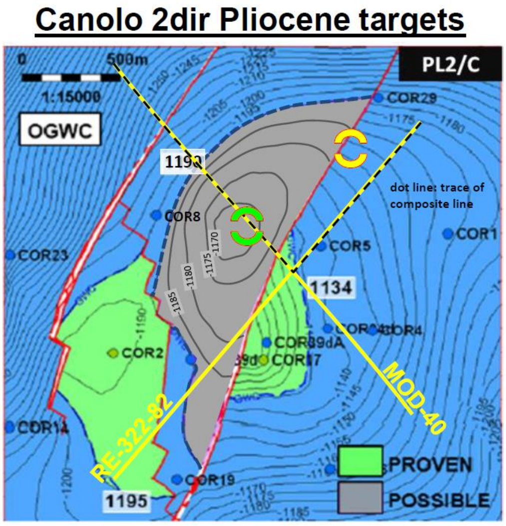
(A) Seismic cross-section of Canolo Qu-A structure **(B) Depth map of Canolo Qu-A structure**

Figure 3.25 Canolo Qu-A structure

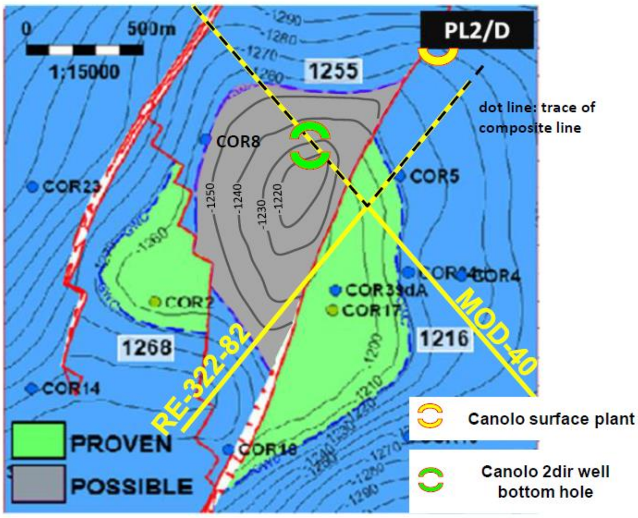
PVO assign contingent resources of 19.8 MMscm, 31.2 MMscm and 48.1 MMscm in P90, 50, 10 cases to the Qu-A reservoirs. CGG have audited these values and find them reasonable. Anticipated recovery factors are modest; 50-60-70% in P90-50-10 cases. This is probably due to strong water drive.

3.4.4 Canolo Pliocene

The Pliocene sands in the Canolo structure also form part of the Correggio Field. Below the Canolo Qu-A reservoir are folded Pliocene strata which have been interpreted on seismic at reflections labelled Top PL2-A and Top PL2-D. The target reservoirs, however, are at PL2-C and PL2-D levels. As with Qu-A, seismic interpretation has been carried out by PVO with additional volumetric studies carried out by DREAM. Horizon interpretation has been confirmed on the available purchased seismic data; the gross rock volume remains the greatest uncertainty.



(A) Depth map of Canolo Pliocene PL2/C structure



(B) Depth map of Canolo Pliocene PL2/D structure

Figure 3.26 Canolo Pliocene reservoirs

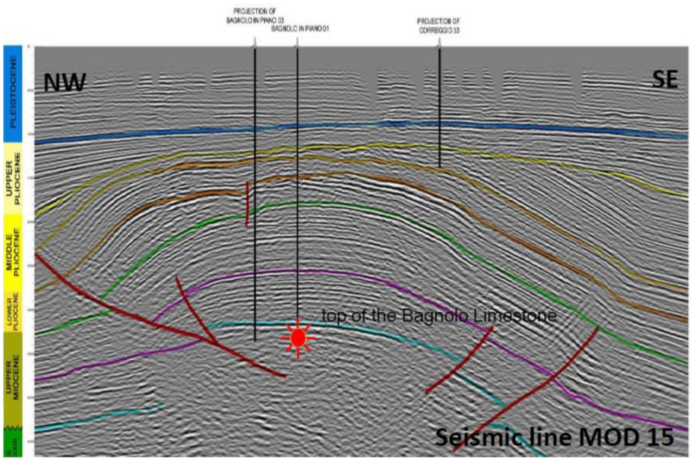
The Pliocene sands formed the main productive intervals in the Correggio gas field, and so their potential at the Canolo structure is considered very good. After review of the data and previous work, CGG consider that the Canolo Pliocene PL2-C and PL2-D sands has contingent gas resources of 11.3, 102 and 297.4 MMscm in the P90, 50 and 10 cases respectively.

3.4.5 Bagnolo in Piano

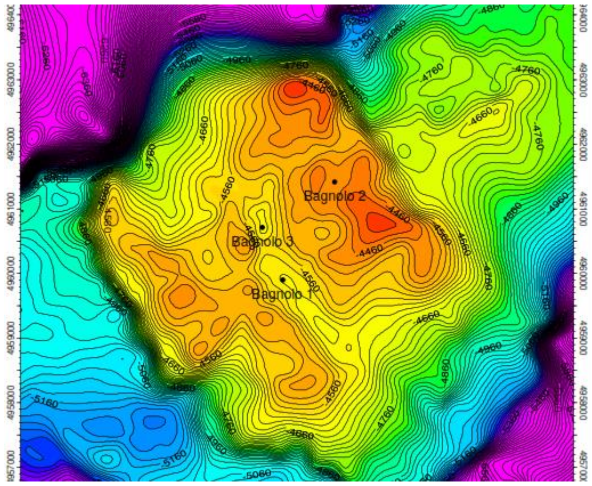
Beneath thick Tertiary sands and shales, the Lower Cretaceous Bagnolo Limestone was drilled, cored and tested by three wells between the years 1970 and 1981. Acidisation and frac jobs carried out on the wells stimulated this reservoir to flow oil at 300-400 bbl/d under nitrogen lift from Bagnolo-2 and 195 bbl/d 17.9° API oil from a 20 metre thick perforated section in Bagnolo-3.

Geologically, the upper metre of reservoir section is described as tight, consistent with carbonate underlying an unconformity. Karst features including fractures and fissures are recorded from core, and some of this is filled by silt and carbonate cement. The presence of occluded karst porosity in the upper metre does not preclude open fractures and fissures being present deeper in the ancient weathering profile. Core descriptions tell us that the reservoir rock is made up of compact and fractured micritic carbonates with rudistid and other fossil debris. In wells BIP-1 and BIP-2 the upper section is a karst breccia. Folded and faulted brittle limestones are predicted to be fractured, therefore the discovery is considered potentially viable.

The Bagnolo in Piano feature is interpreted as a fault bounded anticline on eight seismic lines with 0.5km to 2km line spacing. The anticline at Top Bagnolo limestone level is interpreted as compartmentalised by a regional NE-SW reverse fault and two NW-SW oriented faults. The 2016 horizon interpretation is good, given the 2D line quality, although gross rock volume uncertainty remains significant.



(A) Cross-section through Bagnolo in Piano structure



(B) Top Bagnolo Limestone Depth Map (2016)

Figure 3.27 Bagnolo in Piano structure

Having reviewed the data and available interpretations, CGG has made an independent assessment of the potential resource volumes at Bagnolo-in-Piano (Table 3.13).

Table 3.13 Bagnolo-in-Piano Reservoir Parameters and Volumetric Assessment

LOW CASE	GBV MMbbl	NtG frac	Phi frac	Sw frac	Bo	OOIP MMbbl	RF %	Resource (MMbbl)
ODT -4608	8219.7	0.8	0.01	0.20	1.2	44	15	6.6
BEST CASE	**GBV MMbbl**	**NtG frac**	**Phi frac**	**Sw frac**	**Bo**	**OOIP MMbbl**	**RF %**	**Resource (MMbbl)**
OWC (mid) -4660	13867.2	0.9	0.02	0.15	1.1	137	20	27.3
HIGH CASE	**GBV MMbbl**	**NtG frac**	**Phi frac**	**Sw frac**	**Bo**	**OOIP MMbbl**	**RF %**	**Resource (MMbbl)**
WUT -4709	19911.0	0.9	0.02	0.10	1	323	25	80.6

3.4.6 Bagnolo in Piano, South West Prospect

To the South West of the Bagnolo discovery lies a separate fault block that may be considered highly prospective if a step-out well were to be drilled on the Bagnolo structure.

