WHIreland

2 February 2016

UK EQUITY RESEARCH

OIL & GAS

BUY

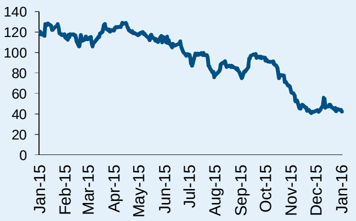
Price	**52p**
Target Price	162p

Reuters/BBG	PMG.L / PMG LN
Index	FTSE AIM
Sector	Oil & Gas
Market Cap	£51.4m
Shares in Issue	98.9m

Performance	**Absolute**
1 month:	0.6%
3 months:	-54.1%
12 months:	-65.0%
High/Low	135p/41p

Key Data:	
EPS CAGR 3-year	n.a.
ROCE	n.a.
Free Cashflow Yield	n.a.

Last Results	Prelims – Nov 15
Next Results	Interims – Mar 16
Next Event	Operations /Acquisition



Source: Capital IQ

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Marketing Communication
This document has not been prepared in accordance with legal requirements designed to promote the independence of investment research. Please refer to important disclosures towards the end of this document.

Parkmead

Accelerated Dana

Parkmead is led by the highly successful entrepreneur Tom Cross, who founded and grew Dana Petroleum plc into the largest independent oil company in the UK before selling it to the Korea National Oil Corporation (“KNOC”) for over US$ 3.0 billion in 2010. Parkmead’s strategy is to replicate the success of Dana by applying that company’s proven business model on an accelerated basis. We initiate with a Buy and a target price of 162 p/share.

Aligned focus: Management owns circa 27% of the company with Tom Cross, Executive Chairman, holding 19%.

The team: Within its mid-cap peer group we believe that Parkmead’s management has an unrivalled track record of delivering shareholder value through the commodity cycle.

Expect acquisitions: We believe that Parkmead’s balance sheet strength, proven technical expertise and acquisitive history suggests that Parkmead is uniquely positioned within its peer group to capitalise on sector weakness.

Timing the cycle: The company’s capital spend is almost entirely discretionary and its exposure to projects (sunk costs, commitments, debt-funded projects) that are dependent on the high commodity price environment that prevailed until the end of 2014 is limited.

Perth economics: Falling service costs have reduced our estimate of the NPV10 breakeven Brent crude oil price for Perth to US$ 41/b from US$ 61/b in 2013. Our cost assumptions are based on Senergy’s cost estimates (CPR, 2012) for all capex above the seabed and our own detailed well costs based on current rig rates.

Bear Market Valuation: We have been ruthless in pricing in only the highest quality assets in the company’s portfolio which we have risked aggressively.

Political Safety: We believe that the overlap of high quality assets in the political safety of the UK and the Netherlands increases the attractiveness of Parkmead.

Estimates (June - £m)	**2013A**	**2014A**	**2015A**	**2016E**
Production (boe/d)	1,121	1,862	1,149	957
Oil/total production	0%	83%	87%	48%
Revenue (£m)	4.1	24.7	18.6	7.3
EBITDA (£m)	-5.6	6.6	-13.1	-1.5
Operating cash flow (£m)	-1.4	8.7	-18.4	-2.7
Earnings (£m)	-5.6	1.2	-31.4	-8.0
Brent oil price ($/bbl)	108.69	109.34	73.46	42.23
UK natural gas price ($/mcf)	10.31	10.09	7.70	6.24

Investment Case

We believe Parkmead sets high-water marks in respect of the key factors that determine the success of oil & gas companies: it has an excellent management team, excellent assets and a strong balance sheet.

Shifting to Natural Gas: We expect Parkmead to increase its weighting towards natural gas in the future.

Fig 1: Contribution to target price by commodity

Contribution to target price	Contribution to Target Price p/share	(%)
Total contribution from natural gas assets	51.3	31.6%
Total contribution from oil assets	80.7	49.7%
Balance sheet adjustements	30.4	18.7%
Total for valuation/target price	**162.4**	**100.0%**

Source: WH Ireland

Diversified: Parkmead has a broad base of high quality assets.

