EVALUATION OF COLLE SANTO GAS PROJECT, ITALY AS AT SEPTEMBER 30, 2022

Field Study

Prepared on behalf of LN Energy Limited

218221
Final
October 26, 2022

rpsgroup.com

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Prepared on behalf of LN Energy Limited

Peer Review			
Andy Kirchin		Andy.Kirchin@rpsgroup.com	26 October 2022

Approval for issue		
Michael Gallup, P. Eng.	Michael.Gallup@rpsgroup	26 October 2022

Prepared by:

RPS

Michael Gallup
Technical Director - Engineering, North America

Suite 600
555 4th Avenue SW
Calgary AB
T2P 3E7

T +1 403 265 7226
E michael.gallup@rpsgroup.com

Prepared for:

LN Energy Limited

Mark Frascogna
CEO – LN Energy Limited

Suite 400,
3400 East Bayaud Avenue
Denver, Colorado 80209

T +1-601-942-3030
E mark.frascogna@lnenergygroup.com

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Project Title	**Evaluation of Colle Santo Gas Property as at September 30, 2022**		
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	Michael Gallup, P. Eng.	Michael Gallup	Publication Date
	Thomas Jerome, P. Geo.		
File Location:	**RPS Energy Canada Ltd.** Suite 600, 555 – 4th Avenue SW Calgary, Alberta T2P 3E7 Tel:1(403) 265-7226 Fax:1(403) 269-3175 Email: rpscal@rpsgroup.com		

Our Ref: 218221

Date: October 26, 2022

Suite 600
555 4th Avenue SW
Calgary AB
T2P 3E7
T +1 403 265 7226

LN Energy Limited
Attention: Mark Frascogna
Suite 400,
3400 East Bayaud Avenue
Denver, Colorado 80209

Dear Mr. Frascogna,

Evaluation of Colle Santo Gas Project as of September 30, 2022

As requested in the engagement letter dated June 6, 2022, RPS has evaluated the Proved and Proved+Probable Reserves of certain gas assets in which LN Energy Limited has a 100% working interest in the Abruzzo region of central Italy as of September 30, 2022 (“Effective Date”), and submit the attached report of our findings.

The evaluation was conducted based on the Petroleum Resources Management System, published in 2007, and revised in June 2018, and sponsored by the Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG), Society of Petroleum Evaluation Engineers (SPEE), Society of Exploration Geophysicists (SEG), Society of Petrophysicists and Well Log Analysts (SPWLA), and the European Association of Geoscientists & Engineers (EAGE). The assets have been evaluated and classified as Reserves within the Proved (1P) and Proved plus Probable (2P) categories. A summary of the resources and associated net present values are presented in the attached tables.

This report contains forward looking statements including expectations of future production and capital expenditures. Potential changes to current regulations may cause volumes actually recovered and amounts future net revenue actually received to differ significantly from the estimated quantities. Information concerning Reserves may also be deemed to be forward looking as estimates imply that the Reserves described can be profitably produced in the future. These statements are based on current expectations that involve a number of risks and uncertainties, which could cause the actual results to differ from those anticipated. These risks include, but are not limited to, the underlying risks of the oil and gas industry (i.e., operational risks in development, exploration and production; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of resources estimates; the uncertainty of estimates and projections relating to production, costs and expenses, political and environmental factors), and commodity price and exchange rate fluctuation. Present values for various discount rates documented in this report may not necessarily represent fair market value of the resources.

A boe conversion ratio of six (6) Mcf : one (1) barrel has been used within this report. This conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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Yours sincerely,
for RPS Energy Canada Ltd

Michael Gallup
Principal Advisor - Engineering, North America
T+1 403 265 7226
E michael.gallup@rpsgroup.com

INDEPENDENT PETROLEUM CONSULTANT'S CONSENT AND WAIVER OF LIABILITY

The undersigned firm of Independent Petroleum Consultants of Calgary, Alberta, Canada knows that it is named as having prepared an independent technical study of the Italian property controlled by LN Energy Limited and it hereby gives consent to the use of its name and to the said report. The effective date of the report is September 30, 2022.

In the course of the assessment, LN Energy Limited provided RPS Energy personnel with information which included petroleum and licensing agreements, geologic, geophysical and production information, cost estimates, contractual terms and studies made by other parties. Any other engineering or economic data required to conduct the assessment upon which the original and addendum reports are based, was obtained from public literature, and from RPS Energy non-confidential client files and previous technical resource assessment reports on the subject property. The extent and character of ownership and accuracy of all factual data supplied for this assessment, from all sources, has been accepted as represented. RPS Energy reserves the right to review all calculations referred to or included in the said reports and, if considered necessary, to revise the estimates in light of erroneous data supplied or information existing but not made available at the effective date, which becomes known subsequent to the effective date of the reports.

There is considerable uncertainty in attempting to interpret and extrapolate field and well data and no guarantee can be given, or is implied, that the projections made in this report will be achieved. The report and production potential estimates represent the consultant's best efforts to predict field performance within the scope, time frame and budget agreed with the client. Moreover, the material presented is based on data provided by LN Energy Limited. RPS Energy cannot be held responsible for decisions that are made based on this data or reports. The use of this material and reports is, therefore, at the user's own discretion and risk. The report is presented in its entirety and may not be made available or used without the complete content of the reports. RPS Energy liability shall be limited to the correction of any computational errors contained herein.

RPS Energy Canada Ltd.

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RPS ENERGY CANADA LTD.

RM SIGNATURE:

RM APEGA ID #: 85104

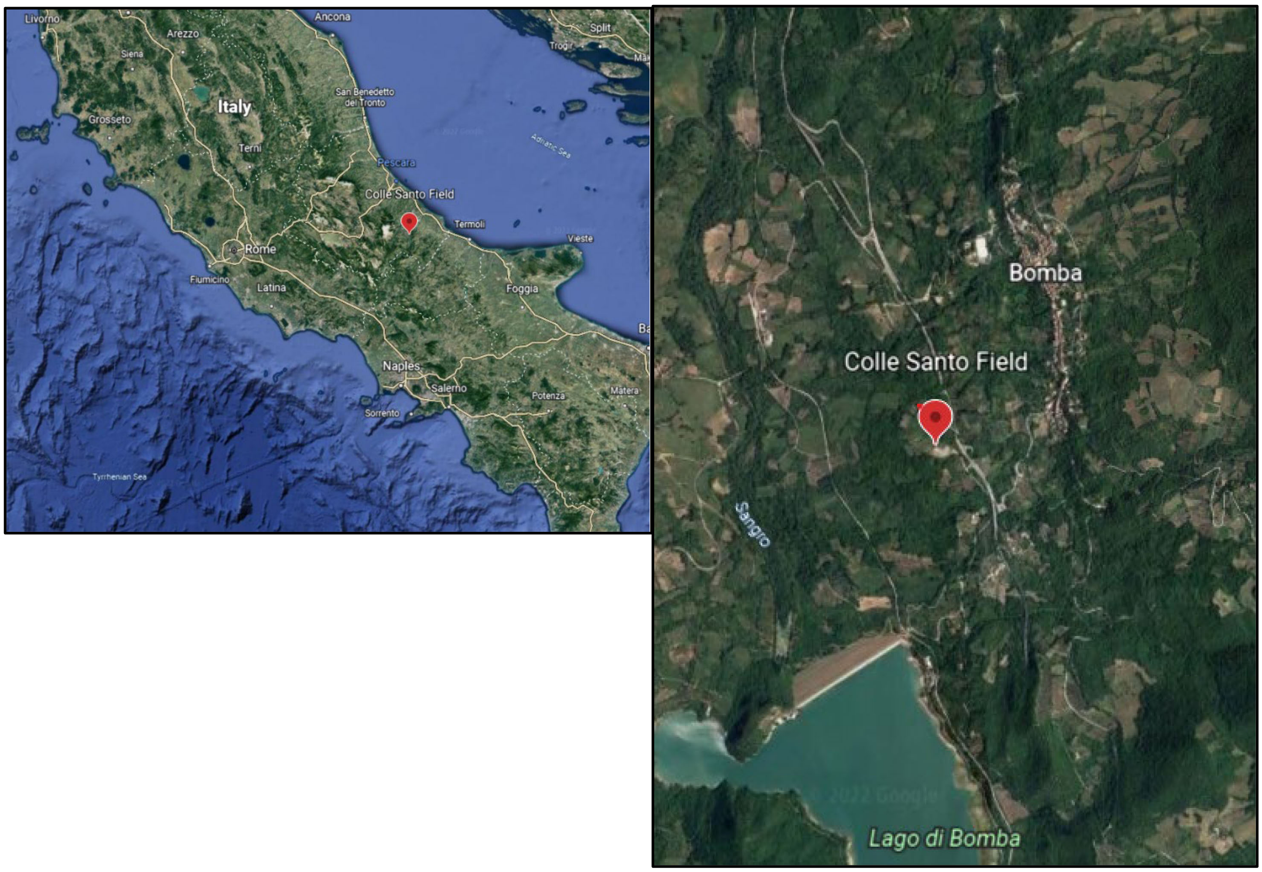
DATE: 26/10/2022

PERMIT NUMBER: P004348
The Association of Professional Engineers and Geoscientists of Alberta (APEGA)

EXECUTIVE SUMMARY

RPS Energy Canada Ltd. ("RPS") was commissioned by LN Energy Limited ("LN Energy") to provide an independent evaluation of the oil and gas resources contained within the Colle Santo field in the province of Chieti in the Abruzzo region of central Italy. The evaluation is focused on the Upper and Lower Apulian formations. The effective date of this report is September 30, 2022.

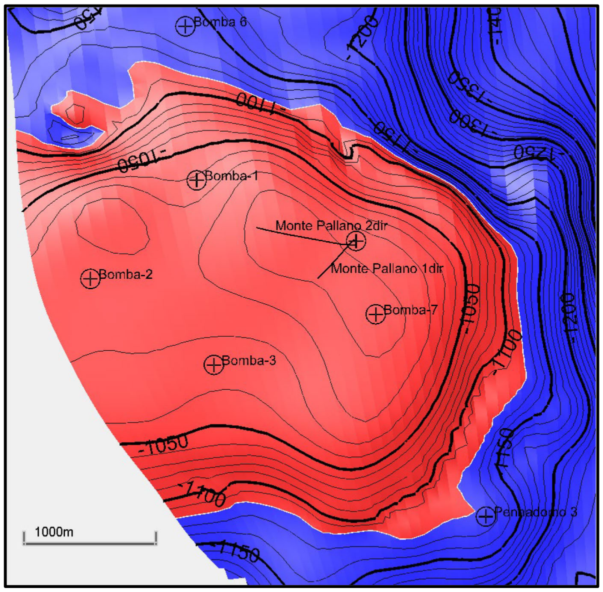
The location of the Colle Santo field is shown in the following map:



Colle Santo Field Location

Source: Base images from Google Earth

This report covers a 100% percent working interest in the Colle Santo field. Within the Colle Santo field area there a total of 8 wells that have penetrated the formations of interest, 2 of which were drilled, completed and tested in 2007 and are available for production.



Colle Santo Well Site

Source: Base image from Google Earth

RPS estimates of Reserves for LN Energy's interests (100%) in the Colle Santo field are summarized in the tables below. Cash flow forecasts have been generated for Reserves using RPS production forecasts which incorporate development plans and capital and operating cost estimates supplied by LN Energy and are also summarized below.

Summary of Reserves – 2050 Truncation

LN Energy Limited - Working Interest Reserves for Colle Santo as of September 30, 2022 Modified TTF Price Forecast								
	Gross Reserves				Net Reserves			
Reserves Category	Oil (MMstb)	Sales Gas (Bscf)	NGL& C5+ (MMbbl)	BOE (MMbbl)	Oil (MMstb)	Sales Gas (Bscf)	NGL& C5+ (MMbbl)	BOE (MMbbl)
PROVED	-	56.8	-	9.5	-	45.7	-	7.6
PROVED + PROBABLE	-	65.3	-	10.9	-	51.7	-	8.6

Net Present Value of Future Cash Flow for Reserves

LN Energy Limited - Reserves for Colle Santo - LNG Scenario as of September 30, 2022 Modified TTF Price Forecast					
Reserve Category	NPV Before Tax Million EUR€				
	0%	5%	10%	15%	20%
PROVED (1P)	628.8	402.3	290.7	227.5	187.4
PROVED + PROBABLE (2P)	727.9	440.0	307.0	235.3	191.5

A reconciliation is not included as this is the first evaluation of these assets completed by RPS, and the first independent evaluation of the assets by any independent third party since 2016.

RESERVE AND RESOURCE DEFINITIONS

The following definitions have been used by RPS Energy Canada Ltd. (RPS) in evaluating reserves. These definitions are based on the Petroleum Resources Management System, published in 2007, and revised in June 2018, and sponsored by the Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG), Society of Petroleum Evaluation Engineers (SPEE), Society of Exploration Geophysicists (SEG), Society of Petrophysicists and Well Log Analysts (SPWLA), and the European Association of Geoscientists & Engineers (EAGE).

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 satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

Reserves are classified according to a range of uncertainty according to the following categories:

Proved Reserves (P1)

Proved Reserves are those quantities of Petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from known reservoirs and under defined technical and commercial conditions. 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.

