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United Oil & Gas Plc*

10 July 2019

BUY

Stock Data

Share Price:	3.65p
Market cap.:	£12.6m
Shares in issue:	345.6m
Fully diluted equity:	434.6m

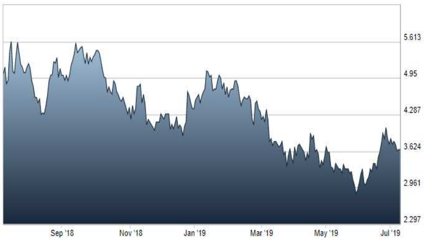
Company Profile

Sector:	Oil & Gas
Exchange:	AIM
Ticker:	UOG

Activities

Oil and gas exploration, development and production company with existing assets in the UK, Italy and Jamaica. Management strategy is to expand the current portfolio with value accretive acquisitions focused primarily on stable international jurisdictions.

Performance Data



Directors

Graham Martin:	Non-Exec. Chairman
Brian Larkin:	Chief Executive Officer
Jonathan Leather:	Chief Operating Officer
David Quirke:	Chief Financial Officer
Alberto Cattaruzza:	Non-Exec. Director

Important Notice

United demonstrates continued progress

United has demonstrated strong progress since the beginning of 2019. In Italy, the Selva gas field has been awarded preliminary approval for a production concession and with it; a CPR published by CGG has declared maiden gas reserves attributable to United. This trend has continued over H1 with CPRs upgrading resource estimates for several of United's interests in Jamaica, Italy and the UK. With the portfolio recently augmented by the provisional award of new UK acreage as part of the UKCS 31st Licensing Round and an option to farm-in to exciting new acreage in Benin signed in March, we believe that United has provided additional layers of potentially exciting upside to the portfolio.

In February 2019, United achieved a key milestone with the first reserves of gas (2.7 BCF) attributed to the company's 20% economic interest in the Selva field on the Podere Gallina licence in Italy. This was followed in April by an upgraded CPR which factored in a further 14.1 BCF of gross contingent resources and a 74% increase in best case prospective resources to 91.5 BCF for Podere Gallina. Selva was awarded preliminary approval for a production concession in early 2019 and United, with its partners, plans to install final production facilities within the next 12 months with a view to commencing production in mid-2020.

In the UK, the Crown discovery on UKCS Licence P2366 was attributed maiden gross unrisked 2C contingent recoverable oil resources of 6.35 mmbbls (UOG: 95%) and the same classification of resources on the onshore Waddock Cross field were also upgraded from 1.23 mmbbls to 1.55 mmbbls (UOG: 26.25%) in a CPR published by ERCE in early February. With regards to Crown, United has instigated discussions with potential farm-in partners in order to expedite future drilling activity on the licence. In the event that the company can secure a carried interest or a partial carry on a future appraisal well, we believe that a reduced equity interest represents significant potential value to United.

In late February 2019, ERCE also upgraded the key Colibri lead on the Walton-Morant licence offshore Jamaica in which United with a 20% interest, is partnered with Tullow Oil. The competent person increased the gross unrisked mean prospective resource estimate for Colibri from 219 mmbbls to 229 mmbbls and also boosted the geological chance of success from 16% to 20% on the back of positive 3D seismic data acquired in 2018.

Following the Colter appraisal well completed in March 2019 on Licence P1918 (UOG: 10%) in the English Channel, the operator delivered a new discovery on Colter South, the most recent assessment of which has indicated up to 15 mmbbls of gross recoverable resources. Although smaller than initial prognosis, United believes that such a resource comfortably exceeds the threshold for commerciality and the Colter accumulation merits further analysis.

The company has augmented its portfolio of assets significantly in 2019. In West Africa, United has signed an option agreement to farm-in to a 20% interest in the onshore Elephant Oil operated Block B in Benin, an exciting frontier exploration region surrounded by prolific hydrocarbon regions. The exploration portfolio was boosted further in early June as United was provisionally awarded 100% interests in four UK North Sea blocks and 10% interests in a further two licences in the English Channel as part of the UK 31st Licensing Round.

We have ascribed United a risked valuation of 11.4p per share on a fully diluted basis (note that this includes no value for Benin or the provisionally awarded 31st Round Blocks.. Although we reserve the opportunity to adjust our assessment in the event of the conclusion of potential farm-in opportunities, we note that that our unrisked valuation for United is over 51p per share at this stage, representing major potential upside to the company. This could be augmented further should United's most recent acquisitions demonstrate significant promise upon further analysis.

Contents

Current status of United Oil & Gas

In less than three years, United Oil & Gas (United) has assembled an attractive portfolio of core assets in the UK, Italy and Jamaica. This has been recently augmented by the establishment of an option agreement to farm into onshore acreage in Benin in March 2019 and also the provisional award of interests in six UK offshore Blocks in the North Sea and English Channel as part of the UK 31st Offshore Licensing Round in early June 2019.

On the corporate side, the company's ordinary shares recently commenced trading on AIM on 1 March 2019 following the cancellation of the trading of its shares on the standard list of the LSE.

Experienced management team

United possesses a highly experienced management with extensive industry experience. In particular, United CEO Brian Larkin and COO, Dr Jonathan Leather both acquired extensive experience in their time with Tullow Oil where both directors held senior positions within the larger group prior to establishing United.

The company recently appointed David Quirke as Chief Financial Officer and Company Secretary to the Board in May 2019. David established and led the Tullow Oil Group Treasury function between 2003 and 2015. His appointment to management team at United is effective from 24 June 2019. Additional information regarding all United's management team can be found in the Appendix at the end of this report.

The portfolio in summary

United possesses an increasingly well-balanced portfolio of near term development with appraisal upside in Italy, a broad range of appraisal and exploration opportunities in the UK and frontier exploration upside in Jamaica and Benin where the company is partnered with Tullow Oil and Elephant Oil respectively.

With the company continuing to demonstrate a track record of completing value adding asset acquisitions and an ongoing pipeline of new potential opportunities continuously under examination, we believe that United has established the foundations of a solid mid-tier E&P company with significant growth potential. Our table below summarises United's full portfolio of licences and highlights the key assets within each licence.

United's asset portfolio summary

Country	Licence	Key assets	UOG	Operator	Status
UKCS	P2366	Crown oil discovery	95.00%	United Oil & Gas	Farm-out opportunity
UKCS	P1918	Colter oil discovery	10.00%	Corallian Energy	Long term appraisal/development project
UKCS	31st Licensing Round	Four Blocks	100.00%	United Oil & Gas	Acreage with multiple prospects in the CNS
		Two Blocks	10.00%	Corallian Energy	Acreage adjacent to Colter discovery
Italy	Podere Gallina	Selva field	20.00%	Po Valley Energy	Gas field under development
		Selva Malvezzi	20.00%	Po Valley Energy	Portfolio of undeveloped gas resources and prospects
UK (onshore)	PL090	Waddock Cross field	26.25%	Egdon Resources	Shut-in discovery
UK (onshore)	PL090 Exploration	Broadmayne prospect	18.95%	Egdon Resources	Largest of several exploration prospects on licence
Jamaica	Walton Morant	Colibri lead	20.00%	Tullow Oil	Multi-billion bbl potential frontier exploration play
Benin	Onshore Block B	Frontier exploration	20.00%	Elephant Oil	Option to farm into PSC

Source: Company

Fund raising at increasing levels

We believe that United has built a formidable portfolio with relatively modest financial resources. At the time of the company's reversal into Senterra in July 2017, United raised £3.0m before expenses through the placing of 120 million shares at 2.5p per share. This was followed up by a modest raising of £1.25m in December 2017 at a higher price of 4.0p per share. This cash was used primarily to fund United's share of costs in Italy and to expedite the Colter farm-in agreement at the beginning of 2018.

United raised a further £2.5m at 4.25p per share in April 2018 of which £1.1m was used to pay United's share of 3D seismic work on the Walton-Morant licence in Jamaica and a further £1.0m was utilised for the company's share of drilling costs on the Colter appraisal well and subsequent sidetrack.

The company's most recent placing was expedited in September 2018 when United raised gross proceeds of £3.0m at a price of 5.5p per share with which to pursue new projects. We estimate that United currently has cash resources of £3.5m with which to fulfil short term obligations and fund future expansion plans.

Company valuation summary

Outlined in the table below is our sum of the parts valuation for United Oil & Gas. Our valuation assumptions are based on United's fully diluted equity which consists of almost 345.6 million shares and a further 89.0 million warrants at various levels from 1.43p to 8.00p. Our indicative valuations have been generated in a combination of US dollars (Euros in the case of Podere Gallina in Italy) and converted into a Sterling equivalent at the average exchange rate for the year to date of approximately US$1.27: £1.00.

Within our valuation, we have attributed valuations for the company's core assets in Italy and the UK as well as a risked assessment of United's interest in Jamaica. Presently, we view the recent provisional award of interests in six blocks in the UKCS and the company's option to acquire a 20% farm-in interest in block 20 in Benin as longer term upside and we will ascribe initial valuation to these assets upon a more definitive demonstration of prospectivity.

United Oil & Gas valuation summary

Licence	Country	Status	Valuation US$m	Valuation £m	Undiluted p	Diluted p
P1918 (Colter)	UK	Appraisal/Development	10.9	8.6	2.5	2.0
P2366 (Crown)	UK	Appraisal	10.2	8.0	2.3	1.9
Podere Gallina (Selva field)	Italy	Development	6.4	5.1	1.5	1.2
Podere Gallina	Italy	Contingent resources	1.6	1.3	0.4	0.3
Podere Gallina	Italy	Prospective resources	2.3	1.8	0.5	0.4
PL090 (Waddock Cross)	UK	Appraisal/Development	5.0	3.9	1.1	0.9
PL090 (Broadmayne)	UK	Exploration	3.7	2.9	0.9	0.7
Walton-Morant	Jamaica	Exploration	13.7	10.8	3.1	2.5
Block B	Benin	Exploration	0.0	0.0	0.0	0.0
UKCS 31st Licensing Round	UK	Exploration	0.0	0.0	0.0	0.0
Overheads		Corporate	-1.0	-0.8	-0.2	-0.2
Cash (debt)		Corporate	4.4	3.5	1.0	0.8
Warrants		Corporate	5.5	4.4	0.0	1.0
Total			**62.8**	**49.6**	**13.1**	**11.4**

Source: Optiva estimates

Fully funded in 2019

We understand that United does not have many substantial capital commitments within the next six months. We believe that assets including Waddock Cross, Walton-Morant and exploration activity on Podere Gallina have no immediate or significant near term funding requirement in 2019. However, in the case of the Selva field development, we anticipate that additional development capex in the €0.5m to €0.6m range for the company's interest to complete the final field infrastructure facilities can be comfortably funded from existing resources within the next 12 months.

Of the other key assets in the portfolio, United is targeting discussions for potential farm-in partners on the P2366 (Crown), a process that can be funded largely from ongoing administration costs and we are not anticipating any further significant exploration expenditure on the P1918 (Colter) licence in the current year.

Finally, we note that the initial work programmes for the licences provisionally awarded in the 31st Licensing Round do not commit the company to any substantial capital outlay within the next 12 months.

Unrisked upside is significant

Within our report, we have applied a range of technical and commercial risk factors to our valuations. However, to illustrate the degree of potential upside within the portfolio, we have calculated an unrisked base-case valuation for United’s fully diluted equity equivalent to over 51p per share.

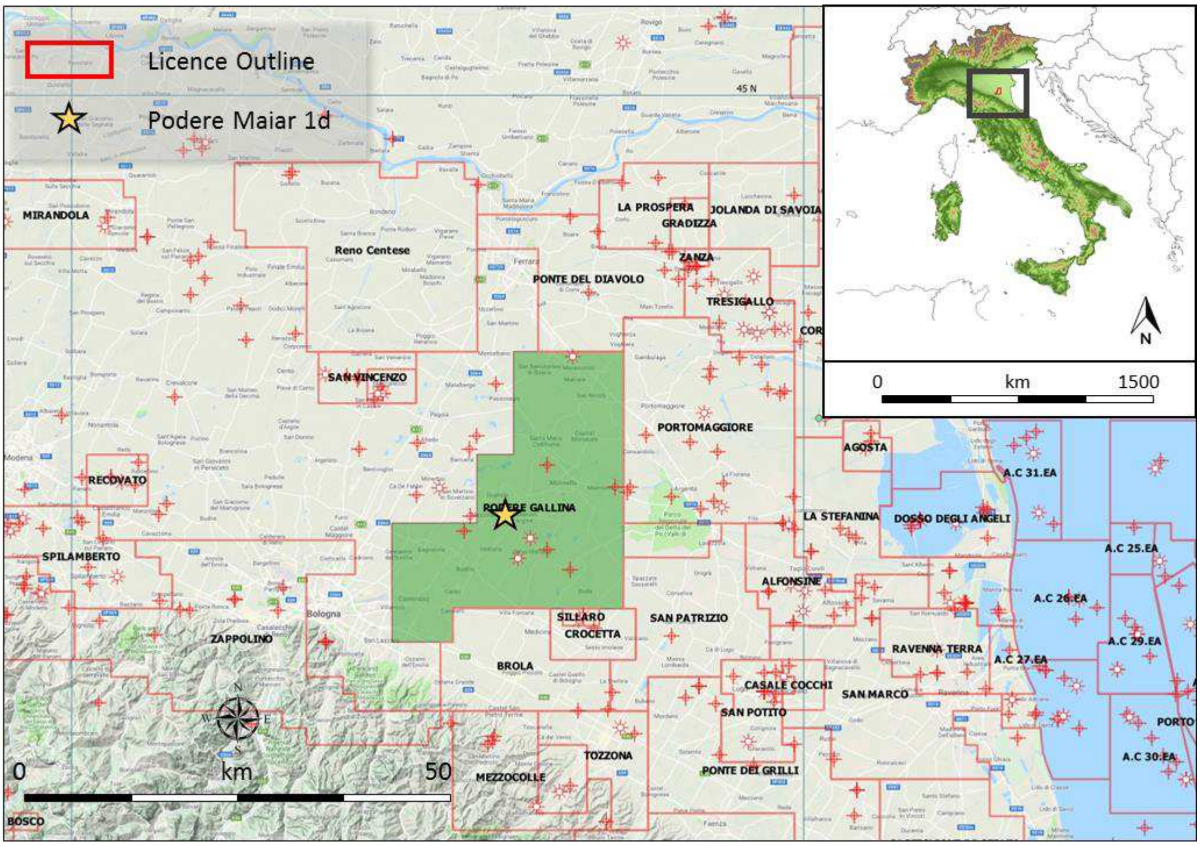
The primary driver of this upside case is the company’s interest in the Walton-Morant licence in Jamaica which accounts for nearly half of this indicative valuation. Although United is likely to be required to farm down its 20% interest in the asset in order to fund an exploration well, our unrisked illustration of United’s portfolio illustrates starkly the potential upside that exists from a successful well on a single prospect in this exciting frontier region.

Italy – The Podere Gallina permit

United holds a 20% economic interest of the 506 km^2 Podere Gallina Exploration Permit located in the Po Valley river region of Northern Italy. The company's partners in Podere Gallina are ASX listed Po Valley Energy which is operator with 63% and AIM quoted Prospex Oil & Gas (AIM: PXOG) with the remaining 17%.

The Po Valley river region is a proven and mature hydrocarbon province with over 5,000 wells drilled to date. Podere Gallina, located near the city of Bologna contains the Selva gas field on which a successful appraisal/development well, Podere Maiar-1d, was drilled at the end of 2017 and subsequently flow tested in January 2018 (See Appendix 2 for further details of the Podere Maiar-1d well and the subsequent testing programme results). The permit also contains several additional exploration targets which are examined in greater detail in this report.

Location of the Podere Gallina Exploration Permit



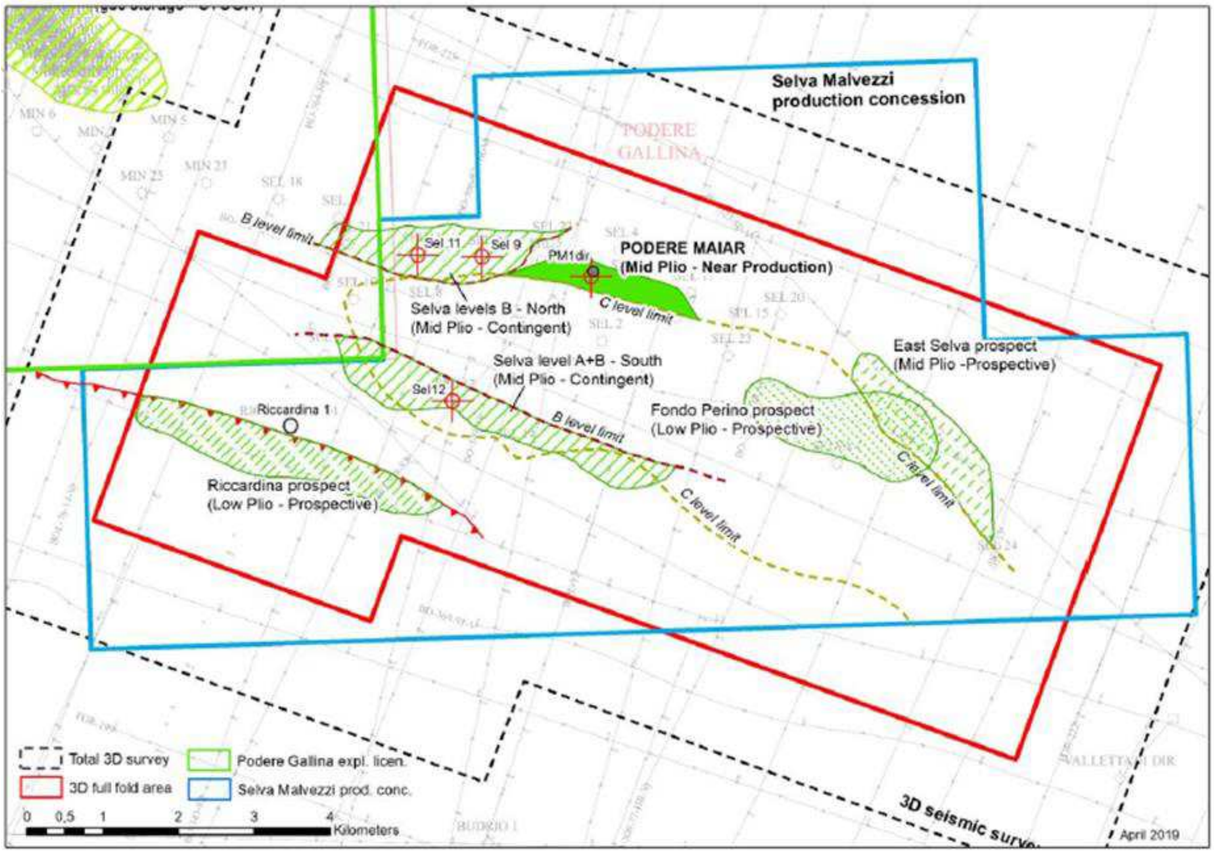
Sources: UNMIG, ViDEPI, Natural Earth, Google Physical and Prospex Oil & Gas

Selva Malvezzi

Outlined below is an area called 'Selva Malvezzi', a clearly defined 80.7 km^2 sub-section of the wider Podere Gallina licence, which is under application for a Production Concession after being granted preliminary approval by the Italian government in December 2018.