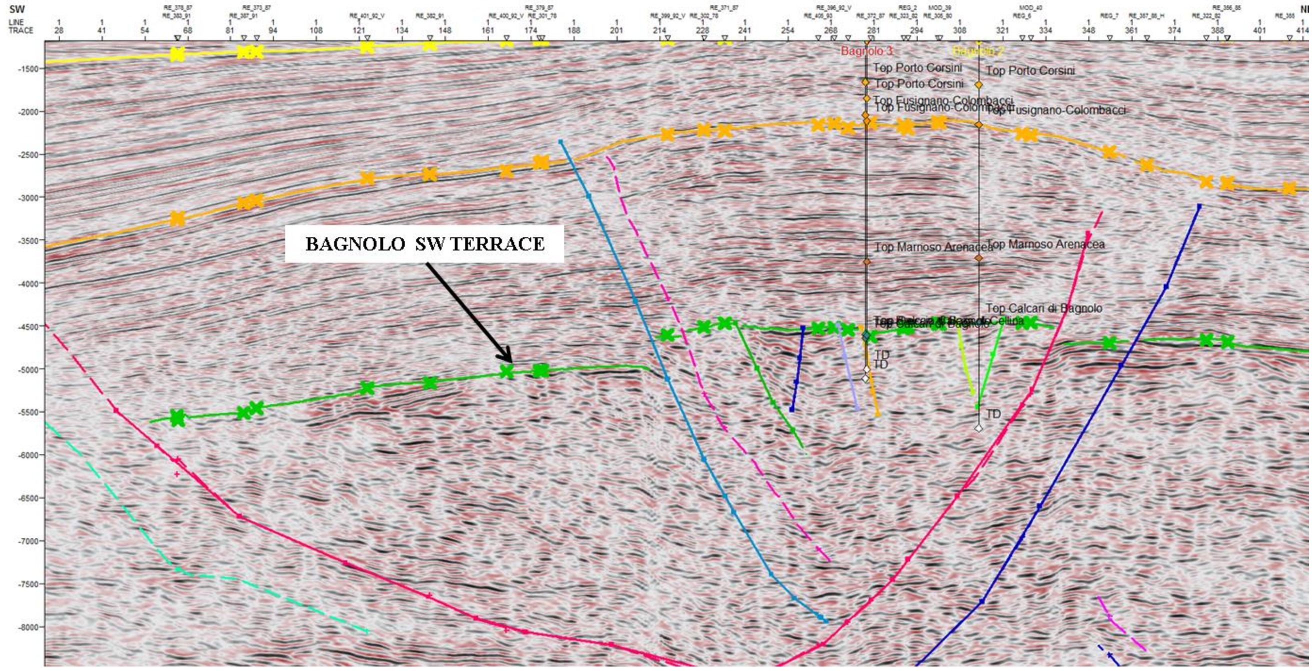


Figure 3.28 Bagnolo SW Prospect, Seismic Section showing Location and Structure

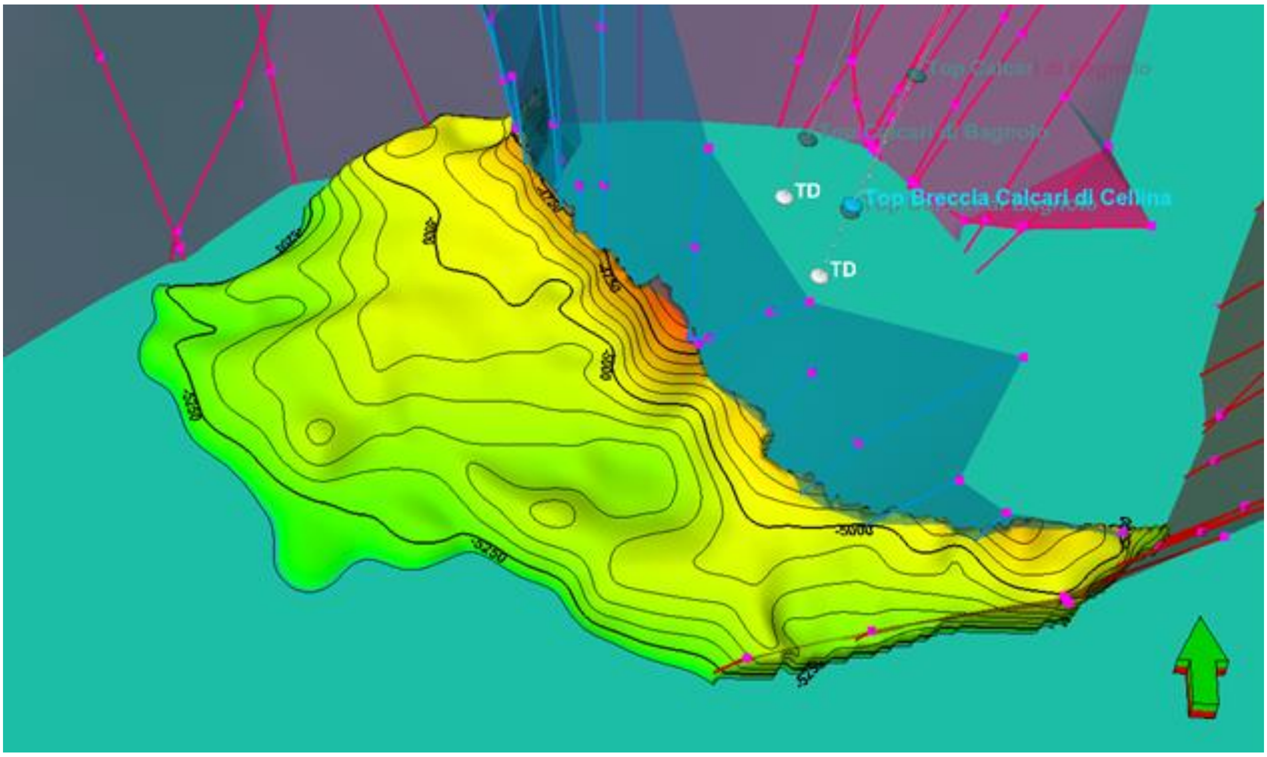


Figure 3. Bagnolo SW Prospect, Depth Structure Map in 3D View

Using the same reservoir parameters, PVO has arrived at the assessment shown in Table 3.14.

Table 3.14 Bagnolo-in-Piano, SW Prospect: Reservoir Parameters and Volumetric Assessment

LOW CASE	GBV MMbbl	NtG frac	Phi frac	Sw frac	Bo	OOIP MMbbl	RF %	Resource (MMbbl)
OWC -5300	27652.7	0.8	0.01	0.20	1.2	147	15	22.1
BEST CASE	**GBV MMbbl**	**NtG frac**	**Phi frac**	**Sw frac**	**Bo**	**OOIP MMbbl**	**RF %**	**Resource (MMbbl)**
OWC -5300	27652.7	0.9	0.02	0.15	1.1	272	20	54.5
HIGH CASE	**GBV MMbbl**	**NtG frac**	**Phi frac**	**Sw frac**	**Bo**	**OOIP MMbbl**	**RF %**	**Resource (MMbbl)**
OWC -5300	27652.7	0.9	0.02	0.10	1	448	25	112.0

CGG has reviewed PVO's information and estimates the chance of success to be 34%. Perceived risks are provided in Table 3.15.

Table 3.15 Bagnolo-in-Piano, SW Prospect: Risk Assessment

RISK ELEMENTS		RISK SCORE (probability)	
CLOSURE	Interpretation	0.75	0.75
	Depth Conversion	0.75	
SEAL	Top Seal	0.95	0.9025
	Base / Side Seal	0.95	
RESERVOIR	Presence	0.8	0.7
	Quality	0.7	
CHARGE	Source Rock	0.85	0.7225
	Migration	0.85	
	RISK TOTAL		**0.34**

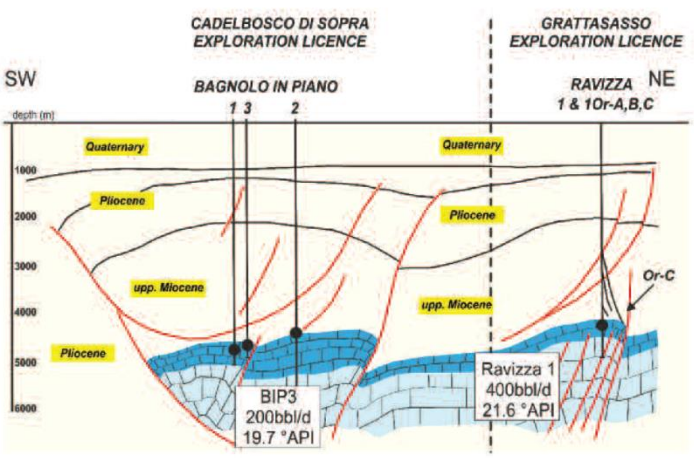
3.5 GRATTASASSO LICENCE

3.5.1 Ravizza Oil Discovery

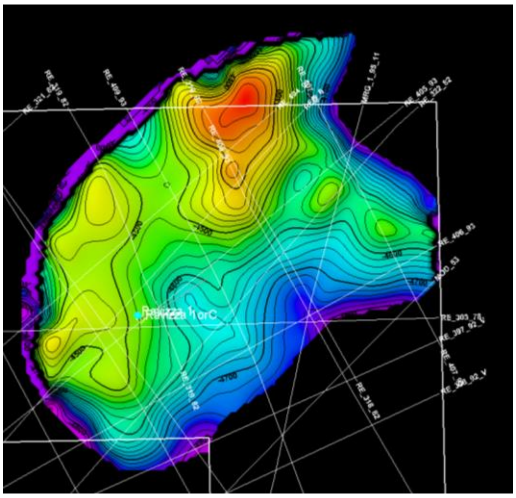
Ravizza is an oil discovery in the Eocene/Oligocene limestone located to the NE of the Bagnolo in Piano discovery. The seismic data show that this is a faulted anticline. This is supported by formation tops from the Ravizza-1. The 2016 structural interpretation of the Ravizza discovery is considered fairly good.

The reservoir has similar lithology as the adjacent Bagnolo-in-Piano discovery; it is fractured micritic carbonates with presence of karst below the unconformity. The fine-grained brittle limestones are fractured and it is the fractures that provide the bulk of the permeability. The major uncertainties will be the extent of fracture networks and the connected volume which can be accessed by a wellbore as well as the storativity of the matrix.

Ravizza-1 tested 453 bbl/d of 21.6° API oil with 84.7 Mscf/d gas from these fractured limestones.



(A) Ravizza cross-section



(B) Ravizza Depth Map 2016

Figure 3.29 Ravizza structure

Like the Bagnolo-in-Piano discovery, the Ravizza discovery is thought to be a folded, faulted and fractured carbonate reservoir with matrix oil in addition to a fracture volume.

Table 3.16 Ravizza: Reservoir Parameters and Volumetric Assessment

LOW CASE	GBV MMbbl	NtG frac	Phi frac	Sw frac	Bo	OOIP MMbbl	RF %	Resource (MMbbl)
OWC -4568	3628.8	0.8	0.01	0.20	1.25	19	15	2.8
BEST CASE	**GBV MMbbl**	**NtG frac**	**Phi frac**	**Sw frac**	**Bo**	**OOIP MMbbl**	**RF %**	**Resource (MMbbl)**
OWC -4668	9276.3	0.85	0.015	0.15	1.25	80	20	16.1
HIGH CASE	**GBV MMbbl**	**NtG frac**	**Phi frac**	**Sw frac**	**Bo**	**OOIP MMbbl**	**RF %**	**Resource (MMbbl)**
OWC -4718	12848.4	0.9	0.02	0.10	1.25	167	25	41.6

4 RESERVOIR ENGINEERING

4.1 SELVA

4.1.1 Historical production

The Selva gas field was previously on production during the 1950s-1980s. Total historical production from the C level is shown in Table 4.1 below:

Table 4.1 Summary of Total Gas Recovered from Selva Stratigraphic (MMscm)

Well	Total Gas Recovered, MMscm
Selva-5-C	295.74
Selva-6-C	878.80
Selva-9-C	124.38
Selva-11-C	124.05
Selva-17-C	332.58
Selva-21-C	2.31
Selva-22-C	173.33
Total	**1,931.19**

Figure 4.1 shows the total gas produced from each historical well. CGG has no records of perforation intervals of Level C, only well tops. Therefore, CGG consider "height of sand top above Gas-Water Contact (GWC)". The height above contact of each historical well is as follows:

- Selva-21 was watered-out when GWC was at ~1,340 mTVDss, assuming this is the original water contact
- Selva-11's Top C is at 1,315 mTVDss, 25 m above contact. Produced 124 MMscm
- Selva-9's Top C is at 1,296 mTVDss, 44 m above contact. Produced 124 MMscm
- Selva-22's Top C is at 1,295 mTVDss, 45 m above contact. Produced 173 MMscm
- Selva-17's Top C is at 1,281 mTVDss, 59 m above contact. Produced 333 MMscm
- Selva-5's Top C is at 1,246 mTVDss, 94 m above contact. Produced 296 MMscm
- Selva-6's Top C is at 1,235 mTVDss, 105 m from the contact. Produced 879 MMscm

CGG postulates that the PM-1dir well will perform within the range of the posted cumulative produced gas values at historical wells. CGG consider that height of perforations above water is a key indicator of when water breaks through.

- In the C1 sand, PM-1's GWC is estimated at 1239 mTVDss; PM-1's Top C1 is at 1222 mTVDss, that is, 17 m above contact.
- In the C2 sand, PM-1's GWC is estimated at 1278 mTVDss; PM-1's Top C2 is at 1251 mTVDss which is 27 m above contact.

Therefore, the most closely analogous wells are Selva-11 (124 MMscm cumulative), Selva-9 (124 MMscm) and Selva-22 (173 MMscm). The PM-1dir well could perform as well as Selva-5 (296 MMscm) and Selva-17 (333 MMscm). In the high case, the PM-1dir could possibly produce as much as Selva-6 (879 MMscm cumulative). On the basis that the new well is closer to the water than most Selva wells on the map prior to the well being put on production, and there being some production history, CGG do not expect PM-1dir to out-perform these prior to suffering water breakthrough.

It is based on these historic production histories that the reserves volumes for the PM-1dir have been bench marked against.

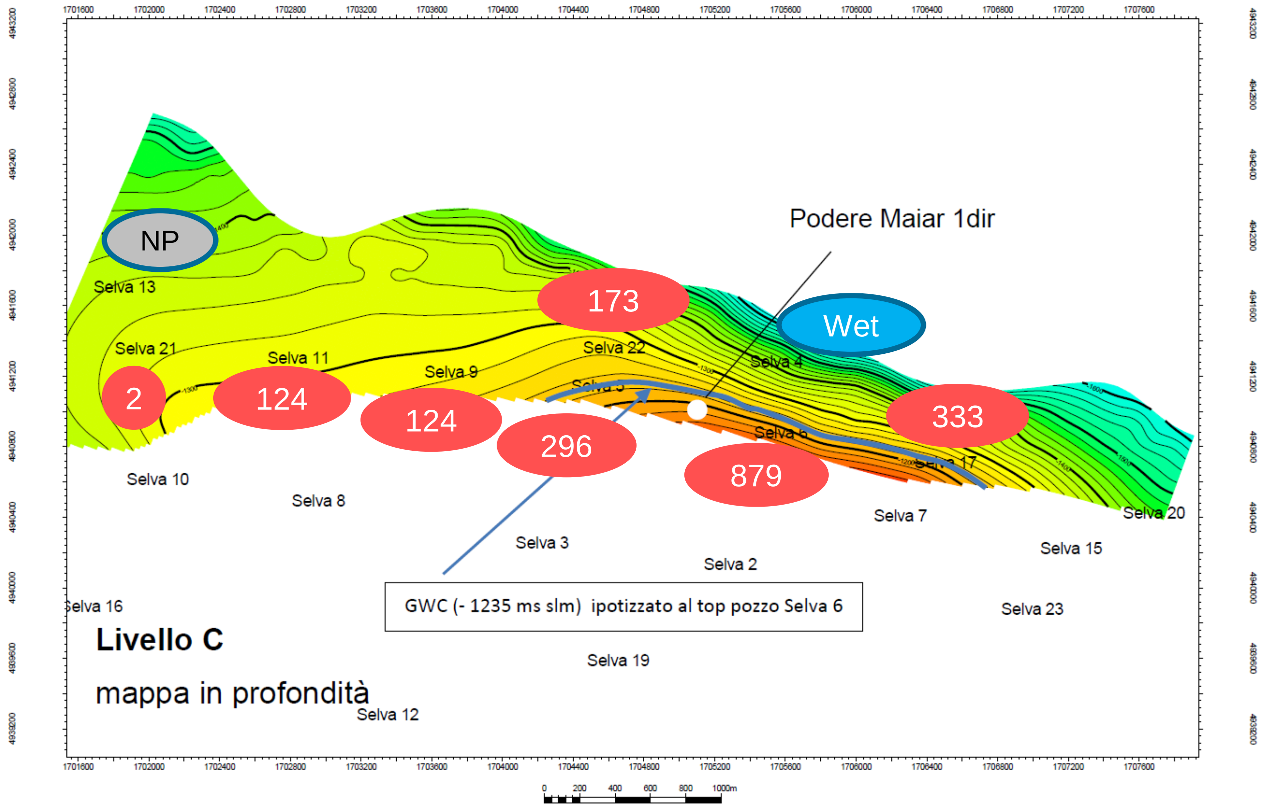


Figure 4.1 Historical Well Locations in Selva Stratigraphic Trap and Well Total Gas Production (MMscm)

4.1.2 Podere Maiar-1dir well test results

Podere Maiar-1 was drilled targeting remaining updip gas of the C Level in the Selva Stratigraphic Trap. The new pressure data taken over the C level has established a separate GWC in C1 and C2 sands. In both C1 and C2 sands, the GWC has been identified. The depths of C1 and C2 sands are tabulated in Table 4.2. The bottom perforation is over 13 m above the contact.