Probable Reserves (P2)

Probable Reserves are those additional Reserves which 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 plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

Possible Reserves (P3)

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 plus Probable plus Possible (3P) Reserves, 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. Possible Reserves that are located outside of the 2P area (not upside quantities to the 2P scenario) may exist only when the commercial and technical maturity criteria have been met (that incorporate the Possible development scope). Standalone Possible Reserves must reference a commercial 2P project (e.g., a lease adjacent to the commercial project that may be owned by a separate entity), otherwise stand-alone Possible is not permitted.

Reserves in each of the above three categories are subdivided according to their development and producing status according to the following:

Developed Reserves

Developed Reserves are reserves that are expected to be recovered from existing wells and facilities.

Developed Reserves may be further sub-classified as Producing or Non-Producing.

- **Developed Producing Reserves** are Developed Reserves that are expected to be recovered from completion intervals that are open and producing at the effective date. Improved recovery reserves are considered producing only after the improved recovery project is in operation.
- **Developed Non-Producing Reserves** are Developed Reserves that are either shut-in or behind-pipe.

Undeveloped Reserves are those quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling and completing a new well) is required to recomplete an existing well.

Contingent Resources

Contingent Resources are defined as those quantities of oil and gas estimated on a given date to be potentially recoverable from known accumulations using established technology or technology under development but is not currently economic. Contingent resources include, for example, accumulations for which there is currently no market. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

- **3C**: High Case – the actual resource quantity has a 10% chance of being higher than this volume
- **2C**: Best Estimate, or Expected Case – the actual resource quantity is equally likely to be greater than or less than this volume
- **1C**: Low Case – the actual resource quantity has a 90% chance of being greater than this volume
- **Development Pending:** 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 reasonably expected to be resolved within a reasonable time frame.
- **Development Unclarified or On Hold:** No current plans to develop or to acquire additional data at this time. 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. Development may be subject to a significant time delay.
- **Development Not Viable:** 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 recognized in the event of a major change in technology or commercial conditions.

Prospective Resources

Prospective Resources are defined as those quantities of oil and gas estimated on a given date to be potentially recoverable from undiscovered accumulations. They are technically viable but are not currently economic.

- **3U**: High Case – the actual resource quantity has a 10% chance of being higher than this volume
- **2U**: Best Estimate, or Expected Case – the actual resource quantity is equally likely to be greater than or less than this volume
- **1U**: Low Case – the actual resource quantity has a 90% chance of being greater than this volume

1 INTRODUCTION

RPS Energy Canada Ltd. (“RPS”) was commissioned by LN Energy Limited (“LN Energy”) to provide an independent evaluation of the oil and gas resources contained within the Colle Santo field in the province of Chieti in the Abruzzo region of central Italy. The evaluation is focused on the Upper and Lower Apulian formations. The effective date of this report is September 30, 2022.

1.1 Evaluated Property Summary

The Colle Santo field is located in the province of Chieti in the Abruzzo region of central Italy and currently covers an area of approximately 3000 acres, as shown in Figure 1-2. The field was discovered in 1966 and a total of 8 wells have been drilled since that time, Bomba-1, Bomba-2, Bomba-3, Bomba-6, Bomba-7, Pennadomo-3, MP-1, and MP-2. Seven of the wells produced gas during testing but have never been further developed for production, currently 6 of the 8 wells have been abandoned. The two most recent wells, MP-1 & MP-1, were drilled, completed and tested in 2007 with a combined rate of production of 20.5 MMscfd.

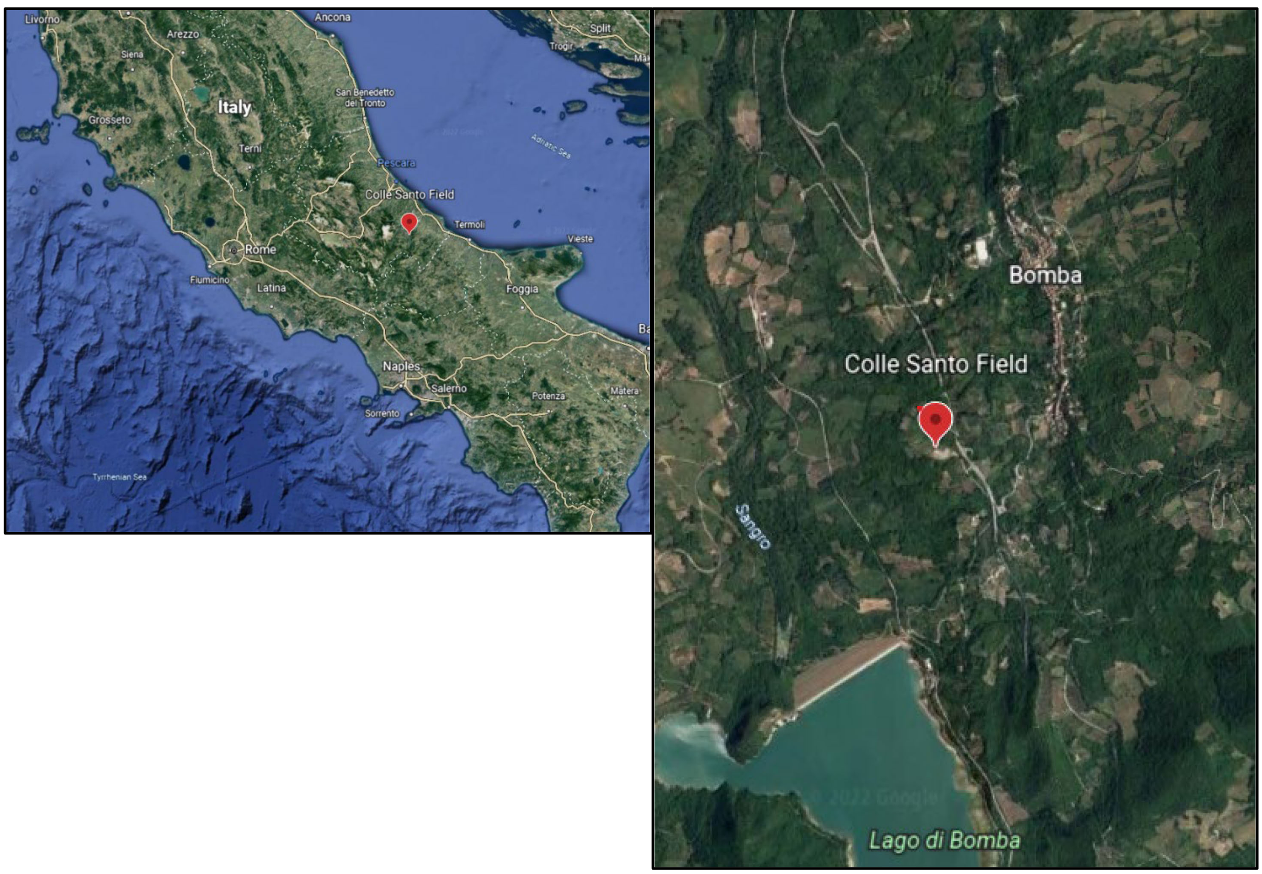


Figure 1-1: Location Map of Colle Santo Field

Source: Base images from Google Earth

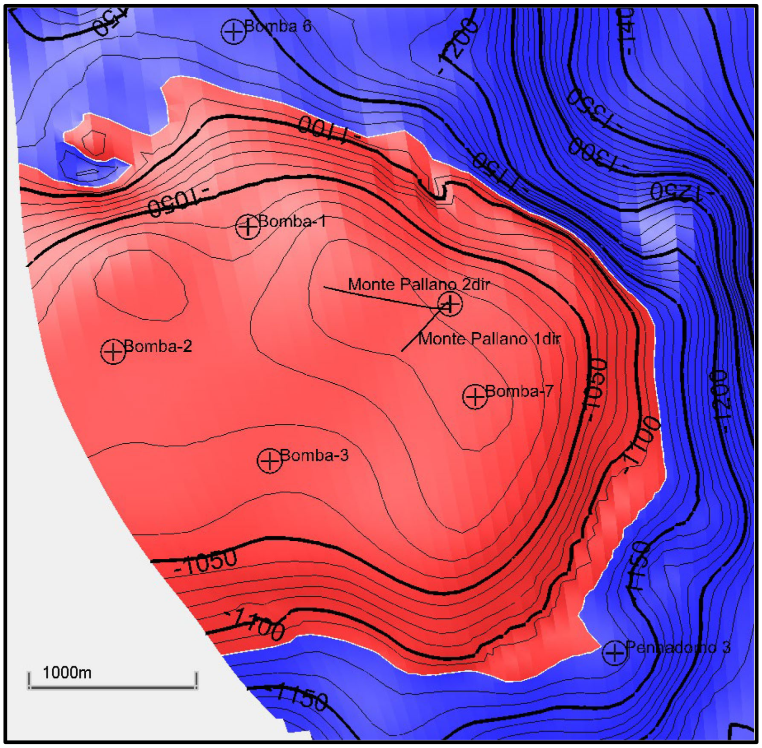


Figure 1-2: Well Location Map of Colle Santo Field

Table 1-1: Well Summary

Well Name	Year	Current Status
Bomba 1,2,3,6 & 7	Pre-1992	Plugged and Abandoned
Pennadomo-3	Pre-1992	Plugged and Abandoned
MP-1, MP-2	2007	Shut-in

1.2 Data Sources

RPS has based this assessment on data supplied by LN Energy. Key data and reports which form the basis of RPS' estimates, as provided by LN Energy unless noted otherwise, are as follows:

- Technical well data for the Colle Santo Wells, including well logs, tests, historical production, pressures, and PVT data
- Petrophysical analysis, presentation, and data
- Geophysical presentation and workstation review
- Presentation of geological interpretations, analogues, assumptions, and mapping/models
- Completion models and expected production forecasts generated by RPS

No site visit was conducted as a part of this evaluation.

2 GEOLOGICAL REVIEW

2.1 Geological Context

The Colle Santo gas field is located in central Italy, 36 km south-east of Chieti (Figure 2-1 and Figure 2-2). The Italian peninsula and its surrounding marine areas went through a complex geological evolution since the end of the Paleozoic (Giani et al., 2017).

The architecture of the Apennine fold-and-thrust belt is the result of this evolution. The ENE-trending Apennine belt developed during the Neogene and migrated eastward, as documented by the age of the syntectonic siliciclastic foredeep and piggyback deposits. In this geodynamic setting, several petroleum systems have developed, some of which have a primary economic significance. During the Neogene-Quaternary, in the Central Apennines, pre-orogenic normal faults related to the Mesozoic rift were reactivated with compressional kinematics generating positive structures (Figure 2-2). The Casoli-Bomba structure can be interpreted as a pop-up or a shortcut structure resulting from normal fault inversion. The Colle Santo gas field (average depth 1000 m ssl) is hosted in the southern portion of the buried Casoli-Bomba structure (Figure 2-2b).

From a lithological point of view, the reservoir is made up of limestones belonging to the Bolognano Formation (upper Miocene) and to the underlying undifferentiated carbonate platform units (Cretaceous - Miocene age Apulia-Adriatic deformed units as shown in Figure 2-3). The trap is a NS trending asymmetric anticline associated with a NNW-SSE striking back thrust verging toward SW (Figure 2-3). The aquifer connected to the reservoir extends to the north and is bounded in the other directions by two sealing faults. They correspond to the SW-verging back thrust and to an east-verging thrust, respectively. The cap rock which seals the reservoir is a continuous layer made up of shaly marl (Bolognano Formation) with an average thickness of 20–25 m.

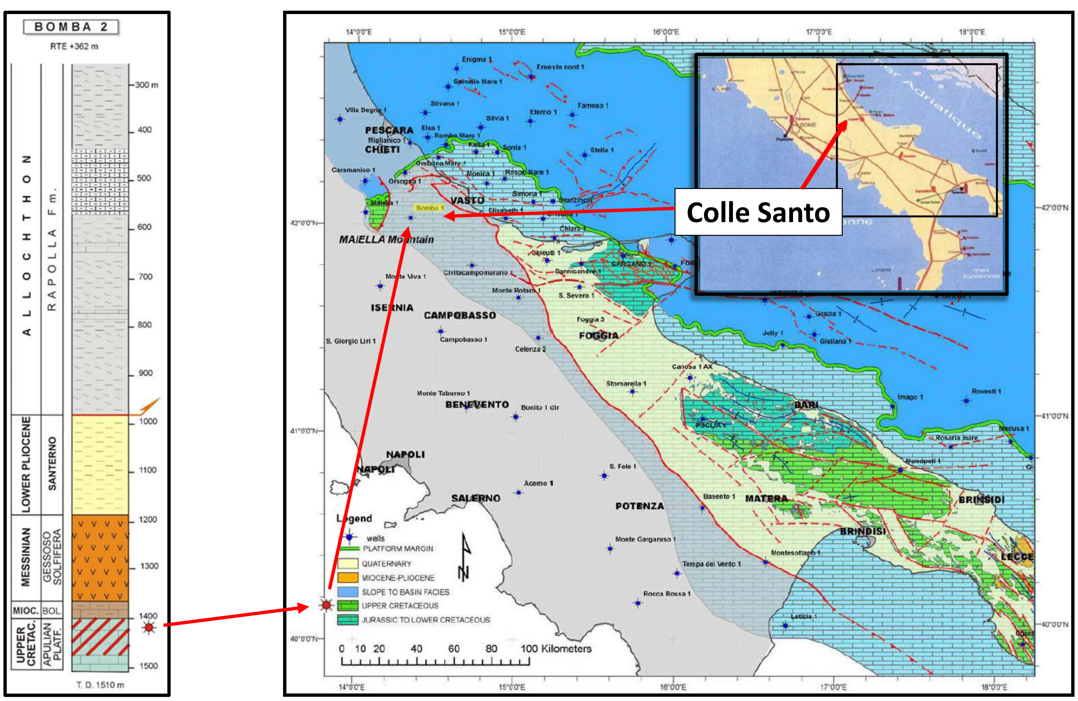


Figure 2-1: Apulia Carbonate Platform and the Colle Santo field. Map location vs stratigraphy along the well Bomba 2