Selva Malvezzi contains the Selva gas field, substantial contingent resources in the form of the Selva North and South structures in addition to the East Selva, Riccardina and Fondo Perino prospects which have the potential to provide significant longer term upside to the Selva field development. These accumulations are depicted clearly on the map below.

Location of the Podere Gallina Exploration Permit



Sources: Company

Production Concession preliminary award

The operator submitted a Production Concession application for the Selva gas field to the Italian Ministry at the end of May 2018. As outlined previously, the application covers the 80.7 km^2 Selva Malvezzi area outlined in blue on the map above.

In January 2019, the Production Concession application was granted preliminary approval by the Italian government and PVE has outlined its plans for a development of the Selva field. This will include the installation of a fully automated gas plant at the existing Podere Maiar-1d well site and the running of a 1 km pipeline to connect to the nearby Italian National Grid. This phase of development is budgeted to cost approximately €2.34m gross.

The development is targeting the installation of facilities with a capacity of up to 150,000 scmpd (5.3 mmcfpd) gross from the C1 and C2 reservoirs. Although we note that the reservoirs have tested successfully at these volumes, we anticipate that initial production is likely to commence at a stabilised rate of c.100,000 scmpd in order to provide effective reservoir management in the initial production stages.

Capacity for additional production

Subject to a planned 3D seismic survey on the Selva area, the scope of which is also outlined on the previous map in red, Po Valley has outlined plans to drill additional wells targeting further prospectivity on the licence. These include the Selva South and North Flanks which have been attributed contingent resources and also the Selva East and Riccardina structures which could represent major resource upside for the company.

It is important to note that the Production Concession covering the area shown on the licence map will enable subsequent gas discoveries adjacent to Selva to be tied in quickly with gas production infrastructure across the whole concession.

Selva field reserves

In a recent Competent Persons Report (CPR) published by CGG Services (UK) Limited in February 2019 and subsequently updated in April 2019, the independent consultant has estimated that remaining 2P gross reserves on the Selva field are 13.4 BCF (2.7 BCF net to United's 20% economic interest). The reserves estimates in both metric and imperial denominations are outlined in the tables below.

Selva field reserves (MMscm and BCF)

	Gross	MMscm		Net	MMscm	
Sand	**1P**	**2P**	**3P**	**1P**	**2P**	**3P**
C1	48	129	209	10	26	42
C2	69	250	637	14	50	127
Total	**117**	**379**	**846**	**23**	**76**	**169**

	Gross	BCF		Net	BCF	
Sand	**1P**	**2P**	**3P**	**1P**	**2P**	**3P**
C1	1.7	4.6	7.4	0.3	0.9	1.5
C2	2.4	8.8	22.5	0.5	1.8	4.5
Total	**4.1**	**13.4**	**29.9**	**0.8**	**2.7**	**6.0**

Source: CGG

Indicative valuation of the Selva field

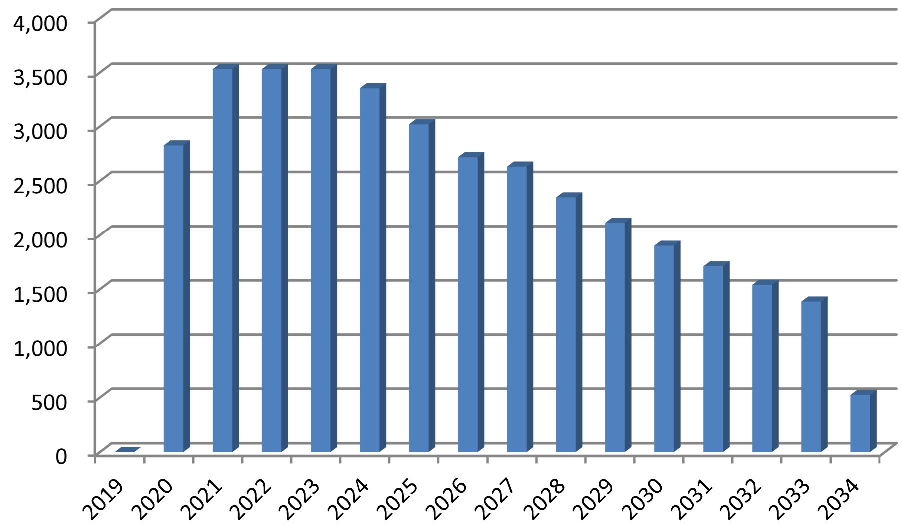
Utilising guidance from the CPR coupled with our internal estimates, we have attempted to ascribe an indicative valuation to United's interest in the Selva gas field using an NPV based cash flow model.

We expect that United will fund its share of final development expenditure at its working interest share of 20% and we note from the CPR that a further €2.34m of gross development expenditure, related primarily to final surface facilities, compression equipment and pipeline connection to the grid, is required.

We anticipate that the field can be developed and most of the 2P gas resources recovered from the Podere Maiar-1d well. The Selva field was previously on production since the 1950s to the 1990s and several analogous wells recovered substantial volumes of gas, the most notable of which was the Selva-6-C well which recovered 31 BCF. Other significant producers included Selva-5-C and Selva-17-C which also recovered 10.5 BCF and 11.75 BCF of gas respectively.

We have assumed that a single well will commence production in mid-2020 and that initial rates of approximately 100,000 scmpd (3.5 mmcfpd) will be sustained for the first three to four years consistent with the long term production potential of the Pliocene reservoirs across the Selva structure. Our assumptions are based on the production profile below which is adapted from CGG's CPR.

Anticipated gross gas production profile for the Podere Maiar well (mcfpd)



Source: CGG Services (UK) Limited

Revenue and cost assumptions

To our production profile, we have applied a flat long term gas price of €0.23 per cubic metre (equivalent to €6.51 per mcf), a reflection of average Italian gas prices since 2016. In line with CPR guidance, we have applied a royalty of 10% on all revenue from gas produced in excess of the annual royalty free allowance of 25 million cubic metres.

Cost assumptions

Within our assumptions, we have assumed fixed opex of €0.3m per annum over the life of the field. CPR guidance also indicates a €0.015/m^3 unit charge for compression from 2024 which we have factored into our assumptions. This implies a significant increase in field opex to an annual level in excess of €0.8m at this time, declining gradually as gas volumes fall.

To profits from production, we have applied Italian corporation tax of 24% and a further 3.9% of regional income tax (IRAP) which is applicable to onshore production.

Indicative NPV

On the basis of our assumptions, we have ascribed a net NPV of €5.7m for United’s 20% economic interest in the Selva gas field. This is more or less in line with CGG’s assessment of €5.5m, the slight difference being attributable to CGG’s treatment of the gas price which dips during the earlier years of production before inflating over later productive years.

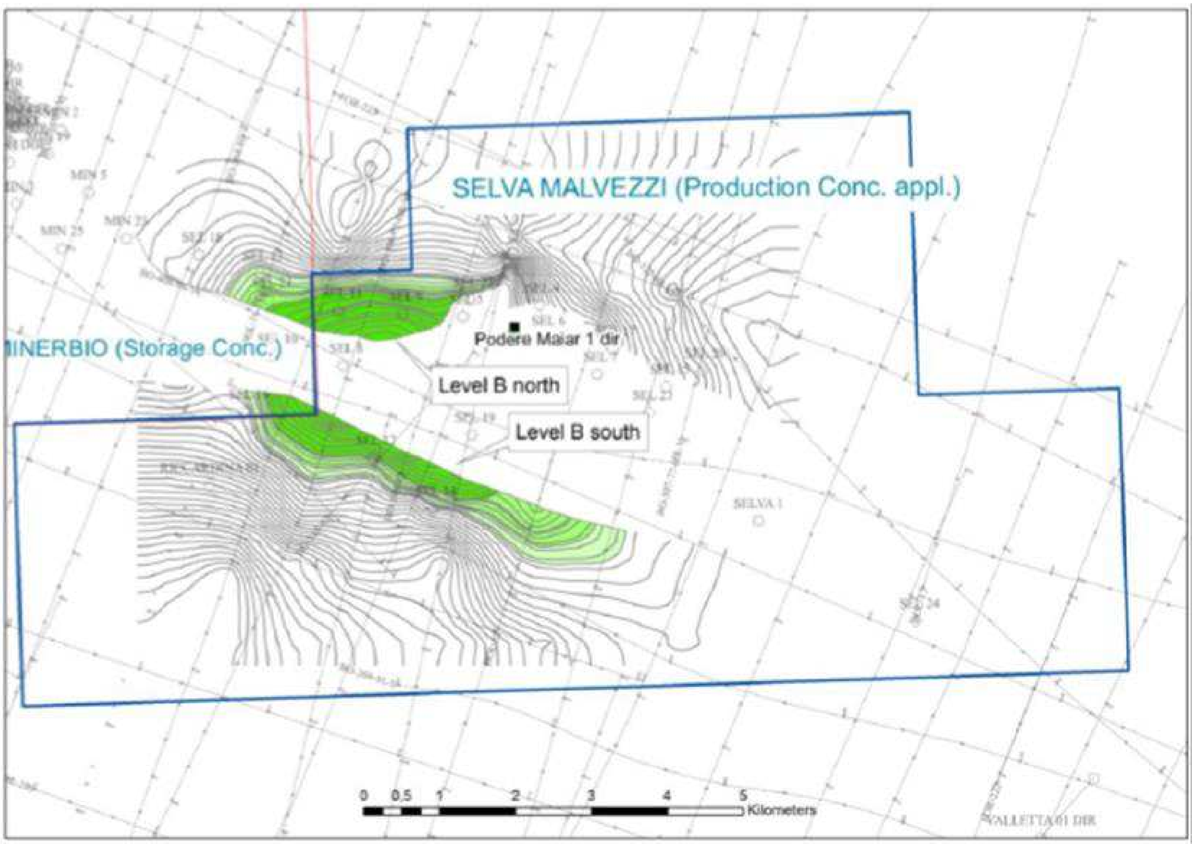
Podere Gallina – Contingent resources

Selva North and South

Following the drilling of the Podere Maiar-1d well, two additional prospects on the north and south crests of the original Selva gas field have been firmed up. Structurally, both prospects rely on the same stratigraphic pinch-out concept that the Podere Maiar-1d well demonstrated and both are located almost entirely within the Selva Malvezzi production concession area as demonstrated below.

Both structures are termed 'prospects' by the operator. However, by virtue of already having produced gas to surface in commercial quantities from previous wells, leaving significant volumes of gas updip in each accumulation, they fall into the contingent resources category and are viewed as attractive low risk potential additions to the longer term Selva production profile.

Level B North and South prospects within Selva Malvezzi



Source: Po Valley Energy

Proof of concept

CGG has identified Level A and Level B sands which were productive in the Selva field and pinch out onto the underlying thrust fold structure in the same way the Level C sands do on Podere Maiar-1d. United expects that the A and B sands will demonstrate comparable reservoir properties to the Level C sands and the thickness of the sands is known from older producing wells such as Selva-9 for the North prospect and Selva-12 for the South prospect.

In this particular case, CGG expects that for the North prospect, only the Level B sand is expected although both sands are expected to be present in the South prospect.

Both prospects were worked up by information provided by eleven reprocessed 2D seismic lines and historical Selva gas well data. The indicative contingent resources ascribed to each prospect is outlined in the tables below suggesting that substantial and potentially producible gas resources will exist in close proximity to the Podere Maiar production facilities when they are completed.

Selva North and South prospects resources (MMscm and BCF)

	Gross	MMscm		Net	MMscm	
Prospect	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
Level B North	99.8	252.3	504.5	20.0	50.5	100.9
Level B South	27.5	96.6	264.5	5.5	19.3	52.9
Level A South	29.3	51.2	102.1	5.9	10.2	20.4
Total	**156.6**	**400.1**	**871.1**	**31.3**	**80.0**	**174.2**

	Gross	BCF		Net	BCF	
Prospect	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
Level B North	3.5	8.9	17.8	0.7	1.8	3.6
Level B South	1.0	3.4	9.3	0.2	0.7	1.9
Level A South	1.0	1.8	3.6	0.2	0.4	0.7
Total	**5.5**	**14.1**	**30.7**	**1.1**	**2.8**	**6.2**

Source: CGG

Establishing an initial value for contingent resources

The table below indicates that CGG has established project Chance of Success of 70% for Level B North and 60% for Level A and B South which is slightly less defined. This reflects the estimated chances that the volumes ascribed can be commercially extracted.

To establish a conservative indicative valuation for these resources at this stage, we have applied a unit NPV per mcf of gas based on the existing Selva field development. This has been calculated on the basis of including the cost of the Podere Maiar-1d well in 2017 rather than the higher unit NPV calculated from 2019 onwards. To this risked metric, we have also applied a substantial commercial risk factor to account for non-technical aspects such as permitting for a potential development in order to generate an initial assessment. We note that successful future drilling on either prospect will firm up these numbers and serve to reduce the associated risk factors, boosting the indicative valuation significantly.

Indicative valuation for Selva North and South contingent resources (2C)

	Gross	UOG	Net	CoS	NPV/mcf	Unrisked	Risked	Commercial risk	Fully risked
Prospect	**BCF**	**%**	**BCF**	**%**	**€**	**€m**	**€m**	**discount (%)**	**€m**
Level B North	8.9	20%	1.8	70%	**1.52**	2.7	1.9	50%	0.9
Level B South	3.4	20%	0.7	60%	1.52	1.0	0.6	50%	0.3
Level A South	1.8	20%	0.4	60%	1.52	0.5	0.3	50%	0.2
Total	**14.1**		**8.9**			**4.3**	**2.8**		**1.4**

Source: CGG, TPI estimates

Podere Gallina - Prospective resources

There are several additional large prospects located within the Podere Gallina licence of which three, East Selva, Fondo Perino and Riccardina are located within the Selva Malvezzi production concession. A fourth smaller prospect; Cembalina, is located outside the concession towards the north of the wider licence area.

The prospective resources as outlined in the CGG CPR are outlined in the tables below in both metric and imperial and gross and net to United's 20% interest in the licence. We note that these additional structures represent significant additional upside to the planned development at Podere Maiar, with over 88 BCF of gross gas resources estimated to be contained in the three primary structures within Selva Malvezzi.