Table 4.2 Podere Maiar-1dir – Depths of C1 and C2 Sands

Podere Maiar-1dir (RT 22.71 m)		
C1	Top, m MD RT (m SSL)	1253.5 (1221.9)
	Bottom, m MD RT (m SSL)	1275.5 (1244.4)
	GWC, m MD RT (m SSL)	1270.5 (1239)
	Perforation, m MD RT	1253.5-1256
C2	Top, m MD RT (m SSL)	1282.5 (1251)
	Bottom, m MD RT (m SSL)	1318.5 (1286.5)
	GWC, m MD RT (m SSL)	1309.5 (1277.8)
	Perforation, m MD RT	1282.5-1296

The well has been completed by a conventional completion with sliding side door (see Figure 4.2). Each sand can produce individually or co-mingle.

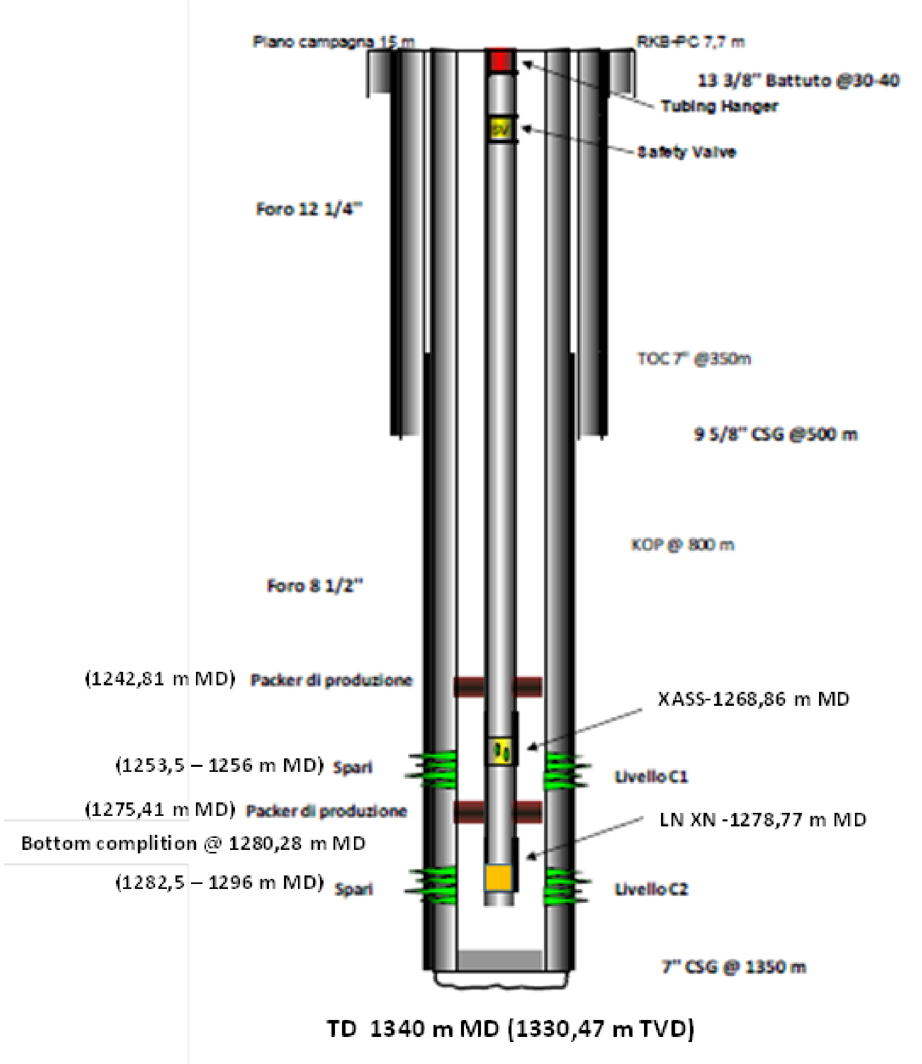


Figure 4.2 Podere Maiar-1dir – Well Schematic

The initial flow test performed in January 2018 by testing each sand individually indicates good initial gas flow rates as shown below. Although both sands have high well deliverability, the perforations of the Podere Maiar 1dir well are sited at over 13 m above the gas-water-contacts encountered in both the C1 and C2 reservoirs. An appropriate production flow rate will be required to prevent water coning and early breakthrough into the well.

Table 4.3 Summary of Flow Test Results of C1 Sand

Choke ("/64)	Avg FWHP (bara)	Avg Gas (scm/day)	Duration (hours)
SBHP 132.9 bara at 1253.5 m MD RT, STHP 120.7 bara			
8	119.3	14,300	6
16	115.0	64,000	6
18	113.2	77,400	6
Build up			30
24	105.0	127,000	3
Build up			1

Table 4.4 Summary of Flow Test Results of C2 Sand

Choke ("/64)	Avg FWHP (bara)	Avg Gas (scm/day)	Duration (hours)
SBHP 135.5 bara at 1275 m MD RT, STHP 122.9 bara			
8	122.7	17,800	6
16	120.7	64,800	6
18	119.5	78,000	6
Build up			50
24	104.6	142,000	4
Build up			6

The build-up tests have been interpreted by PVO's consultant (DREAM, Dedicated Reservoir Engineering And Management, based in Torino). Figure 4.3 to Figure 4.8, Table 4.5, and Table 4.6 are extracted from DREAM's interpretation in the submission document to the Italian authorities.

C1 sand's well test interpretation indicates that the well sees two no-flow boundaries. In Figure 4.3 during the late time i.e. after 3 hours, the pressure derivative shows positive slope indicating no-flow behaviour. In this case, DREAM interprets it as two parallel no-flow boundaries. CGG accepts DREAM interpretation of the C1 sand. The two no-flow boundaries can be interpreted as the pinch-out (South) and the structural closure (North). Pressure builds up to the pre-test pressure suggesting that the well has some pressure support and good connectivity. CGG therefore considers that the Podere Maiar-1dir is capable of draining the whole area of the updip gas.

For the C2 sand, DREAM interprets the well test as three boundaries and mentions that one of the boundaries might be the aquifer. In Figure 4.6, during the late time (i.e. after 1 hour), the pressure derivative starts to divert from radial flow (zero slope) to slightly positive slope and the pressure derivative continues to show positive slope indicating no-flow behaviour. The boundaries could be leaking, although CGG have not observed this during the short test. This could not be an aquifer effect as the derivative of pressure would have shown a negative slope in the late time.

CGG agree with DREAM that the C2 sand has encountered three boundaries. Two of the boundaries are no-flow and can be interpreted as the pinch-out (South) and the structural closure (North). The shortest boundary, at a distance of 80 m, could indicate that there is a boundary that could not be seen in the existing seismic data. However, the well test data does not identify if the boundary at 80 m is to the East or the West of the well. The hypothesis of a third boundary is supported by the fact that the final build-up reservoir pressure that does not reach the pre-test value. This may indicate some depletion of a limited connected gas volume.

Although the pressure loss during the test is very small (1/10th bar after 50 hours of shut-in), the pressure did not build-up back to the pre-test value as observed in C1 (in which the pressure returned to the pre-test value after 30 hours of shut-in, as CGG would expect in high quality reservoir with a longer shut-in time). CGG therefore has taken into consideration that the Podere Maiar-1dir well may only drain a limited area of the updip gas and assigns only 44% (considering the boundary is located to the West of the well) of the total drainage area of the low in-place volumes in the 1P reserves.

For the 2P reserves, only 63% (considering the boundary is located to the East of the well) of the total drainage area of the mid in-place volumes is assigned. However, the 80 m no-flow boundary may not fully seal (i.e. leaking) and the whole area could possibly be drained by the Podere Maiar-1dir well. CGG therefore assign 100% of the high drainage area in CGG's 3P reserves.

For the C2 sand, CGG recognises that the three no-flow boundaries interpretation may not be a unique solution. Alternative interpretations are possible. This has been taken into consideration with CGG's reserves uncertainty, i.e. 44%, 63%, and 100% drainage area.

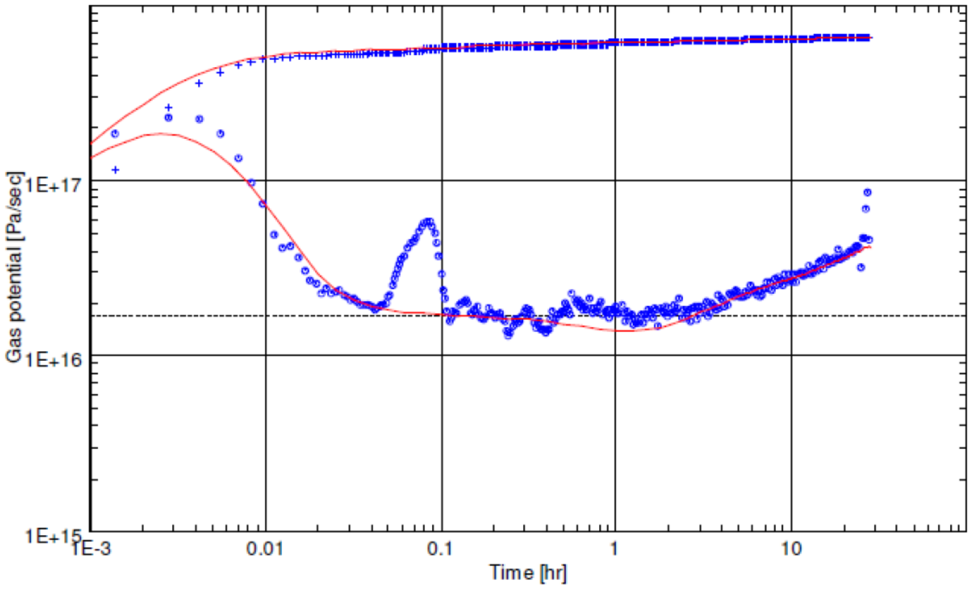


Figure 4.3 Log-log Plot of Pressure and Pressure Derivative of C1 Sand

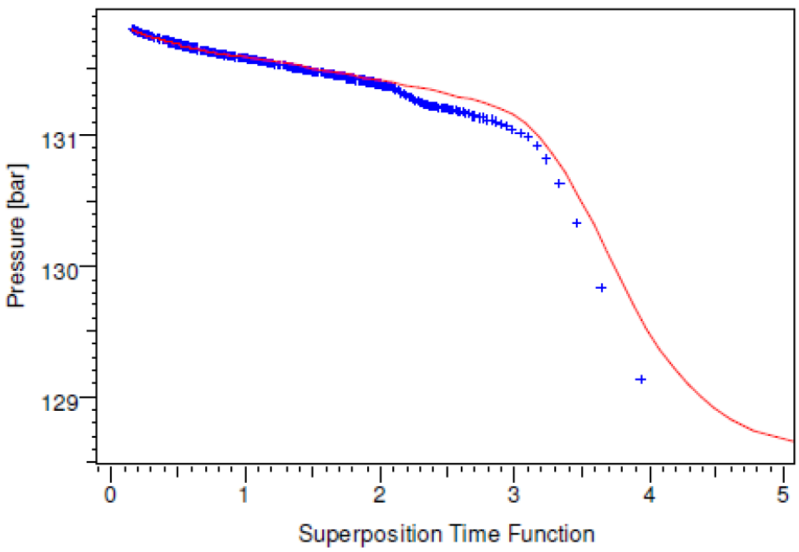


Figure 4.4 Horner Plot of C1 Sand

Created by
Andrew Webb, Manager, Petroleum Reservoir and Economics
Tel: +44 (0)1293 683000 – andrew.webb@cgg.com