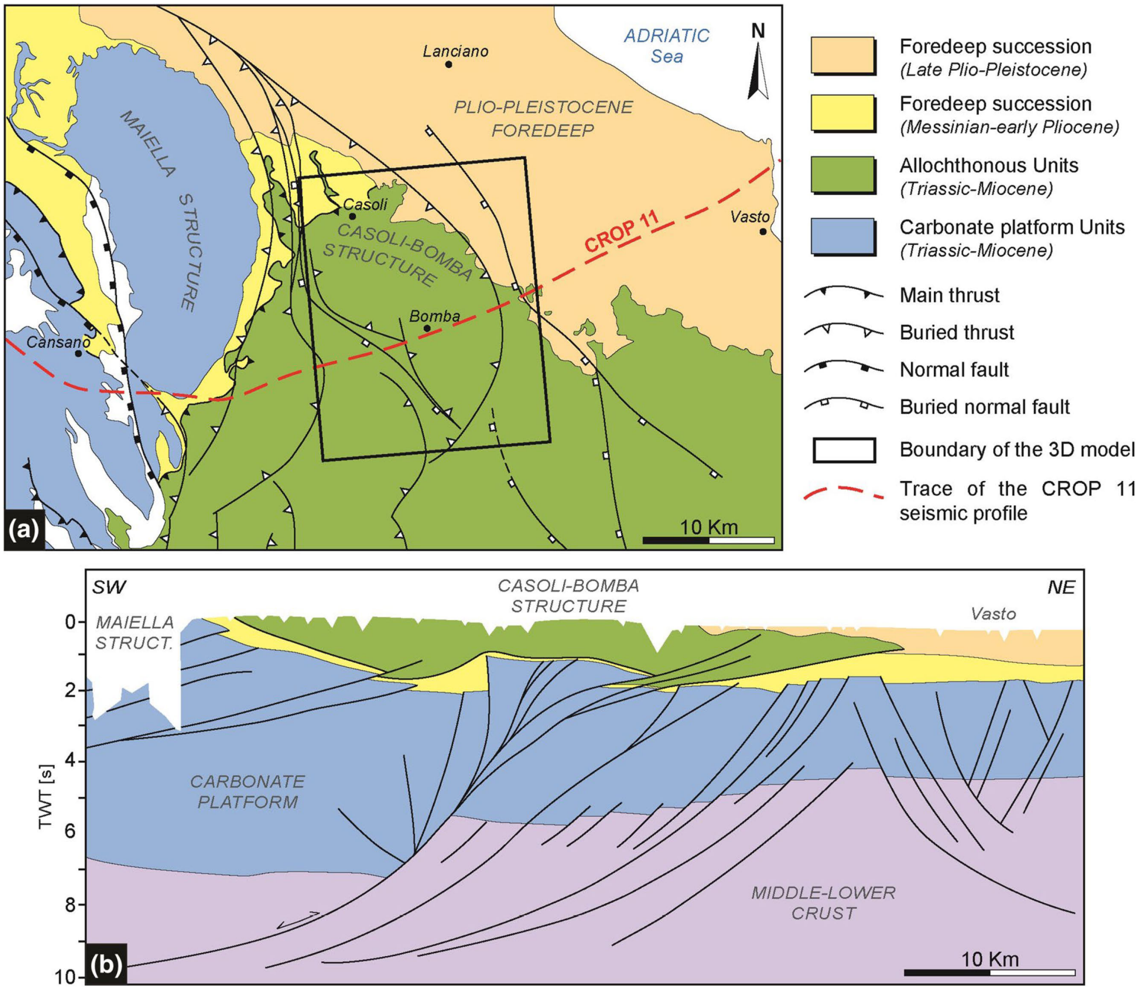


Figure 2-2: **a) Simplified structural map of the central-southern Apennine around the modeled area. b) Line drawing of the eastern part of the CROP 11 seismic profile (from Giani et al, 2017).**

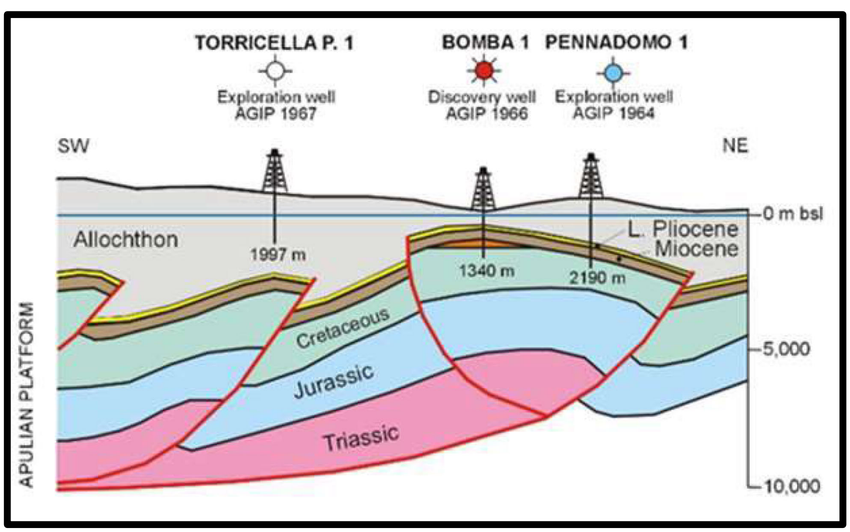


Figure 2-3: **SW-NE cross-section through the structure**

2.2 Geophysical Data

Multiple seismic 2D lines were shot between the 1960s and 1980s.

The data available for the present study were taken from work done for the construction of a 3D regional model used to characterize the possible subsidence on the surface due to this gas reservoir (Giani et al., 2017). That study concluded that the average annual ground displacement due to production should be one order of magnitude lower than the existing natural annual excursion monitored at the time via GPS systems.

For that work in the late 2010s (Giani et al., 2017), approximately half of the 2D seismic lines were used (2D lines highlighted in yellow on Figure 2-4A to compare with all the lines (yellow and green) shown on Figure 2-4B). This coverage is good enough to have a reasonable estimate of the structure associated with the main faulting which can be reliably used for in-place volume calculations (see the next section). A summary of the work done in the late 2010s on this subset of the 2D seismic lines is set out below.

The seismic data available for that study ranged from mid-1960’s 24-channel single-fold profiles to 96-channel 12-fold data recorded in the early-1980’s (Table 2-1). No more recent seismic data have been recorded in this area. As would be expected with the different acquisition parameters, the data quality can be highly variable.

The ½ scale paper sections were scanned to SEGY format and basic filtering applied. A generalized velocity function was derived and the stack only sections were migrated. The migration was not particularly successful as a result of the structural complexity. Of the nine lines in the project, there are five different datums annotated on the sections but in no case is a correction velocity shown. Bomba-7 is the only vertical well that has a complete sonic log and it falls on the intersection of two seismic lines, CH-380-80 and PEN-4 (Figure 2-4A and Figure 2-5). An integration of the Bomba-7 sonic log was used to generate a time-to-depth (T-D) curve at this location. The top Messinian marker has a large reflection coefficient and it was correlated with the stacked seismic data. Line PER-76-07 provided the most confident correlation, having a good expression of the unconformity with the overlying flysch sequence. The T-D curve generated at Bomba-7 generally provided a good tie with the Messinian marker at other well locations with the exception of Bomba-1 and Bomba-3, which required a lower correction velocity.

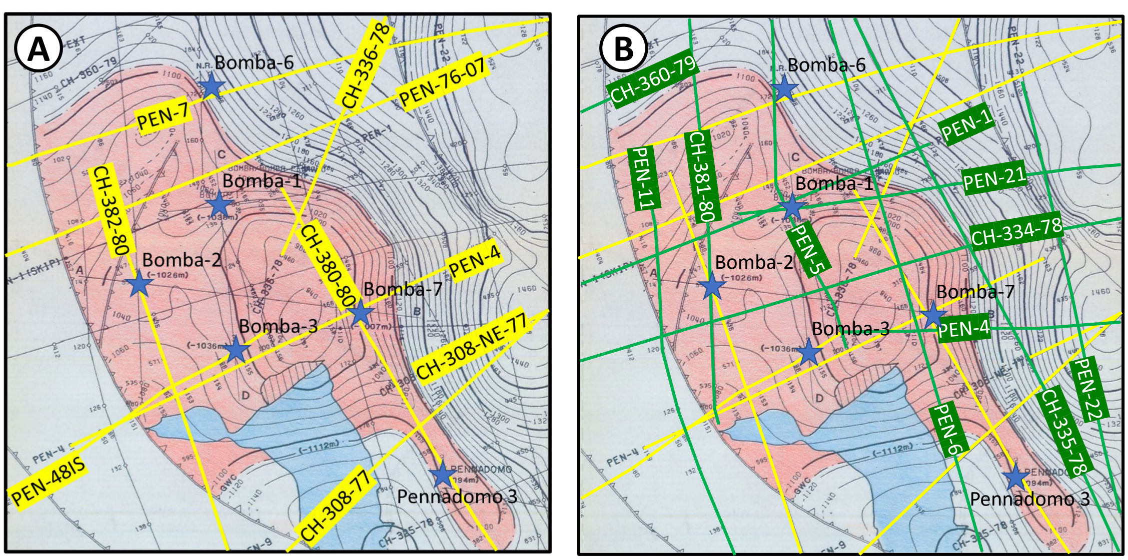


Figure 2-4: Existing 2D seismic lines.
A) Lines (yellow) used to build a static model in 2015.
B) Additional lines in the area (green).

Table 2-1: 2D seismic data used for building a static model in 2015

Line No.	Data Type	Date Recorded	Processed Version	Processed By	Source	Max Offset (m)	Fold (%)	Datum (m)	Data Quality
PER-76-07	MIG	Sept.1976	Oct.1996	CGG	Dynamite	1900	1200	400	G
PEN-7	MIG	Aug.1967	May.1980	Western	Geoflex	1350	600	MSL	F
PEN-4-BIS	MIG	Aug.1967	May.1980	Western	Geoflex	1350	600	MSL	F
PEN-4	STK	April.1966	May.1967	AGIP	Dynamite	300	100	150	P
CH-308-77	STK	July.1977	April.1978	CGG	Dynamite	1900	1200	MSL?	F
CH-308NE-77	STK	July.1977	April.1978	CGG	Dynamite	1900	1200	MSL?	F
CH-380-80	MIG	Oct.1980	Aug.1989	Western	Dynamite	1900	1200	800	F
CH-382-80	STK	Oct.1981	July.1989	Western	Dynamite	1900	1200	800	F
CH-336-78	STK	Oct.1978	March.1982	AGIP	Dynamite	1900	1200	MSL	G

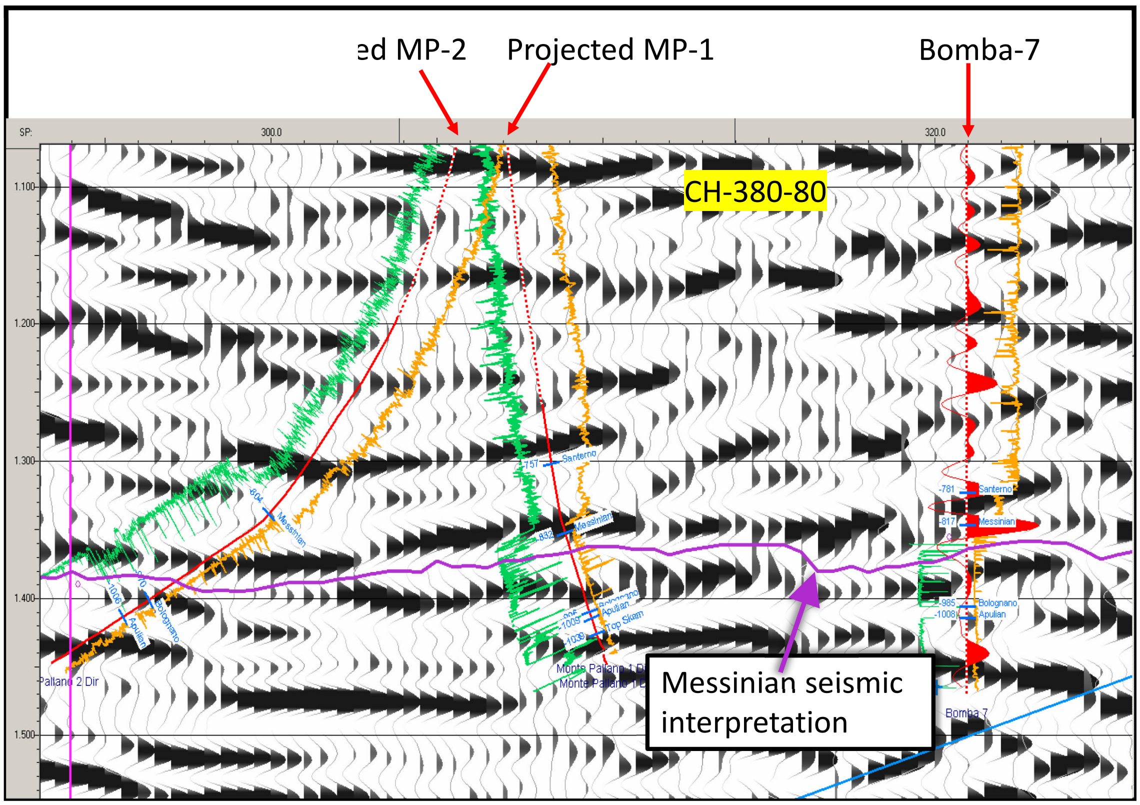


Figure 2-5: Line CH-380-80 Showing well ties. Wells are projected, MP-2 dir. 180m SW, MP-1 dir. 80m SW and Bomba-7 50m ENE.