Podere Gallina prospect inventory (MMscm and BCF)

	Gross	MMscm		Net	MMscm		CoS
Prospect	**Low**	**Best**	**High**	**Low**	**Best**	**High**	
East Selva	824.1	985.6	1,149.8	164.8	197.1	230.0	40%
Fondo Perino	288.9	413.5	580.6	57.8	82.7	116.1	34%
Cembalina	59.5	93.5	133.1	11.9	18.7	26.6	51%
Riccardina	367.2	1,097.8	3,651.5	73.4	219.6	730.3	21%
Total	**1,539.7**	**2,590.4**	**5,515.0**	**307.9**	**518.1**	**1,103.0**	

	Gross	BCF		Net	BCF		CoS
Prospect	**Low**	**Best**	**High**	**Low**	**Best**	**High**	
East Selva	29.1	34.8	40.6	5.8	7.0	8.1	40%
Fondo Perino	10.2	14.6	20.5	2.0	2.9	4.1	34%
Cembalina	2.1	3.3	4.7	0.4	0.7	0.9	51%
Riccardina	13.0	38.8	128.9	2.6	7.8	25.8	21%
Total	**54.4**	**91.5**	**194.7**	**10.9**	**18.3**	**39.0**	

Source: CGG

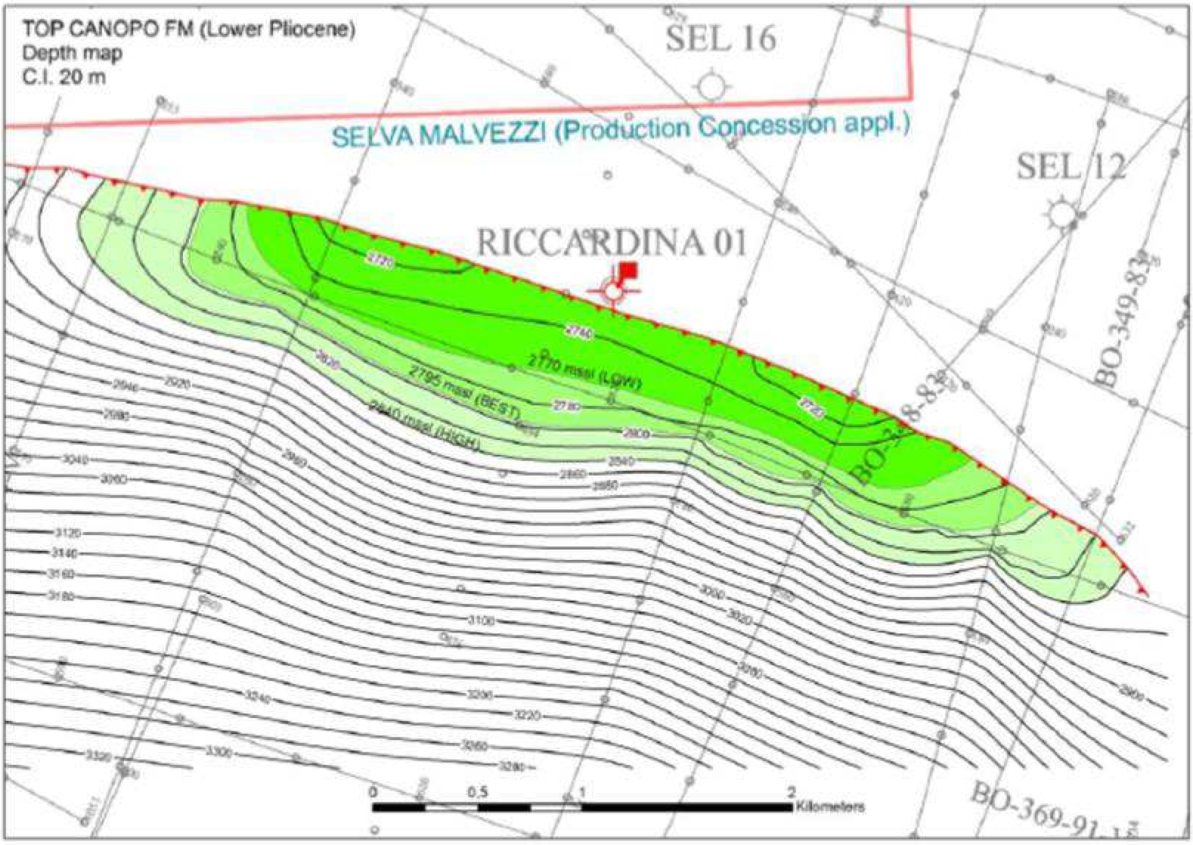
Riccardina prospect

The largest prospect within the production concession area is Riccardina located only 5 km from the Podere Maiar-1d well. This accumulation has already been identified by ENI which tested the prospect in 2004 but encountered water bearing sands and abandoned the well. However, the operator has reinterpreted the 2D seismic data which comprises ten lines and is of the opinion that the original well just missed the prospect, coming in on the wrong side of a thrust fault and lying outside the area that is interpreted to signify the presence of gas.

The depth structure map below depicts very clearly the Riccardina prospect and the location of the original ENI well which is believed to have probed the wrong side of a major fault.

The structure is reasonably well defined by 2D seismic lines although the partners are keen to acquire additional 3D data over the structure to better define the area. This information is likely to serve to increase the current Chance of Success which is currently 21%. Within the calculations to arrive at this CoS, CGG notes that the primary risk for Riccardina is the seal capacity of the fault that defines the northern margin of the prospect.

Depth structure map of the Riccardina prospect



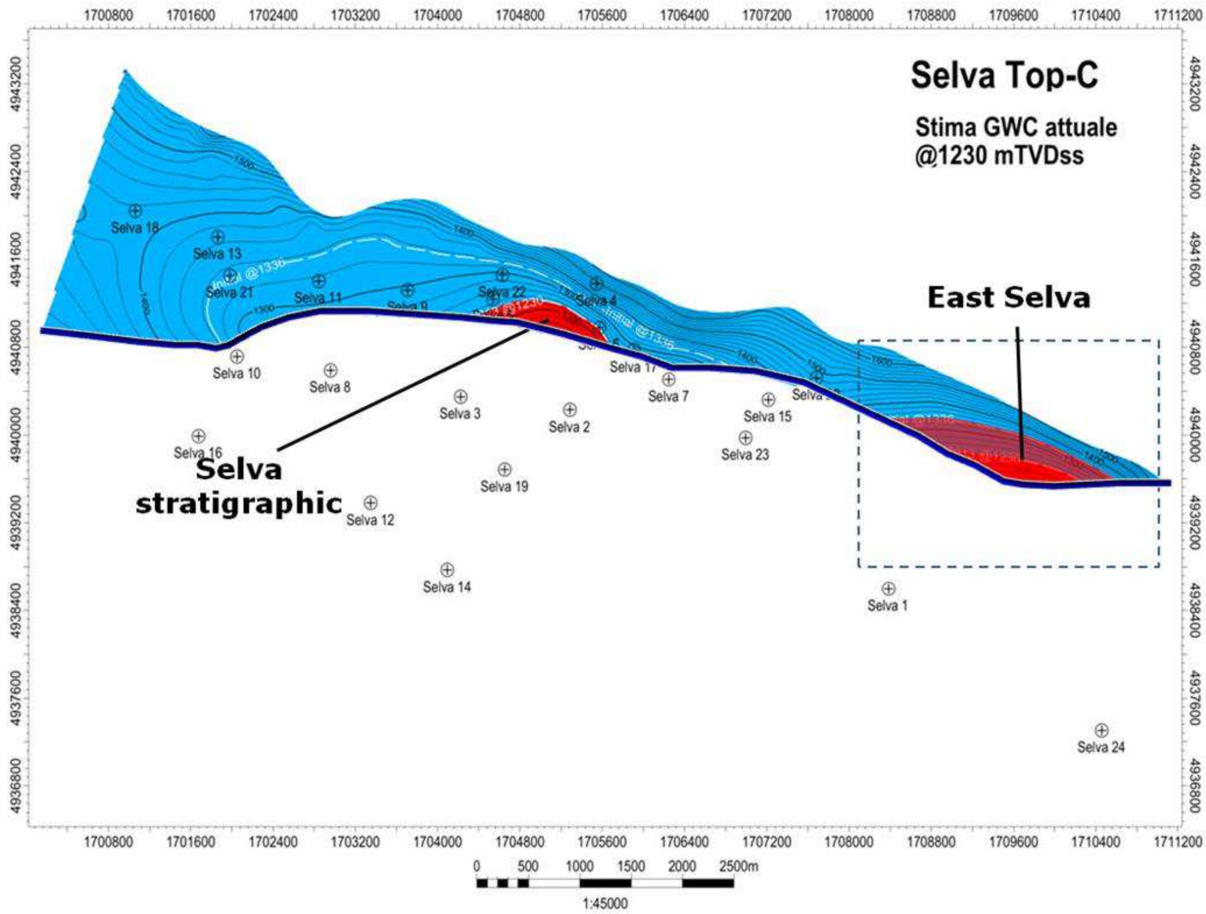
Source: Company

East Selva prospect

Within Selva Malvezzi, United has also highlighted the large East Selva prospect which lies on the pinch-out edge to the east of the main Selva field. Both Selva and East Selva are identical in concept and located on the same play trend as the nearby Minerbio field to the northwest of Selva outside the Podere Gallina licence.

Minerbio is now depleted although still used for gas storage by its operator, SRG (Snam Rete Gas). As with the main Selva field, East Selva represents a target in the C sand interval, the top of which is estimated to be at a vertical depth of c.1,230 metres. The map below depicts the East Selva prospect clearly in addition to valuable additional data including the location of the historical wells on the wider Selva structure.

Stratigraphic location map of East Selva



Source: Company

Recoverable resources double that of Selva

CGG has indicated that East Selva could contain Best case gross recoverable gas resources of almost 35 BCF. Since the successful well result from Podere Maiar-1d, CGG has increased the CoS for East Selva from 30% to 40% and we believe that this could increase further if the 3D seismic survey proposed by the operator can delineate the structure more clearly and de-risk the work programme prior to drilling. Presently, the primary risk remains the definition of gross rock volume based on a limited number of seismic lines.

Other prospects

Fondo Perino

Fondo Perino is defined by the dip closed cap of a hanging wall anticline located between the Selva-1 and Selva-23 wells which are clearly defined on the map above. Like the existing Selva field, the reservoirs are Lower Pliocene sandstones and the Fondo Perino structure is believed to be the updip gas bearing level tested on the Selva-1 well, as such the CoS is quite high at 34% according to CGG.

Cembalina

The small Cembalina prospect is located to the north of the Podere Gallina licence outside the Selva Malvezzi production concession. The prospect is defined by five 2D seismic lines at the Upper Pliocene level. Prospective resources carry a high CoS of 51% as a function of the relatively close proximity of other gas fields producing from Early Pliocene sands.

We note that plans to assess the smaller Cembalina prospect with additional seismic work have yet to be firmed up at this stage although given its relatively separate location north of the Selva prospect group; we would assume that any seismic work conducted within the next 12 months would not include it.

Establishing an initial value for prospective resources

To engineer an indicative valuation for the key prospects on Podere Gallina, we have applied the unit NPV per mcf of gas produced from our Selva field valuation outlined earlier to the unrisked net prospective resource for each prospect. However, to risk this appropriately we have applied the indicative CoS and commercial risk factors to account for non-geological risks.

At this early stage, we have elected to exclude Cemballina from our core assumptions at this stage as it falls outside the current area of focus for the company. We note that with production facilities in place at Podere Maiar, it would likely be straightforward to tie production from the core prospects into a wider development project assuming a successful drilling programme. However, given that additional seismic work and evaluation, exploration drilling and permitting are yet to be completed, we have ascribed a relatively high commercial risk factor to the Podere Gallina prospect inventory at this stage.

Indicative valuation for prospect inventory on Podere Gallina (Best case)

	Net Resource	CoS	NPV/mcf	Unrisked	Risked	Commercial risk	Fully risked
Prospect	**BCF**	**%**	**€**	**€m**	**€m**	**%**	**€m**
East Selva	7.0	40%	1.52	10.6	4.2	75%	1.1
Fondo Pierino	2.9	34%	1.52	4.4	1.5	75%	0.4
Cembalina	0.7	51%	1.52	1.0	0.5	100%	0.0
Riccardina	7.8	21%	1.52	11.8	2.5	75%	0.6
Total	**18.3**			**27.8**	**8.7**		**2.1**

Source: Company, TPI estimates

Cash flow can fund future exploration activity

As yet, future exploration activity is largely unfunded. However, we expect that net cash flow to United from the Podere Maiar-1d well could be at least €1.1m per annum for several years after full production is instigated. This would provide the company with appreciable financial resources from which to draw in order to participate in further exploration activity on Podere Gallina and realise significant value within its core asset portfolio.

UKCS Licence P2366 – the Crown discovery

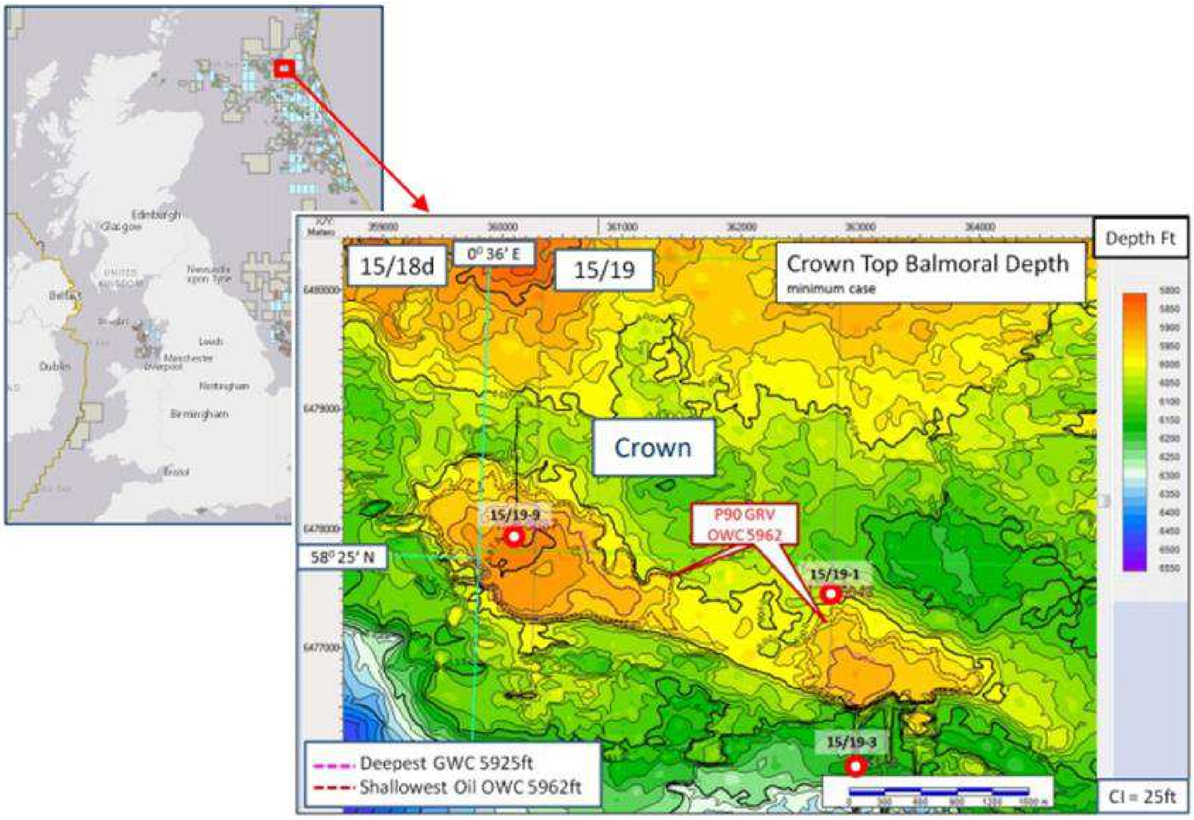
In August 2018, the UK Oil and Gas Authority (OGA) awarded United a 95% interest in UKCS Licence P2366 in the Central North Sea (CNS) which contains Blocks 15/18d and 15/19b. The company applied for the licence in conjunction with Swift Exploration which holds the remaining 5% interest. These licences contain multiple hydrocarbon targets. However, of primary interest is the Crown oil discovery which is estimated to contain gross unrisked 2C contingent resources of 6.35 mmbbls of oil. This maiden resource number was published in a CPR by ERCE in February 2019 and represents the first such study of the Crown discovery.

We note that United believes that the initial CPR estimates for Crown are based on a conservative recovery of the oil in place. Nevertheless, the report is likely to prove valuable in attracting new investors into the project and a farm-out process is currently underway.

Licence P2366

Blocks 15/18d and 15/19b cover an area of approximately 13.6 km^2 and contain the Palaeocene Crown oil discovery. The Crown discovery was made by well 15/19-9 drilled by ConocoPhillips in 1998 and the map below depicts the location of the 15/19-9 discovery well on Crown in addition to the location of P2366 situated close to the Piper, MacCulloch and Dumbarton/Donan oil fields in the Central North Sea.

Location of P2366 and the Crown discovery



Source: Company

Initial work commitments

We understand that there were a number of competing bids for the acreage. However, United was awarded the blocks on the basis of a work programme focused on seismic reprocessing in order to reduce the uncertainty of the estimated oil volumes and also to optimise the location of a future development well. We estimate that the initial costs for this work, which has been completed, was modest and did not exceed £150,000.

We believe that Crown would have been considered too small for development upon discovery over 20 years ago. However, with significant advances in technology since 1998, we believe that Crown could be suitable for a single horizontal well development and a subsea completion tied back to an existing platform, the closest of which is located less than 12 km away.

Indicative valuation

With the confirmation of the award of the licence to United, it is possible to ascribe a preliminary valuation to the Crown discovery. Using an oil price assumption of $70 per barrel over the life of a 6.35 mmbbls development with production commencing in 2022, we arrive at net valuation of $53.7m for United's 95% interest. However, we expect that United will ultimately hold a considerably smaller equity interest which could still be subject to a funding requirement in the event of a partial carry. As such, for the purposes of illustrative value, we have assumed that United will retain a 20% carried interest in the licence which equates to an indicative valuation of US$10.2m net to the company's suggested interest.

