OPERATIONAL REVIEW ALGERIA

Highlights

Ain Tsila development Front End Engineering and Design contract awarded

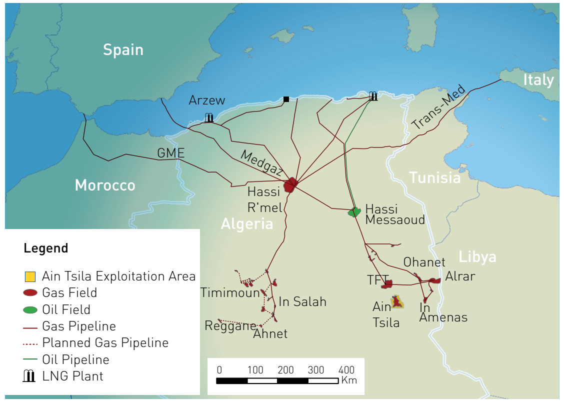
Contract awarded to Sinopec for drilling rig

First 12 development well locations agreed

Mobilisation of the Joint Operating Organisation to Hassi Messaoud complete

Fully termed Gas Sales Agreement signed and approved

Divestment to Sonatrach of an 18.375% interest in the field



During 2014, Petroceltic made significant progress towards the development of the strategically important Ain Tsila gas condensate field, which lies within the Isarene concession in the Illizi basin in south east Algeria.

An experienced Project Team has been established and the Joint Operating Organisation ("JOO" or "Groupement"), which is responsible for executing the field development plan, is now conducting operations on behalf of Sonatrach, Petroceltic and Enel. The Front End Engineering and Design ("FEED") contract was awarded in September and the Gas Sales Agreement was signed and approved by the Algerian authorities in November. By early 2015, the JOO had relocated from Algiers to the main Algerian oil and gas operating centre at Hassi Messaoud. Planning for the drilling programme is also well advanced with a rig contract awarded to Sinopec in April 2015 and contract award recommendations made for long lead time equipment, and the first 12 development well locations agreed.

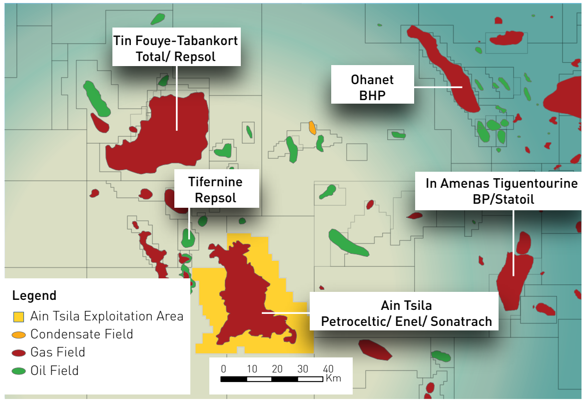
Of particular importance during the year was the successful completion of a second farm-out of a 18.375% interest in the Ain Tsila field to Sonatrach, the National oil and gas company of Algeria. The total consideration for the farm-out is $160m, with up to $20m of potential further payments contingent on certain project milestones. Under this agreement, Petroceltic's cost in the project will be carried until the second quarter 2016.

2015 will see the completion of the FEED studies and the tender and award of the EPC contract for the major project construction contracts. During the course of the FEED studies, the project cost estimate and schedule will also be updated. Subsurface engineering and geoscience activities will focus on optimising the development plan prior to the commencement of drilling late 2015. In April 2015, the Groupement successfully completed the tendering process for the rig contract resulting in the award and signature of the contract to SINOPEC. The 1500 horse power rig, which is now built and ready to ship, will drill up to 24 new development wells. The first 12 drilling locations, all in the northern region of the field, have already been selected and approved. This will enable drilling to commence on schedule in 2015.

In June 2015 an amendment to the Algerian PSC approving the transfer of Petroceltic's interest in the Isarene development to a subsidiary company was signed by all parties; this amendment and the associated transfer will become effective on gazettal following approval by the Algerian Council of Ministers.

Background

Petroceltic was awarded operatorship of the Isarene PSC in April 2005 with a 75% equity interest, this was subsequently reduced to



2015 will see the completion of the FEED studies and the tender and award of the EPC contract for the major project construction contracts.

56.625% through the divestment of an 18.375% interest to Enel SpA in early 2012, and reduced further to 38.25% through divestment of a further 18.375% to Sonatrach in 2014.

After the initial Ain Tsila discovery in 2009, Petroceltic applied for a two year extension period, from the end of the exploration period in April 2010 through to 26 April 2012, to allow time for the appraisal of the gas accumulation. During this period, the Group drilled six appraisal wells on the Ain Tsila structure.

Approved development plan

Following the completion of the appraisal drilling campaign and technical and economic studies, a full field development plan was submitted to the Algerian authorities and approved in December 2012. The plan envisages the production of 2.1 Tcf of sales gas and 179 MMbbl of liquids (comprising 69 MMbbl of condensate and 110 MMbbl of liquid petroleum gas or "LPG") from the field during the 30 year Production Sharing Contract ("PSC") exploitation period. The initial plan will result in a recovery factor of 24% of the Gas Initially in Place ("GIIP") in the field and the Company anticipates that the recovery factor is likely to grow over time with additional well data and the potential installation of additional gas processing facilities.