2.3 Structure and gas-water contact

Since its discovery in the 1960s, multiple structural maps of this reservoir have been built. All the maps show the same structural closure to the west against the main east-dipping fault. All the maps demonstrate similar depths for the gas-water contact (-1112m TVDSS to -1120m TVDSS) interpreted from the logs on the Bomba wells and the well Pennadomo-3. Additionally, all have similar surface area.

However, only two of them show structural contours that are not only based on well tops but also on the seismic interpretation of the horizons. The first of these was generated in 1996 (Figure 2-6A). It uses interpretation from all the seismic lines but it was constructed without the benefit of the more recent wells MP-1 and MP-2 which were drilled in 2007. A second map was generated some time in the period 2015-2017 for the study on subsidence (Giani et al., 2017) (Figure 2-6B). That final map is based on a (sufficient – see previous section) subset of the 2D lines and it includes the well picks from MP-1 and MP-2. Therefore, this map was used as the reference for this present study.

However, it is noted that the 1996 map is the only map showing a secondary fault West of Bomba-1 and Bomba-2 (Figure 2-6A). The fault is assumed to have no significant impact on in-place estimates since its throw is minimal and well above the mapped gas-water contact but future production could be monitored to check whether it has any baffling effect on future gas-flow.

The petrophysical workflow, as well as the definition of the net pay in terms of property cut-offs, is described in the next section. Figure 2-6B shows the net pay thickness and the average effective porosity in the pay-zone at each well. The thickest part of the reservoir is around Bomba-2, Bomba-3 and MP-2 with approximately 130 ft of net pay, while MP-1 shows that some areas might have less pay (23ft for MP-1). This might imply some subtle but local fault cut-out of the reservoir which might also have potential impact on production rates. The average net porosity is similar across the reservoir, with possibly a slight increase from the east to the west ranging from 9.2% to 10.3% at Bomba-7, MP-1 and MP-2, to over 11% at Bomba-1, Bomba-2 and Bomba-3. Water saturation (Sw) is not shown on Figure 2-6B probably as a result of the fact that Sw is more difficult to assess (as described in the Petrophysical section of this report).

As previously described, the map shown as Figure 2-6B was an input a regional geomodel build used to run simulation related to potential subsidence (Giani and al., 2017). That model was regional, covering a larger area than the reservoir itself and modelled the overburden as well as the reservoir. The regional nature of the geomodel meant that it was deemed too coarse to represent the likely variation of petrophysical parameters across the field area and for that reason, the 2017 static model was used only to estimate the areal extent of the reservoir. The volumes were estimated after defining uncertainty range for the net thickness and the effective porosity and water saturation from the well data (see sections 2.4 and 3).

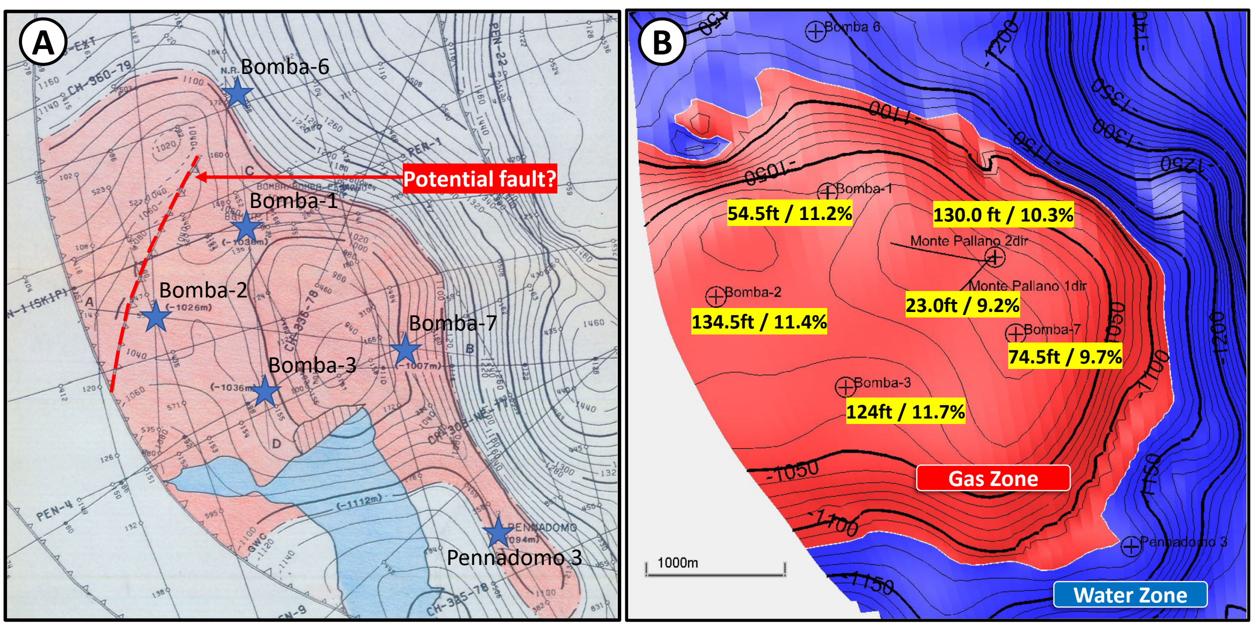


Figure 2-6: **a) 1996 map showing a secondary fault not found in any other map.**
b) Reference 2017 top structure of the reservoir. Gas-water contact @ -1120m TVDSS. Average net pay thickness and effective porosity at each well

2.4 Petrophysical Data

The wells Bomba 1, 2, 3 and 7 were all drilled and logged in the late 1960s. A 2005 report about their petrophysical analysis was made available to RPS for review.

The wells Monte Pallano 1 (MP-1) and Monte Pallono 2 (MP-2) were drilled and logged in 2007 following a slightly different workflow. A formal petrophysical report for these two wells was not available, but a list of the main equations used was found (Figure 2-7). While not all aspects of the workflow are available, these equations were enough to guide the definition of the uncertainty ranges for the volume calculation.

There are no petrophysical interpretations available for Bomba-6 nor Pennadomo-3, as these two wells are located in the aquifer outside of the gas bearing area.

Well MP-1

MONTE PALLANO NO1 ANALYSIS COMMENTS -- TVD DISPLAY

HIGH RESOLUTION TRIPLE COMBO DATA USED FROM SLB DLIS
EC PERFORMED ON GR AND NEUTRON

CLAY VOLUME FROM GR USING LARINOV OLD, CLEAN=19, SHALE=120

PHIE FROM DENSITY/NEUTRON CROSSPLOT POROSITY
PHIE = PHIND - (VCL* 15%)

PHIE SET TO 0.001 WHEN VCL>17%

SW USING ARCHIE; RW=0.73 @68F, A=1,M=2.0,N=2.0
SW SET TO A CONSTANT BELOW 1534 WHICH IS THE RESISTIVITY FIRST READING

KA COMPUTED USING PHIE SCALED TO DENSITY POROSITY FIT TO CORE WHERE
KA = 10^(+2.731230E+01*PHIENFIT -2.224781E+00)

RESERVOIR CUTOFF: PHIE>=8%
PAY CUTOFF: SW<=50%

TOTAL GAS CURVE FROM MUDLOG DISPLAYED (NO DEPTH SHIFT APPLIED)
LOWER AND UPPER TEST PERFS DISPLAYED

Well MP-2

MONTE PALLANO NO2 ANALYSIS COMMENTS -- MD DISPLAY

PROPOSED PERFORATIONS DISPLAYED

HIGH RESOLUTION TRIPLE COMBO DATA USED FROM SLB DLIS
ECS PERFORMED IN THE FIELD ON GR AND NEUTRON

DEEP RESISTIVITY (DSRT) DEPTH MATCHED TO RXO. DIFFERENCES FROM INVESTIGATION VOLUMES AND HOLE GEOMETRY.

CLAY VOLUME FROM GR USING LARINOV OLD, CLEAN=15, SHALE=110

PHIE FROM DENSITY/NEUTRON CROSSPLOT POROSITY
PHIE = PHIND - (VCL* 15%)

PHIE SET TO 0.001 WHEN VCL>30%

SW USING ARCHIE: RW=0.73 @68F, A=1,M=2.0,N=2.0
COMPUTED USING SWS INVERTED RT AND RXO.

KANU COMPUTED USING PHIENU

KANU = 10^(+2.731230E+01*PHIENU -2.224781E+00)

RESERVOIR CUTOFF: PHIE>=8%
PAY CUTOFF: SW<=50%

Figure 2-7: Main petrophysical equations used on the wells MP-1 and MP-2

Table 2-2 summarizes the logs available for petrophysics.

Table 2-2: Logs available for petrophysics

	Bomba-1	Bomba-2	Bomba-3	Bomba-7	MP-1	MP-2
Year drilled	1966	1967	1967	1968	2007	2007
GR	YES	YES	YES	YES	YES	YES
Neutron	YES	YES	YES	YES	YES	YES
Density	NO	NO	YES	YES	YES	YES
Sonic	YES*	YES	NO	YES	NO	NO
Resistivity	YES	YES	YES	YES	YES	YES
Core data/analysi	YES	YES	YES	NO	YES	NO

* washouts make it problematic

Table 2-3 summarizes the thickness as well as the average effective porosity and water saturation for each well in the pay zone. The pay was defined based on PHIE>=8%, SWE<=50% and Kair>=1mD (last cutoff applied only to the Bomba wells).

Table 2-3: Net pay parameters for each well (PHIE>=8%, SWE<=50% + Kair>=1mD for the Bomba wells)

	Bomba-1	Bomba-2	Bomba-3	Bomba-7	MP-1	MP-2
Thickness (ft TVD)	54.5	134.5	124.0	74.5	23.0	130.0
Avg Effective Porosity	11.2%	11.4%	11.7%	9.7%	9.2%	10.3%
Avg Effective Water Saturation	39.9%	35.1%	36.2%	45.6%	31.4%	11.1%

2.4.1 Shale volume calculation (Vshale)

Shale volume was calculated for the Bomba and the MP wells from GR with GR clean and GR clay picked specifically at each well:

$$VSH = (GR - GRClean)/(GRClay - GRClean)$$

In 2007 (for MP-1 and MP-2), the VSH was further corrected using the Larionov equation for Older Rocks:

$$VSH = VSH_{Larionov} = 0.33(2^{2VSH} - 1)$$

2.4.2 Effective Porosity

The effective porosity equation and the shale porosity constant (15%) used in it are the same on all the wells:

$$PHIE = PHIT - VSH * ShalePoro = PHIT - VSH * 15\%$$

However, the total porosity PHIT was calculated in 3 different ways.

All the Bomba wells have a neutron log, but that log was deemed not reliable, especially in the gas environment. It was not used for calculating PHIT. Instead, for Bomba-3 and Bomba-7, density-porosity DPHI was computed from the density log, assuming a limestone matrix and a freshwater drilling fluid. Core porosity data from Bomba-3 were used to calibrate the DPHI on that well. The calibrated DPHI is then used as PHIT. That equation was then applied on Bomba-7.

$$DPHI = \frac{Dens_{Limestone} - DensLog}{Dens_{Limestone} - Dens_{Freshwater}} = \frac{2.71 - DensLog}{2.71 - 1.00}$$

$$PHIT = DPHI * 0.866 + 0.0017$$

As Bomba-1 and Bomba-2 do not have a density log, a sonic-porosity SPHI was derived from the sonic log. Matrix and fluid slowness values are set respectively for limestone and freshwater drilling fluid (values in µs/ft). SPHI is used for total porosity PHIT for both wells.

$$PHIT = SPHI = \frac{\Delta t_{Limestone} - SonicLog}{\Delta t_{Freshwater} - \Delta t_{Limestone}} = \frac{47.6 - SonicLog}{190 - 47.6}$$

The petrophysicist also reported that the sonic log for Bomba-1 seemed highly filtered, maybe due to cycle skips or bad hole conditions (washouts were observed on Bomba-1). As such, the petrophysicist recommended caution with PHIT measurement on Bomba-1.

For MP-1 and MP-2, PHIT is derived from density/neutron cross-plot. No other details are provided.

2.4.3 Effective water saturation

On all the wells, effective water saturation was calculated using the Archie equation with the effective porosity as an input. The saturation exponent 'n' was set at 2 and the water resistivity R_w was calculated based on a resistivity of 0.73 ohmm at 20 degC measured on recovered water from the DST No.2 in Bomba-2.

The cementation exponent 'm' was set differently though by the different petrophysicists having work on the asset through the years. In the Bomba wells, it was set to 2.45 based on the idea that the limestone shows predominately vuggy porosity. For the two MP wells, m was set to 2.