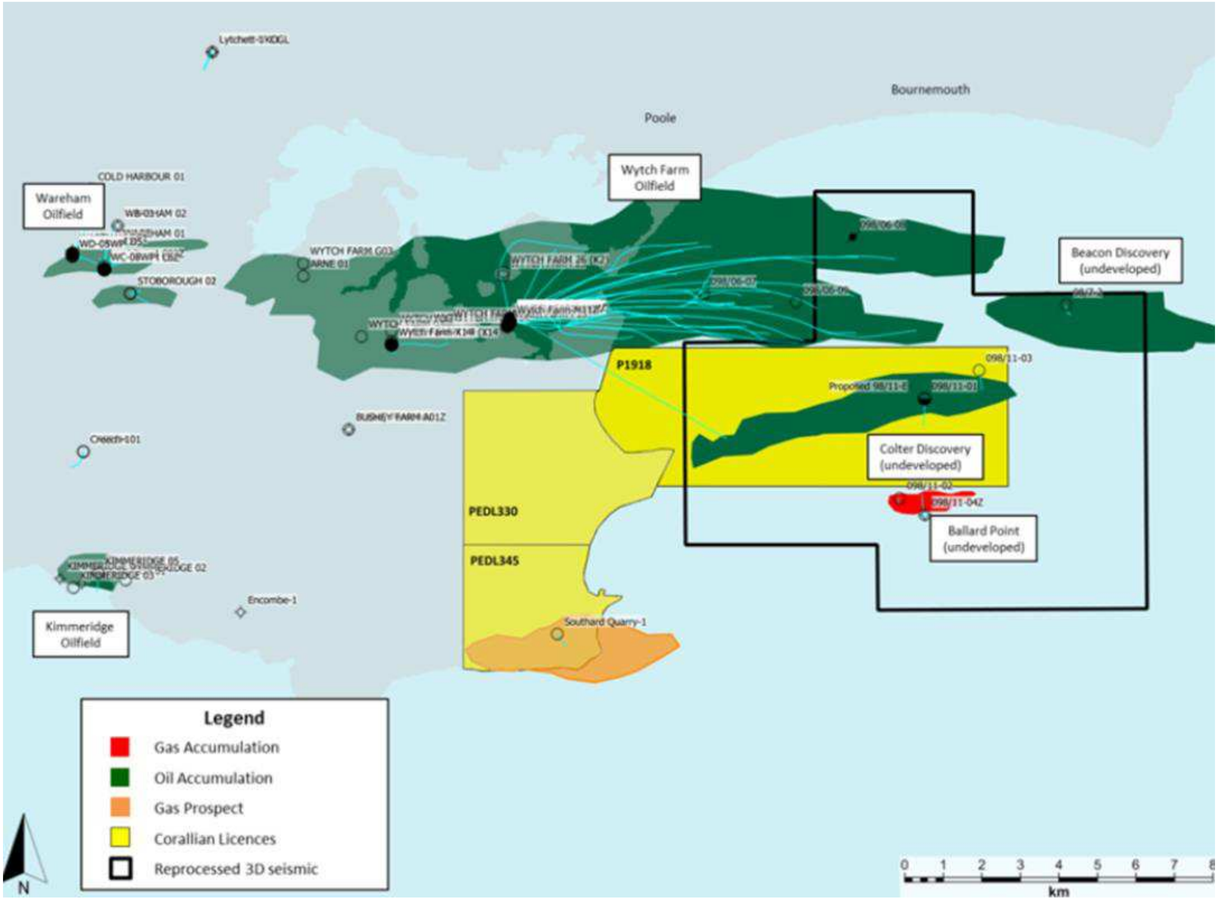
At this pre-farm out discussion stage, we reserve the right to adjust our valuation of United's interest in P2366 upon the completion of a farm-in agreement.

UKCS Licence P1918 – Colter

In January 2018, United agreed a farm-in deal to acquire a 10% interest in three UK licences offshore southern UK from private E&P company, Corallian Energy Limited. The other participants in the licences which include P1918, PEDL330 and PEDL345, as outlined on the map below, are Corallian (51.67% and operator), Corfe Energy Limited (33.33%), and Baron Oil (5%).

Activity to date has focused on the Colter appraisal project on licence P1918 which is located adjacent to the large Wytch Farm oilfield in the south of England. Wytch Farm has been a prolific producer since discovery by British Gas Corporation in 1973 and has produced over 450 mmbbls of oil with peak production reaching 110,000 in 1997 under the operatorship of BP. The current operator is large independent oil and gas company, Perenco which acquired the asset from BP in 2011.

Location of the undeveloped Colter prospect on licence P1918 (southern UK)



Source: Corallian Energy Limited

Appraisal drilling on Colter

On 25 February 2019, Corallian announced that the initial Colter appraisal well (98/11a-6) reached a total depth of 1,870 metres in the main target, the Sherwood Sandstone reservoir. Although the well unexpectedly remained on the southern side of the prospect bounding fault, it did encounter oil and gas shows over a 9.4 metre gross interval, representing a separate discovery to the original target. A petrophysical evaluation of the LWD (logging while drilling) data calculated a net pay of approximately 3 metres.

Immediately following the results from 98/11a-6 Corallian drilled the 98/11a-6Z sidetrack well on the Colter prospect to a depth of 1,910 metres in the Sherwood Sandstone to the north of the prospect bounding fault. However, Corallian concluded that the smaller areal extent of the Colter feature north of the fault boundary would be unlikely to yield commercial volumes of hydrocarbons and consequently the 98/11a-6Z sidetrack well was plugged and abandoned and the rig released.

Provisional analysis of Colter

Provisional analysis of the 98/11a-6 well indicates that it shares a common oil-water contact with the original 98/11-1 discovery well drilled by British Gas in 1983, both having intersected the down-dip region of the southern portion of the Colter prospect. Corallian's most recent assessment of Colter South prior to drilling 98/11a-6 indicated an estimated gross mean recoverable resource of 15 mmbbls.

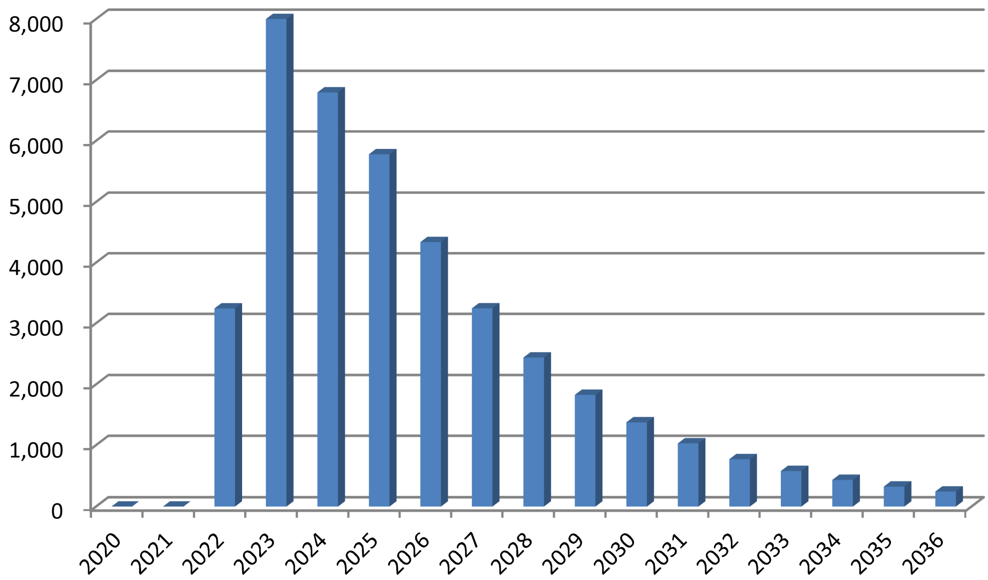
Although smaller than United's justified prospect size estimate of approximately 19 mmbbls (Corallian's estimate was higher at c.23 mmbbls), United noted that a discovery of this size comfortably exceeds the threshold for commerciality and further work will be required to refine this assessment. Although the partners already possess significant well and seismic data, we do not rule out the potential for further 3D seismic work to improve the imaging of the Colter South structure. The timing and details of a future work programme have not been outlined by Corallian at this stage.

United notes that Colter South is confirmed to be aerially more extensive that than indicated from pre-drill mapping. Additionally, the sidetrack well encountered hydrocarbon shows in the Jurassic Cornbrash-Lower Oxfordian interval which represents the producing Kimmeridge oilfield. This represents an additional potential target on trend to the west of Colter.

Indicative valuation

For the purposes of establishing an indicative valuation for United's net interest, we have valued Colter on the gross base case resources scenario of approximately 15 mmbbls. To this we have applied a range of variables to a notional development of a field of this size in order to assess the potential value of a successful appraisal project to United. Within our calculations, we have assumed the following production profile from a full two well development.

Estimated Colter production profile (bopd)



Source: United, Optiva estimates

Development cost assumptions

Our assumptions also factor in a development consisting of two extended reach development wells of the type producing oil at Wytch Farm, a water injector and a processing tie-in again at Wytch Farm. This portion of the development is expected to cost approximately US$120m in total subject to agreement with the field operator.

We have applied a long term oil price of US$70 per barrel from 2022, when production commences, flat over the life of the field and for operating cost assumptions, we have factored in fixed opex of approximately US$2.6m per annum coupled with variable opex of US$10 per barrel of oil produced.

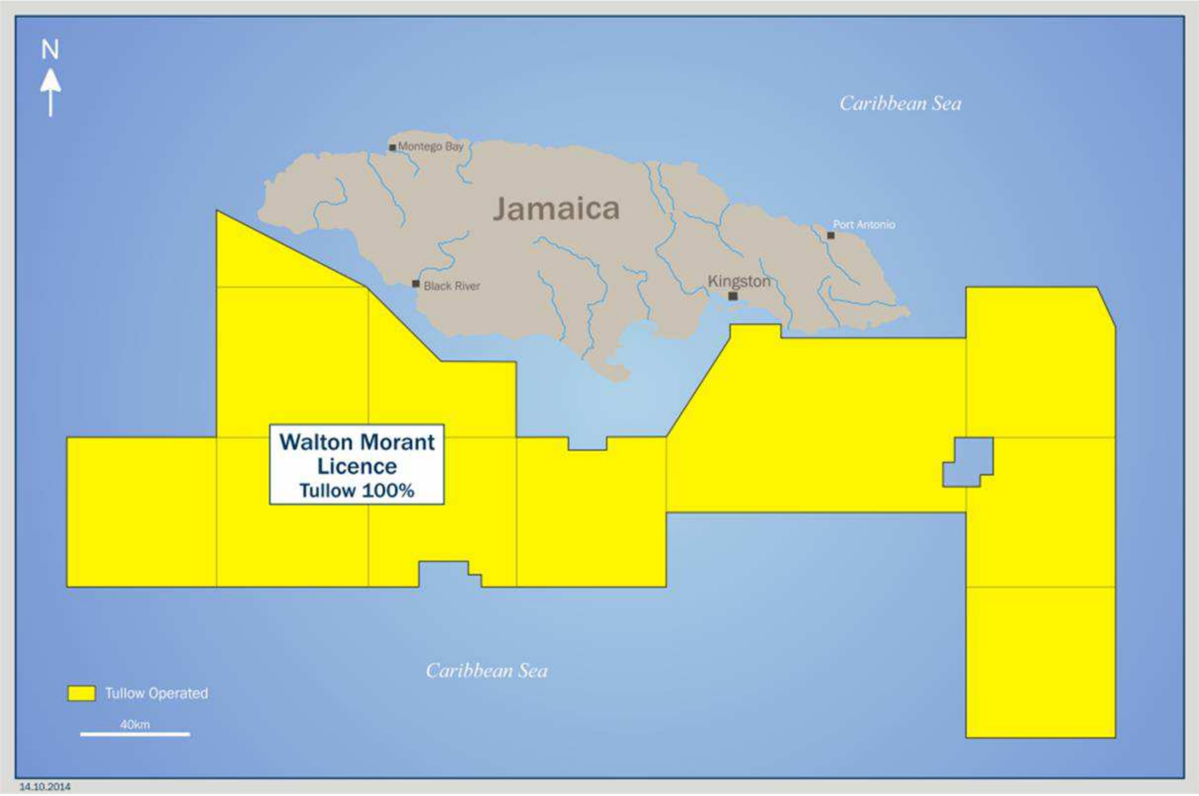
After applying the appropriate levels of UK oil and gas taxation to profits from production, we arrive at an indicative NPV for Colter of US$21.6m for United's 10% interest. However, with further exploration work required to de-risk Colter we have applied a commercial risk factor of 50% to this unrisked NPV to arrive at a technically risked NPV of US$10.8m net to United's interest.

Jamaica - High impact exploration

In November 2017, United agreed to farm-in for a 20% interest to the high potential Walton-Morant licence offshore Jamaica operated by global E&P company; Tullow Oil. United's management (see Appendix 1 for additional details) has a longstanding relationship with Tullow and we note that United secured attractive terms by which to gain entry to an extremely exciting high risk/high reward frontier exploration play with huge resource upside potential.

The Walton Morant licence seen on the map below is located in the offshore region south of the island of Jamaica, covers 32,065 km^2 and comprises ten full exploration blocks in water depths ranging from 20 metres to 2,000 metres.

Location of the Walton Morant licence



Source: Tullow

Terms of United's farm-in agreement

United agreed to pay a 20% share of costs from 1 November 2017. We believe that United struck a very good deal with Tullow, primarily given that it is common for farm-inees to offer a 2 for 1 share of early stage exploration costs and possibly fund a pro rata share of operator's past costs.

With positive indications from a recently completed 3D data set already announced, the next stage for the partners is to commit to an exploration well in the current year with drilling likely to commence in 2020. Given that we would expect an exploration well to cost up to US$40m, a 20% interest for a junior company such as United is a major undertaking. As such we would expect Tullow and United to farm down its interests as a joint venture partnership to a global major with the intention of acquiring a carried interest on a high impact exploration well.

Exploration history of the Walton-Morant licence

Offshore Jamaica represents a frontier exploration play encompassing three distinct geological basins. Although historical exploration drilling has been limited to only 11 wells, all drilled prior to 1982 with only two offshore, all of the wells drilled bar one exhibited hydrocarbon shows. In addition, Tullow recognised an active thermogenically derived offshore oil seep (Blower Rock seep) on the south central part of its licence adding further credence to evidence of a working petroleum system.

Tullow secured the Walton-Morant licence in late 2014. In addition to securing a large portfolio of legacy 2D seismic data, Tullow also shot a further 3,650 km of 2D seismic in 2016 and 2017 and interpretation of the data set has indicated numerous attractive Cretaceous to Tertiary-aged clastic and carbonate reservoir targets.

Recent 3D seismic survey high grades Colibri target

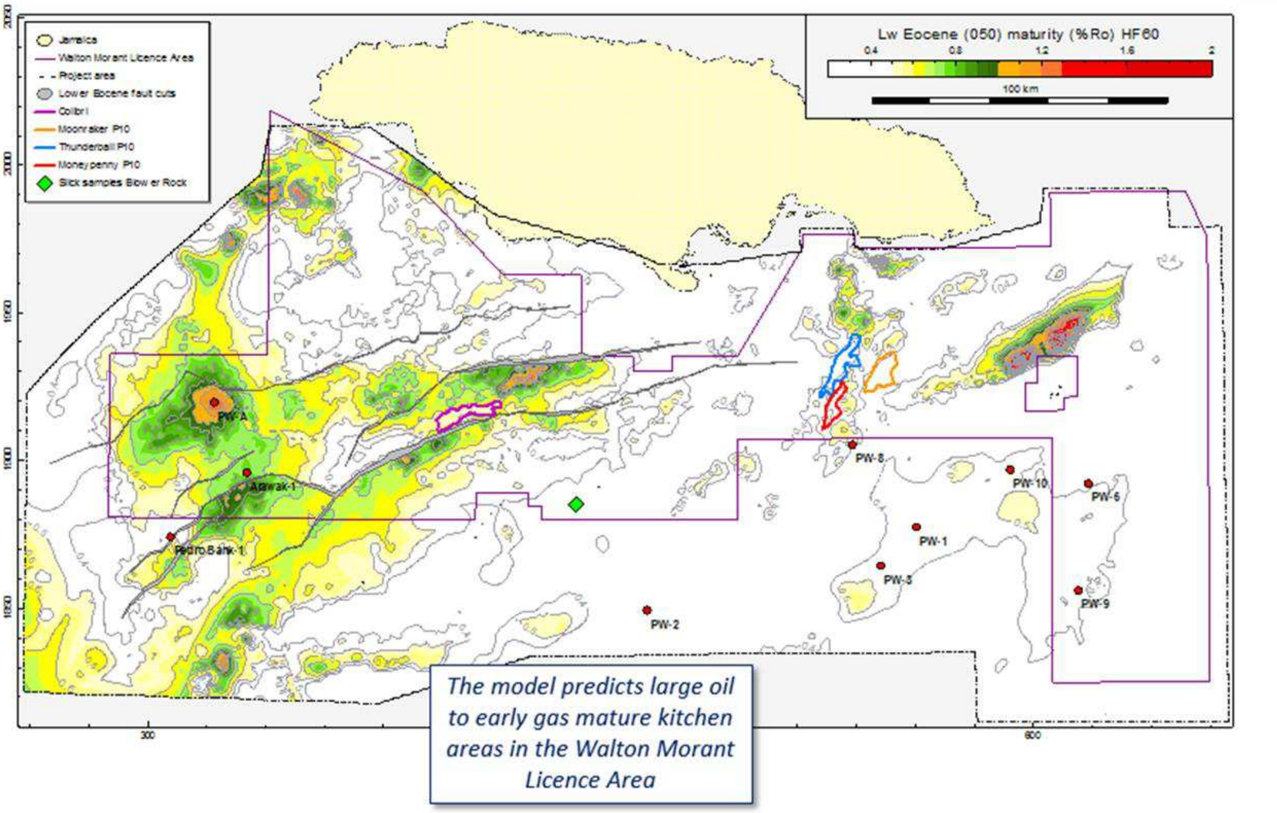
In mid-August, Tullow delivered a portfolio of fast track 3D seismic data following the completion of a 2,250 km^2 survey over the licence and the high graded Colibri exploration target (200 mmbbls+ mean recoverable resources) can be clearly identified on the dataset in addition to several additional attractive exploration targets. This survey is the first of its type to be acquired in Jamaica and constitutes a progressive stage of the programme to de-risk this potentially multi-billion barrel frontier hydrocarbon play.