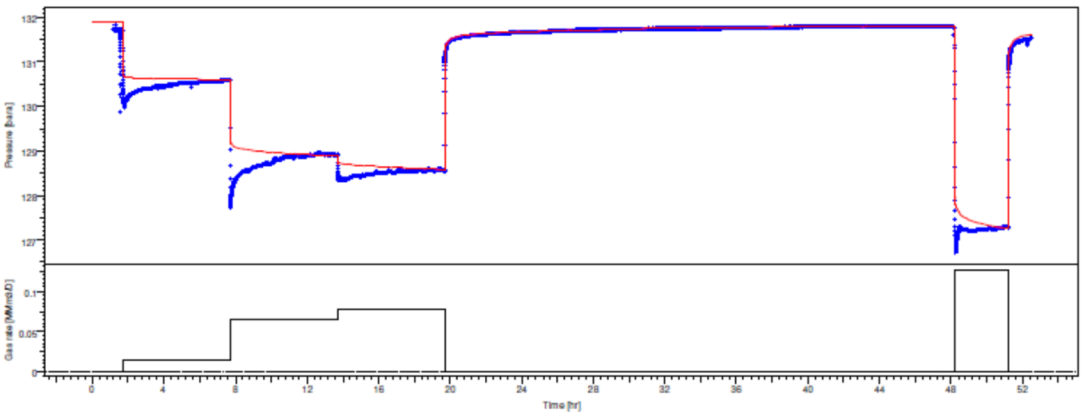


Figure 4.5 Pressure and Gas Rate of C1 Sand

Table 4.5 Well Test Interpretation Result of C1 Sand

p_i	131.9	bar
kh	949	mD m
h	2.5	m
k	380	mD
S_m	decreasing	
d1	120	m
d2	190	m

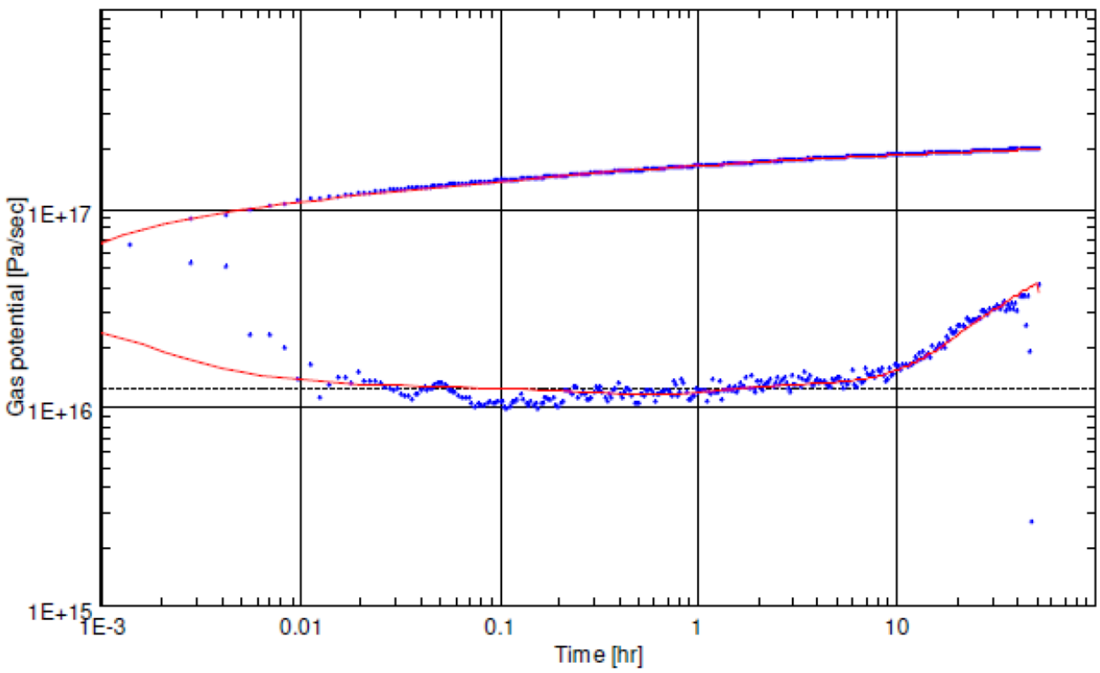


Figure 4.6 Log-log Plot of Pressure and Pressure Derivative of C2 Sand

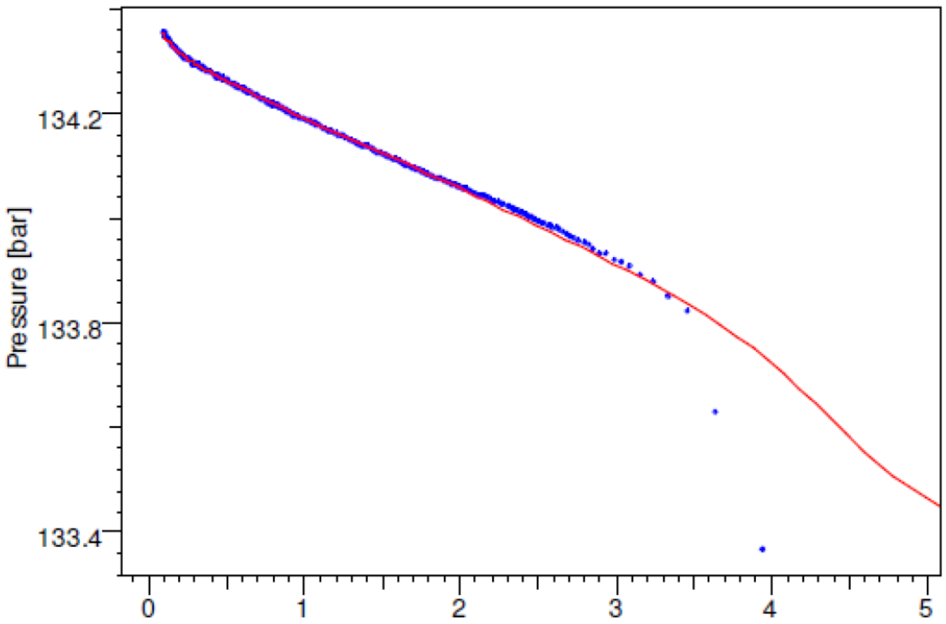


Figure 4.7 Horner Plot of C2 Sand

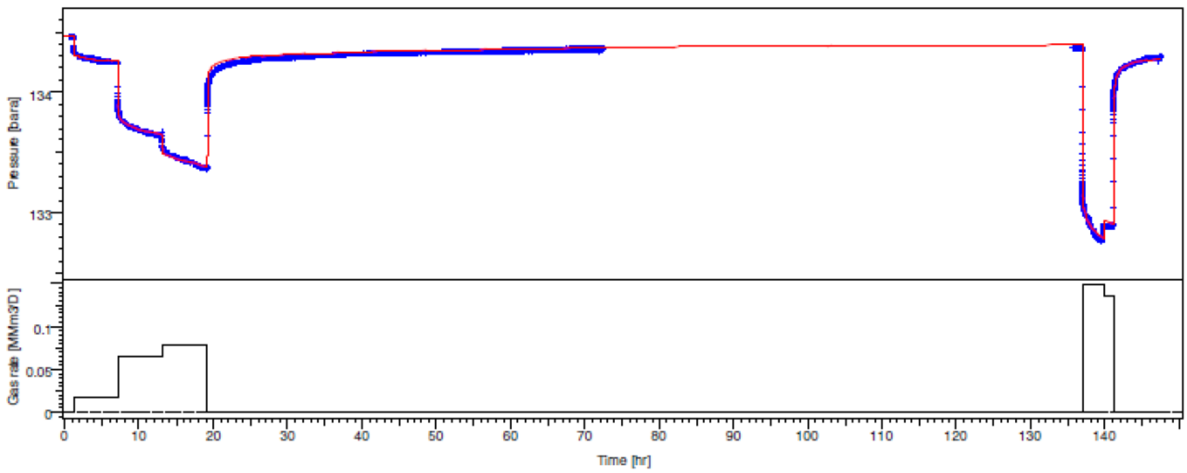


Figure 4.8 Pressure and Gas Rate of C2 Sand

Table 4.6 Well Test Interpretation Result of C2 Sand

p_i	134.5	bar
kh	1440	mD m
h	8.5	m
k	169	mD
d1	80	m
d2	120	m
d3	170	m

4.1.3 Reserves

Selva gas consists of approximately 99.5% methane and has low hydrocarbon liquids content, and as such will require minimal surface processing when the field is redeveloped.

CGG has reviewed both historical well production and the Podere Maiar-1dir well test results. CGG have estimated 1P, 2P and 3P reserves using parameters tabulated in Table 4.7. The 1P, 2P and 3P reserves are summarized in Table 4.8.

- For 1P reserves, with low in-place volumes, C1 sand can drain 100% of the area and C2 sand can drain only 44% of the area. The recovery factor of 60% is assigned for both sands.
- For 2P reserves, with mid in-place volumes, C1 sand can drain 100% of the area and C2 sand can drain only 63% of the area. The recovery factor of 68% is assigned for both sands.
- For 3P reserves, with high in-place volumes, both C1 and C2 sands can drain 100% of the area. The recovery factor of 70% is assigned for both sands.

This range covers the uncertainties in the volumes, taking into consideration the uncertainty of the location and presence of "boundaries".

Table 4.7 Summary of Parameters Used for Reserves Calculation

Sand	Case	GIIP (MMscm)	% Area Contacted by PM-1	Contacted GIIP (MMscm)	Recovery Factor (%)	Reserves (MMscm)*
C1	1P	81	100	81	60	48
	2P	190	100	190	68	129
	3P	299	100	299	70	209
C2	1P	261	44	115	60	69
	2P	585	63	369	68	250
	3P	910	100	910	70	637
Total	1P	342	N/A	195	N/A	117
	2P	775	N/A	558	N/A	379
	3P	1,208	N/A	1,208	N/A	846

** The numbers may not add due to rounding error.*

As water breakthrough is the major risk to recoverable gas volumes, PVO proposes to produce at a maximum gas rate of around 80,000 scm/day, solely from C2 sand then switch to C1 sand. In the event of earlier than expected water breakthrough, it would have a major impact on the project and as such could require an additional well.

Table 4.8 Summary of Technical Reserves for the Selva Redevelopment Project

Selva Stratigraphic Trap	Gross (MMscm)		
	Proved	**Proved & Probable**	**Proved, Probable & Possible**
C1 Sand	48	129	209
C2 Sand	69	250	637
Total	**117**	**379**	**846**

**The reserves classification is subject to the award of a production concession.*

CGG has compared the reserves to the historical production as shown in Figure 4.9. CGG find the reserves are in the reasonable range of low, mid, and high historical well performance. CGG's 1P, 2P and 3P reserves are based on producing with the minimum WHP of 70 barg and lower to 30 barg towards the end of well life. Therefore, it is reasonable to see slightly higher 2P reserves comparing to the historic wells that were limited at 80 barg WHP.