For the Bomba wells, the equation is:

$$SWE = \sqrt[n]{\frac{R_w}{PHIE^m * R_t}} = \sqrt{\frac{R_w}{PHIE^{2.45} * LL7}}$$

For the MP wells, the equation is:

$$SWE = \sqrt[n]{\frac{R_w}{PHIE^m * R_t}} = \sqrt{\frac{R_w}{PHIE^2 * DeepResLog}}$$

The Bomba wells only had one type of resistivity log available (Laterolog 7 = LL7). As a result, they lack multiple depths of investigation. The laterolog 7 does provide a relatively deep measurement of resistivity, however, the lack of shallow resistivity makes it hard to assess the exact impact of fluid invasion on these wells. As a result of this uncertainty in the resistivity and the saturation parameters on these wells, the petrophysicist in charge of the Bomba wells recommended to use a constant water saturation of around 27%, as defined by the single capillary pressure measurement available.

On the contrary, the MP wells have modern resistivity logs with multiple depths of investigation. Having no petrophysical report per se for these wells, it is assumed that the deep resistivity was used for calculating Sw on these two wells.

2.4.4 Permeability

On all the wells, an equation was defined to derive air permeability from effective porosity PHIE. The parameters are different for the Bomba and the MP wells.

For the Bomba wells, the equation is:

$$Kair(mD) = 10\text{^}(31.137 * PHIE - 2.888)$$

For the MP wells, the equation is:

$$Kair(mD) = 10\text{^}(27.312 * PHIE - 2.224)$$

Permeability was used to define the pay on the Bomba wells. It does not seem to have been used to define the pay on the MP wells.

2.4.5 Conclusions on the Petrophysical workflows

A correction such as the Vsh Larionov correction is applied to account for specific lithology characteristics. The decision to use it or not is linked to the reservoir characteristics, not to the vintage of the input logs. As such, either it should be used on all the wells or on none. That said, Vsh in the pay zones is extremely low, often equal to zero. For very low Vsh values, the Larionov correction is negligible. This methodological discrepancy between the Bomba and the MP wells will therefore not significantly impact the volume estimates.

Bomba-7 is the only Bomba well with sonic and density logs. Sonic-porosity was calculated and compared to the density-porosity log (adjusted to the core-porosity values). The petrophysicist concluded that density-porosity on Bomba-7 was higher by an average of 21% to the sonic-porosity on that well. It reflects the idea that density-porosity responds to the whole, total porosity, while sonic-porosity does not reflect the secondary porosity found in limestones such as in this reservoir.

On Bomba-1 and Bomba-2, sonic-porosity is the only porosity which can be measured and effective porosity on these two wells was derived from it, though the Bomba petrophysicist deemed the Bomba-1 sonic=porosity problematic due to hole issues (washouts etc.) For Bomba-3 and 7 and then on MP-1 and MP-2, the effective porosity was derived from respectively the density-porosity and the density and neutron porosity.

This could imply that the total porosity is underestimated in Bomba-1 and Bomba-2.

Despite these issues, the average effective porosity in all wells is very similar (Table 2-3). While the difference in log availability, log quality and methodology create challenges in comparing wells, the range of average net effective porosity is relatively narrow and is therefore considered reasonable.

The average effective water saturation in the pay zone is overall much higher in the Bomba wells than in the MP wells (Table 2-3 & Table 2-4). The petrophysicist who worked on the Bomba wells pointed out that log calculated Sw is significantly different from that estimated from capillary pressure measurements. Furthermore, the impact of using a value of 2.45 for the cementation factor ‘m’ instead of 2 should also be considered. If the average effective Sw on the Bomba wells is estimated using m=2, average effective Sw is much closer to the 27% from the capillary pressure measurement (Table 2-4).

Furthermore, the average effective Sw on the Bomba wells is now much closer to the average effective Sw on the MP wells. Alternatively, changing the calculation of effective Sw on the MP wells by using m=2.45 instead of m=2 increases effective Sw on these two wells (Table 2-4). However, using this ‘m’ value results in a greater difference to the average effective Sw calculated from capillary pressure measurement.

Finally, note that the permeability Kair has different equations on the Bomba and the MP wells and does not appear to have been used to estimate the net pay on the MP wells. Further analysis may determine if a single equation could be determined based on the core analysis from the Bomba and MP wells but at this stage, RPS has assumed that the 8% PHIE cut off used to define the pay, does approximately correspond to the 1mD cut off on Kair.

Table 2-4: Impact on the SWE in the pay zone by using the same m coefficient everywhere (either 2.0 or 2.45)

	Bomba-1	Bomba-2	Bomba-3	Bomba-7	MP-1	MP-2	Avg SWE
Avg Effective Water Saturation provided	39.9%	35.1%	36.2%	45.6%	31.4%	11.1%	33.2%
Avg Effective Water Saturation (m=2)	24.4%	21.5%	22.3%	27.0%	31.4%	11.1%	23.0%
Avg Effective Water Saturation (m=2.45)	39.9%	35.1%	36.2%	45.6%	53.8%	18.6%	38.2%

3 VOLUMETRIC ESTIMATES AND PRODUCTION FORECASTS

3.1 Probabilistic Analysis

RPS has undertaken a probabilistic estimation of Gas Initially in Place ('GIIP') for the Colle Santo field.

As part of this estimation, RPS has assessed the following volumetric parameters: areal extent, gross and net thickness, average porosity, average hydrocarbon saturation, and gas formation volume factor.

The parameters used for the volumetric estimation for Colle Santo were derived from a variety of sources including well logs, gas analyses, production tests, and detailed seismic maps provided by the Company and audited by RPS staff.

The distributions for each parameter are shown in Table 3-2. During the preparation of the distributions, the P99 (minimum) and P1 (maximum) outcomes are also reviewed to ensure an appropriate and reasonable distribution. As defined by PRMS, the P50 estimate is the "best estimate" for reporting purposes.

3.2 In-Place Volume Estimation

Surface condition in-place gas volumes were calculated using a probabilistic approach. A range of uncertainty was defined for each input parameter (Table 3-1).

Table 3-2 summarizes the resulting range of probabilistic gas-in-place volumes.

Table 3-1: Input parameters for volume calculations

Input parameter (Unit)	Distribution shape	Min	P90	P50	P10	Max	Mode	Mean
Surface area (acre)	Beta	2095.0	2273.0	2368.0	2479.0	3095.0	2357.0	2373.0
Net Thickness (ft)	Normal	82.0	90.4	100.0	110.0	123.0	100.0	100.0
Porosity (%)	Normal	7.0	8.2	10.1	12.0	14.7	10.0	10.0
SW (%)	Normal	23.0	25.0	26.5	28.0	30.0	26.5	26.5
Dry gas FVF (scf/cf)	Normal	127.0	140.0	150.0	160.0	173.0	150.0	150.0

Table 3-2: Estimated range of GIIP (Bscf)

	P99	P90	P50	P10	P1	Mode	Mean
GIIP (bcf)	76.0	90.3	114.1	142.0	166.3	106.3	115.3

3.2.1 Reservoir Pressure and Temperature

Measurements have indicated actual bottom-hole pressures at Colle Santo ranging from 2,028 psia to 2,033 psia. These values have been used in the material balance model for the Upper and Lower Apulian sands respectively. Reservoir temperatures ranging from 126 ºF to 128 ºF have been measured during pressure testing and well logging which have been used to define the temperature distribution in the analysis.

3.2.2 Gas Properties

Multiple gas analyses have been performed on samples from Colle Santo since first discovery. RPS used the range of gas gravities to estimate a range of gas compressibility factors for use in the probabilistic analysis. A sales gas heating value of 700 Btu/scf has been used for raw produced gas.

3.3 Resource Categorization

The Colle Santo gas reservoir is classified as Reserves. The accumulation was discovered by the Bomba-1 well in 1966. Several wells have been drilled into the reservoir with gas samples and production tests of various success having been completed. In 2007, two wells were successfully completed and tested showing good productivity (combined rate of 20.5 MMcf/d). In accordance with the Petroleum Resource Management System (PRMS) guidance, the accumulation is currently sub-classified as a Developed Non-Producing, indicating that the two most recent wells are currently shut-in but have shown economical production capabilities. LN Energy has put in-place a development program for the Colle Santo field which is expecting to commence in next 6-12 months. This development scenario consists of opening and producing gas from the two most recent wells and then converting to LNG directly onsite using a small modular LNG processing unit.

LN Energy is awaiting approval of an Environmental Impact Assessment (‘EIA’) that has been submitted to the Italian government (Ministry of Ecological Transition) which should be responded to within the next 1-3 months. Following this approval, a Production Concession would be requested from the Ministry of Economic Development and once received the project will commence. Current market and political conditions point toward a high probability of success and RPS believes that there is reasonable expectation that the above applications will be approved in a timely manner. It should be noted that significant delays to approvals to either the EIA or the Production Concession could cause the classification to revert to Contingent Resources (Development Pending) in the future.

Future seismic programs and drilling results in the target formations could change expectations on future recovery with time and have a material impact on the resource volumes, classifications, and economic values presented in this report.

3.4 Production Forecasts

The field production system includes:

- Two production wells (MP-1 and MP-2)
- Individual well monitoring (pressure/flowrate and well testing) equipment
- Small-scale Liquid Natural Gas (LNG) processing unit operating on produced gas

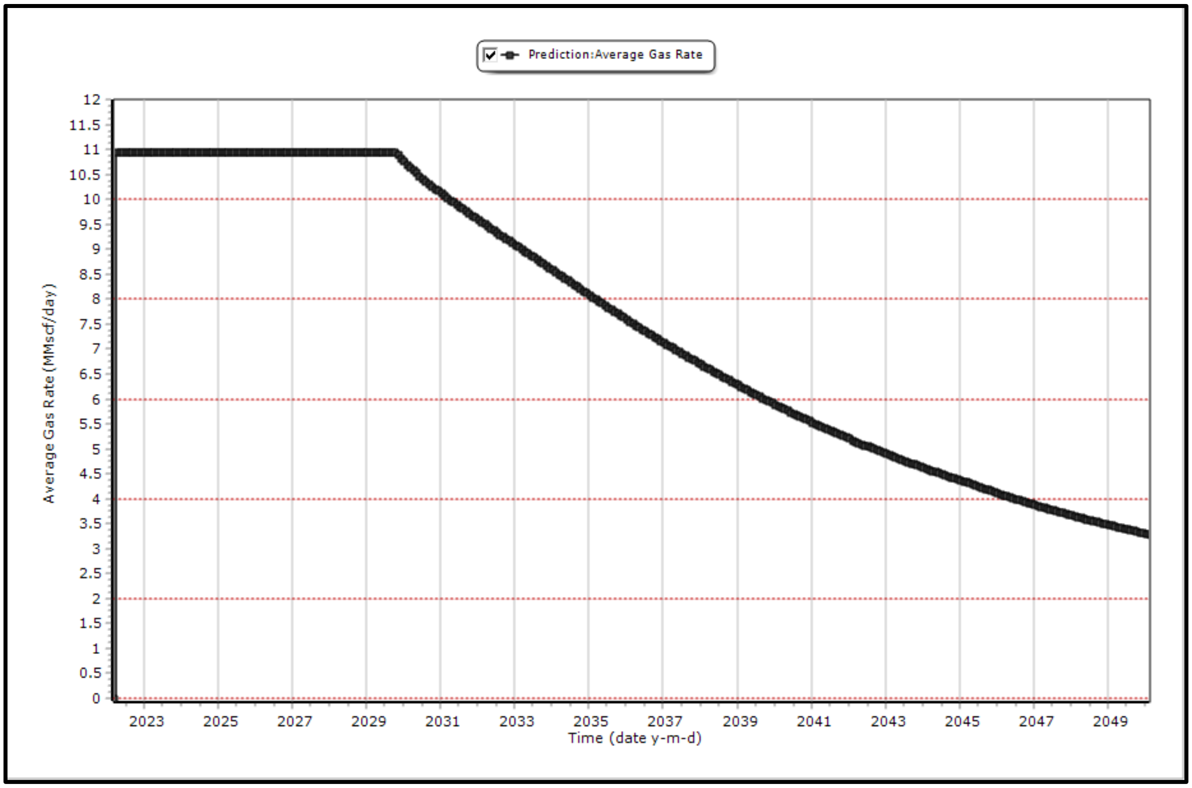


Figure 3-1: Colle Santo Field Raw Gas Forecast

4 ECONOMICS

4.1 Company Ownership and Burdens

4.1.1 License Terms

The commercial terms and conditions utilized in this evaluation, are based on the anticipated burdens which will affect production and revenues from the Colle Santo asset, as advised by LN Energy. These assumptions include a LN Energy 100% working interest ownership of the Colle Santo license.

4.2 Royalties and Taxation

With respect to hydrocarbon exploration and production, the royalties are applied on the basis of the value of production. The royalties for onshore gas production are currently 10%, if 25 million cubic meters per year are exceeded. The royalties for onshore oil production are currently 10% (7% royalty and 3% to the oil prices reduction fund), if 20,000 tonnes per year are exceeded and are applied to the sale value of the quantities produced. Royalties for the production of onshore hydrocarbons are split, as follows 55% to the Regions, 30% to the State and 15% to the Municipalities.