The field plateau production rate is forecast to be 355 MMscfpd gross wet gas and the plateau should last for some 14 years. The development plan involves the drilling and completion of 124 vertical development wells, of which 30 (including 6 existing wells) are scheduled to be available prior to first production. Along with basic in-field support infrastructure, the facilities will comprise a gas processing plant with water separation, condensate and LPG recovery equipment, gas compression, export pumps and metering facilities. The gas will be evacuated via a 95 kilometre pipeline which will tie into the main Algerian gas transmission network near the Tin Fouye Tabankort field. Dedicated condensate and LPG export lines will also be constructed to tie into liquids transmission infrastructure.

The gross project cost prior to first production is expected to be in the region of $1.6 billion with the majority of the expenditure incurred from 2016 through 2018. The capital estimate and phasing will be confirmed in more detail after the FEED studies have been completed and EPC contract awarded.

Gas commercialisation

Following the execution of a legally binding Heads of Terms for the Gas Sales Agreement with Sonatrach in 2012, the comprehensive Gas Sales Agreement detailing operation procedures and processes required for nominations and payments was signed in September 2014 and approved by the Algerian Energy Ministry in November 2014.

OPERATIONAL REVIEW ALGERIA
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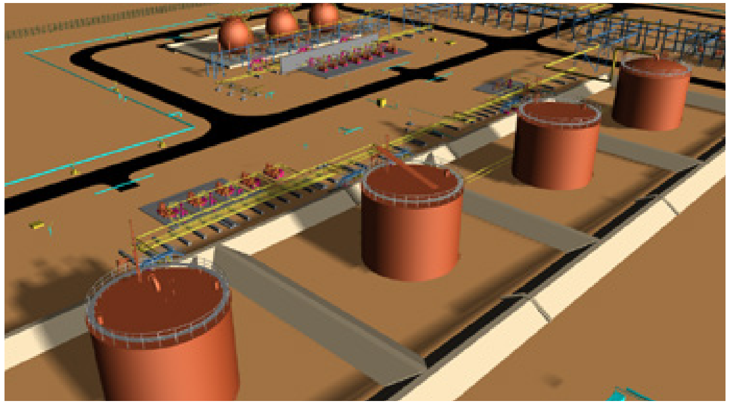


Liquids

Condensate and stabilised LPG form a significant part of the reserves and revenues from the Ain Tsila field. Based on data from similar developments, the Company anticipates that both condensate and LPG will be sold in the local market at a price related to Brent.

Second farm-out

A process to divest an additional 18.375% of Petroceltic's equity in the Isarene PSC was initiated in 2012 as part of the Company's strategy to manage its overall financial and operational commitment to the Ain Tsila development. In early 2013, Petroceltic agreed a farm-out proposal from an international oil company and initialled a Sale and Purchase Agreement. However, in July 2013, Sonatrach exercised their right to pre-empt the transaction and acquire the interest on similar terms.

The agreement to effect the transfer of the interest to Sonatrach was signed in February 2014 and ratified by the relevant Algerian government authorities in June. The consideration included a $20m initial cash payment, a cost carry of up to $140m and two potential further $10m payments contingent on the achievement of certain key project milestones. Petroceltic retained a 38.25% interest in the project through to first gas.

The farm-out has resulted in a reduction in Petroceltic's booked proved plus probable reserves from 300.0 MMboe to 202.7 MMboe, which has been reflected in the Company's year end 2014 reserves figures.

Exploration licencing round

The Algerian government launched a new exploration licencing round in 2014. The Group evaluated the tendered blocks, but due to a combination of technical and commercial considerations decided against making a licence application in the round.

The agreement to effect the transfer of the interest to Sonatrach was signed in February 2014 and ratified by the relevant Algerian government authorities in June.

Isarene concession timeline

2005	- Award of Isarene Production Sharing Contract
2006	- First exploration drilling of two wells
2008	- 3D seismic acquisition
2009	- Five wells drilled, resulting in the Ain Tsila discovery, the year's 9th largest worldwide
2010	- Two year delineation licence extension awarded
2011	- Successful six well drilling campaign
2012	- Farm-out of 18.375% interest to Enel - Declaration of Ain Tsila field commerciality - Development Plan and Gas Sales Heads of Terms approval - Award of 30 year exploitation licence - Booking of 304 MMboe of proved plus probable reserves
2013	- Formation of Joint Operating Organisation to develop the field - FEED tender issued to market
2014	- FEED contract awarded and studies commence - Farm-out of 18.375% interest to Sonatrach - Drilling contracts tendered
2015	- Mobilisation of Joint Operating Organisation to Hassi Messaoud - Rig contract awarded - Major project EPC contract to be tendered and awarded - Commencement of development drilling
2016	- **2018** Project execution phase including, drilling 24 wells and constructing gas processing plant and related infrastructure

CASE STUDY
GROUPEMENT ISARENE

When the Isarene PSC was awarded in 2005, Petroceltic was qualified as an operator in Algeria. During the initial exploration and appraisal phase of activity, almost 10,000 km of 2D and 900 sq km of 3D seismic were shot, processed and interpreted, supporting the drilling and testing of 13 wells and the preparation of a field development plan for the Ain Tsila gas field. Enel joined Petroceltic as an investor in the field in 2012 and Petroceltic remained as joint venture operator.

Following approval of that development plan by the Algerian authorities at the end of 2012, Sonatrach joined the venture as a paying participant in the exploitation phase. Upon commencement of this phase, consistent with the requirements of the PSC, the responsibility for the execution of petroleum operations on the Isarene permit passed to a newly constituted Joint Operating Organisation called "Groupement Isarene". This entity was set up in mid-2013 under the control of the PSC parties. It is financed by monthly cash calls to the Isarene PSC partners and is directed by a management council with representation of all the PSC parties.