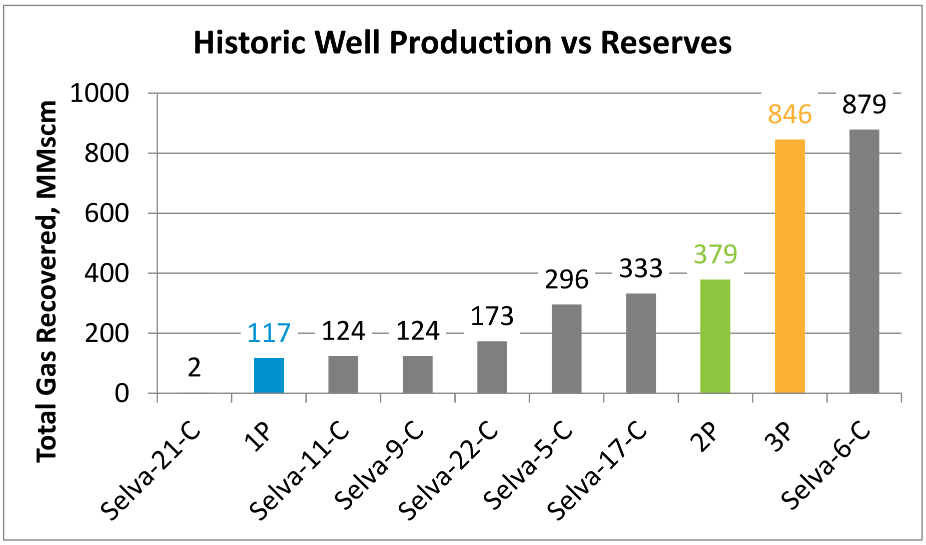


Figure 4.9 Comparison between historical production and reserves

The production profiles for 1P, 2P and 3P reserves are graphically shown in Figure 4.10. Table 4.9 shows the annual production and cumulative production.

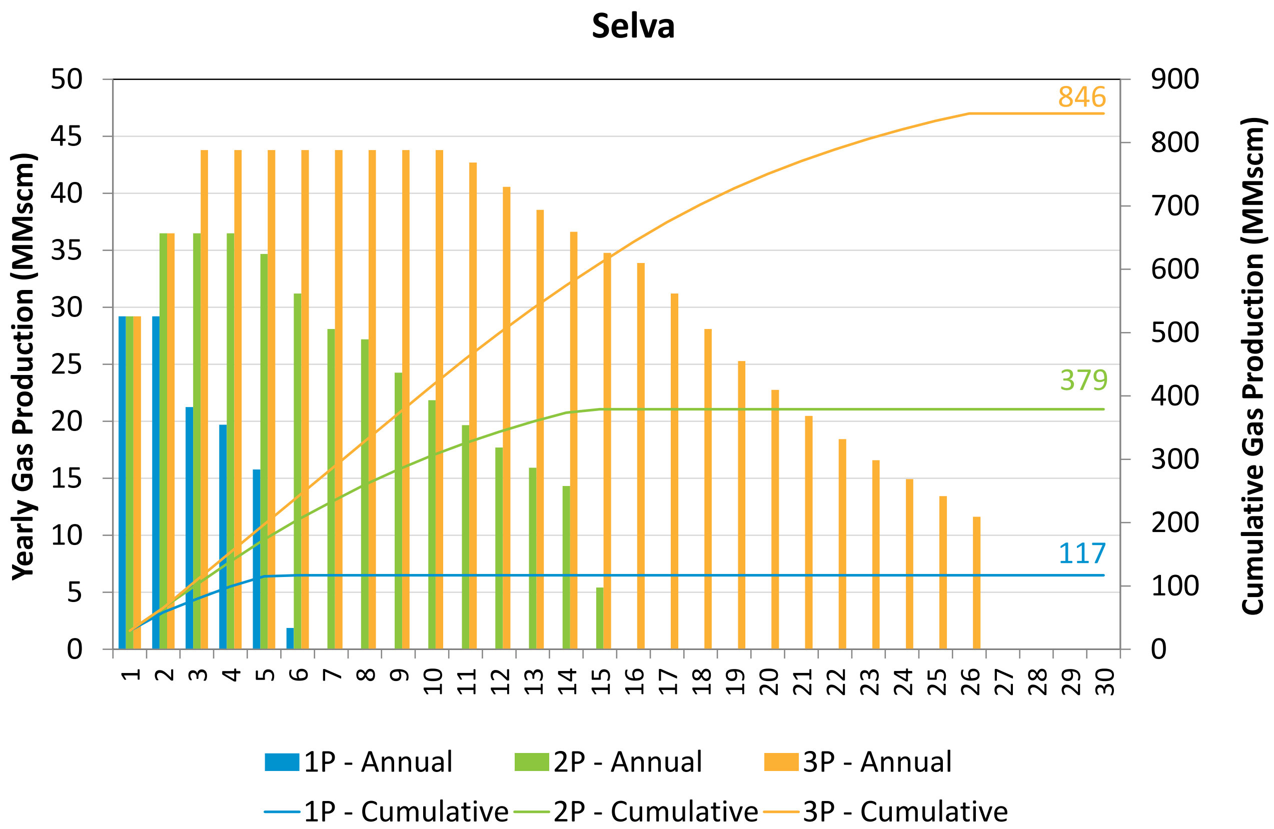


Figure 4.10 Technical Production Profiles of Selva 1P, 2P and 3P (before Economic Cut-off)

Table 4.9 Annual Production and Cumulative Production of Selva (before Economic Cut-off)

Year	1P		2P		3P	
	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)
1	29.20	29.20	29.20	29.20	29.20	29.20
2	29.20	58.40	36.50	65.70	36.50	65.70
3	21.25	79.65	36.50	102.20	43.80	109.50
4	19.71	99.36	36.50	138.70	43.80	153.30
5	15.77	115.12	34.68	173.38	43.80	197.10
6	1.88	117.00	31.21	204.58	43.80	240.90
7	0.00	117.00	28.09	232.67	43.80	284.70
8	0.00	117.00	27.19	259.86	43.80	328.50
9	0.00	117.00	24.27	284.13	43.80	372.30
10	0.00	117.00	21.85	305.97	43.80	416.10
11	0.00	117.00	19.66	325.63	42.71	458.81
12	0.00	117.00	17.69	343.33	40.57	499.37
13	0.00	117.00	15.93	359.25	38.54	537.92
14	0.00	117.00	14.33	373.59	36.61	574.53
15	0.00	117.00	5.41	379.00	34.78	609.31
16	0.00	117.00	0.00	379.00	33.89	643.21
17	0.00	117.00	0.00	379.00	31.21	674.41
18	0.00	117.00	0.00	379.00	28.09	702.50
19	0.00	117.00	0.00	379.00	25.28	727.78
20	0.00	117.00	0.00	379.00	22.75	750.53
21	0.00	117.00	0.00	379.00	20.48	771.00
22	0.00	117.00	0.00	379.00	18.43	789.43
23	0.00	117.00	0.00	379.00	16.58	806.02
24	0.00	117.00	0.00	379.00	14.93	820.94
25	0.00	117.00	0.00	379.00	13.43	834.38
26	0.00	117.00	0.00	379.00	11.62	846.00
27	0.00	117.00	0.00	379.00	0.00	846.00
28	0.00	117.00	0.00	379.00	0.00	846.00
29	0.00	117.00	0.00	379.00	0.00	846.00
30	0.00	117.00	0.00	379.00	0.00	846.00

4.2 TEODORICO

Wells Carola-1, Carola-2, Irma-1 and Irma-2X were drilled by ENI between 1988 and 2001. These wells generated successful production tests for different sands as quoted earlier. Production profiles are based on these production test data.

The Teodorico field is divided into different horizons. Because of the wide range of depths at which these horizons are located, crossflow from one deeper horizon to another shallower horizon may occur if the horizons are not isolated from each other. Hence some of the horizons cannot be produced at the same time. Consequently the development wells will be dual completion with selective sleeves. Table 9.2 provides a list of the horizons associated with the reserves and contingent resources and Table 9.3 below provides CGG's estimates of reserves and contingent resources for the Teodorico discovery. The criterion for classifying gas volumes to contingent resources is that they are in sands that extend within the 12nm limit and so CGG assume they cannot be developed under current Italian law.

Table 4-10 Teodorico Field: Summary of Reserves and Contingent Resources

		Reserves (MMscm)			Contingent Resources (MMscm)		
Licence	**Field**	**1P**	**2P**	**3P**	**1C**	**2C**	**3C**
d40 AC PY	Teodorico	770.3	1039.4	1365.1	209.8	300.5	395.9

Two wells with dual string completion are proposed with the first production targeted in July 2022. CGG has constructed production profiles sand-by-sand using various initial rates and decline rates as tabulated in Table 9.4 to Table 9.6. The range of initial rates is similar to the production tests of Wells Carola-1 and Irma-1 as stated earlier in section 9.3.1.1.

To demonstrate the field's deliverability, unconstrained production profiles are constructed for 1P, 2P and 3P cases as graphically shown in Figure 9.5 and Table 9.7 shows the estimated unconstrained annual production and cumulative production.

A permanent offshore facility is proposed for field development with the gas rate capacity of 300,000 scm/d. The unconstrained production profiles were updated to honour this gas capacity. The constrained production profiles with the maximum gas rate of 265,000 scm/d were constructed. The spare capacity of 35,000 scm/d is planned in order to allow maintenance down time and seasonal fluctuations to the delivery rates. The constrained production profiles for 1P, 2P and 3P cases are graphically shown in Figure 9.6. Table 9.8 shows the estimated constrained annual production and cumulative production.

Table 4-11 Initial Rates and Decline Rates for 1P reserves in Teodorico Field

Sand	Recoverable Volumes (MMscm)	Initial Rate (Day 1), scm/d	Decline Rate per Year	First Production	Well
PLQ-C	181.3	100,000	0.15	Jul-2022	Teodorico-1 S1
PLQ-D1	184.1	120,000	0.22	Jul-2022	Teodorico-2 S1
PLQ-D2	87.8	80,000	0.22	Jul-2022	Teodorico-2 S2
PLQ-E2-F	317.2	100,000	0.10	Jul-2022	Teodorico-1 S2

Table 4-12 Initial Rates and Decline Rates for 2P reserves in Teodorico Field

Sand	Recoverable Volumes (MMscm)	Initial Rate (Day 1), scm/d	Decline Rate per Year	First Production	Well
PLQ-C	277.5	120,000	0.12	Jul-2022	Teodorico-1 S1
PLQ-D1	212.4	120,000	0.19	Jul-2022	Teodorico-2 S1
PLQ-D2	133.1	100,000	0.15	Jul-2022	Teodorico-2 S2
PLQ-E2-F	416.3	130,000	0.10	Jul-2022	Teodorico-1 S2

Table 4-13 Initial Rates and Decline Rates for 3P reserves in Teodorico Field

Sand	Recoverable Volumes (MMscm)	Initial Rate (Day 1), scm/d	Decline Rate per Year	First Production	Well
PLQ-C	413.5	150,000	0.09	Jul-2022	Teodorico-1 S1
PLQ-D1	243.6	140,000	0.19	Jul-2022	Teodorico-2 S1
PLQ-D2	186.9	120,000	0.15	Jul-2022	Teodorico-2 S2
PLQ-E2-F	521.1	150,000	0.10	Jul-2022	Teodorico-1 S2