4.2.1 Royalties

The royalty rate for onshore gas is 10%, with the first 25 million cubic meters exempted, see

Table 4-1

Table 4-1: Royalties

Production		Royalty Rate	Additional Rate	Exempted production
Gas	Onshore	7%	3%	< 25 Million Cubic Meters
Oil	Onshore	7%	3% Oil Prices Reduction Fund	< 20,000 tons/year

4.2.2 Overriding Royalties

There are overriding royalties of 14% anticipated to be payable on this project.

4.3 Infrastructure

Colle Santo field is located in the midst of a well-developed infrastructure system for natural gas and LNG. It is strategically positioned near a major pipeline, industrial centers, gas storage, and trucking lanes running north-south along the Adriatic Coast.

4.3.1 Natural Gas

All gas production is commercialized by supply into the SNAM gas transmission grid, via either the national or regional transmission grid systems in Italy. The Colle Santo project lies within very short distance from several existing sections of the gas transmission grid.

Gas quality is a key element in planning the delivery of gas to market. SNAM has set parameters within which all gas presented for delivery into the grid must comply. Current indications are that the gas recovered at Colle Santo requires minimal processing to meet required parameters and could be delivered to the grid with minimal treatment.

The current development plan involves converting produced gas on site with a small scale LNG unit and loading for sale on-site thus avoiding any transportation or pipeline tie-in requirements and logistic issues. Fuel gas will be supplied from the produced gas on-site. Production forecast includes a 1% consumed fuel and shrinkage factor.

4.4 Operating Costs

Operating costs used in the economic evaluation have been provided by LN Energy management. RPS has reviewed these costs and accepted them as reasonable. Estimates of operating costs are shown in Table 4-2.

Table 4-2: Operating Cost Estimates

Operating Cost Estimates		
Category	Amount (EUR)	Unit
Well Costs	€ 120,000	€/year/well
Variable Gas	€ 0.047	€/Mcf
Fixed Gas	€ 2,253,000	€/yr

4.5 Development Schedule and Capital Costs

The following development schedule has been provided by LN Energy management and accepted by RPS as reasonable. For the planned LNG processing scenario only the MP-1 and MP-2 wells will be used, no additional wells are planned at this time.

Primary development and capital investment for the LNG processing scenario consists of the LNG unit being delivered and set up which is included in a rental agreement, requiring payment of €4.2 Million each year for 10 years. The current schedule is based on the LNG unit being in place for a February 2023 start date.

4.5.1 Abandonment and Reclamation Costs

Abandonment and reclamation costs of €30,000 per well are included in the evaluation, timed to be spent at the end of production (2050) or the month after each well ceases production, whichever comes first. An additional €1,100,000 is included to abandon and reclaim the well area and any facility components at the end of the life of the project.

4.6 Product Prices

Product Prices are based on the Dutch TTF Price Forecast with a modified floor pricing of €850/Tonne at the fourth year, as summarized in Table 4-3. Produced natural gas from the Colle Santo reservoir is assumed to sell at discount to the base TTF forecast prices due to a lower BTU value (700 BTU/scf), this conversion has been included in the Colle Santo specific prices shown in Table 4-3. In the LNG scenario, the LNG product will be upgraded during the conversion process, to a standard LNG product, and the LNG pricing (EUR/Tonne) shown in Table 4-3, reflects this upgrading. Alternative pricing scenarios and corresponding economics, with floor pricing of €750/Tonne and €650/Tonne, are available in Appendix B.

Table 4-3: Price Forecast Summary

Forecast of Prices Modified TTF Price Forecast (€850/Tonne Floor)				
Year	Gas Price TTF EUR/MWh	Gas Price LNG EUR/Tonne	Gas Price (700 BTU/scf) EUR/scf	Gas Price (1050 BTU/scf) EUR/scf
2023	188.43	2872.10	38.69	58.03
2024	123.46	1881.84	25.35	38.02
2025	85.19	1298.55	17.49	26.24
2026	55.77	850.00	11.45	17.17
2027	56.88	867.00	11.68	17.52
2028	58.02	884.34	11.91	17.87
2029	59.18	902.03	12.15	18.22
2030	60.36	920.07	12.39	18.59
2031+	2%	2%	2%	2%

4.7 Price and Cost Inflation

RPS forecasts all capital and operating costs inflation to be 2% per annum over the whole period of this evaluation. This forecast is also shown in the above price forecast table.

4.8 Economic Analysis

RPS has used the above inputs in an Excel spreadsheet economic cash flow model and forecast the cash flow and resulting Net Present Values before income tax. The economic model incorporates cash flow based on production forecasts, capital costs, and operating costs of the Colle Santo field. Production is truncated at the year 2050 or the last year of positive before-tax cash flow using forecast operating costs and prices. A summary of the results from the cash flow models from the LNG development scenario is shown in Table 4-4 and Table 4-5.

Table 4-4: Colle Santo Reserves Summary – 2050 Truncation

LN Energy Limited - Working Interest Reserves for Colle Santo as of September 30, 2022 Modified TTF Price Forecast								
	Gross Reserves				Net Reserves			
Reserves Category	Oil (MMstb)	Sales Gas (Bscf)	NGL& $C5^+$ (MMbbl)	BOE (MMbbl)	Oil (MMstb)	Sales Gas (Bscf)	NGL& $C5^+$ (MMbbl)	BOE (MMbbl)
PROVED	-	56.8	-	9.5	-	45.7	-	7.6
PROVED + PROBABLE	-	65.3	-	10.9	-	51.7	-	8.6

Table 4-5: Colle Santo NPV Summary (Reserves) – 2050 Truncation

LN Energy Limited - Reserves for Colle Santo - LNG Scenario as of September 30, 2022 Modified TTF Price Forecast					
Reserve Category	NPV Before Tax Million EUR€				
	0%	5%	10%	15%	20%
PROVED (1P)	628.8	402.3	290.7	227.5	187.4
PROVED + PROBABLE (2P)	727.9	440.0	307.0	235.3	191.5

4.8.1 Cash Flow Summaries

A cash flow summary for the 1P and 2P reserves for Colle Santo is included in the following Tables: Table 4-6 and Table 4-7.

It should be noted that based upon the 2050 forecast cut-off and RPS estimates of production profiles and recoverable resources per well, not all of the recoverable volumes are forecast to be recovered within the economic analysis.

Table 4-6: Detailed Economic Summary – 1P Reserves

SUMMARY OF OIL AND GAS FIELD RESERVES, PRODUCTION AND CASHFLOW

Company: LN Energy Limited
Operator: LN Energy Limited
Field: Colle Santo
Company Share: 100.00%

Reserves Category: Total Proved
Price Forecast Case: Modified TTF Price Forecast
Average Annual Cost Inflation: 2.00%
Effective Date: 2022-09-30

RESERVES		Total Field		Company Share	
		Gross	Net	Gross	Net
Crude Oil	(MMstb)	-	-	-	-
Sales Gas	(Bcf)	56.8	45.7	56.8	45.7
NGL	(MMbbl)	-	-	-	-
Condensate	(MMbbl)	-	-	-	-
Total BOE *	(MMboe)	9.5	7.6	9.5	7.6

PRESENT VALUE - COMPANY SHARE (Million EUR€)					
Discount Rate:	0%	5%	10%	15%	20%
Gross Revenue	963.2	619.8	448.3	349.9	287.0
Net Revenue	774.3	485.3	345.5	267.3	218.2
Operating Costs	96.2	47.3	27.6	18.3	13.3
Capital Costs	46.9	35.1	27.1	21.5	17.4
Cash Flow Before Tax	628.8	402.3	290.7	227.5	187.4

ABANDONMENT AND RECLAMATION COSTS
Company Share, Net of Salvage Value

Cost (Million EUR€):	2.44
Year:	2051

PRODUCT PRICES (EUR€) Year		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042+
Field Prices																						
Sales Gas	(EUR€/MMBtu)	-	58.03	38.02	26.24	17.17	17.52	17.87	18.22	18.59	18.96	19.34	19.73	20.12	20.52	20.93	21.35	21.78	22.22	22.66	23.11	23.58
LNG	(EUR€/Tonne)	-	2,872.10	1,881.84	1,298.55	850.00	867.00	884.34	902.03	920.07	938.47	957.24	976.39	995.91	1,015.83	1,036.15	1,056.87	1,078.01	1,099.57	1,121.56	1,143.99	1,166.87
COST INFLATION (%/annum)		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

COMPANY SHARE GROSS PRODUCTION Year		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042+	Total
Production Wellcount (#)		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	
Annual Gross Production																							
Crude Oil	(MMstb)																						
Gas (Pre-conversion)	(Bcf)	-	3.09	3.38	3.37	3.37	3.37	3.38	3.37	3.23	2.91	2.69	2.48	2.29	2.11	1.95	1.80	1.67	1.55	1.45	1.36	7.98	56.82
LNG	(Tonnes)	-	44,324	48,570	48,438	48,438	48,437	48,570	48,437	46,389	41,816	38,685	35,615	32,851	30,305	28,041	25,834	23,940	22,265	20,841	19,467	114,498	815,763
Condensate	(MMbbl)																						

COMPANY SHARE CASHFLOW (Million EUR€) Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042+	Total
Gross Production Revenue	-	127.30	91.40	62.90	41.17	42.00	42.95	43.69	42.68	39.24	37.03	34.77	32.72	30.79	29.05	27.30	25.81	24.48	23.37	22.27	142.29	963.23
Effective Royalty	-	30.6	22.7	15.6	10.2	10.4	10.7	10.9	10.4	9.2	8.4	7.5	6.7	6.0	5.3	4.6	4.1	3.5	3.0	2.6	6.4	188.92
Net Production Revenue	-	96.7	68.7	47.3	30.9	31.6	32.3	32.8	32.2	30.1	28.7	27.3	26.0	24.8	23.7	22.7	21.8	21.0	20.3	19.7	135.9	774.31
Other Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oper. Costs + G&A	-	2.66	2.73	2.79	2.84	2.90	2.96	3.02	3.07	3.11	3.16	3.21	3.26	3.31	3.36	3.42	3.48	3.54	3.60	3.67	36.11	96.18
Abandonment Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.4	2.44
Op. Cash Inc. Before Tax	-	94.07	65.94	44.49	28.10	28.66	29.31	29.82	29.18	26.94	25.51	24.05	22.72	21.47	20.36	19.24	18.28	17.43	16.73	16.03	99.78	678.13
Capital	-	4.28	4.37	4.46	4.55	4.64	4.73	4.82	4.92	5.02	5.12	0.00	0.00	0.00	0.00							46.91
Cash Flow Before Tax	-	89.79	61.57	40.03	23.56	24.03	24.58	25.00	24.26	21.92	20.39	24.05	22.72	21.47	20.36	19.24	18.28	17.43	16.73	16.03	97.34	628.78

Table 4-7: Detailed Economic Summary – 2P Reserves

SUMMARY OF OIL AND GAS FIELD RESERVES, PRODUCTION AND CASHFLOW

Company: LN Energy Limited
Operator: LN Energy Limited
Field: Colle Santo
Company Share: 100.00%

Reserves Category: Total Proved + Probable
Price Forecast Case: Modified TTF Price Forecast
Average Annual Cost Inflation: 2.00%
Effective Date: 2022-09-30

RESERVES		Total Field		Company Share	
		Gross	Net	Gross	Net
Crude Oil	(MMstb)	-	-	-	-
Sales Gas	(Bcf)	65.3	51.7	65.3	51.7
NGL	(MMbbl)	-	-	-	-
Condensate	(MMbbl)	-	-	-	-
Total BOE *	(MMboe)	10.9	8.6	10.9	8.6

PRESENT VALUE - COMPANY SHARE (Million EUR€)					
Discount Rate:	0%	5%	10%	15%	20%
Gross Revenue	1,102.5	674.2	472.3	361.6	293.2
Net Revenue	874.1	523.3	362.0	275.2	222.4
Operating Costs	96.8	47.6	27.7	18.4	13.4
Capital Costs	46.9	35.1	27.1	21.5	17.4
Cash Flow Before Tax	727.9	440.0	307.0	235.3	191.5

ABANDONMENT AND RECLAMATION COSTS Company Share, Net of Salvage Value	
Cost (Million EUR€):	2.44
Year:	2051

PRODUCT PRICES (EUR€) Year		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042+
Field Prices																						
Sales Gas	(EUR€/MMBtu)	-	58.03	38.02	26.24	17.17	17.52	17.87	18.22	18.59	18.96	19.34	19.73	20.12	20.52	20.93	21.35	21.78	22.22	22.66	23.11	23.58
LNG	(EUR€/Tonne)	-	2,872.10	1,881.84	1,298.55	850.00	867.00	884.34	902.03	920.07	938.47	957.24	976.39	995.91	1,015.83	1,036.15	1,056.87	1,078.01	1,099.57	1,121.56	1,143.99	1,166.87
COST INFLATION (%/annum)		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

COMPANY SHARE GROSS PRODUCTION Year		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042+	Total
Production Wellcount (#)		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	
Annual Gross Production																							
Crude Oil	(MMstb)																						
Gas (Pre-conversion)	(Bcf)	-	3.09	3.38	3.37	3.37	3.37	3.38	3.37	3.36	3.19	3.03	2.86	2.71	2.55	2.40	2.25	2.11	1.98	1.87	1.75	11.84	65.25
LNG	(Tonnes)	-	44,324	48,570	48,438	48,438	48,437	48,570	48,437	48,223	45,795	43,442	41,048	38,838	36,610	34,520	32,336	30,359	28,491	26,794	25,080	170,052	936,800
Condensate	(MMbbl)																						