Historical drilling reveals wet gas shows

Of the two offshore wells drilled on the block, Arawak-1 is of particular interest in that it is located within Tullow's licence area. Arawak-1 was one of the last wells drilled in Jamaica by Union Texas in 1982 and exhibited wet gas shows at the time. The well was intended to probe a Cretaceous carbonate target in a four way dip closed anticline structure although this interval was not reached ultimately and the well was plugged and abandoned at a depth of 4,488 metres.

The map below depicts a number of key characteristics of the Walton-Morant licence including the location of the two key wells drilled in the offshore sector (Arawak-1 and Pedro Bank-1), several key fault zones which represent important potential hydrocarbon trapping mechanisms, the Blower Rock oil seep and several key leads as identified by existing 2D seismic data. These include the large Colibri lead outlined in purple in the Walton Basin and a cluster of three additional major leads outlined within the Morant Basin region of the licence.

Key characteristics of the Walton-Morant Licence offshore Jamaica



Source: Tullow Oil

Recent activity on Walton-Morant

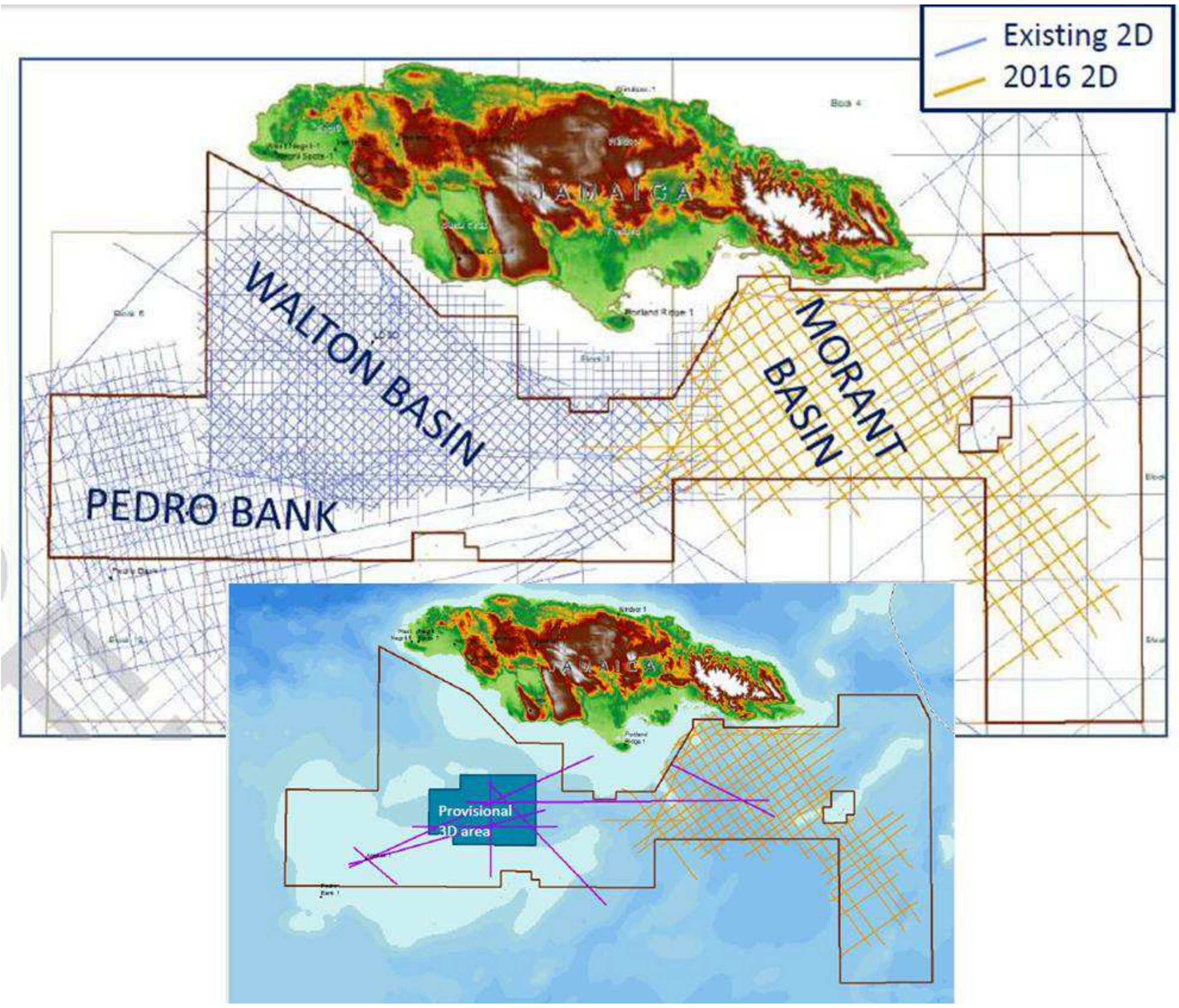
Over the course of 2016-2017, Tullow shot a further 3,650 km of 2D seismic in two tranches: 3,000 km in 2016 and 650 km in 2017. This was combined with extensive fieldwork aimed at de-risking the various petroleum system elements in preparation for the recently completed 2,250 km^2 3D survey. The map overleaf depicts very clearly the comprehensive 2D seismic coverage across Tullow's licence area with the more recent 2D survey focusing on the Morant Basin located in the eastern section of the licence. The map inset also depicts the area focused on by the more recent 3D survey (depicted in blue shading) focused on the high graded Colibri structure.

Drilling commitment in 2019

A 'Drill or Drop' decision for an exploration well on the licence is required by end-2019 and we would anticipate that drilling could commence in H2 2020. A successful result from an initial well is likely to instigate a second exploration well, possibly in 2022. We anticipate that a single exploration well in the region would cost approximately US$35-40m on a gross basis.

As even a 20% interest in such a programme is a major undertaking for a junior oil and gas explorer such as United, we believe that Tullow and United may look to farm down their interests together as a joint venture partnership prior to exploration drilling. At this stage, even a modest 10% carried interest in the first exploration well could provide United with huge potential upside in relation to its comparatively modest initial investment.

Extensive 2D seismic coverage in Jamaica and the location of the recent 3D seismic survey



Source: Tullow Oil

Primary focus on the Walton Basin

At this early stage, the Walton Basin is the favoured location for exploration activity given that it is believed to contain siliciclastic reservoirs (clastic non-carbonate sedimentary rocks that are almost exclusively silica-bearing, either as forms of quartz or other silicate minerals) trapped in structures adjacent to a thermally mature kitchen area. The primary area of interest is also located close to the Blower Rock oil seep outlined earlier. The Walton Basin is characterised by the presence of large tilted fault blocks and basement highs in addition to stratigraphic traps and sandstone and limestone exploration plays.

The Morant Basin represents a secondary exploration focus for Tullow and United. The 2D data acquired in 2016, which focused exclusively on the Morant Basin, revealed a significant tilted fault block play in this offshore region. The recent survey also indicates the presence of several stratigraphic plays and onlap formations (the termination of shallowly dipping, younger rocks against more steeply dipping, older rock strata) and pinch out traps (the thinning or tapering out of a reservoir against a nonporous sealing rock creating a favourable geometry to trap oil and gas) which have the potential to be hydrocarbon bearing.

At present, the Pedro Bank carbonate platform to the southwest of the licence is currently not the primary focus of Tullow's and United's ongoing exploration activity.

The Colibri structure

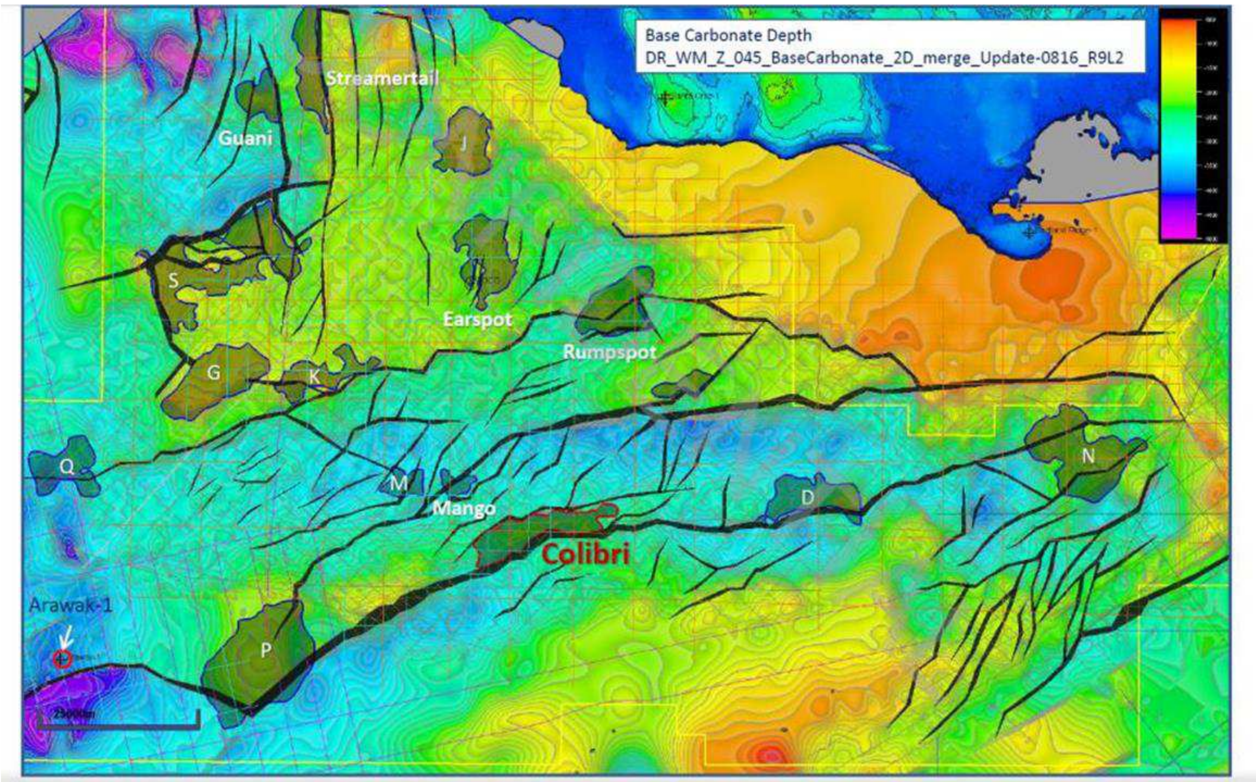
Colibri is located in the Walton Basin south off Jamaica in water depth of approximately 750 metres. It is a well-defined fault-bounded structure with onlap characteristics and Tullow surmises that the lead has received charge from surrounding Eocene or Cretaceous aged kitchens. Although it is still at a comparatively early stage, an updated competent person's report by ERCE in February 2019 confirmed that Colibri could contain gross unrisked mean recoverable resources of 229 mmbbls of oil as outlined in the table below. This metric represents an increase of 10 mmbbls compared to ERCE's 2017 estimate. However, the competent person also upgraded the geological chance of success from 16% in 2017 to 20% in the 2019 report.

Colibri prospect resource estimates (mmbbls)

Resources (mmbbls)	Low	Mid	High	Mean	CoS
Gross unrisked prospective resources	30	108	513	229	
Net unrisked prospective resources	6	26	103	46	20%
Net risked prospective resources (United: 20%)	1	5	21	9	

Source: ERCE

Location of Colibri and associated leads in the Walton Basin



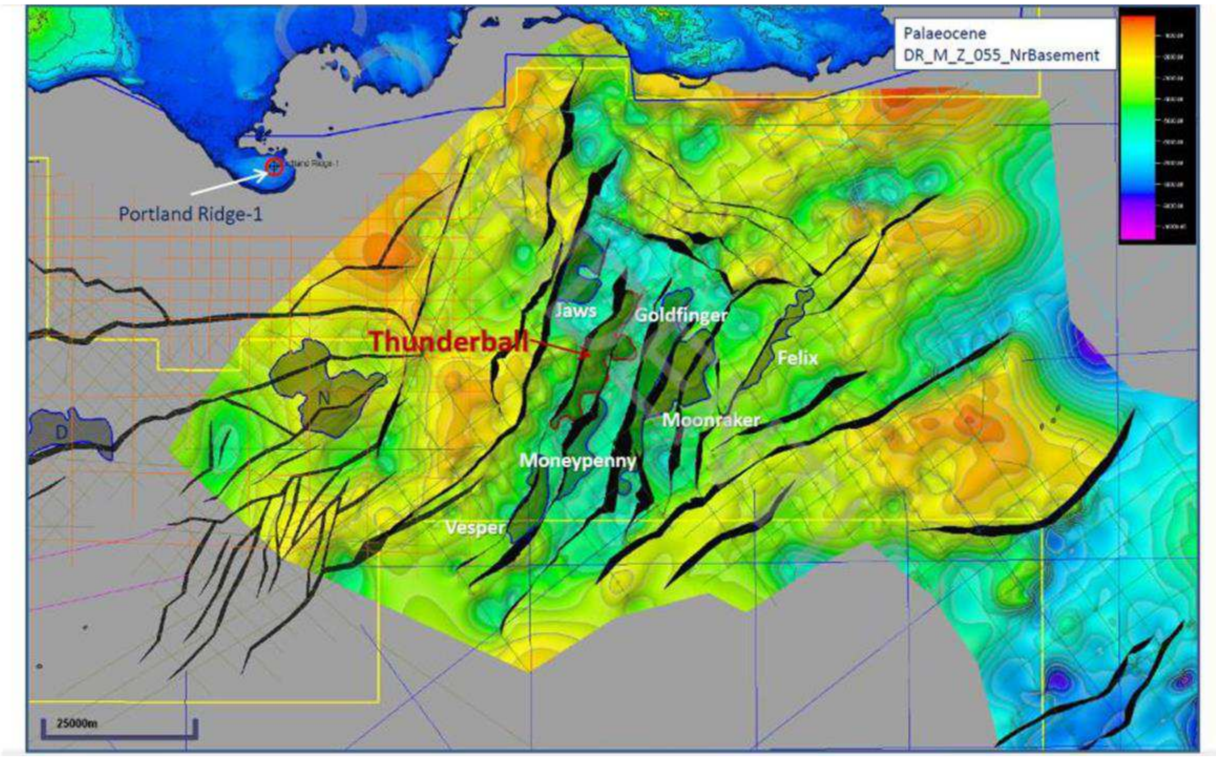
Source: Tullow Oil

Additional leads indicate a major hydrocarbon play

It is very important to note that the first exploration well in Jamaica since 1982 would be highly momentous as a successful result has the potential to open up a new multi-billion barrel hydrocarbon play and would also serve to de-risk considerably any follow-on structures that Tullow opts to drill. This strategy has been demonstrated by Exxon's ongoing exploration success in Guyana where the company has made a string of substantial discoveries in the offshore region.

With this in mind, it is important to note that Tullow has also identified a range of additional Lower Eocene targets on its acreage including numerous leads In the Morant Basin as depicted on the map below.

Location of leads in the Morant Basin



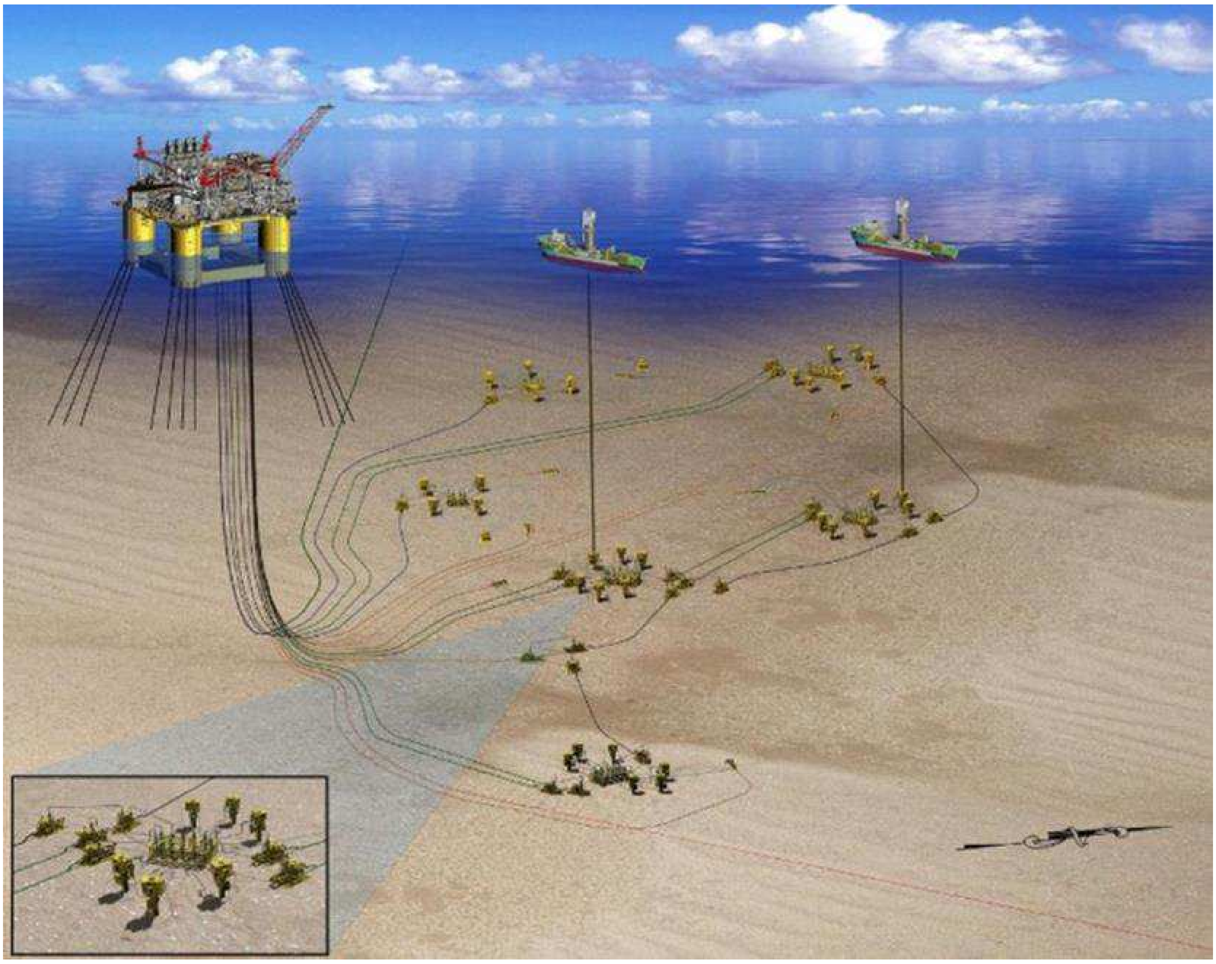
Source: Tullow

Development concepts

Although it is very early to begin discussions of potential development concepts prior to any commercial discoveries in the region, we believe that a tension leg platform (TLP) development would be appropriate for the commercialisation of discoveries in water depths of approximately 750 metres where Colibri is located.