Prior to the constitution of the Groupement Isarene, Petroceltic and Sonatrach negotiated the organisational structure and the allocation of positions between the parties, and, through the course of 2013, Petroceltic has redeployed or recruited more than 50 experienced professionals on behalf of itself and Enel to take up these positions, primarily in management, supervisory, finance and technical roles. These secondees are located alongside their Sonatrach counterparts in the Groupement offices, initially in Algiers through to the end of 2014, prior to their deployment to major contractor sites, the field and Hassi Messaoud (the oil and gas operating and logistical centre of Algeria).

Through 2014, the Groupement project team concentrated on the preparation of the contract tender packages for the Ain Tsila production facilities and infrastructure FEED and development drilling. The FEED contract was awarded to Chicago Bridge & Iron BV in the Netherlands, while at year end the drilling rig had been identified and the contract was subsequently awarded in 2015, to Sinopec International Petroleum Services Corporation.

In January 2015, the Groupement relocated its main office from Algiers to Hassi Messaoud to allow access to a larger resource pool of Sonatrach secondees, and from there development operations will ramp up with the preparation of the tenders for the main production facilities construction packages, the award of those construction packages, and the commencement of drilling. In the Ain Tsila field, a forward operations base and basic infrastructure will be constructed, allowing for the mobilisation of drilling rigs and construction crews in the second half of the year. Opportunities were taken during 2014 to optimise the timing of drilling start-up which will now take place in Q4 2015. This will ensure that the required number of wells are available to be hooked up for production at first gas in Q4 2018.

In line with other operators in Algeria, the Company has prepared and issued a Development Security Philosophy to ensure appropriate security controls for all in-country activities. The FEED study will address a number of these critical controls – physical, procedural, organisational – and ensure that best practice is designed and engineered into all aspects of construction and subsequent operation of the project facilities.

Through 2014, the Groupement project team concentrated on the preparation of the contract tenders packages for the Ain Tsila production facilities and infrastructure FEED and development drilling.

OPERATIONAL REVIEW EGYPT

Highlights

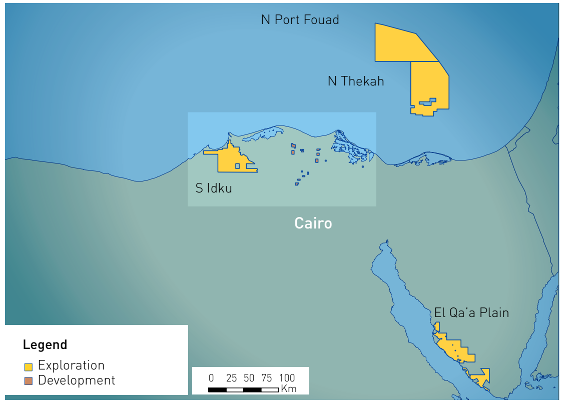
Average production of 95.3 MMscfpd of gas and 2,821 bopd of hydrocarbon liquids

Completion of two successful development wells and one workover

Commissioning of the West Khilala and South Damas compression projects

Ratification of two new exploration licences and the award of a third

EGPC receivables reduced from $81m to $50m



Petroceltic's core area of operations in Egypt is in the onshore Nile Delta where it holds a 100% operated interest in 12 producing fields in 14 development concessions in the El Mansoura and the South East El Mansoura concession areas. The field development operations are managed through a Joint Operating Company called Mansoura Petroleum Company jointly owned by Petroceltic and the Egyptian Government.

During 2013 and 2014, the Company has significantly renewed its exploration portfolio in Egypt and in January 2014 PSCs were signed for two new licences. These include a 75% interest in the onshore South Idku concession and a 50% interest in the exciting, deep water North Thekah block, which is thought to contain an extension of the prolific Levantine basin exploration play. In the second half of the year, the Company was also awarded a 50% interest in the North Port Fouad block, which is adjacent to North Thekah, and the PSC was signed in January 2015. These licences, combined with the Company's existing 37.5% interest in the El Qa'a Plain concession, provide Petroceltic with a diversified exploration portfolio, containing oil and gas prospectivity and with high volume potential.

Political and economic situation

2014 marked a return to political stability in Egypt with a number of key developments taking place. In January the new Egyptian constitution was approved by referendum and this was shortly followed by Presidential elections in May. The winner of the elections was President El Sisi who assumed office in June and swiftly formed a new Government. Preparations are now underway for Parliamentary elections in 2015.

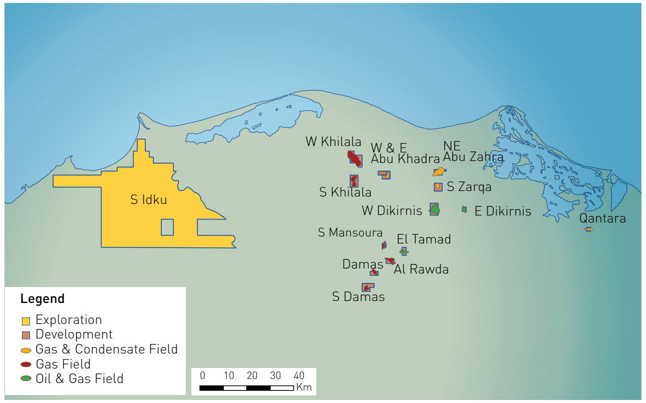
The economy continued its gradual path of improvement during the year and the country's credit rating and outlook were raised by Standard & Poor's and Fitch twice from "CCC+/C" to "B-/B" with a "stable" outlook. Several initiatives are being pursued by the government to attract foreign investment and the decision in the summer of 2014 to reduce fuel subsidies by an average of 30% was a clear sign of the government's desire to begin to implement important market reforms.