COMPANY SHARE CASHFLOW (Million EUR€) Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042+	Total
Gross Production Revenue	-	127.30	91.40	62.90	41.17	42.00	42.95	43.69	44.37	42.98	41.58	40.08	38.68	37.19	35.77	34.17	32.73	31.33	30.05	28.69	213.44	1,102.48
Effective Royalty	-	30.6	22.7	15.6	10.2	10.4	10.7	10.9	11.0	10.5	9.9	9.3	8.8	8.2	7.6	7.0	6.4	5.8	5.3	4.7	22.8	228.35
Net Production Revenue	-	96.7	68.7	47.3	30.9	31.6	32.3	32.8	33.4	32.5	31.7	30.8	29.9	29.0	28.2	27.2	26.3	25.5	24.8	24.0	190.6	874.13
Other Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oper. Costs + G&A	-	2.66	2.73	2.79	2.84	2.90	2.96	3.02	3.08	3.13	3.18	3.23	3.28	3.34	3.40	3.45	3.51	3.57	3.63	3.70	36.45	96.85
Abandonment Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.4	2.44
Op. Cash Inc. Before Tax	-	94.07	65.94	44.49	28.10	28.66	29.31	29.82	30.29	29.40	28.50	27.54	26.64	25.69	24.78	23.75	22.83	21.93	21.12	20.25	154.16	777.28
Capital	-	4.28	4.37	4.46	4.55	4.64	4.73	4.82	4.92	5.02	5.12	0.00	0.00	0.00	0.00							46.91
Cash Flow Before Tax	-	89.79	61.57	40.03	23.56	24.03	24.58	25.00	25.37	24.38	23.38	27.54	26.64	25.69	24.78	23.75	22.83	21.93	21.12	20.25	151.73	727.93

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Appendix A
Glossary of Technical Terms

1C	The low estimate of Contingent Resources. There is estimated to be a 90% probability that the quantities actually recovered could equal or exceed this estimate
2C	The best estimate of Contingent Resources. There is estimated to be a 50% probability that the quantities actually recovered could equal or exceed this estimate
3C	The high estimate of Contingent Resources. There is estimated to be a 10% probability that the quantities actually recovered could equal or exceed this estimate
1P	The low estimate of Reserves (proved). There is estimated to be a 90% probability that the quantities remaining to be recovered will equal or exceed this estimate
2P	The best estimate of Reserves (proved+probable). There is estimated to be a 50% probability that the quantities remaining to be recovered will equal or exceed this estimate
3P	The high estimate of Reserves (proved+probable+possible). There is estimated to be a 10% probability that the quantities remaining to be recovered will equal or exceed this estimate
1U	The unrisked low estimate of Prospective Resources
2U	The unrisked best estimate of Prospective Resources
3U	The unrisked high estimate of Prospective Resources
AVO	Amplitude versus Offset
B	Billion
bbl(s)	Barrels
bbl/d	Barrels per day
Bcm	Billion cubic metres
B_g	Gas formation volume factor
B_{gi}	Gas formation volume factor (initial)
B_o	Oil formation volume factor
B_{oi}	Oil formation volume factor (initial)
B_w	Water volume factor
boe	Barrels of oil equivalent
stb/d	Barrels of oil per day
BHP	Bottom hole pressure
Bscf	Billions of standard cubic feet
bwpd	Barrels of water per day
condensate	A mixture of hydrocarbons which exist in gaseous phase at reservoir conditions but are produced as a liquid at surface conditions
cP	Centipoise
E_{gi}	Gas Expansion Factor
EMV	Expected Monetary Value
EUR	Estimated Ultimate Recovery
FBHP	Flowing bottom hole pressure
FTHP	Flowing tubing head pressure
ft	Feet
FWHP	Flowing well head pressure

FWL	Free Water Level
GDT	Gas Down To
GIIP	Gas Initially in Place
GOC	Gas oil Contact
GOR	Gas/oil ratio
GRV	Gross rock volume
GWC	Gas water contact
IPR	Inflow performance relationship
IRR	Internal rate of return
KB	Kelly Bushing
k_a	Absolute permeability
k_h	Horizontal permeability
km	Kilometres
LPG	Liquefied Petroleum Gases
m	Metres
m^3	Cubic metres
m^3/d	Cubic metres per day
ma	Million years
M	Thousand
M$	Thousand dollars
MBAL	Material balance software
Mbbl	Thousand barrels
mD	Permeability in millidarcies
MD	Measured depth
MDT	Modular formation dynamics tester tool
MM	Million
MMbbl	Million barrels
MMscf/d	Millions of standard cubic feet per day
MMstb	Million stock tank barrels (at 14.7 psi and 60° F)
MMt	Millions of tonnes
MM$	Million dollars
MPa	Mega pascals
m/s	Metres per second
msec	Milliseconds
Mt	Thousands of tonnes
mV	Millivolts
NTG or N:G	Net to gross ratio
NGL	Natural Gas Liquids
NPV	Net Present Value
NZ$	New Zealand dollars
OWC	Oil water contact
P90	There is estimated to be at least a 90% probability (P_{90}) that this quantity will equal or exceed this low estimate

P50	There is estimated to be at least a 50% probability (P_{50}) that this quantity will equal or exceed this best estimate
P10	There is estimated to be at least a 10% probability (P_{10}) that this quantity will equal or exceed this high estimate
PDR	Physical data room
petroleum	Naturally occurring mixtures of hydrocarbons which are found beneath the Earth's surface in liquid, solid or gaseous form
phi	Porosity
p_i	Initial reservoir pressure
PI	Productivity index
ppm	Parts per million
psi	Pounds per square inch
psia	Pounds per square inch (absolute)
psig	Pounds per square inch (gauge)
p_{wf}	Flowing bottom hole pressure
PSDM	Pre-stack depth migrated seismic data
PSTM	Pre-stack time migrated seismic data
PVT	Pressure volume temperature
rb	Barrel(s) at reservoir conditions
rcf	Reservoir cubic feet
RF	Recovery factor
RFT	Repeat formation tester
RKB	Relative to kelly bushing
rm^3	Reservoir cubic metres
SCADA	Supervisory control and data acquisition
SCAL	Special Core Analysis
scf	Standard cubic feet measured at 14.7 pounds per square inch and 60° F
scf/d	Standard cubic feet per day
scf/stb	Standard cubic feet per stock tank barrel
SGS	Sequential Gaussion Simulation
SIBHP	Shut in bottom hole pressure
SIS	Sequential Indicator Simulation
sm^3	Standard cubic metres
S_o	Oil saturation
S_{oi}	Initial oil saturation
S_{or}	Residual oil saturation
S_{orw}	Residual oil saturation relative to water
sq. km	Square kilometers
stb	Stock tank barrels measured at 14.7 pounds per square inch and 60° F
stb/d	Stock tank barrels per day
STOIIP	Stock tank oil initially in place
S_w	Water saturation
S_{wc}	Connate water saturation
t	Tonnes

THP	Tubing head pressure
Tscf	Trillion standard cubic feet
TVDSS	True vertical depth (sub-sea)
TVT	True vertical thickness
TWT	Two-way time
US$	United States Dollar
VDR	Virtual data room
VLP	Vertical lift performance
V_{sh}	Shale volume
VSP	Vertical Seismic Profile
W/m/K	Watts/metre/° K
WC	Water cut
WUT	Water Up To
Z	A measure of the “non-idealness” of gas
ϕ	Porosity
μ	Viscosity
μ_g	Viscosity of gas
μ_o	Viscosity of oil
μ_w	Viscosity of water

Appendix B
Alternative Pricing Forecasts

Forecast of Prices Modified TTF Price Forecast (€750/Tonne Floor)				
Year	Gas Price TTF EUR/MWh	Gas Price LNG EUR/Tonne	Gas Price (700 BTU/scf) EUR/scf	Gas Price (1050 BTU/scf) EUR/scf
2023	188.43	2872.10	38.69	58.03
2024	123.46	1881.84	25.35	38.02
2025	85.19	1298.55	17.49	26.24
2026	49.20	750.00	10.10	15.15
2027	50.19	765.00	10.30	15.46
2028	51.19	780.30	10.51	15.77
2029	52.22	795.90	10.72	16.08
2030	53.26	811.82	10.93	16.40
2031+	2%	2%	2%	2%

Forecast of Prices Modified TTF Price Forecast (€650/Tonne Floor)				
Year	Gas Price TTF EUR/MWh	Gas Price LNG EUR/Tonne	Gas Price (700 BTU/scf) EUR/scf	Gas Price (1050 BTU/scf) EUR/scf
2023	188.43	2872.10	38.69	58.03
2024	123.46	1881.84	25.35	38.02
2025	85.19	1298.55	17.49	26.24
2026	42.64	650.00	8.76	13.13
2027	43.50	663.00	8.93	13.40
2028	44.37	676.26	9.11	13.66
2029	45.25	689.79	9.29	13.94
2030	46.16	703.59	9.48	14.22
2031+	2%	2%	2%	2%

Appendix C
Alternative Pricing/Economic Summaries

Economic Summary for case study using 750 EUR/Tonne floor price.

SUMMARY OF OIL AND GAS FIELD RESERVES, PRODUCTION AND CASHFLOW

Company:	LN Energy Limited	**Reserves Category:**	Total Proved + Probable
Operator:	LN Energy Limited	**Price Forecast Case:**	Modified TTF Price Forecast (€750/Tonne Floor)
Field:	Colle Santo	**Average Annual Cost Inflation:**	2.00%
Company Share:	100.00%	**Effective Date:**	2022-09-30

RESERVES		Total Field Gross	Total Field Net	Company Share Gross	Company Share Net
Crude Oil	(MMstb)	-	-	-	-
Sales Gas	(Bcf)	65.3	51.7	65.3	51.7
NGL	(MMbbl)	-	-	-	-
Condensate	(MMbbl)	-	-	-	-
Total BOE *	(MMboe)	10.9	8.6	10.9	8.6

PRESENT VALUE - COMPANY SHARE (Million EUR€) Discount Rate:	0%	5%	10%	15%	20%
Gross Revenue	1,005.9	624.6	443.5	343.3	280.8
Net Revenue	796.3	484.1	339.6	261.2	212.9
Operating Costs	96.8	47.6	27.7	18.4	13.4
Capital Costs	46.9	35.1	27.1	21.5	17.4
Cash Flow Before Tax	650.1	400.9	284.6	221.3	182.1

ABANDONMENT AND RECLAMATION COSTS
Company Share, Net of Salvage Value

Cost (Million EUR€):	2.44
Year:	2051

PRODUCT PRICES (EUR€) Year		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042+
Field Prices																						
Sales Gas	(EUR€/MMBtu)	-	58.03	38.02	26.24	15.15	15.46	15.77	16.08	16.40	16.73	17.06	17.41	17.75	18.11	18.47	18.84	19.22	19.60	19.99	20.39	20.80
LNG	(EUR€/Tonne)	-	2,872.10	1,881.84	1,298.55	750.00	765.00	780.30	795.90	811.82	828.06	844.62	861.51	878.74	896.31	914.24	932.53	951.18	970.20	989.60	1,009.40	1,029.58
COST INFLATION (%/annum)		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

COMPANY SHARE GROSS PRODUCTION Year		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042+	Total
Production Wellcount (#)		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	
Annual Gross Production																							
Crude Oil	(MMstb)																						
Gas (Pre-conversion)	(Bcf)	-	3.09	3.38	3.37	3.37	3.37	3.38	3.37	3.36	3.19	3.03	2.86	2.71	2.55	2.40	2.25	2.11	1.98	1.87	1.75	11.84	65.25
LNG	(Tonnes)	-	44,324	48,570	48,438	48,438	48,437	48,570	48,437	48,223	45,795	43,442	41,048	38,838	36,610	34,520	32,336	30,359	28,491	26,794	25,080	170,052	936,800
Condensate	(MMbbl)																						

COMPANY SHARE CASHFLOW (Million EUR€) Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042+	Total
Gross Production Revenue	-	127.30	91.40	62.90	36.33	37.05	37.90	38.55	39.15	37.92	36.69	35.36	34.13	32.81	31.56	30.15	28.88	27.64	26.52	25.32	188.33	1,005.90
Effective Royalty	-	30.6	22.7	15.6	9.0	9.2	9.4	9.6	9.7	9.2	8.7	8.2	7.7	7.2	6.7	6.1	5.6	5.1	4.7	4.2	20.1	209.59
Net Production Revenue	-	96.7	68.7	47.3	27.3	27.8	28.5	29.0	29.4	28.7	28.0	27.1	26.4	25.6	24.9	24.0	23.2	22.5	21.8	21.1	168.2	796.31
Other Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oper. Costs + G&A	-	2.66	2.73	2.79	2.84	2.90	2.96	3.02	3.08	3.13	3.18	3.23	3.28	3.34	3.40	3.45	3.51	3.57	3.63	3.70	36.45	96.85
Abandonment Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.4	2.44
Op. Cash Inc. Before Tax	-	94.07	65.94	44.49	24.46	24.95	25.52	25.96	26.36	25.57	24.78	23.92	23.12	22.27	21.46	20.55	19.73	18.93	18.21	17.44	131.74	699.46
Capital	-	4.28	4.37	4.46	4.55	4.64	4.73	4.82	4.92	5.02	5.12	0.00	0.00	0.00	0.00							46.91
Cash Flow Before Tax	-	89.79	61.57	40.03	19.92	20.31	20.79	21.13	21.44	20.55	19.66	23.92	23.12	22.27	21.46	20.55	19.73	18.93	18.21	17.44	129.30	650.11

Economic Summary for case study using 650 EUR/Tonne floor price.