The TLP development concept has the inherent advantage of being able to tie-in multiple step-out wells targeting associated hydrocarbon accumulations up to 4 km away from the main platform. With a permanently moored FSO (Floating storage and offloading) vessel located near the TLP, produced oil could be stored and exported on a continuous basis.

Conceptual TLP development for an offshore development



Source: Royal Dutch Shell

Indicative NPV underplays the potential

We believe that risked NPVs for individual exploration targets should not be given excess credence on a standalone basis in a play like offshore Jamaica. This is based on the premise that the de-risking of adjacent follow up structures implies the opening up of multi-billion barrel potential in the region and the subsequent development of multiple structures at a time as depicted by the development concept above. This will have the effect of enhancing potential unit NPVs (per barrel) as the play opens up and subsequent discoveries can be tied into nearby infrastructure at a fraction of the cost of a standalone development.

Nevertheless, we have ascribed a very modest risked basic NPV for United's current interest in the Walton-Morant based solely on the Colibri structure. In line with the assessment made by ERCE, we have assumed a gross mean recoverable prospective resource of 229 mmbbls to which we have applied United's equity interest and a conservative CoS of 20% at this stage. Applying a unit NPV of only US$3.00 per risked barrel and a 50% commercial risk factor given that this is currently an unfunded project, we arrive at an indicative risked value for United's current 20% interest in the whole licence.

Naturally, as Colibri and associated structures are firmed up into drillable prospects over the next 18 months, we anticipate an increase on CoS and the inclusion of additional exploration targets into our assumptions. This has the potential to significantly enhance the scope and value of United's interest in the licence.

Indicative risked valuation for United's interest in Colibri

Item	Unit	Low	Mid	High	Mean
Walton Morant prospective resources	mmbbls	30	128	513	229
United interest	%	20%	20%	20%	20%
Net unrisked prospective resources	mmbbls	6.0	25.6	102.6	45.8
Chance of success	%	20%	20%	20%	20%
Net risked recoverable resources	mmbbls	1.2	5.1	20.5	9.2
NPV per barrel	USD	3.00	3.00	3.00	3.00
NPV	US$m	3.6	15.4	61.6	27.5
Commercial risk factor	%	50%	50%	50%	50%
Indicative valuation	**US$m**	**1.8**	**7.7**	**30.8**	**13.7**

Source: ERCE, Optiva estimates,

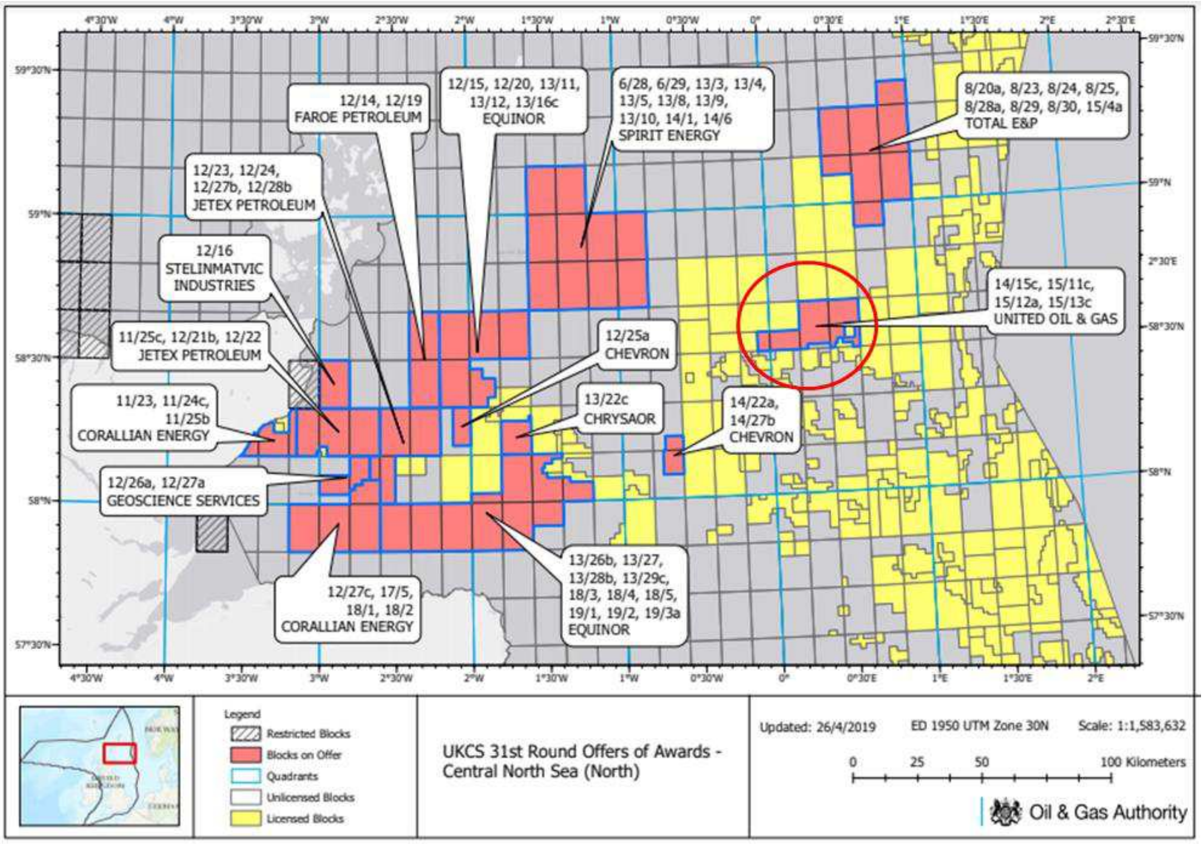
UK offshore – 31st Licensing Round award

United announced on 5 June 2019 that as part of the UK Continental Shelf 31st Offshore Licensing Round, the company had been provisionally awarded 100% interests in four highly prospective blocks in the UK North Sea in addition to 10% interests in two blocks in the English Channel. The award of these licences, which contain a range of potentially exciting prospects and leads, is highly strategic given that several of the new blocks are adjacent to and contiguous with the Crown discovery in the Central North Sea and the Colter discovery in the English Channel.

North Sea blocks awarded

United has been provisionally awarded a 100% interest in Blocks 14/15c, 15/11c, 15/12a and 15/13c which cover an area of c.500 km^2 in the Central North Sea. The acreage contains multiple targets and is located only 10 km from United's Crown oil discovery located on adjacent licences. United's blocks are also close to the Marigold and Yeoman discoveries and the large Piper, MacCulloch and Claymore producing fields.

Location of United's Central North Sea blocks awarded in the 31st Licensing Round



Source: OGA

Prospectivity

In particular, Block 15/12a contains the Palaeocene 'Zeta' prospect, a large four-way dip closed structure in the same play as the Crown discovery. With a mean case, in-place resource estimate of over 90 mmbbls, Zeta is believed to be a low risk prospect. Several smaller Palaeocene prospects, namely Brooks, Cook, Hudson and Bering have also been identified on the block in addition to plays in the shallower Eocene and deeper Mesozoic intervals.

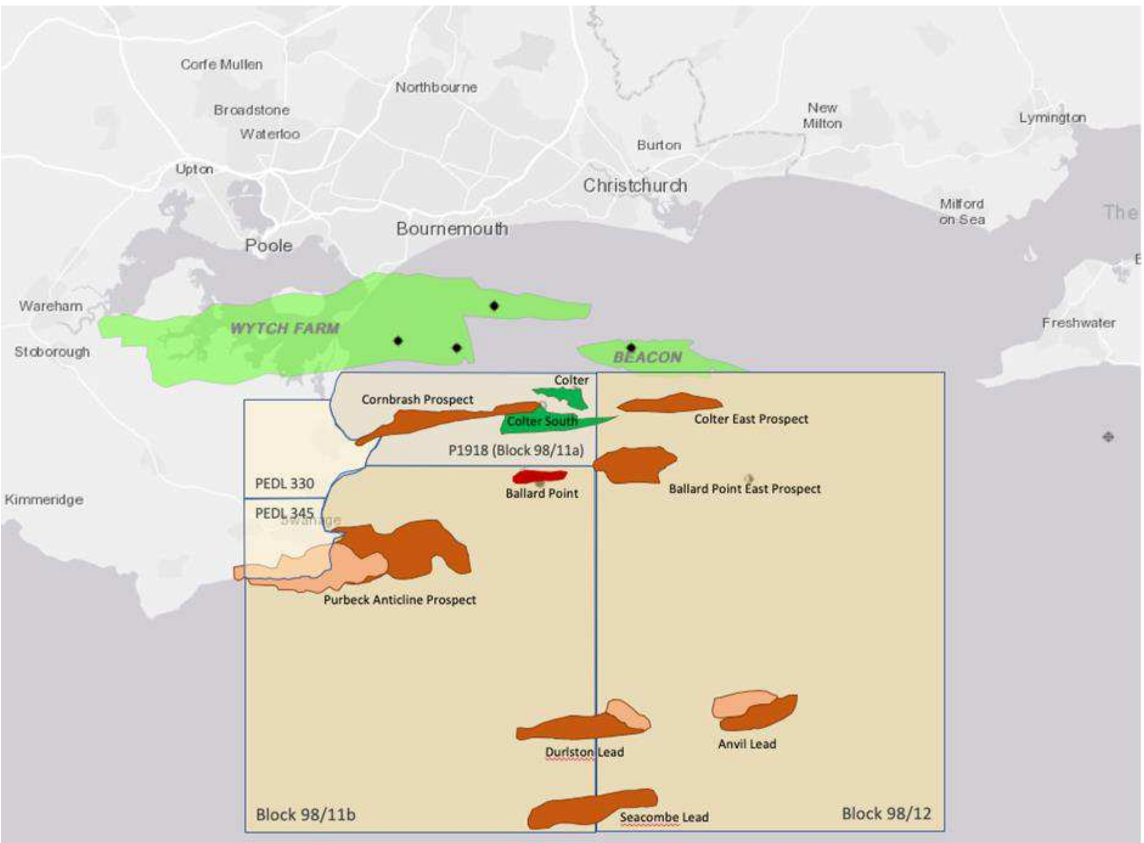
The North Sea blocks have been awarded on the basis of a modest work programme involving the purchase of existing high quality 3D seismic and detailed geological and geophysical analysis. This work is planned to improve the chances of success and reduce the uncertainty of estimated oil volumes on the blocks ahead of a potential drilling commitment. This implies modest capital commitment from United and, subject to final OGA approval; the company expects the work programme to commence in late 2019 or early 2020.

English Channel blocks awarded

In the English Channel, United has also been offered a 10% interest in blocks 98/11b and 98/12 as part of a partnership with the operator, Corallian Energy. Block 98/12 contains the eastern portion of the Colter South Discovery and Block 98/11b contains the Ballard Point discovery drilled by Gas Council Exploration in 1984. The well 98/11-2 flowed at 9.6 mmcfpd with 170 barrels of 45° API condensate from the Triassic Sherwood Sandstone. Several additional prospects and leads have been identified on the English Channel blocks which Corallian and United intend to incorporate into a broader work plan for the region.

We note that the addition of further interests in the area to the south of the Wytch Farm field means that United now provisionally holds acreage covering the entirety of the Colter South discovery.

Location of Blocks 98/11b and 98/12



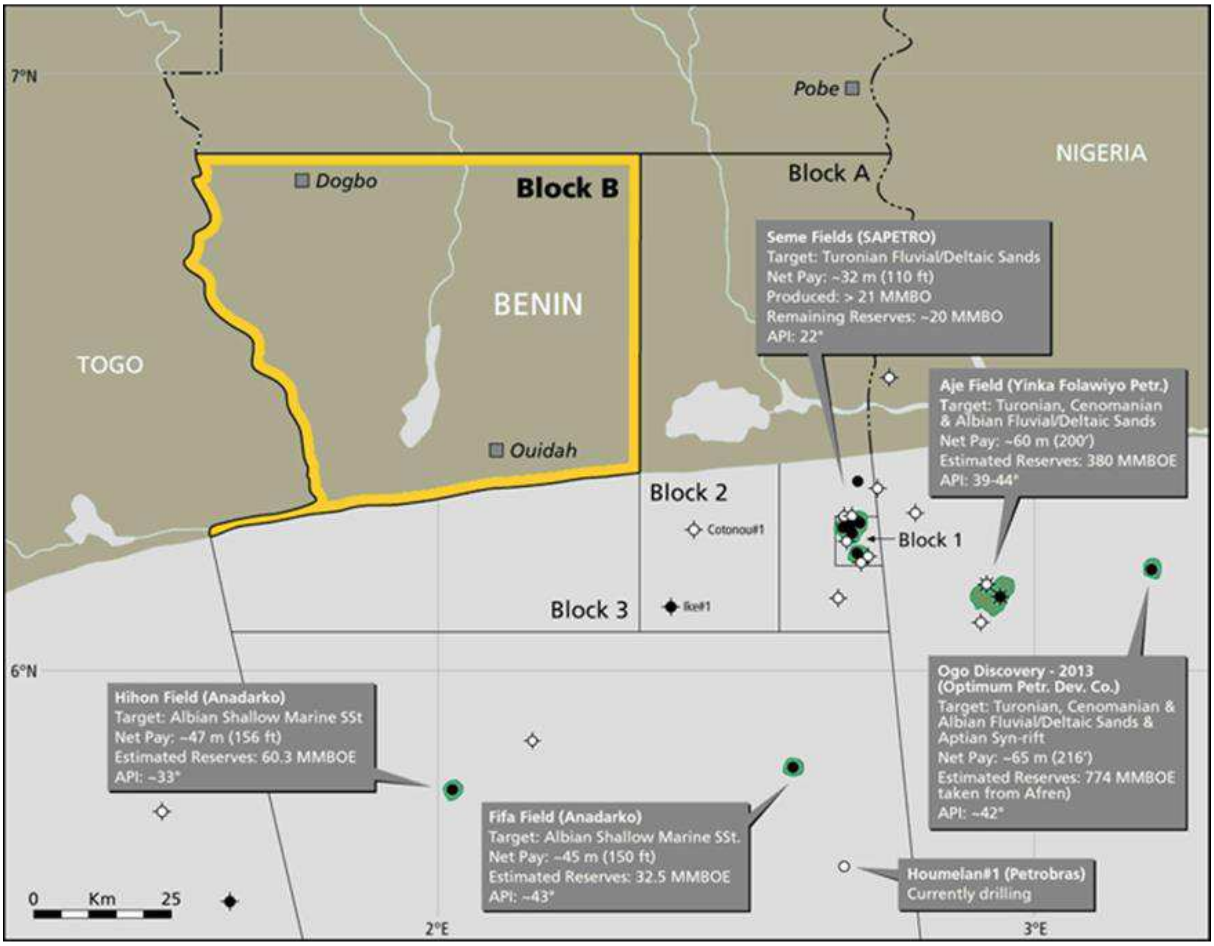
Source: Andalas Energy & Power

Benin – West African exposure

In March 2019, United signed an option agreement with private oil and gas company, Elephant Oil Ltd to farm into Elephant's Block B onshore licence located in Bénin, West Africa. Under the terms of the deal, United could potentially take a 20% interest in the Production Sharing Contract (PSC) for the licence which is believed to possess the potential to hold structures in excess of 200 mmbbls.

Onshore Block B is located in the Dahomey Embayment (Coastal Basin) and covers a large area of 4,590 km^2, equivalent to 1.1 million acres. Block B is located to the west of Bénin's capital Cotonou and abuts the border with neighbouring Togo as seen on the map below.

Location of Block B onshore Benin



Source: Elephant Oil

The Dahomey Embayment

The Dahomey Embayment of onshore Bénin is a frontier exploration region with no wells drilled to date. However, Block B is surrounded by prolific hydrocarbon producing regions, particularly Nigeria to the immediate east and Ghana to the west. There are strong indications of a working petroleum system in the Shelfal area offshore Bénin where the Seme and Dahomey fields contain approximately 100 mmbbls of oil reserves.