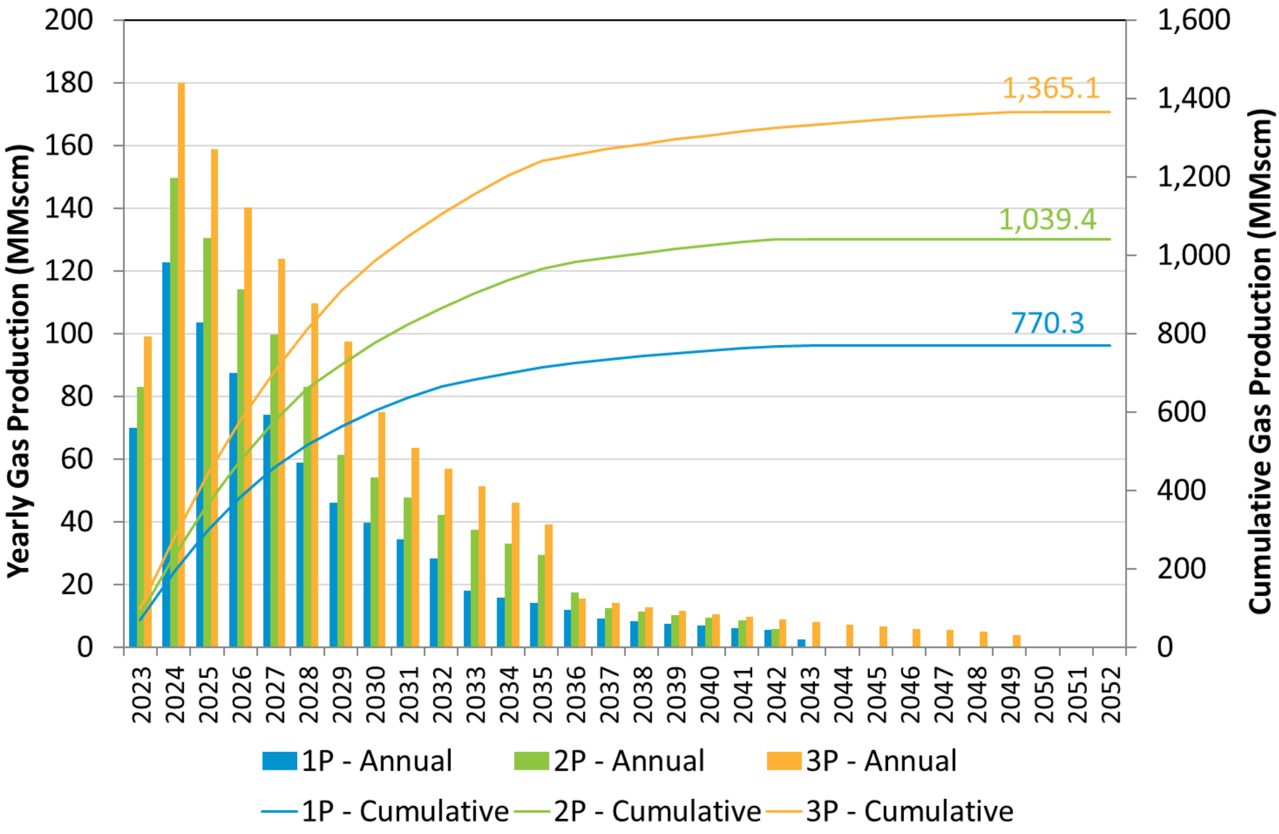


Figure 4-11 Unconstrained Production Profiles of Teodorico 1P, 2P, 3P (before economic cut-off)

Table 4-14 Unconstrained Production Profiles, Teodorico (before economic cut-off)

Year	1P		2P		3P	
	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)
2023	69.90	69.90	82.88	82.88	98.99	98.99
2024	122.78	192.68	149.58	232.47	180.00	279.00
2025	103.39	296.07	130.47	362.94	158.66	437.66
2026	87.32	383.40	113.93	476.87	140.08	577.73
2027	73.97	457.37	99.62	576.49	123.87	701.61
2028	58.74	516.11	83.09	659.58	109.72	811.33
2029	46.02	562.13	61.43	721.01	97.34	908.67
2030	39.76	601.90	54.13	775.13	75.04	983.70
2031	34.44	636.34	47.76	822.89	63.54	1047.24
2032	28.26	664.60	42.19	865.08	56.99	1104.23
2033	18.10	682.70	37.31	902.39	51.19	1155.42
2034	15.90	698.59	33.04	935.43	46.04	1201.46
2035	14.00	712.59	29.29	964.71	39.22	1240.68
2036	11.95	724.54	17.31	982.02	15.54	1256.22
2037	9.10	733.64	12.37	994.39	14.10	1270.32
2038	8.24	741.88	11.24	1005.64	12.80	1283.12
2039	7.46	749.34	10.21	1015.85	11.62	1294.74
2040	6.75	756.09	9.28	1025.12	10.54	1305.28
2041	6.12	762.20	8.43	1033.55	9.57	1314.85
2042	5.54	767.74	5.81	1039.36	8.69	1323.54
2043	2.57	770.31	0.00	1039.36	7.88	1331.42
2044	0.00	770.31	0.00	1039.36	7.16	1338.58
2045	0.00	770.31	0.00	1039.36	6.49	1345.07
2046	0.00	770.31	0.00	1039.36	5.89	1350.97
2047	0.00	770.31	0.00	1039.36	5.35	1356.32
2048	0.00	770.31	0.00	1039.36	4.86	1361.18
2049	0.00	770.31	0.00	1039.36	3.88	1365.06
2050	0.00	770.31	0.00	1039.36	0.00	1365.06
2051	0.00	770.31	0.00	1039.36	0.00	1365.06
2052	0.00	770.31	0.00	1039.36	0.00	1365.06

Created by
Andrew Webb, Manager, Petroleum Reservoir and Economics
Tel: +44 (0)1293 683000 – andrew.webb@cgg.com

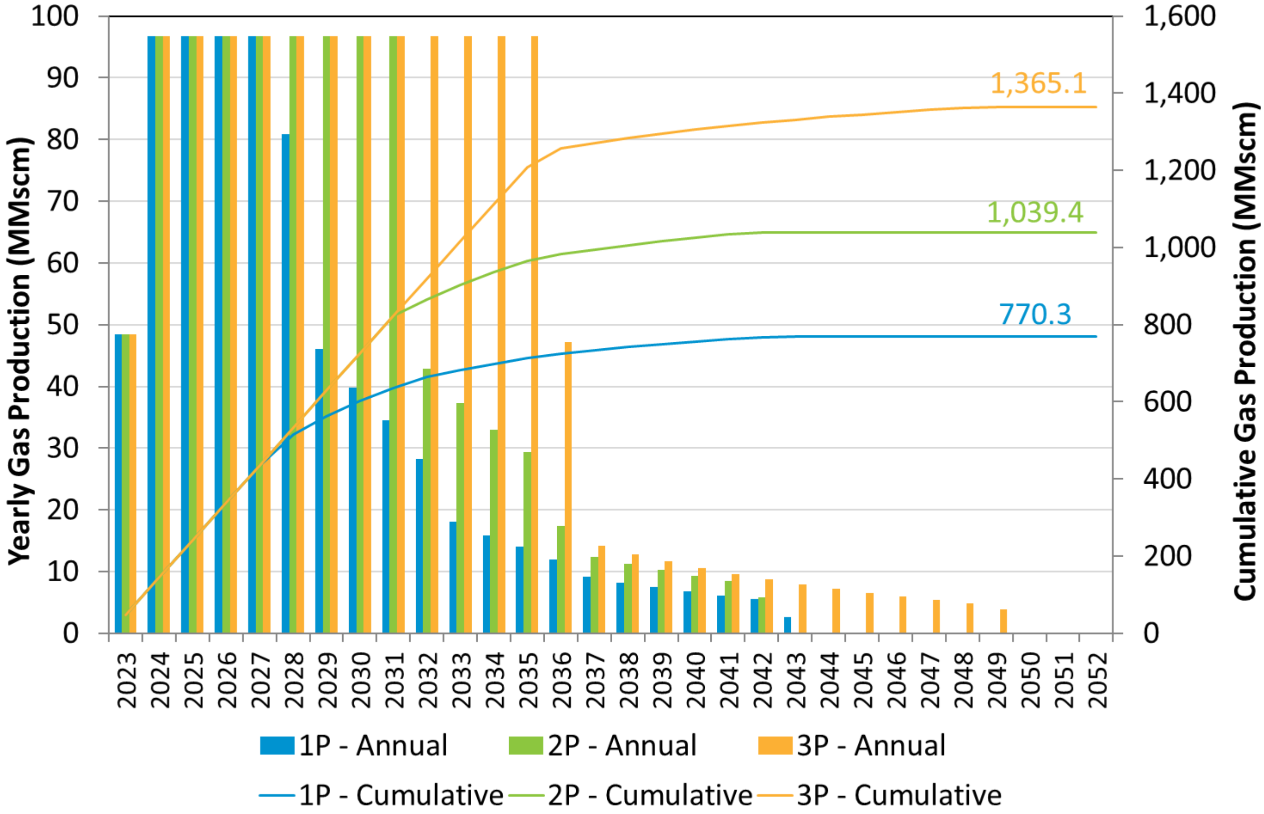


Figure 4-12 Constrained Production Profiles of Teodorico 1P, 2P, 3P (before economic cut-off)

Table 4-15 Constrained Production Profiles, Teodorico (before economic cut-off)

Year	1P		2P		3P	
	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)	Annual Production (MMscm)	Cumulative Production (MMscm)
2023	48.36	48.36	48.36	48.36	48.36	48.36
2024	96.73	145.09	96.73	145.09	96.73	145.09
2025	96.73	241.81	96.73	241.81	96.73	241.81
2026	96.73	338.54	96.73	338.54	96.73	338.54
2027	96.73	435.26	96.73	435.26	96.73	435.26
2028	80.85	516.11	96.73	531.99	96.73	531.99
2029	46.02	562.14	96.73	628.71	96.73	628.71
2030	39.76	601.90	96.73	725.44	96.73	725.44
2031	34.44	636.34	96.73	822.16	96.73	822.16
2032	28.26	664.60	42.91	865.08	96.73	918.89
2033	18.10	682.70	37.31	902.39	96.73	1015.61
2034	15.90	698.59	33.04	935.43	96.73	1112.34
2035	14.00	712.59	29.29	964.71	96.73	1209.06
2036	11.95	724.54	17.31	982.02	47.16	1256.22
2037	9.10	733.64	12.37	994.40	14.10	1270.32
2038	8.24	741.88	11.24	1005.64	12.80	1283.12
2039	7.46	749.34	10.21	1015.85	11.62	1294.74
2040	6.75	756.09	9.28	1025.12	10.54	1305.28
2041	6.12	762.20	8.43	1033.55	9.57	1314.85
2042	5.54	767.74	5.81	1039.36	8.69	1323.54
2043	2.57	770.31	0.00	1039.36	7.88	1331.43
2044	0.00	770.31	0.00	1039.36	7.16	1338.58
2045	0.00	770.31	0.00	1039.36	6.49	1345.08
2046	0.00	770.31	0.00	1039.36	5.89	1350.97
2047	0.00	770.31	0.00	1039.36	5.35	1356.32
2048	0.00	770.31	0.00	1039.36	4.86	1361.18
2049	0.00	770.31	0.00	1039.36	3.88	1365.06
2050	0.00	770.31	0.00	1039.36	0.00	1365.06
2051	0.00	770.31	0.00	1039.36	0.00	1365.06
2052	0.00	770.31	0.00	1039.36	0.00	1365.06

5 ECONOMIC ANALYSIS

5.1 METHODOLOGY

Net Present Values (NPVs) have been calculated using industry standard discounted cash flow analysis. CGG have created an after-tax economic model in Excel™ for this purpose. The estimated production profiles and costs have then been used to calculate NPVs for each of the reserve categories.

The tax benefit of any brought forward losses and/or undepreciated capex arising from trading activities and expenditure prior to the effective date has not been included in the valuation. Corporate overhead costs not specifically allocated to the operating costs and any payments relating to the farm-in agreements have also not been included.

It should be noted that the NPVs presented are not deemed to be the market value of the asset, and that the values may be subject to significant variation with time due to changes in the underlying input assumptions as more data becomes available and interpretations change.

5.2 ASSUMPTIONS

5.2.1 Gas prices

It is assumed that future gas production is sold at the Italian spot gas price – the Punto di Scambio Virtuale (PSV) price. CGG have assumed that the PSV price will follow the forward curve for the Dutch TTF spot price plus Euro 1.9/Mwh, which was the average difference between the two prices in 2018. Beyond the end of the current quoted TTF forward curve in 2024, it is further assumed that the price escalates at 2% per year. The PSV price assumption used in the economic evaluation, which is based on the TTF forward curve on 24th April 2019, is tabulated below.

Table 5.1 PSV gas price assumption

Year	Base price (Euro/m^3)
2019	0.199
2020	0.232
2021	0.228
2022	0.222
2023	0.219
2024	0.215
2025+	+2% pa

In order to capture gas price uncertainty, low and high price decks have been taken as +/- 15% for 2019 and 2020, and +/-20% for 2021 onwards. The narrower near-term range reflects the greater certainty of near-term pricing.

Created by
Andrew Webb, Manager, Petroleum Reservoir and Economics
Tel: +44 (0)1293 683000 – andrew.webb@cgg.com

The calorific value of gas from the fields is assumed to be 38MJ/m3. No condensate sales have been assumed from any of the fields.

5.2.2 Fiscal System

Italy's upstream oil and gas industry operates under a concessionary royalty and taxation system. Concessions are granted by the state through the National Office of Mining, Hydrocarbons and Geothermal Resources (UNMIG).