During the year, the Government continued to address the issue of payment arrears with the international oil and gas companies and in December made a significant disbursement amounting to the equivalent of $2.1bn. This brought the total paid to the industry since December 2013 to around $5bn (over 60% of the arrears).

Petroceltic received payments totalling $120m in 2014, and the receivables were reduced from $81m to $50m over the course of the year. The payments were made in cash and also by means of the allocation of sales proceeds from part cargoes of crude and crude oil products.

Production and reserves

In 2014, Petroceltic's daily production in Egypt averaged 19,256 boepd on a working interest



basis, which is equivalent to 8,675 boepd on a net entitlement basis. The working interest production split between hydrocarbon types was 95 MMscfpd of gas and 2,821 bpd liquids (oil, condensate and LPG) representing an 85%/15% split on a volume basis. Approximately 74% of the production was derived from the West Dikirnis, South Damas, and the West and South Khilala fields, with the remainder from eight smaller accumulations.

Throughout the year, the Company continued to invest in its producing assets with new compression facilities installed at the West Khilala field to reduce the well head flowing pressures and hence maximise gas recovery, and a small booster compressor commissioned for the South Damas field. The Company also drilled and completed two successful development wells during the year, namely West Khilala-4ST and East Abu Khadra-1ST and conducted work-overs to re-establish production from the West Dikirnis-2 and 8 wells. While the production figure for the year was positive, a small number of reservoir performance issues have required a downwards adjustment to booked reserves as at 31 December 2014. In particular, recent well performance on West Khilala has been negatively impacted by water and sand production, requiring a reduction of 35 Bcf; a more modest reduction was made in respect of West Dikirnis where heavier risking was applied to the gas reserves which will be recovered during the gas cap blowdown phase late in field life.

West Dikirnis field

The West Dikirnis field, which contains a 70 foot oil rim, overlain by a gas cap, was discovered In 2005. The field commenced production in 2007 and to date, the Company has focused on maximising the hydrocarbon liquids recovery by drilling a combination of vertical, high angle and horizontal wells and installing Liquid Petroleum Gas ("LPG") extraction and Gas Reinjection facilities. These facilitates are used to strip the hydrocarbon liquids out of any gas which is produced with the oil, and then to re-inject the gas back into the reservoir to maintain the reservoir pressure.

An active reservoir management programme is in place for the field, and individual well withdrawal rates are managed to prevent excessive quantities of water, sand or gas being produced. We are also planning to implement an Enhanced Oil Recovery Scheme using a form of miscible gas flood. This will take advantage of the fact that the West Dikirnis crude oil is highly volatile and can be vapourised in the reservoir if it is contacted by re-injected gas. To implement the scheme, Government approval is being sought to convert 3 redundant oil wells to gas injection in 2015/16 (to supplement the one existing gas injector) and to increase the gas cycling rate in the field. Two more additional producers will also be drilled in 2015/16.

During the year, a successful workover was performed on the West Dikirnis-8 well to correct a safety problem (tubing to casing pressure communication) and the well was returned to production at 200 boepd. A low cost rig-less workover was also conducted on West Dikirnis-2 to add perforations and the well, which had been shut-in due to water production, resumed production at 400 bopd.

The field's average production rate in 2014 was 1,967 bopd of oil, condensate and LPG, and approximately 33 MMscfpd of gas. Approximately 19 MMscfpd of the produced gas were re-injected into the reservoir, 11 MMscfpd were sold to the local market and the remainder used to run the facilities. Gas sales were maintained sporadically during the year until the end of September in response to a request from the Government to supply gas during periods of domestic supply shortfall (particularly during the summer months).

The field's ultimate proved and probable reserves are estimated at 18.2 MMbbl of hydrocarbon liquids and 62.4 Bcf of gas. By the end of 2014, the field had produced 10.9 MMbbl of liquids and 26.2 Bcf of gas.

West Khilala field

The West Khilala gas field was discovered in 2005 and came on stream in February 2007. The average production rate during 2014 was 30 MMscfpd of gas and 30 bopd of condensate from six wells.

The field is now relatively mature and the focus of the field management programme is to minimise the impact of water and sand production on individual well performance and surface flowlines and facilities. As part of a programme, the Company has standardised on open hole gravel packs as being the best downhole completion design and in early 2014 the watered out West Khilala-4 well was sidetracked and successfully

OPERATIONAL REVIEW EGYPT
CONTINUED

completed with a gravel pack and returned to production at 6 MMscfpd. At the end of the year, the West Khilala-3 well was also sidetracked but unexpectedly encountered a swept area of the reservoir and was plugged and abandoned in early 2015.

The year end 2014 ultimate proved plus probable reserves are 250 Bcfe and the remaining reserves estimated at 42 Bcfe. These figures reflect a downward revision of some 35 Bcfe based on the West Khilala-3 sidetrack results and other recent well performance data. This reserve write-down had a direct impact on the NPV of the asset and this contributed to the impairment charge at year end.

South Khilala field

The South Khilala field was discovered in May 2009 and was placed on production in October 2009 through the West Khilala processing facilities. The average production rate in 2014 was 9 MMscfpd of gas and 13 bopd of condensate from two wells. A third well (South Khilala-3) is under consideration to drain the most crestal part of the field, to help maintain the field's production rate and maximise reserves. The field's remaining reserves as at year end 2014 are estimated at 24 Bcfe and the cumulative gas production to date is 30 Bcfe.