Wells drilled in the Dahomey Embayment region in onshore Ghana and Nigeria have previously encountered hydrocarbons and oil and gas seeps have been reported from water wells within Block B. Additionally, an extensive tar belt, potentially indicating the migration of oil through the targeted Cretaceous stratigraphy of Block B, has been reported to the northeast of the licence.

Data on Block B is modest at present; limited to a single seismic line and a 4,600 km^2 airborne Falcon Gravity Gradiometer survey acquired by Fugro-CGG in 2013. This data suggests the presence of large structures on the licence which have the potential to contain over 200 mmbbls of prospective resources. Elephant Oil has already identified the Allada structure as a significant prospect on Block B.

Regional geology

Block B is located in an area with an already proven hydrocarbon system, representing the onshore extent of the prolific West African Transform Margin. As outlined earlier, no exploration wells have been drilled onshore Benin or Togo to date although there are oil fields in the shallow waters offshore Togo, Benin and western Nigeria given that the oil source kitchen is located to the south in deeper water.

Elephant posits that oil has migrated further northwards into the onshore region as demonstrated by evidence of oil and gas seeps in water wells in the Block B area and also in regions to the north and east represented by the Mamu Tar Sands.

The subsurface rocks in Block B reach the surface to the north and west of the acreage and it possible to see thick fluvio-deltaic sandstones of presumed Turonian age, overlain by thick red fluvio-lacustrine mudstones in these areas. Consequently, Elephant believes that the components for a significant new petroleum play are present in Block B.

Terms and conditions

Under the terms of the farm-in United has agreed to fund a passive seismic survey and field studies up to a value of $175,000. The purpose of this early stage work is to calibrate the depth to basement and to obtain further information on oil and gas seeps in the area. The ultimate objective of this programme is to de-risk maturity and migration ahead of a decision to exercise the farm-in option.

Should the company exercise the option, United will farm-in to the PSC for a 20% interest and will be responsible for 30% of the non-drilling work and 20% of the drilling costs in a Phase 1 programme as approved under the PSC terms. United will also pay Elephant a pro rata contribution to past costs spread over an 18-month period.

We believe that it is too early to ascribe an initial value to United's potential interest in Block B. However, the management has again leveraged its extensive experience in a potentially exciting region known to the company. As with United's Jamaican interests, Bénin represents entry to high potential impact frontier exploration at very modest initial cost.

UK onshore PL090 Licence - Waddock Cross

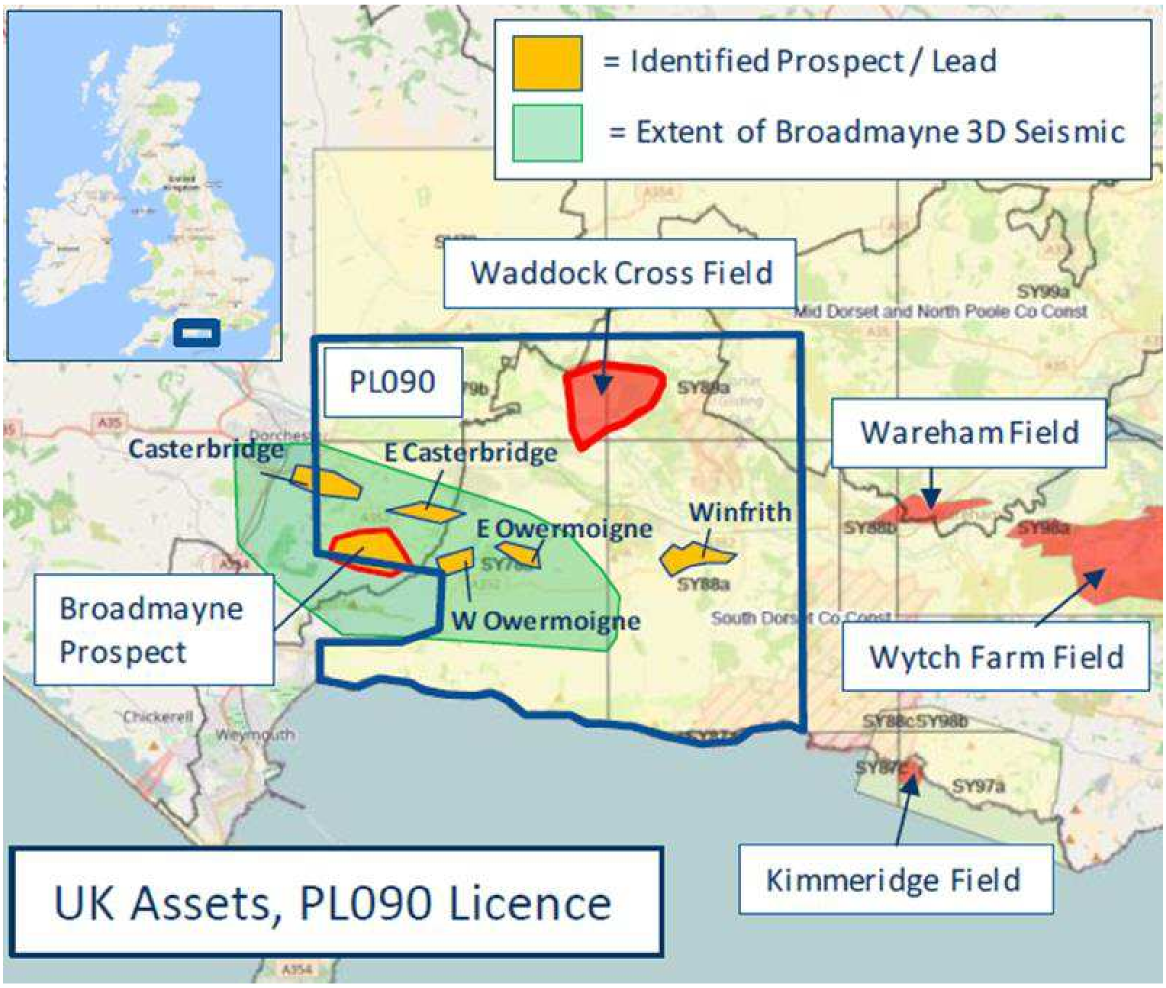
In August 2016, United acquired First Oil Expro Ltd.'s interests in UK onshore licence PL090. These interests include a 26.25% interest in the Waddock Cross field, which covers an area 19 km^2, in addition to an 18.95% interest in the wider PL090 exploration licence surrounding Waddock Cross covering a further 183 km^2. This exploration area includes several leads and the promising Broadmayne prospect located to the southwest of Waddock Cross. The operator of Waddock Cross and PL090 is Egdon Resources, a company with significant experience in the UK onshore sector and both licences do not expire until 2024.

Equity partners in PL090

Partner	Waddock Cross field	Exploration interest
Egdon Resources (Operator)	55.00%	42.50%
United Oil & Gas	**26.25%**	**18.95%**
Aurora Exploration	18.75%	13.50%
Corfe Energy	0.00%	25.00%

Source: Company

Licence PL090 including the Waddock Cross field



Source: Company

The Waddock Cross field in detail

The Waddock Cross field is a shallow oil discovery located at an approximate depth of 600 metres. There is a large oil-in-place volume estimated to be up to 29 mmbbls located in two main intervals within the Jurassic Bridport Sandstone reservoirs. Independent consultant, ERC Equipoise estimates that unrisked gross 2C contingent resources are 1.55 mmbbls held within two productive intervals. This equates to approximately 0.4 mmbbls net to United's equity interest.

United's working interest in Waddock Cross

Contingent resources (mmbbls)	1C	2C	3C
Gross contingent resources	0.46	1.55	5.30
Net to United (26.25%)	**0.12**	**0.41**	**1.39**

Source: ERCE

Drilling history

The field was discovered with the Waddock Cross-1 (WX-1) well by BG in 1982. This well intersected a 22 metre oil column in the Bridport Sandstone interval at a vertical depth of 610 metres. The discovery was subsequently appraised by Egdon with the vertical WX-2 well in 2004, followed up by the horizontal WX-3 well in 2005 which was intended to target the better quality Cycle 2 reservoir. However, WX-3 came in deep compared to prognosis and was eventually completed in the Cycle 3 reservoir. This well produced at a rate of up to 53 bopd upon testing. However a diesel squeeze, a technique of forcing dry cement mixed with diesel oil through casing openings to repair water-bearing areas without affecting the oil-bearing areas, damaged the reservoir and halted production.

The field was finally brought into production through the WX-2 well in late September 2013. However, initial production rates were disappointing due to a higher than expected water cut and the field was shut-in during 2014.

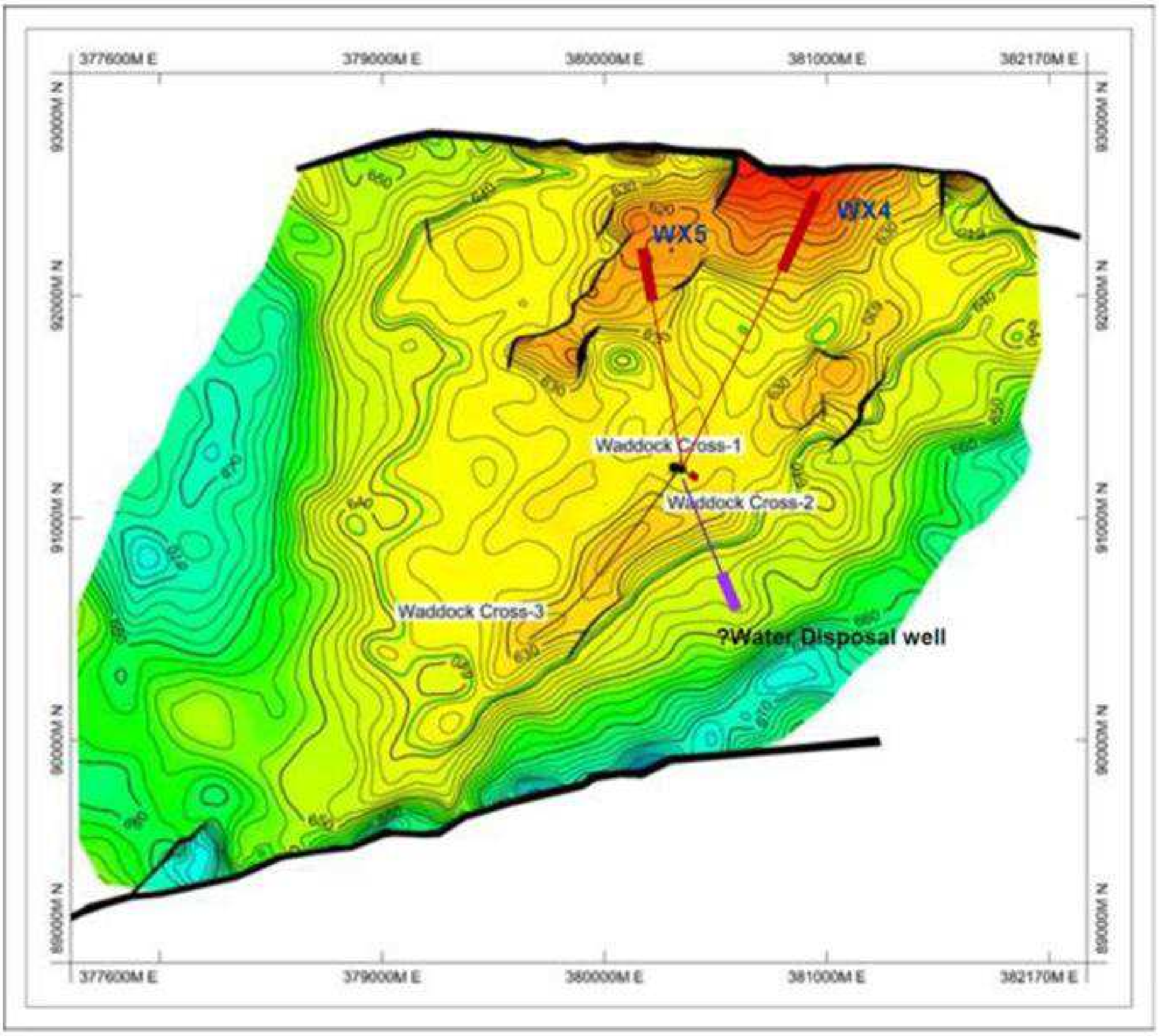
Work programme

United has noted that all three wells drilled to date were located in the same area of the field and the higher quality Cycle 2 sands have always been encountered close to the oil-water contact (OWC) with the associated high water cuts when put on flow testing or production.

With this in mind, United has examined existing 3D seismic data and noted that the crest of the field is located to the north of the WX-1 and WX-2 wells and it is the company's suggestion to drill a sidetrack well to intersect the Cycle 2 reservoir located higher above the OWC. The company has examined reservoir simulation modelling which implies that a well in this area could produce at a rate above 200 bopd.

Our assumptions for Waddock Cross factor in a sidetrack well and an additional development well in order to access the bulk of the ascribed contingent resources within the field. Their indicative names; WX-4 and WX-5 and their approximate locations, in addition to the existing wells on the field are depicted clearly on the map below.

Location of existing and potential new development wells on the Waddock Cross structure



Source: Company, ERCE, Egdon Resources

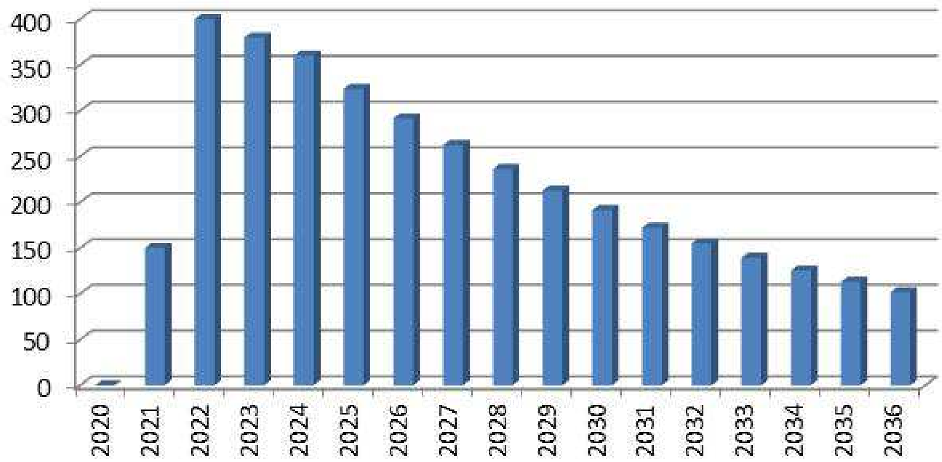
Indicative valuation of Waddock Cross

Within our assessment of the Waddock Cross field, we have assumed that a successful horizontal sidetrack well could be drilled at a gross cost of US$1.6m although at this stage, we do not have a firm date for such a well. Additional core capex will also include a second horizontal development well at a cost of US$1.5m and a water injection well at a similar cost although the potential to use the WX-2 well as a water injector has been suggested by the company. Assuming that the first two wells could be drilled in 2020/2021, we anticipate that the water injector could be completed by 2022 with oil production commencing prior to this part of the work programme in late 2021.

We have assumed that the development plan produces approximately 1.3 mmbbls barrels of oil from a gross 2C contingent resource of 1.55 mmbbls. We also assume that gross production peaks at 400 bopd when both production wells are on stream at 200 bopd each and declines thereafter at approximately 10% per annum over a period of 15-20 years. We believe that these are comparatively modest assumptions given that horizontal development wells in this region have the potential to flow at initial rates in excess of 500 bopd.

Within our assumptions we have used a flat oil price of US$70 per barrel and factored in an aggregate tax rate of 40% on pre-tax cash flow, reflecting a corporation tax rate of 30% and a Supplementary Charge of 10%. For the purposes of currency conversion, we have applied the current US Dollar to Sterling exchange rate of US$1.27: £1.00.

Gross indicative oil production profile (bopd)



Source: Optiva estimates, Company

Cost assumptions

We have factored in fixed operating expenditure (opex) of US$100,000 per year and variable opex of US$5.00 per barrel into our assumptions in addition to a gross fixed abandonment cost of US$1.0m.