Fig 2: Contribution to target price by project

Project	Location	Commodity	Contribution to Target Price p/share	(%)
Perth (Phases 1 and 2)	UK CNS	Oil	56.1	34.5%
Selene Prospect	UK SNS	Gas	16.9	10.4%
Davaar Prospect	W. of Shet.	Oil	12.8	7.9%
Skerryvore Prospect	UK CNS	Oil	11.7	7.2%
Pharos Discovery	UK SNS	Gas	10.9	6.7%
Platypus Discovery / Possum Prospect	UK SNS	Gas	8.4	5.2%
Netherlands Discoveries	Onshore	Gas	8.1	5.0%
Blackadder Prospect	UK SNS	Gas	7.1	4.3%
Balance sheet adjustements	n.a.	n.a.	30.4	18.7%
Total for valuation/target price			**162.4**	**100.0%**

Source: WH Ireland

Exploration: We have reviewed the geological viability of each of the company's exploration assets included in our target price and believe that they are truly high quality prospects. The company has a 100% drilling success record and has one of the most respected technical teams in Europe. Building on the company's track record and based on our appreciation of the geology of the company's prospects, we would be delighted to see more exploration drilling going forward. Our favourite prospects are Blackadder (a gas prospect in the Southern North Sea adjacent to the Pharos discovery), Selene (a gas prospect in the Southern North Sea) and Davaar (a world-class oil prospect West of Shetland), for which we estimate "unrisked" success case values of 42.3 p/share, 88.8 p/share and 205.4 p/share, respectively.

Risking: We have aggressively reduced the values included in our target price to reflect commercial risks as shown in Figure 3. This sets the scene for value to be unlocked as commercial catalysts are realised.

Fig 3: Aggressive "bear market" risking factors for high quality assets

Commercial chance of success factors	
If unfunded	Value reduced by at least 25%
If non-operated and decision to progress pending	Value reduced by at least 25%
If pending a commercial agreement	Value reduced by at least 25%
If dependent on prior exploration success	No inclusion in valuation
If a satellite field of an undeveloped core development	No inclusion in valuation

Source: WH Ireland

Commodity Prices: Our valuation and target prices are premised on our long-term commodity price assumptions: We assume that in 2018 the price of Brent crude oil is US$ 70/b, which we inflate at 2% in subsequent years. We assume that in 2018, the price of natural gas in the UK and the Netherlands is 50p/therm (circa US$ 7.71/mcf), which we also inflate at 2% in subsequent years.

Breakeven costs falling: Based on a detailed analysis of costs (outlined in this note) we estimate that the break-even (NPV10) Brent crude oil price for Perth has fallen by US$ 20/b to US$ 41/b with the rapid decline in oilfield service costs. The economic robustness of Perth should not be surprising given the field is one of the largest undeveloped oil fields in the UK (we estimate 69.4 million barrels of gross recoverable oil for Phases 1 and 2). In our opinion, the absence of mobile H_2S processing capability, which only recently became commercially available was the only reason this low-hanging conventional field benefiting from five well penetrations had not yet been developed. We believe that by recognising the strides made in the last decades to address H_2S challenges, Parkmead has created a tremendous opportunity for its shareholders.

Fig 4: The evolution of rig-rates for the Perth development

Time	Day rate	Type	Source
2013	$360,000	Semi-sub (all year drilling)	Company
February 2015	$217,000	Jack-up (drilling in summer)	Direct from drill co.
December 2015	$155,000	Jack-up (drilling in summer)	Direct from drill co.

Source: WH Ireland

Quality assets: We believe that Parkmead has assembled a high quality portfolio of assets from a standing start in 2011.

Risks

General risks for almost all investments in the oil & gas sector include: i) commodity price risk, ii) risks related to the estimation of future production, iii) risks related to capital and operating costs, iv) operational risks, v) funding risks, vi) the risk of delays, vii) adverse changes to the tax system, viii) the risk that the regulatory regime changes adversely, ix) exploration risks and x) environmental risks.

In addition to the risks noted above, investors should be aware of the following specific risks in relation to Parkmead:

i) Oil from the Perth field is produced with high levels of hydrogen sulphide gas (H_2S). The gas needs to be treated as it can pose a risk to human health and a heightened quality of materials (mainly steel) is required to produce the field to avoid pipework corrosion issues. We believe we have appropriately factored in related costs for H_2S-resistant materials. Nonetheless, investors should consider any associated technical, economic and regulatory risks.