Damas and South Damas fields

The Damas and South Damas fields were discovered in 2008 and 2010 respectively. Damas was brought on production during 2009 but was temporarily shut in during 2010 to enable the South Damas field to flow through a common pipeline to the South Mansoura production facilities. In November 2014, the flow line pressure was decreased by transferring a booster compressor from the South Batra gas plant to the South Mansoura gas plant. This allows for the continuity of the production from this field and potential upgrade of its ultimate recoverable reserves.

The South Damas field has performed exceptionally well since inception and the field's initial gas in place has been progressively upgraded to 67 Bcf. The field is being drained by 2 wells, with one completed with a gravel pack to control sand production. The average production rate for the year was 18 MMscfpd of gas and 144 bopd of condensate.

The ultimate proved plus probable recoverable reserves are estimated at around 58 Bcfe and the field had produced about 25 Bcfe by year end 2014.

The South Damas field has performed exceptionally well since inception and the field's initial gas in place has been progressively upgraded to 67 Bcf.

Other fields

The Group also operates eight smaller fields in the Nile Delta which contributed 5,244 boepd of the total production in 2014.

The Tamad field gas cap blow down commenced in 2013 and, in 2014, the field contributed 10.4 MMscfpd and 93 bopd of condensate.

The South Zarqa field, which has a very active aquifer and produces from a single gravel packed well, contributed 7.9 MMscfpd of gas and 254 bopd of condensate.

In the East Abu Khadra field, an old watered out production well was successfully sidetracked to an updip location during the year and the new wellbore is currently producing at a rate of 3 MMscfpd.

The East Dikirnis oil and gas field, which has a thin oil rim, was tied back to the West Dikirnis facilities in January 2013 and the single production well is currently flowing at approximately 226 bopd and 0.9 MMscfpd under rate control.

Exploration

Petroceltic has been expanding its exploration portfolio in Egypt during 2013 and 2014 in order to replenish the prospect inventory. The Company now has interests in four exploration concessions as follows:

El Qa'a Plain
(Petroceltic 37.5%, Dana 37.5% (operator), Beach Energy 25%)

This concession is located in an under-explored sub basin on the eastern shore of the Gulf of Suez and contains a substantial number of oil leads identified on existing 2D seismic data. The gross unrisked mean prospective resource potential is estimated at 140 MMbbl. The concession was ratified in October 2013 and signed in January 2014 and the forward plan is to acquire 450 sq km of 3D seismic in 2015 followed by the drilling of one or more exploration wells in 2016. The seismic contract was tendered, evaluated and signed by Q2 2015.

South Idku
(Petroceltic 75% (operator), Edison 25%)

This concession was awarded in April 2013 and is located in an under explored part of the onshore Nile Delta on trend with Edison's offshore producing Abu Qir field (1.5 Tcf + 40 MMbbl). A number of amplitude supported leads have been identified in the Miocene formations on 2D seismic and the total prospective resources are estimated to lie in the range 400 Bcf to 1900 Bcf. A tendering process is underway for the acquisition of a 3D seismic survey and exploration drilling is likely to occur in 2016.

North Thekah
(Petroceltic 50%, Edison 50% (operator))

This concession was also awarded in April 2013 and is located in the deepwater Nile Delta within an underexplored part of the Levantine Basin. The primary exploration target in this block are Nile Delta Oligocene and Levantine Basin Miocene plays on trend with the giant Leviathan and Tamar discoveries in Israel. A number of potentially significant leads and prospects have been identified on existing 2D seismic. 3D seismic acquisition is now completed and although there are no commitment wells in the current exploration period, a decision will be made with respect to exploration drilling following evaluation of the new 3D seismic survey.

North Port Fouad
(Petroceltic 50%, Edison 50% (operator))

The concession which was awarded in September 2014, is adjacent to North Thekah in the deepwater Nile Delta and has similar plays and objectives. 3D seismic tendering will start later in 2015 and a decision will be made with respect to any exploration drilling which is likely to occur in 2018/2019.

Exploration in Development Concessions
(Petroceltic 100%)

Exploration well South Dikirnis-1 was drilled in May 2014 to test the extension of Qawasim formation reservoir in a tilted fault block within the West Dikirnis development concession. The well results showed minor gas shows in Qawasim formation which indicated the main reason for failure was the ineffective lateral seals in the well.

OPERATIONAL REVIEW BLACK SEA BULGARIA

Highlights

Average gas production rate of 18.6 MMscfpd

Kavarna East development planning completed

Successful export compressor major overhaul

Petroceltic has a 100% operated interest in three producing gas fields and one future development in the Galata Exploration Block, which is located in shallow water, offshore Bulgaria, in the Black Sea. The producing fields were developed using an unmanned platform located on the main Galata field, to which the Kaliakra and Kavarna fields have been tied-back using subsea completions.

Production

The combined production rate from the Galata, Kaliakra and Kavarna fields averaged 18.6 MMscfpd during the year, with a cumulative production volume of 6.8 Bcf. The gas was sold to two customers, Bulgargaz (the state gas utility company) and Agropolychim (an independent fertiliser plant) at an average price of $8.34/Mcf giving total revenues of $51m.

The Galata field continued to perform well during 2014 and data acquisition surveys run in the wells have confirmed a relatively static water level in the field and continued gas recharge into the main reservoir from the remote areas of the field. Consequently, the field was capable of producing at an average rate of 9.7 MMscfpd during the year.