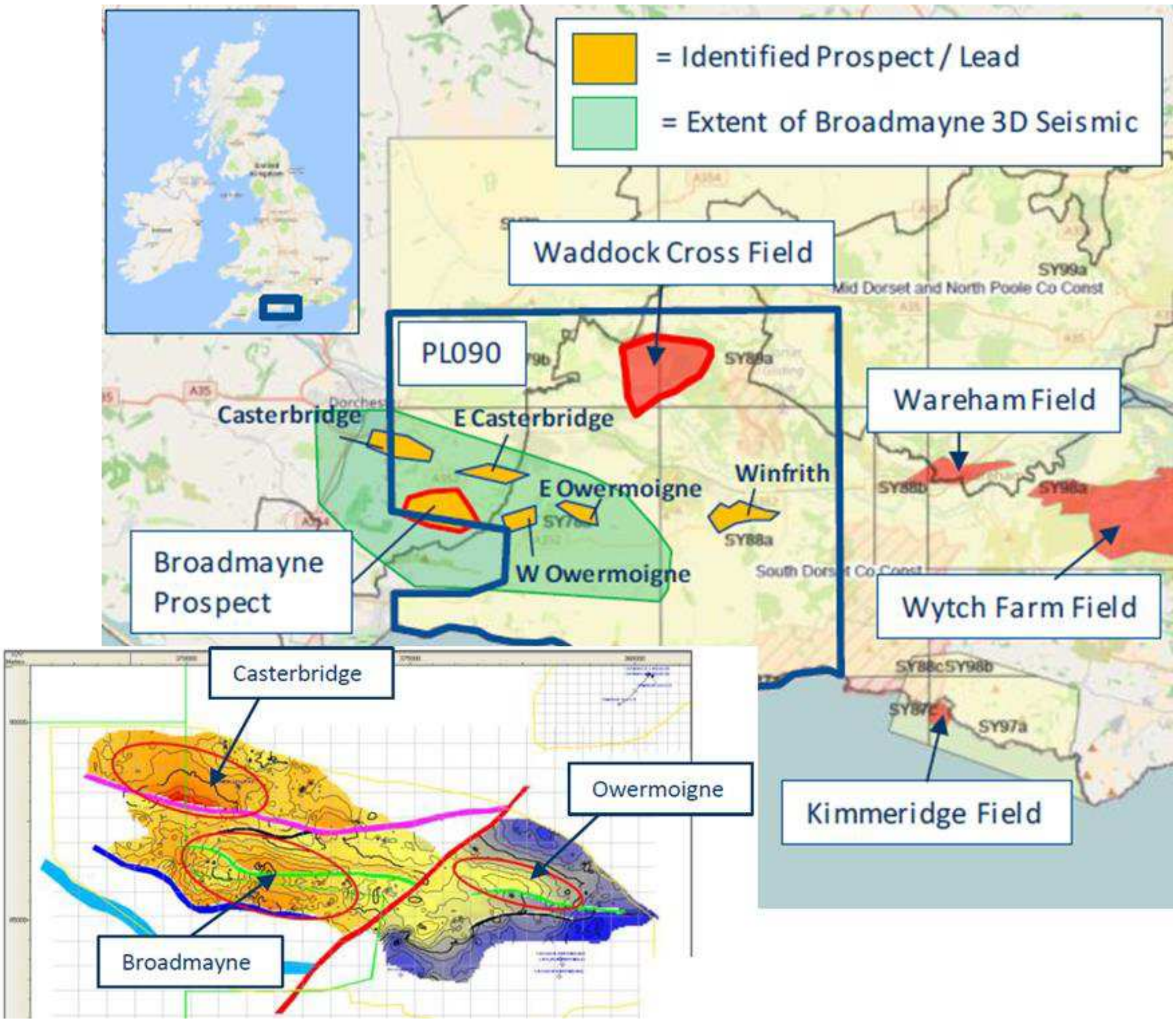
Indicative NPV for Waddock Cross

On the basis of our assumptions, we have ascribed an unrisked net NPV of US$6.2m for United's 26.25% working interest in the Waddock Cross field. Although we are confident that United's development plan for Waddock Cross will eradicate the technical issues associated with the excess water production from the field, we feel it appropriate to attach a discount of 20% to our valuation to reflect the risk associated with drilling the first sidetrack development well on the project. Note that a successful result with the first well will de-risk the second development well to a major extent. Consequently, we have ascribed a risked NPV of US$5.0m for the company's interest in Waddock Cross.

Broadmayne - Exploration upside on PL090

United and its partners have identified several exciting leads and prospects on the wider PL090 licence in which United holds a 18.95% working interest. These are outlined on the general location map in the previous section of this report. This map also depicts the area which has been covered by the Broadmayne 3D seismic survey from which much of the portfolio of leads and prospects has been compiled.

Primary prospects and leads on PL090



Source: Company

The Broadmayne prospect

Valuing exploration upside is considerably more indicative than ascribing value to reserves. As such, we have provided an assessment of the risked potential of the Broadmayne prospect located to the southwest of Waddock Cross. As outlined previously, there are several additional leads of interest on the licence. However, their evaluation is at an earlier stage compared to Broadmayne and further technical work will be required to mature these structures into drillable prospects.

Broadmayne development plan

We have assumed that a 4.0 mmbbls oil development at Broadmayne would comprise of up to five development wells at a gross cost of US$3.0m each, coupled with an additional US$7.0m of infrastructure investment. Variable opex is assumed to be similar to Waddock Cross although we have assumed a fixed opex of US$400,000 per annum as a Broadmayne development would be considerably larger than Waddock Cross. Abandonment costs are flagged to be US$2.0m gross and incurred in 2030 when the 4.0 mmbbls are exhausted.

Note that current resource estimates include resources that extend into the neighbouring licence PEDL 237. This block was relinquished by the partners in PL090 prior to United's participation in the licence in August 2016. However, United is confident that this block will be successfully re-applied for when the current partners in PL090 file a commitment to drill the Broadmayne prospect.

Indicative NPV for Broadmayne

We have used the same oil price and taxations assumptions that we applied to Waddock Cross in our earlier analysis and with our combined assumptions, we arrive at an unrisked gross NPV of US$78.8m for a full field development. United's interest would be approximately US$14.9m in accordance with its equity interest in this part of the PL090 licence.

At this stage, it is appropriate to risk our valuation to reflect the geological chance of drilling success (CoS) in this region of the UK. As such, we have applied a 25% CoS in order to establish a risked valuation for United's interest. This values the company's interest in this single prospect at US$3.7m. Although exploration drilling is not yet scheduled on the Broadmayne prospect or any prospects subsequently worked up over the next two years and the company is not yet funded for such activities, we believe that the company's maximum exposure to a project of the scale outlined would be approximately US$2.0m net to the group.

It is pertinent to note that should early exploration drilling on Broadmayne be successful, the CoS for subsequent appraisal and development wells on the structure would increase significantly, reducing the risk factor and boosting NPV accordingly.

Appendix 1 - Directors Biographies

Graham Martin – Non Executive Chairman

Graham is an experienced senior natural resources executive and brings a wealth of international expertise. He is currently a Non-Executive Director at Kenmare Resources plc, one of the leading global producers of titanium minerals and zircon listed in London and Dublin. He has also previously served as an Executive Director, General Counsel and Company Secretary at Tullow Oil. From 1997 to 2016, Graham was centrally involved in the growth of Tullow into a FTSE100 business and in the company's transformative M&A programme. Prior to Tullow, Graham was a partner at the US energy law firm Vinson & Elkins LLP, having started his legal career in Scotland.

Brian Larkin – Chief Executive Officer

Brian is the founding director of United Oil and Gas. He is a Qualified Accountant and has an MBA from Dublin City University. He has extensive oil and gas industry experience having worked for both Tullow and Providence Resources Plc. At Tullow, Brian held positions in both finance and commercial and worked on a variety of production, development and exploration projects in South America and Asia and carried out numerous investment case recommendations. At Providence, Brian worked in senior finance and commercial positions and also on a wide portfolio of assets in regions including the Gulf of Mexico, offshore Ireland, onshore United Kingdom and offshore Nigeria.

Jonathan Leather - Chief Operating Officer

Jon has over 18 years' experience in the oil industry and holds a Geology degree from Oxford University, a PhD in Sedimentology from Trinity College, Dublin and an MBA from Warwick University. He worked for Tullow from 2007 to 2015, where he held a number of senior positions, including membership of the Global Exploration Leadership Team. He also managed Tullow's Subsurface Technology Group – a team he established and built up to provide specialist technical input across the company in both exploration and development. As part of this, he worked on global assets and opportunities ranging from onshore producing fields to deep water frontier exploration. Prior to Tullow, Jonathan worked for Shell UK Ltd. During his time there he was involved in a number of exploration and development projects and worked on North Sea, European, Middle Eastern and Malaysian assets.

David Quirke – Chief Financial Officer

David has 17 years of treasury and corporate finance experience in the upstream oil and gas sector. He established and led the Tullow Oil Group Treasury function for a fifteen-year period from 2003 to 2017, supporting a period of transformational growth. He has extensive experience of the key exploration & production (E&P) debt and equity instruments such as Reserves Based Lending Facilities, Acquisition Facilities, Corporate Bonds, Trade Finance Facilities and Equity Transactions.

More recently, David acted as a Treasury and Financial Consultant advising Assala Energy on their corporate finance and treasury following the acquisition of Shell's onshore assets in Gabon. He has also supported a number of small E&P companies in managing their capital structure and developing financial strategies. David is a qualified chartered management accountant. He holds a BA in Law and Accounting from the University of Limerick.

Alberto Cattaruzza – Non-Executive Director

Alberto graduated as a Chemical Engineer from the University of Padua and having worked in Germany for LURGI, he returned to Italy in 1966 and joined Chevron Oil Italiana as Planning Analyst, moving then to Assistant Manager Planning, Supply & Refining Manager, Marketing Operations Manager and Commercial Sales Manager. During this period, he was appointed Board Member of the two Italian refining companies of which Chevron was shareholder.

When Chevron left Europe in the 1980s, Alberto became General Manager of an Italian private refining and marketing company and was appointed Board Member of a number of companies belonging to the same Group, including the ISAB refinery in Sicily where the majority partners where ENI and ERG

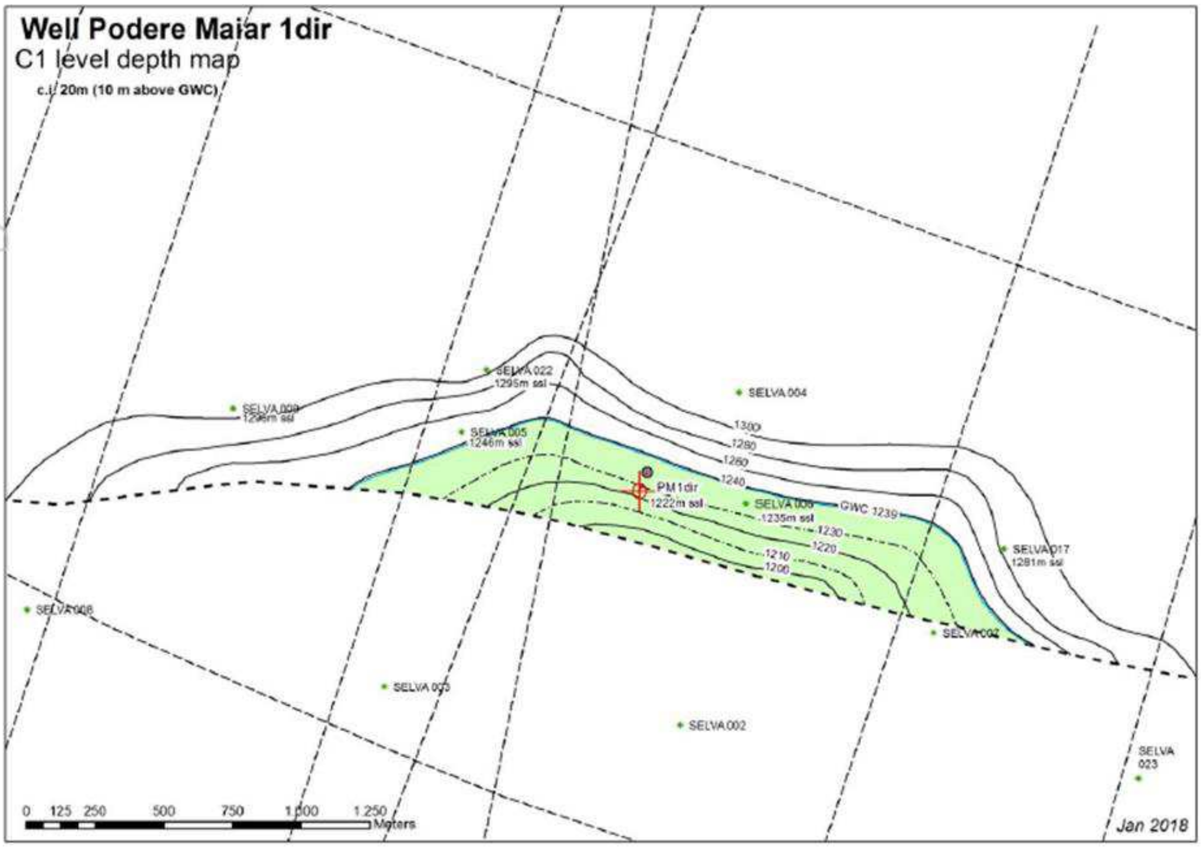
In 1995, Alberto joined the Oilinvest Group, operating in Europe under the brand name Tamoil, as Managing Director of their German affiliate with HQ in Hamburg. He was later appointed Oilinvest Refining & Marketing Officer and Board Member of several other Group companies, in Hungary, in the Czech Republic and in Italy. In 2001, Alberto started an independent entity providing technical and business consultancy services in the oil sector. His clients include a large number of oil companies In Europe and the Middle East, as well as international consulting companies such as Accenture and The Boston Consulting Group.

Appendix 2: Selva – the Podere Maiar-1d well

The Podere Maiar-1d appraisal/development well was spudded in late November 2017 targeting a gas volume updip the existing Selva-5 and Selva-6 wells. Under the terms of the company's farm-in agreements with Po Valley at the time, we estimate that United contributed approximately 40% towards the cost of the well, which we believe cost approximately €3.5m, in return for a 20% working interest.

The well was completed successfully on 20 December 2017 to a depth of approximately 1,350 metres and perforations executed post completion identified two gas reservoirs in the Lower Pliocene sands of the Porto Garibaldi Formation. These reservoirs have been termed C1 and C2.

Location of the Podere Maiar-1d well on Selva



Source: Po Valley Energy

Productive horizons

The C1 and C2 reservoirs were delineated with total gross pay of 62.5 metres and net pay of 44 metres. The shallower C1 gross pay runs from 1,253.5m MD (Measured Depth) to 1,275.5m MD and has a gross pay of 22m and net pay of 15.5m. The gas-water contact (GWC) is located at 1,237m and C1 has been perforated over 2.5m in the uppermost section of pay.

The deeper and thicker C2 horizon runs from 1,282.5m MD to 1,322.5m MD and has a net pay of 25.5m. The GWC is located at 1,274m and the interval has been perforated over 8.5m. At this point, we believe that C2 could be the initial productive horizon on the field.

Flow testing confirms commerciality

The Podere Maiar-1d well was flow tested in January 2018 with peak flow rates of 148,136 scmpd (standard cubic metres per day), equivalent to 5.2 mmcfpd on a 3/8 inch choke from the C2 interval and 129,658 scmpd (4.6 mmcfpd) from C1 on the same sized choke. A summary of the test results is outlined in the tables below.

Flow test results from C2 level

Choke Inches	Flow rate scmpd	Flow rate mcfpd	Flowing well head pressure Bars	% pressure drop across constriction
1/8 inch	17,850	631	122.8	0.2%
2/8 inch	66,000	2,332	120.7	1.9%
18/64 inch	80,700	2,852	119.5	2.8%
3/8 inch	148,136	5,234	111.9	9.0%

Flow test results from C1 level

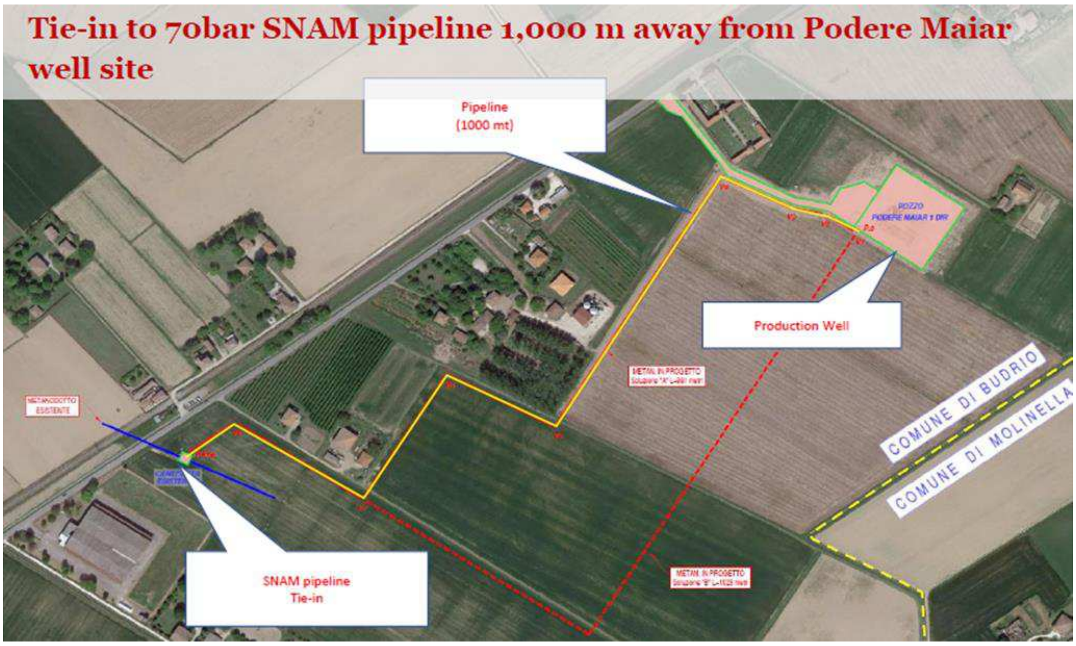
Choke Inches	Flow rate scmpd	Flow rate mcfpd	Flowing well head pressure Bars	% pressure drop across constriction
1/8 inch	14,348	507	119.3	0.3%
2/8 inch	64,475	2,278	115.0	3.9%
18/64 inch	77,351	2,733	113.7	5.0%
3/8 inch	129,658	4,582	105.1	12.2%

Source: Company RNS

Commercial discovery declared

Based on these strong flow rates, which exceeded the pre-test expectations of 100,000 scmpd (3.5 mmcfpd), and a methane content of 99.5% recorded from each horizon, the operator declared Selva a commercial discovery. This status is augmented by the location of the Podere Maiar-1d well which is only 1,000 metres from the Italian national grid connection, enabling an inexpensive tie-in to local transportation infrastructure (see photograph below).

Location of Podere Maiar-1d well in relation to SNAM pipeline tie-in



Source: Po Valley Energy

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