			Key Assumptions			Unrisked Present Value Net to Company (NPV10)			Risked Value					Economic Analysis		
						Total			Risking Factors			Contribution to Target Price			Commodity Price Breakeven (NPV10)	
	Working Interest (%)	Oil/ Gas	Gross Resource Scale (mn boe)	Net Resource Scale (mn boe)	First Production (year)	USD ($mn)	GBP (£mn)	Per Share (p/share)	Geological (%)	Commercial (%)	Combined (%)	Total ($mn)	per Share (p/share)	Value $/boe ($/boe)	Oil ($/b)	Gas ($/mcf)
Oil & Gas Assets																
UK Oil & Gas Assets																
Perth Core (Phase 1)	*52.0%*	Oil	39.0	20.3	2019E	73.1	48.7	45.7	*100.0%*	*50.0%*	*50.0%*	36.6	22.8	3.60	41	n.a.
Perth NW and NE (Phase 2)	*52.0%*	Oil	30.4	15.8	2022E	177.5	118.3	110.9	*60.0%*	*50.0%*	*30.0%*	53.3	33.3	11.23		
Platypus (discovery)	*15.0%*	Gas	17.3	2.6	2019E	14.8	9.9	9.2	*100.0%*	*75.0%*	*75.0%*	11.1	6.9	5.69	n.a.	5.50
Pharos (discovery)	*30.8%*	Gas	27.5	8.5	2020E	53.1	35.4	33.2	*66.0%*	*50.0%*	*33.0%*	17.5	10.9	6.28	n.a.	4.00
Total UK Oil & Gas Assets			114.2	47.2		318.5	212.3	198.9				118.4	74.0	6.76		
Netherlands Oil & Gas Assets																
Grolloo, Geesbrug, Brakel (on production)	*15.0%*	Gas	1.2	0.2	2012A	1.4	0.9	0.9	*100.0%*	*100.0%*	*100.0%*	1.4	0.9	7.78	n.a.	1.91
Diever West (1 well; on production)	*15.0%*	Gas	6.8	1.0	2015A	7.6	5.1	4.7	*100.0%*	*100.0%*	*100.0%*	7.6	4.7	7.45	n.a.	1.59
Geesbrug 2nd Well (step-out well)	*15.0%*	Gas	1.7	0.3	2017E	1.0	0.7	0.6	*100.0%*	*75.0%*	*75.0%*	0.8	0.5	4.00	n.a.	2.90
Papekop (discovery)	*15.0%*	Oil & Gas	3.6	0.5	2017E	6.4	4.3	4.0	*100.0%*	*50.0%*	*50.0%*	3.2	2.0	11.85	18	4.00
Total Netherlands Oil & Gas Assets			13.3	2.0		16.4	10.9	10.2				13.0	8.1	8.24		
Total Oil & Gas Assets		**n.a.**	**127.4**	**49.1**	**n.a.**	**334.9**	**223.3**	**209.2**	**n.a.**	**n.a.**	**n.a.**	**131.4**	**82.1**	**6.82**		
Balance Sheet and Other Adjustments																
Investment in Faroe Petroleum						3.0	2.0	1.9				3.0	1.9			
General & admin cash costs (PV10, three years, £2.2mn)						(8.2)	(5.5)	(5.1)				(8.2)	(5.1)			
Cash (30 June 2015)						61.7	41.1	38.5				61.7	38.5			
Working capital liability						(14.9)	(9.9)	(9.3)				(14.9)	(9.3)			
Cash assumed from option exercise						19.1	12.7	11.9				19.1	11.9			
Cash in escrow for relinquishment						(12.0)	(8.0)	(7.5)				(12.0)	(7.5)			
Total of Balance Sheet and Other Adjustments						**48.7**	**32.5**	**30.4**				**48.7**	**30.4**			
Core NAV						**383.6**	**255.8**	**239.6**				**180.1**	**112.5**			
Lower Visibility Assets																
UK Oil & Gas Assets																
Possum (prospect adjacent to Platypus)	*15.0%*	Gas	6.6	1.0	2019E	6.2	4.1	3.9	*50.0%*	*75.0%*	*37.5%*	2.3	1.5	6.26	n.a.	4.00
Blackadder (prospect adjacent to Pharos)	*30.8%*	Gas	29.1	8.9	2020E	67.8	45.2	42.3	*33.3%*	*50.0%*	*16.7%*	11.3	7.1	7.58	n.a.	3.66
Selene (prospect)	*50.0%*	Gas	38.9	19.4	2020E	142.1	94.7	88.8	*38.0%*	*50.0%*	*19.0%*	27.0	16.9	7.31	n.a.	3.00
Skerryvore (prospect)	*30.5%*	Oil	64.9	19.8	2020E	197.6	131.7	123.4	*38.0%*	*25.0%*	*9.5%*	18.8	11.7	9.98	35	n.a.
Davaar (West of Shetland prospect)	*30.0%*	Oil	175.0	52.5	2022E	328.9	219.3	205.4	*25.0%*	*25.0%*	*6.3%*	20.6	12.8	6.26	41	n.a.
Sanda N/S (Davaar satellites; prospects)	*56.0%*	Oil	125.4	70.2	2024E	464.0	309.3	289.8	*12.5%*	*0.0%*	*0.0%*	-	-	6.61	37	n.a.
Polecat & Marten (Perth satellites; discoveries)	*50.0%*	Oil	33.6	16.8	2022E	25.2	16.8	15.7	*100.0%*	*0.0%*	*0.0%*	-	-	1.50	48	n.a.
Perth West (prospect adjacent to Perth)	*52.0%*	Oil	9.2	4.8	2022E	45.1	30.1	28.2	*40.0%*	*0.0%*	*0.0%*	-	-	9.40	41	n.a.
Total UK Oil & Gas Assets			482.6	193.5		1,276.9	851.2	797.6				79.9	49.9	6.60		
Netherlands Oil & Gas Assets																
n.a.	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*		
Total Netherlands Oil & Gas Assets	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*	*n.a.*		
Total of Lower Visibility Assets			**482.6**	**193.5**		**1,276.9**	**851.2**	**797.6**				**79.9**	**49.9**	**6.60**		
Net Asset Value and Target Price			**610.1**	**243**		**1,660.5**	**1,107.0**	**1,037.2**				**260.1**	**162.4**			