Given the positive field performance, the Company is evaluating the technical merits of performing a low cost wireline workover to potentially restore production from the GP-2 well. This well was shut-in in late 2008 due to the onset of water production but data shows there has been limited movement in the gas water contact ("GWC") in the vicinity of the well and there is still a significant interval of gas bearing perforations above the GWC. The workover would involve the mechanical isolation of the water bearing interval, enabling production to be resumed from the gas bearing zone.

The two smaller fields, Kaliakra and Kavarna produced a combined average rate of 8.9 MMscfpd during the year, which was slightly below forecast. The Kaliakra-1 well rate has continued to slowly decline suggesting that the well is only in partial pressure communication with the main field area. Hence, the Company is actively considering whether an additional well will be required to

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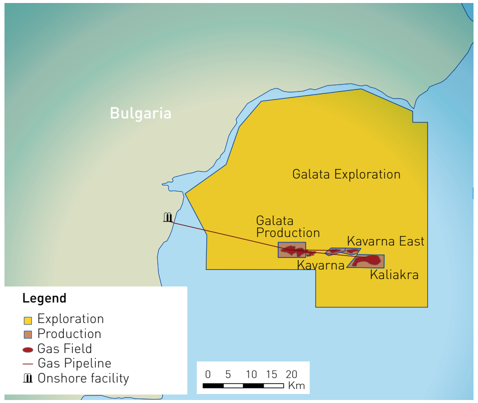


The Kavarna East field was discovered in 2010 and contains approximately 9.6 Bcf of gas reserves.

fully drain the field. The Kavarna-1 well has experienced water breakthrough and is likely to be shut-in when the Kavarna East field comes on stream.

Given the recent field performance, the year end 2014 reserves for the Bulgarian fields have been marginally downgraded and the combined remaining reserves are estimated at 26.6 Bcf.

In November, all the Company's Bulgarian fields were shut-in for a period of 20 days to complete a planned overhaul of the high pressure export compressor. This involved the replacement of the compressor bundle and main drive unit and the work was completed for a cost of $2.5m. Excluding the compressor related work activity, the production facilities uptime in Bulgaria continues to be world class at over 99 percent.

Development

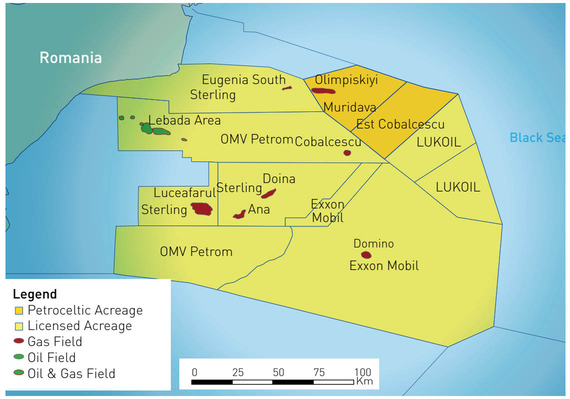
The Kavarna East field was discovered in 2010 and contains approximately 9.6 Bcf of gas reserves. The field will be developed using a single subsea well tied back to a manifold near the Kavarna field and, from there, the gas will flow to the Galata platform using the existing Kavarna flowline. As this is an existing discovery with pipeline laid, the development involves re-entry and completion of the existing well. The project execution plans are well advanced with all the long lead time equipment procurement activities completed. The exact project timing is now dependent on rig and diving support vessel availability.

OPERATIONAL REVIEW BLACK SEA ROMANIA

Highlights

Safely completed the drilling of South Cobalcescu-1 and Muridava-1 exploration wells

Licences divested in June 2015



During 2014, Petroceltic operated two offshore exploration concessions in the Romanian sector of the Black Sea with a 40% operated interest in each. The licences, Block 27 Muridava and Block 28 Est Cobalcescu, are located in shallow water and have a combined area of approximately 2,000 sq km. Both blocks cover an area that has historically been under-explored due to a previous maritime border dispute.

The Block 27 Muridava partnership comprised Petroceltic Romania B.V. (40% equity and operator), Midia Resources S.R.L. which is a wholly owned subsidiary of Sterling Resources Ltd (40% equity) and Petromar Resources S.A. (20% equity). The Block 28 Est Cobalcescu partnership comprised Petroceltic Romania B.V. (40% equity and operator), Beach Petroleum S.R.L. which is a wholly owned subsidiary of Beach Energy Ltd (30% equity) and Petromar Resources S.A. (30% equity). The initial minimum work programme for each Block comprised seismic acquisition and three wells.

The Joint Venture partners has now drilled two wells, one in each of the Blocks, on the highest graded prospects as defined using the 3D seismic acquired in 2012. Both wells were located approximately 170 kilometres northeast of Constanta and drilled using the GSP Prometeu jack up drill rig. Unfortunately, neither of the wells encountered commercial quantities of hydrocarbons and both were subsequently plugged and abandoned. The Cobalcescu South-1 well in Block 28 did encounter good quality sandstones at the target Miocene stratigraphic levels with gas shows while drilling, indicating an active hydrocarbon system. The Muridava-1 exploration well in Block 27 licence was drilled to a total depth of 2,747 metres but failed to encounter commercial quantities of hydrocarbons in the primary Eocene, Paleocene and Upper Cretaceous reservoir targets.