Royalty is based on the wellhead value of production, with certain volumes exempt depending on the region and type of development. The applicable royalty rate for Selva gas production is assumed to be 10%, with an annual royalty free allowance of 25 million cubic metres. For Teodorico gas production the applicable royalty rate is assumed to be 7%, with an annual royalty free allowance of 80 million cubic metres.

Profits are subject to standard Italian corporate income tax (IRES), for which the current rate is 24.0%. Tax losses can be carried forward indefinitely, and allowances are as follows:

- Exploration and Appraisal costs at 100 percent as incurred.
- Non-Well Capital costs depreciated at 15 percent, on a straight line basis (10% in the 7th year).
- Well Capital costs depreciated on a unit of production basis.
- Abandonment expenditure depreciated on a unit of production basis.
- Operating expenditure at 100 percent as incurred.
- Royalty payments at 100 percent as incurred.

In addition to IRES, companies with onshore production are also subject to a regional income tax (IRAP). The IRAP rate is assumed to be 3.9%, and is calculated in a similar way to IRES.

5.2.3 Other assumptions

The following assumptions have also been used by CGG.

Table 5.2 Economic Parameters

Parameter	Value
Discount Factor	10%
Discount Methodology	Mid-Year
Cost /Price Inflation	2% per annum
Discount Date	1st January 2019

Created by
Andrew Webb, Manager, Petroleum Reservoir and Economics
Tel: +44 (0)1293 683000 – andrew.webb@cgg.com

5.3 SELVA

5.3.1 Facilities and costs

The proposed development plan for Selva consists of surface processing facilities and a 1 km export pipeline to the SNAM grid. The surface facilities will include skid mounted separation and dehydration units, fiscal metering and produced water storage tanks. An allowance has also been made to add compression later in field life. The estimated development costs are as follows:

Table 5.3 Development Costs (Gross 100%)

Item	€ MM
Surface facilities	1.420
Compressor	0.230
Pipeline to grid	0.180
Project Management	0.137
Environmental	0.350
Insurance	0.023
Total	**2.339**

Operating costs are estimated to be approximately €0.3MM per year with an additional charge of €0.015/M^3 for compression when required. Abandonment costs at the end of field life are estimated to be €1.363MM. CGG have reviewed these assumptions, which are deemed to be reasonable.

5.3.2 Results

NPVs are presented for the 1P, 2P and 3P cases for a 100% field interest and PVO net interest at base, low and high gas prices.

Table 5.4 Selva NPV10s (Gross and net PVO)

Gas Price	Gross (€ MM)			Net attributable (€ MM)			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Base	10.2	28.8	49.3	6.4	18.2	31.0	PVO
Low	7.6	22.4	38.7	4.8	14.1	24.4	
High	12.8	35.3	59.8	8.1	22.2	37.7	

Capital and operating cost sensitivities to NPV have been performed at the base gas price and are presented in the table below.

Table 5.5 Selva NPV10 cost sensitivities (Gross)

Gas price	NPV10 € MM		
	Proved	Proved & Probable	Proved, Probable & Possible
Base	10.2	28.8	49.3
Capex +25%	9.6	28.3	48.7
Capex -15%	10.6	29.2	49.6
Opex +25%	9.9	28.3	48.6
Opex -15%	10.4	29.2	49.7

5.4 TEODORICO

5.4.1 Facilities and costs

The Teodorico discovery is located in 30 metres of water, approximately 20 km from the coast, in the northern Adriatic Sea. The area is a mature production province with existing gas production platforms connected to the shore by pipelines.

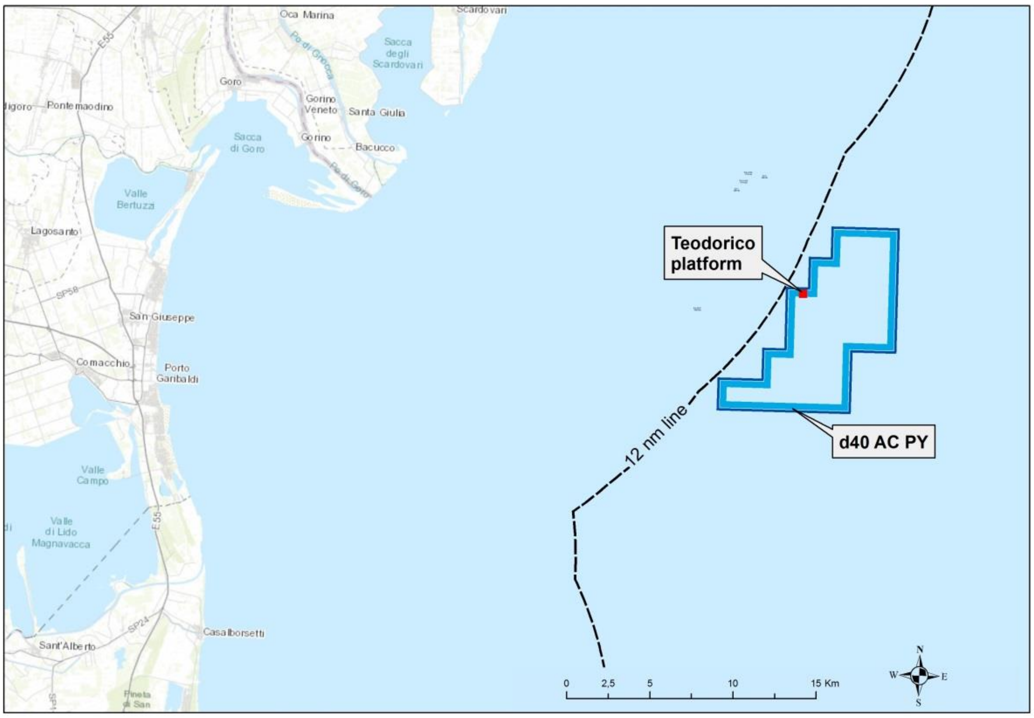


Figure 5-1 Teodorico proposed production licence and proposed platform location re. 12 mile limit

PVO's most likely development concept for Teodorico is an unmanned tripod wellhead platform with minimal topside facilities. This platform, located outside the national 12 mile exclusion zone for economic activities, would be tied-back to, and controlled from, an existing offshore platform approximately 12 km away. This is currently assumed to be Naomi-Pandora (operated by ENI S.p.A), which would provide gas conditioning, compression facilities and an entry point to the existing export pipeline.

Gas would be transported from the Naomi-Pandora platform, using the existing pipeline, to the ENI operated Casalborsetti gas terminal on the coast. This development plan would mean that there would be no new "beach crossing" for a new pipeline and no new construction of infrastructure onshore.

Pre-FEED studies on the tripod option have been performed by RINA D'Appolonia, an experienced firm of Italian engineering consultants. These studies involved geotechnical and metocean reviews, jacket and topsides conceptual design, and well engineering. PVO has stated that to date they have invested over one million Euros in this study and other preliminary work for the field development.

As part of the submission to the Ministry for conversion to a production licence, PVO has updated their previous development cost estimate. This was collated in the PVO document entitled: Stima dei Costi – Conceptual Design Campo Gas Teodorico, Rev 2, which was also submitted to the Ministry. This document was filed and officially approved by the Ministry in November 2015.

CGG has reviewed the cost estimates and schedule provided therein and benchmarked them against its own cost database. CGG's view is that the expenditures and schedules estimated by PVO are reasonable and in line with industry norms. These estimates have therefore formed the basis of CGG's economic evaluation of the resources.

The gross capital costs of developing the field, assuming tie-back to Naomi-Pandora, are summarised in the table below:

-	Wells (2 No.)	21.4 €MM
-	Production facilities and platform	22.7 €MM
-	Tie-in pipeline to nearby platform	4.4 €MM
-	Project management, G&G etc.	3.2 €MM
-	Contingency	2.0 €MM
		Total 53.7 €MM

The profiles are based on production from two dual completed new wells in the Pliocene and Quaternary. Dry trees on the wellhead platform will enable close monitoring of production from multiple reservoirs and low cost work-overs to be carried out if needed.

The upper reservoirs will need compression (lower reservoirs are supported by a strong aquifer). The economics in this report are therefore predicated on there being available existing compression at the host platform as well as sufficient export pipeline capacity.

PVO have assumed fixed operating costs of € 1.00MM per year would be incurred for the offshore production facilities owned by the company. In addition a tariff of €3.5 cents per m3 has been assumed by PVO. This would cover compression and processing at the Naomi-Pandora platform, transportation through the export pipeline, and onshore processing if required. These are deemed by CGG to be reasonable working assumptions, although it is understood that no formal tariff agreements have yet been made with third parties regarding processing and transportation services. Well work-over costs have not been included in the operating costs.

Costs for abandoning the field facilities are assumed by PVO to be € 5.00MM. These are deemed by CGG to be reasonable.

5.4.2 Results

NPVs are presented for the 1P, 2P and 3P cases for a 100% field interest and PVO net interest at base, low and high gas prices.

Table 5.6 NPV10s for Teodorico (Gross and net PVO)

Gas Price	Gross (€ MM)			Net attributable (€ MM)			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Base	5.8	17.8	28.3	5.8	17.8	28.3	PVO
Low	-5.8	3.4	11.0	-5.8	3.4	11.0	
High	17.3	32.3	45.4	17.3	32.3	45.4	

Capital and operating cost sensitivities to NPV have been performed at the base gas price and are presented in the table below.

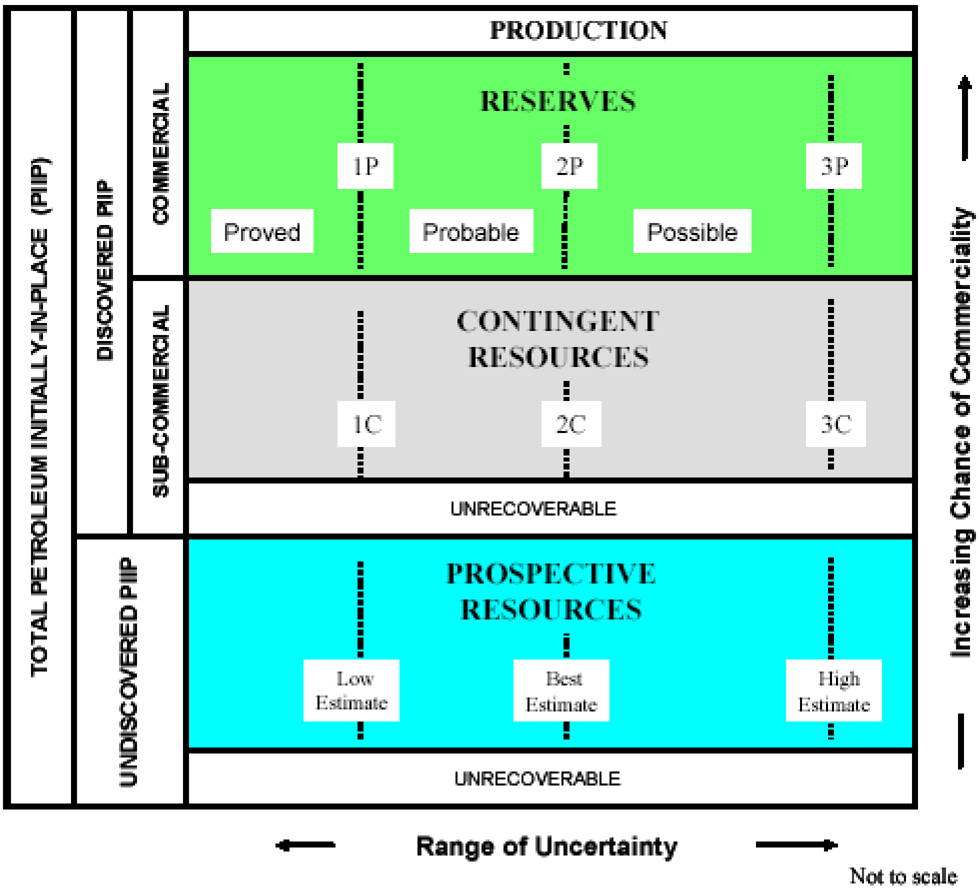
Table 5.7 NPV10 cost sensitivities for Teodorico (Gross)

Gas price	NPV10 € MM		
	Proved	Proved & Probable	Proved, Probable & Possible
Base	5.8	17.8	28.3
Capex +25%	-4.7	7.4	17.8
Capex -15%	12.0	24.1	34.5
Opex +25%	1.7	13.2	22.8
Opex -15%	8.3	20.7	31.6