Key assumptions:

Asset values are based on after-tax discounted cash flow models for each asset using a 10% discount rate (a standard NPV10 approach to oil & gas assets)

Long term (2018) Brent oil price: $70/b (inflated at 2% p.a.); Long term (2018) UK natural gas price: 50p/therm (inflated at 2% p.a.), which equates to circa $7.71/mcf; USD/GBP = 1.50

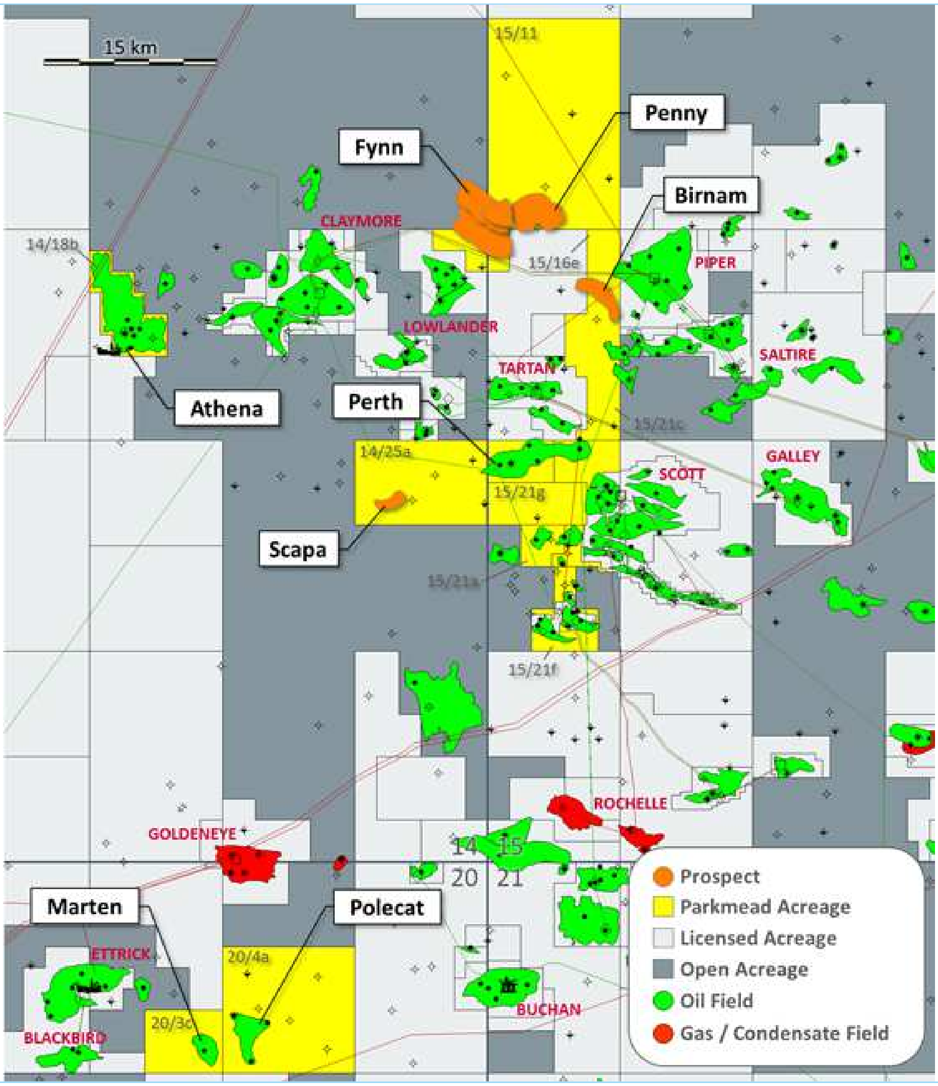
Perth

Overview:

The Perth field is located in licences P218 (Block 15/21a) and P588 (Block 15/21c) in the Outer Moray Firth of the Central North Sea. The field is located about 135 km northeast of the Aberdeeshire coastline in water depths of circa 130-140m. The Perth West exploration prospect is located to the immediate west of the Perth discovery on the opposite side of a fault.

A map of the licence area is provided below.

Fig 5: Perth license area



Source: Parkmead

The Field Development Plan for the Perth Field was submitted to DECC in September 2011 and it has been agreed in principle by DECC.

The discovery well (15/21a-7) was drilled in 1983 by Monsanto. Subsequently, four appraisal wells (and a sidetrack well) were drilled into the field by Hess, the last of which was drilled in 1997. All five wells were drilled into the field's oil-bearing productive reservoir sands with two of the wells also intersecting the oil water contact, which is located on the southern margin of the field.