The disappointing drilling results confirmed an active hydrocarbon system and that good reservoir quality is present, but significantly increased the risk to the residual prospect inventory. A detailed technical review of the remaining prospectivity in each licence was conducted and the conclusion was that the remaining prospects were either sub-commercial from a scale perspective or of unacceptable technical risk to justify further investment.

In June 2015, Petroceltic completed the sale of the entire share capital of Petroceltic Romania B.V (which held the interests in Block 27 and Block 28) to GVC Investment B.V, a private limited company which has considerable oil and gas assets in the region.

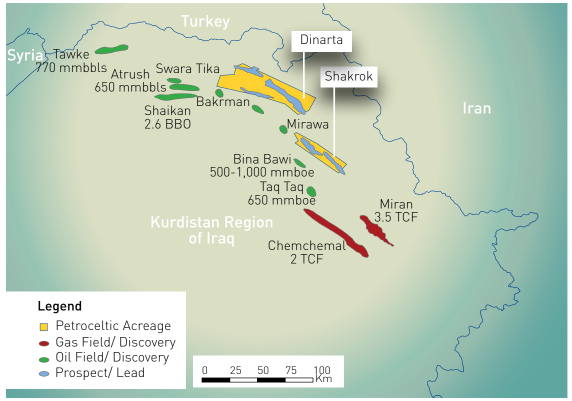
Following the completion of this sale to GVC, Petroceltic has no remaining obligations in Romania.

OPERATIONAL REVIEW KURDISTAN REGION OF IRAQ

Highlights

Shakrok 1 well plugged and abandoned and the Shakrok licence relinquished

Shireen 1 well encountered operational problems and without positive indications of commercial hydrocarbons the Dinarta licence was relinquished



Petroceltic has been active in the Kurdistan Region since 2011 when the Shakrok and Dinarta blocks were awarded with Petroceltic holding a 16% interest (20% paying interest) in each Production Sharing Contract ("PSC") in the northern area of the Kurdistan Region of Iraq ("KRI"). The blocks were awarded in partnership with the operator, Hess Middle East New Ventures Ltd ("Hess"), with a 64% participating interest (80% paying interest) and the KRG with a 20% carried interest.

The work programme for each block consisted of 2D seismic and the drilling of two exploration wells, one on each block. The Company's first exploration well in the KRI, Shakrok-1, was spudded in August 2013 and reached a total depth of 3,538 metres in the Triassic Geli Khana formation in March 2014. Drill Stem Tests were carried out over four prospective zones in the Jurassic. No hydrocarbons flowed to surface although the water flow rates confirmed the presence of some very high quality fractured reservoirs. Wireline logging and fluid sampling established the presence of a 27 metre gas-condensate column in the Triassic formation but this was not viewed as commercial. Hence the well was plugged and abandoned as a sub-commercial gas discovery in May 2014. All work program commitments have been fulfilled on the Shakrok PSC and it was formally relinquished in July 2014.

Operationally, the focus on the Dinarta block in 2014 was the preparation for and drilling of the Shireen-1 well. This was the highest elevation well ever drilled in Kurdistan with a surface location 2,100 metres above sea level. In addition to the logistical hurdles provided by well site excavation and access route construction, further challenges were encountered due to the karstified nature of the near-surface geological environment, the pervasive fracturing of the carbonate stratigraphy and the execution of drilling, casing and cementing operations in the shallow section above the water table.

The Shireen-1 well was spudded in June 2014, using the Parker 247 rig, and the top hole section was successfully drilled and cased. However, in August, a degradation of the regional security environment occurred due to the ISIS incursion into Northern Iraq from Syria. While these developments did not directly impact exploration activities, in line with other operators in the region, it was decided to temporarily secure and suspend operations at Shireen-1 and to evacuate non-essential personnel as a precautionary measure. Further to this temporary suspension announced in August, drilling operations resumed at the Shireen-1 exploration well in October. Subsequently, the well encountered a further series of operational problems which ultimately resulted in its premature suspension in the Jurassic formation. Prior the well suspension, no positive indications of commercial hydrocarbons had been observed.

Following a detailed review of the Shireen-1 well data and the remaining prospectivity on the Dinarta concession, a decision was taken by the Joint Venture partners to relinquish the block. All PSC work program obligations were fulfilled other than the required final remediation of the well sites. All costs associated with both the Shakrok and Dinarta licences were written off as unsuccessful exploration costs, including a provision for 2015 exit costs, in the year ended 31 December 2014.

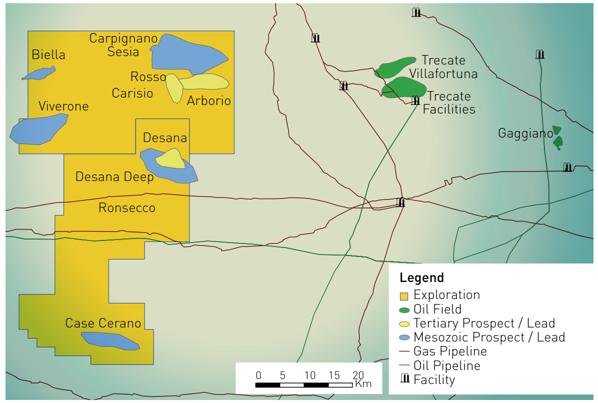
OPERATIONAL REVIEW ITALY

Highlights

Re-submission of Environmental Impact Assessments for approval for Elsa and Carpignano Sesia

International certification of country level HSES Management System

Purchase of 750km 2D seismic data over the high-graded offshore Turchese prospect



The past year has seen steady progress on the Company's Italian assets, with significant milestones achieved on key projects in the Central Adriatic and in the Po Valley. The primary focus has been on recommencing the environmental permitting process in key projects, supported by ongoing engagement with national and local institutions to demonstrate that exploration activity can deliver tangible benefits to local communities and the Government in a safe and environmentally responsible fashion. A significant milestone was achieved in June 2014 when DNV certified the country level HSES management system as meeting the requirements of ISO14001 for environmental management and OHSAS18001 for occupational health and safety management. This brings Italy into line with the Company's other operating areas which also have the international accreditation.