6 APPENDIX A: DEFINITIONS

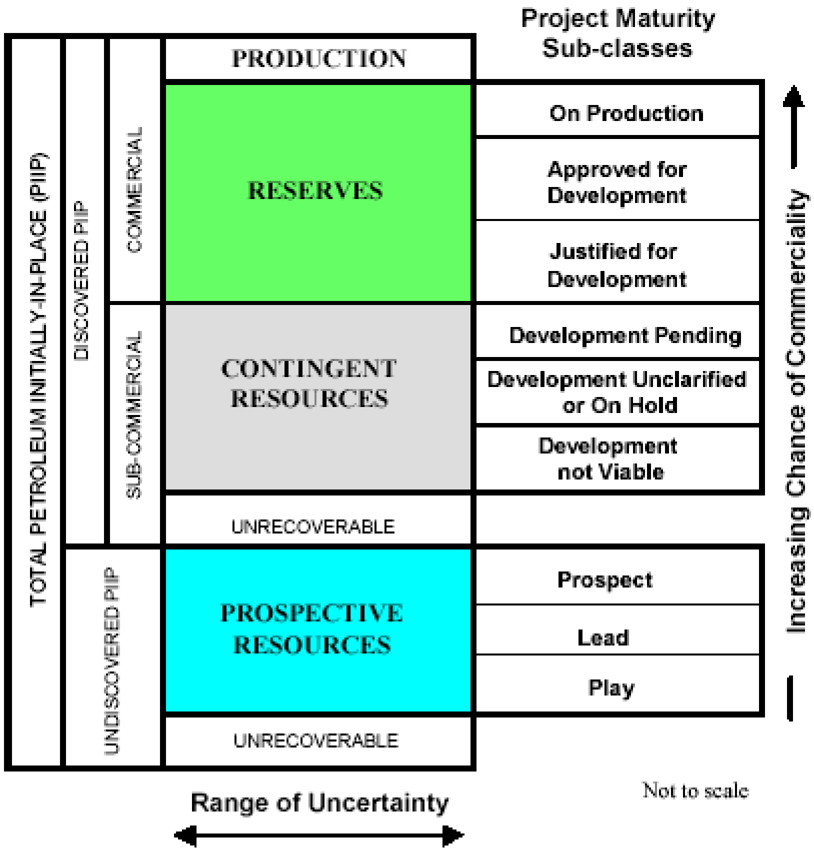
6.1 DEFINITIONS

The petroleum reserves and resources definitions used in this report are those published by the Society of Petroleum Engineers and World Petroleum Congress in 1998, supplemented with guidelines for their evaluation, published by the Society of Petroleum Engineers in 2001 and 2007. The main definitions and extracts from the SPE Petroleum Resources Management System (2007) are presented in the following sections.



Source: SPE Petroleum Resources Management System 2007

Figure 6.1 Resources Classification Framework



Source: SPE Petroleum Resources Management System 2007

Figure 6.2 Resources Classification Framework: Sub-classes based on Project Maturity

6.1.1 Total Petroleum Initially-In-Place

Total Petroleum Initially-In-Place is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

6.1.2 Discovered Petroleum Initially-In-Place

Discovered Petroleum Initially-In-Place is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

6.1.3 Undiscovered Petroleum Initially-In-Place

Undiscovered Petroleum Initially-In-Place is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

6.2 PRODUCTION

Production is the cumulative quantity of petroleum that has been recovered at a given date. Production is measured in terms of the sales product specifications and raw production (sales plus non-sales) quantities required to support engineering analyses based on reservoir voidage.

6.3 RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations, from a given date forward, under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by development and production status.

The following outlines what is necessary for the definition of Reserve to be applied.

- A project must be sufficiently defined to establish its commercial viability
- There must be a reasonable expectation that all required internal and external approvals will be forthcoming
- There is evidence of firm intention to proceed with development within a reasonable time frame
- A reasonable timetable for development must be in evidence
- There should be a development plan in sufficient detail to support the assessment of commerciality
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria must have been undertaken
- There must be a reasonable expectation that there will be a market for all, or at least the expected sales quantities, of production required to justify development
- Evidence that the necessary production and transportation facilities are available or can be made available
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated

The "decision gate" whereby a Contingent Resource moves to the Reserves class is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.

A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives.

Created by
Andrew Webb, Manager, Petroleum Reservoir and Economics
Tel: +44 (0)1293 683000 – andrew.webb@cgg.com

6.3.1 Developed Producing Reserves

Developed Producing Reserves are expected quantities to be recovered from existing wells and facilities. Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

6.3.2 Developed Non-Producing Reserves

Developed Non-producing Reserves include shut-in and behind-pipe reserves.

Shut-in reserves are expected to be recovered from:

- Completion intervals that are open at the time of the estimate but that have not yet started producing
- Wells that were shut-in for market conditions or pipeline connections, or
- Wells not capable of production for mechanical reasons.

Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

6.3.3 Undeveloped Reserves

Undeveloped Reserves are quantities expected to be recovered through future investments such as

- From new wells on undrilled acreage in known accumulations
- From deepening existing wells to a different (but known) reservoir
- From infill wells that will increase recovery, or
- Where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to:
    - Recomplete an existing well or
    - Install production or transportation facilities for primary or improved recovery projects

Incremental recoveries through improved recovery methods that have yet to be established through routine, commercially successful applications are included as Reserves only after a favourable production response from the subject reservoir from either (a) a representative pilot or (b) an installed program, where the response provides support for the analysis on which the project is based.

Where reserves remain undeveloped beyond a reasonable timeframe, or have remained undeveloped due to repeated postponements, evaluations should be critically reviewed to document reasons for the delay in initiating development and justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay is justified, a reasonable time frame is generally considered to be less than five years.

6.3.4 Proved Reserves

Proved Reserves are those quantities of petroleum that, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

6.3.5 Probable Reserves

Probable Reserves are those additional reserves that analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved + Probable Reserves (2P).

When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

6.3.6 Possible Reserves

Possible Reserves are those additional reserves that analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved + Probable + Possible (3P), which is equivalent to the high estimate scenario.

When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

6.4 CONTINGENT RESOURCES

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality.

The term accumulation is used to identify an individual body of moveable petroleum. The key requirement in determining whether an accumulation is known (and hence contains Reserves or Contingent Resources) is that each accumulation/reservoir must have been penetrated by a well. In general, the well must have clearly demonstrated the existence of moveable petroleum in that reservoir by flow to surface, or at least some recovery of a sample of petroleum from the well. However, where log and/or core data exist, this may suffice provided there is a good analogy to a nearby, geologically comparable, known accumulation.

Estimated recoverable quantities within such discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves.

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively.

1C denotes low estimate scenario of Contingent Resources
2C denotes best estimate scenario of Contingent Resources
3C denotes high estimate scenario of Contingent Resources

Contingent Resources are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by their economic status.

6.4.1 Contingent Resources: Development Pending

Contingent Resources (Development Pending) are a discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are expected to be resolved within a reasonable time frame.

6.4.2 Contingent Resources: Development Un-Clarified/On Hold

Contingent Resources (Development Un-clarified / On hold) are a discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development.

6.4.3 Contingent Resources: Development Not Viable

Contingent Resources (Development Not Viable) are a discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential. The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognised in the event of a major change in technology or commercial conditions.

6.5 PROSPECTIVE RESOURCES

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. They are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

6.5.1 Prospect

A Prospect is classified as a potential accumulation that is sufficiently well defined to represent a viable drilling target.

6.5.2 Lead

A Lead is classified as a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.

6.5.3 Play

A Play is classified as a prospective trend of potential prospects that requires more data acquisition and/or evaluation in order to define specific Leads or Prospects.

6.6 UNRECOVERABLE RESOURCES

Unrecoverable Resources are that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities that are estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

7 APPENDIX B: NOMENCLATURE

1-D, 2-D, 3-D	1-, 2-, 3-dimensions
1P	proved
2P	proved + probable
3P	proved + probable + possible
acre	43,560 square feet
AOF	absolute open flow
API	American Petroleum Institute
av.	Average
AVO	Amplitude vs. Off-Set
bbl	barrel
bbl/d	barrels per day
BHP	bottom hole pressure
BHT	bottom hole temperature
boe	barrel of oil equivalent
Bscf	billion standard cubic feet
Bscm	billion standard cubic metres
Btu	British thermal unit
BV	bulk volume
c.	circa
CCA	conventional core analysis
CD-ROM	compact disc with read only memory
cgm	computer graphics meta file
CNG	compressed natural gas
CO_2	carbon dioxide
DHC	dry hole cost
DHI	direct hydrocarbon indicators
DPT	deeper pool test
DROI	discounted return on investment
DST	drill-stem test
DWT	deadweight tonnage
E & P	exploration & production
E	East
e.g.	for example
EAEG	European Association of Exploration Geophysicists
EOR	enhanced oil recovery
ESP	Electrical Submersible Pump
et al.	and others
EUR	estimated ultimately recoverable
FPSO	Floating Production Storage and Offloading vessel
ft/s	feet per second
G & A	general & administration
G & G	geological & geophysical
g/cm^3	grams per cubic centimetre
Ga	billion (10^9) years
GIIP	gas initially in place
GIS	Geographical Information Systems
GOC	gas-oil contact
GOR	gas to oil ratio
GR	gamma ray (log)
GWC	gas-water contact
H_2S	hydrogen sulphide
ha	hectare(s)
HI	hydrogen index
HP	high pressure
Hz	hertz
IDC	intangible drilling costs
IOR	improved oil recovery
IRR	internal rate of return
kg	kilogram
km	kilometre
km^2	square kilometres
kWh	kiloWatt-hours
LoF	life of field
LP	low pressure
LST	lowstand systems tract
LVL	low-velocity layer
M & A	mergers & acquisitions
m	metre
M	thousand
m/s	metres per second
Ma	million years (before present)
Mbbl/d	thousands of barrels per day
Mbbl/d	thousands of barrels per day
mbdf	metres below derrick floor
mbsl	metres below sea level
mD	millidarcies
MD	measured depth
mdst.	mudstone
MFS	maximum flooding surface
mg/gTOC	units for hydrogen index

mGal	milligals
MHz	megahertz
MJ	megajoule
ml	millilitres
mls	miles
MM	million
MMbbl	million bbls of oil
MMboe	million bbls of oil equivalent
MMscfd	million standard cubic feet per day
MMscm	million standard cubic metres
mmsl	metres below mean sea level
MMstb	million stock tank barrels
MMt	million tons
mN/m	interfacial tension measured unit
MPa	megapascals
Mscfd	thousand standard cubic feet per day
Mscm	thousand standard cubic metres
msec	millisecond(s)
MSL	mean sea level
mSS	metres subsea
MWh	MegaWatt-hours
N	north
NaCl	sodium chloride
NFW	new field wildcat
NGL	natural gas liquids
no.	number (not #)
NPV	net present value
Ø	porosity
OAE	oceanic anoxic event
OI	oxygen index
OWC	oil-water contact
P & A	plugged & abandoned
pbu	pressure build-up
perm.	permeability
PESGB	Petroleum Exploration Society of Great Britain
pH	-log H ion concentration
phi	unit grain size measurement
plc	public limited company
por.	Porosity
poroperm	porosity-permeability
ppm	parts per million
PRMS	Petroleum Resource Management System (SPE)
psi	pounds per square inch
RFT	repeat formation test
ROI	return on investment
ROP	rate of penetration
RT	rotary table
S	South
SCAL	special core analysis
scf	standard cubic feet
scm	standard cubic metre*
SPE	Society of Petroleum Engineers
SS	sub-sea
ST	sidetrack (well)
stb	stock tank barrel
std. dev.	standard deviation
STOIIP	stock tank oil initially in place
Sw	water saturation
TD	total depth
TDC	tangible drilling costs
Therm	105 Btu
Tscf	trillion standard cubic feet
TVD	true vertical depth
TVDSS	true vertical depth subsea
TWT	two-way time
US$	US dollar
US$MM	Millions of US dollars
UV	ultra-violet
VDR	virtual dataroom
W	West
WD	water depth
WHFP	wellhead flowing pressure
WHSP	wellhead shut-in pressure
wt%	percent by weight
XRD	X-ray diffraction (analysis)

Created by
Andrew Webb, Manager, Petroleum Reservoir and Economics
Tel: +44 (0)1293 683000 – andrew.webb@cgg.com