SUMMARY OF OIL AND GAS FIELD RESERVES, PRODUCTION AND CASHFLOW

Company:	LN Energy Limited	**Reserves Category:**	Total Proved + Probable
Operator:	LN Energy Limited	**Price Forecast Case:**	Modified TTF Price Forecast (€650/Tonne Floor)
Field:	Colle Santo	**Average Annual Cost Inflation:**	2.00%
Company Share:	100.00%	**Effective Date:**	2022-09-30

RESERVES		Total Field		Company Share	
		Gross	Net	Gross	Net
Crude Oil	(MMstb)	-	-	-	-
Sales Gas	(Bcf)	65.3	51.6	65.3	51.6
NGL	(MMbbl)	-	-	-	-
Condensate	(MMbbl)	-	-	-	-
Total BOE *	(MMboe)	10.9	8.6	10.9	8.6

PRESENT VALUE - COMPANY SHARE (Million EUR€)					
Discount Rate:	0%	5%	10%	15%	20%
Gross Revenue	909.3	574.9	414.7	325.1	268.4
Net Revenue	718.5	445.0	317.2	247.1	203.5
Operating Costs	96.8	47.6	27.7	18.4	13.4
Capital Costs	46.9	35.1	27.1	21.5	17.4
Cash Flow Before Tax	572.3	361.7	262.3	207.2	172.7

ABANDONMENT AND RECLAMATION COSTS Company Share, Net of Salvage Value	
Cost (Million EUR€):	2.44
Year:	2051

PRODUCT PRICES (EUR€) Year		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042+
Field Prices																						
Sales Gas	(EUR€/MMBtu)	-	58.03	38.02	26.24	13.13	13.40	13.66	13.94	14.22	14.50	14.79	15.09	15.39	15.69	16.01	16.33	16.66	16.99	17.33	17.67	18.03
LNG	(EUR€/Tonne)	-	2,872.10	1,881.84	1,298.55	650.00	663.00	676.26	689.79	703.59	717.66	732.01	746.65	761.58	776.82	792.35	808.20	824.36	840.85	857.67	874.82	892.32
COST INFLATION (%/annum)		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

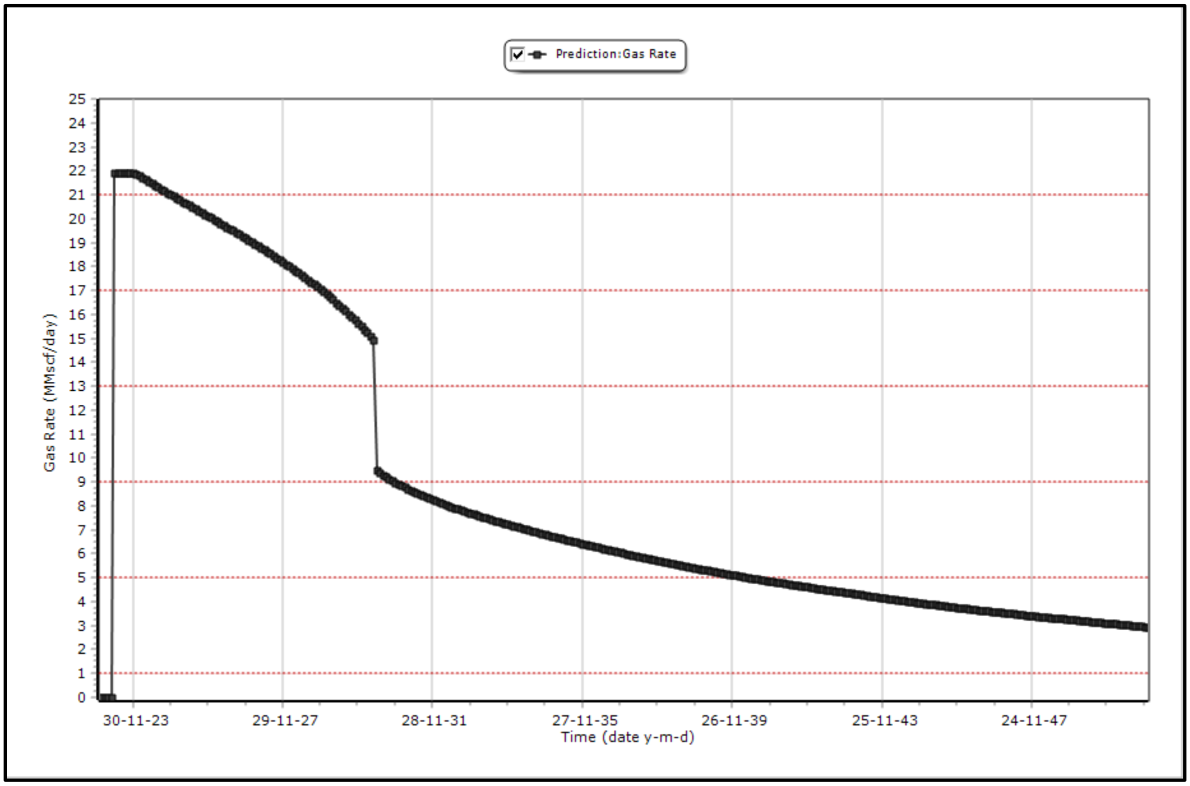
COMPANY SHARE GROSS PRODUCTION Year		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042+	Total
Production Wellcount (#)		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	
Annual Gross Production																							
Crude Oil	(MMstb)																						
Gas (Pre-conversion)	(Bcf)	-	3.09	3.38	3.37	3.37	3.37	3.38	3.37	3.36	3.19	3.03	2.86	2.71	2.55	2.40	2.25	2.11	1.98	1.87	1.75	11.84	65.25
LNG	(Tonnes)	-	44,324	48,570	48,438	48,438	48,437	48,570	48,437	48,223	45,795	43,442	41,048	38,838	36,610	34,520	32,336	30,359	28,491	26,794	25,080	170,052	936,800
Condensate	(MMbbl)																						

COMPANY SHARE CASHFLOW (Million EUR€) Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042+	Total
Gross Production Revenue	-	127.30	91.40	62.90	31.49	32.11	32.85	33.41	33.93	32.86	31.80	30.65	29.58	28.44	27.35	26.13	25.03	23.96	22.98	21.94	163.22	909.33
Effective Royalty	-	30.6	22.7	15.6	7.8	8.0	8.2	8.3	8.4	8.0	7.6	7.1	6.7	6.2	5.8	5.3	4.9	4.5	4.0	3.6	17.5	190.84
Net Production Revenue	-	96.7	68.7	47.3	23.7	24.1	24.7	25.1	25.5	24.9	24.2	23.5	22.9	22.2	21.5	20.8	20.1	19.5	18.9	18.3	145.8	718.50
Other Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oper. Costs + G&A	-	2.66	2.73	2.79	2.84	2.90	2.96	3.02	3.08	3.13	3.18	3.23	3.28	3.34	3.40	3.45	3.51	3.57	3.63	3.70	36.45	96.85
Abandonment Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.4	2.44
Op. Cash Inc. Before Tax	-	94.07	65.94	44.49	20.82	21.24	21.72	22.10	22.44	21.74	21.05	20.30	19.60	18.86	18.15	17.35	16.63	15.93	15.30	14.62	109.32	621.65
Capital	-	4.28	4.37	4.46	4.55	4.64	4.73	4.82	4.92	5.02	5.12	0.00	0.00	0.00	0.00							46.91
Cash Flow Before Tax	-	89.79	61.57	40.03	16.28	16.60	16.99	17.27	17.52	16.72	15.93	20.30	19.60	18.86	18.15	17.35	16.63	15.93	15.30	14.62	106.88	572.30

Gas Production Case Study –

Development plan includes on site separators, gas treatment facility and an export pipeline.

Primary development and capital investment for the gas export scenario consists of the construction costs for wellsite treatment facilities and an export pipeline. Pipeline and wellsite facility costs are estimated at €15 Million with an estimated start date of mid-2023.



Colle Santo Field Raw Gas Forecast – Gas Export Scenario

The marked drop in production in the Gas Export scenario, occurs due to the lower sands being shut-off in anticipation of water breakthrough.

Summary of Reserves – Gas Scenario – 2050 Truncation

LN Energy Limited - Working Interest Reserves for Colle Santo -GAS Scenario as of September 30, 2022 Modified TTF Price Forecast								
Reserves Category	Gross Reserves				Net Reserves			
	Oil (MMstb)	Sales Gas (Bscf)	NGL& C5^{+} (MMbbl)	BOE (MMbbl)	Oil (MMstb)	Sales Gas (Bscf)	NGL& C5^{+} (MMbbl)	BOE (MMbbl)
PROVED + PROBABLE	-	68.1	-	11.3	-	57.7	-	9.6

Net Present Value of Future Cash Flow for Reserves – Gas Scenario

LN Energy Limited - Reserves for Colle Santo - GAS Scenario as of September 30, 2022 Modified TTF Price Forecast					
Reserve Category	NPV Before Tax Million EUR€				
	0%	5%	10%	15%	20%
PROVED + PROBABLE (2P)	846.5	566.1	422.5	336.8	279.6

Economic Summary for Gas Export Case Study

SUMMARY OF OIL AND GAS FIELD RESERVES, PRODUCTION AND CASHFLOW

Company: LN Energy Limited
Operator: LN Energy Limited
Field: Colle Santo
Company Share: 100.00%

Reserves Category: Total Proved + Probable
Price Forecast Case: Modified TTF Price Forecast
Average Annual Cost Inflation: 2.00%
Effective Date: 2022-09-30

RESERVES		Total Field Gross	Total Field Net	Company Share Gross	Company Share Net
Crude Oil	(MMstb)	-	-	-	-
Sales Gas	(Bcf)	68.1	57.7	68.1	57.7
NGL	(MMbbl)	-	-	-	-
Condensate	(MMbbl)	-	-	-	-
Total BOE *	(MMboe)	11.3	9.6	11.3	8.6

PRESENT VALUE - COMPANY SHARE (Million EUR€) Discount Rate:	0%	5%	10%	15%	20%
Gross Revenue	1,104.8	744.0	559.0	448.3	374.3
Net Revenue	935.5	616.6	457.6	364.5	303.3
Operating Costs	71.5	35.2	20.6	13.7	10.0
Capital Costs	15.0	14.6	14.3	14.0	13.7
Cash Flow Before Tax	846.5	566.1	422.5	336.8	279.6

ABANDONMENT AND RECLAMATION COSTS
Company Share, Net of Salvage Value

Cost (Million EUR€):	2.44
Year:	2051

PRODUCT PRICES (EUR€) Year		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042+
Field Prices																						
Sales Gas	(EUR€/MMBtu)	-	38.69	25.35	17.49	11.45	11.68	11.91	12.15	12.39	12.64	12.89	13.15	13.41	13.68	13.96	14.24	14.52	14.81	15.11	15.41	15.72
COST INFLATION (%/annum)		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

COMPANY SHARE GROSS PRODUCTION Year		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042+	Total
Production Wellcount (#)		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	
Annual Gross Production																							
Crude Oil	(MMstb)																						
Sales Gas	(Bcf)	-	3.61	6.04	5.77	5.51	5.24	4.96	4.58	3.29	2.41	2.24	2.09	1.97	1.85	1.75	1.65	1.56	1.48	1.40	1.33	9.37	68.10
LNG	(Tonnes)																						
Condensate	(MMbbl)																						

COMPANY SHARE CASHFLOW (Million EUR€) Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042+	Total
Gross Production Revenue	-	139.80	153.16	100.91	63.11	61.22	59.03	55.65	40.72	30.42	28.86	27.51	26.40	25.38	24.47	23.49	22.64	21.85	21.18	20.45	158.59	1,104.83
Effective Royalty	-	25.3	31.3	20.5	12.7	12.2	11.6	10.8	7.1	4.6	4.2	3.8	3.5	3.2	2.9	2.6	2.3	2.1	1.8	1.6	5.4	169.34
Net Production Revenue	-	114.5	121.8	80.4	50.4	49.0	47.4	44.9	33.6	25.8	24.7	23.7	22.9	22.2	21.6	20.9	20.3	19.8	19.3	18.8	153.2	935.49
Other Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oper. Costs + G&A	-	1.97	2.09	2.12	2.16	2.19	2.23	2.26	2.26	2.27	2.31	2.35	2.39	2.44	2.48	2.53	2.57	2.62	2.67	2.72	26.93	71.54
Abandonment Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.4	2.44
Op. Cash Inc. Before Tax	-	112.56	119.74	78.31	48.26	46.84	45.19	42.64	31.34	23.55	22.38	21.37	20.54	19.78	19.11	18.38	17.75	17.16	16.67	16.13	126.25	863.95
Capital	15.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00							15.00
Cash Flow Before Tax	-15.00	112.56	119.74	78.31	48.26	46.84	45.19	42.64	31.34	23.55	22.38	21.37	20.54	19.78	19.11	18.38	17.75	17.16	16.67	16.13	123.81	846.51

MAKING COMPLEX EASY

Contact

Suite 600
555 4th Avenue SW
Calgary AB
T2P 3E7
T +1 403 265 7226