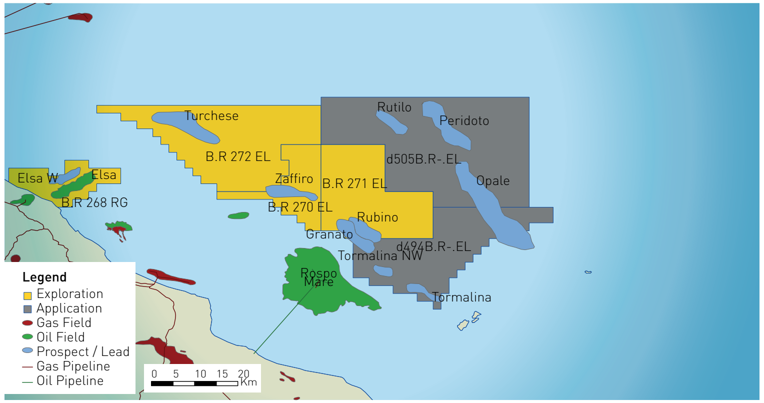
The "Restart Italy" decree, passed into law in November 2014, builds on the National Energy Strategy of 2013 in reaffirming the strategic nature of domestic hydrocarbon exploration and production activities and contains a number of measures aimed at facilitating progress in the sector whilst aligning regulation with offshore safety EU directive. These include the introduction of the "Single Permit" which aims at simplifying permitting by combining exploration and production phases into a single licence and transferring the responsibility for onshore environmental permits from the Regions to the Ministry of the Environment.

Western Po Valley

The Environmental Impact Assessment ("EIA") for the Carpignano Sesia-1 well was resubmitted by the Operator, Eni, to the authorities in December 2014, following revisions aimed at addressing stakeholder concerns relating to the proximity of the well location to the village of Carpignano Sesia. This well is being designed to test a large oil prospect located some 25km west of the analogous Villafortua-Trecate Field, which has gross mean unrisked prospective resources of 237 MMboe. Petroceltic has a 47.5% equity interest in the licence. The process to farm-out a portion of Petroceltic's interest in the block is at an advanced stage and commercial discussions with a potential farminee have been concluded.

Central Adriatic

The Group's main operated asset in Italy is the Elsa oil discovery, offshore Abruzzo, which is expected to contain 95 MMbbl of gross 2C contingent resources (Petroceltic 55%, paying interest 70%). The discovery requires further appraisal drilling and the EIA for the Elsa-2 well was resubmitted in July 2014, following consultative discussions with the government and local institutions. The Elsa-2 well aims at establishing potential production rates and acquiring a high quality fluid sample, both necessary to establishing the basis for



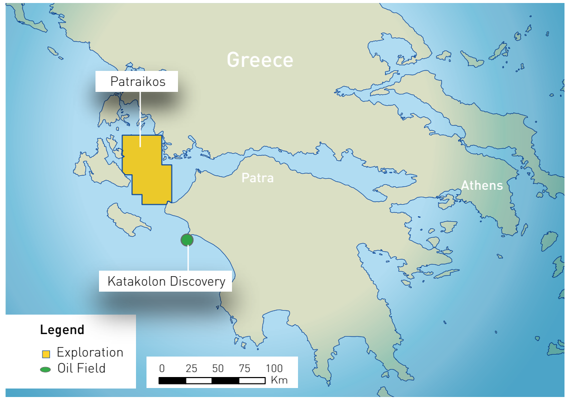
commercial development of the field. In March 2015, technical approval was issued by the EIA Commission, EIA final decree is expected soon, paving the way for the Elsa-2 well which will be started most likely in late 2016.

Further offshore from the Elsa field but in the same exploration play, the Company holds an interest in the B.R272.EL permit which contains the high graded Turchese prospect. This permit was awarded on a 100% basis to Petroceltic, however, Orca Exploration Group Inc retains an option to acquire a 15% interest in the licence. The Company purchased access to 750km of 2D seismic data over the block during the year to further evaluate the prospectivity.

For more information, please see our Petroceltic Italia website www.petroceltic.it

The Group's main operated asset in Italy is the Elsa oil discovery, offshore Abruzzo, which contains 95 MMbbl of gross 2C contingent resources

OPERATIONAL REVIEW GREECE



The award of the Patraikos block (Petroceltic, Hellenic (operator) and Edison 33.3% each) was formally ratified by the Greek parliament in October 2014.

The licence is located in the Gulf of Patra and covers an area of 1,892 sq km with water depths principally in the range of 100 to 300 metres. The concession is potentially oil prospective in the Jurassic, Cretaceous and Eocene formations and the regional hydrocarbon system has been proven by the Katakolon oil discovery wells drilled in 1982, approximately 35 kilometres south of the block. There are also several known oil seeps around the Gulf of Patra area. There is extensive 2D seismic data already available over the block and the unrisked mean prospective resources for the mapped prospects lie in the range of 80 MMbbl to 360 MMbbl.

The Group is currently considering divestment of this licence.