The field remained undeveloped due to the high hydrogen sulphide (H_2S) content of the reservoir fluids which is incompatible with existing infrastructure in the area.

A ten-day extended well test was undertaken on one of the wells (15/21b-56). The well flowed at initial stabilised rates of up to 4,400 b/d, with slowly declining bottom hole pressure and production rates at the end of the test.

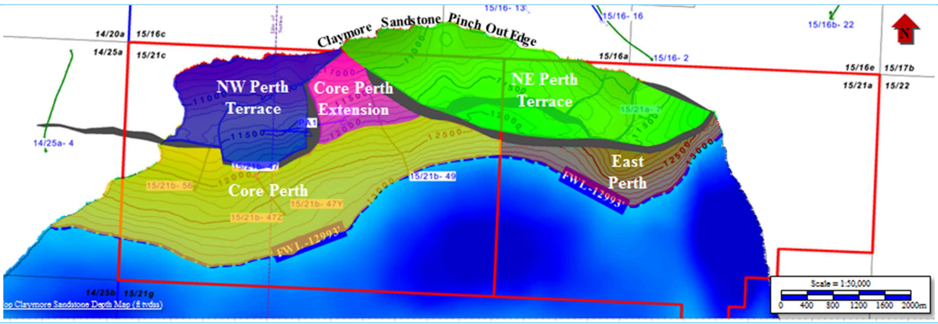
The field is held by Parkmead (52.03%), Faroe Petroleum (34.62%) and Atlantic Petroleum (13.35%). Parkmead operates the field.

Perth produces light oil with an API density of 30-32 degrees. The oil is sour with a hydrogen sulphide concentration of 6,500 ppm and carbon dioxide saturation of 35.4% (mol%) in the produced gas. Our understanding is that the H_2S (gas) is to be removed from the produced fluid (and incinerated) on site in the first stage of processing.

The crude oil produced from Perth is expected to be imminently marketable as its quality leaving the FPSO is essentially identical to that of standard Brent crude oil. We have assumed that the oil is sold at a 1% discount to Brent (consistent with the assumption of Senergy after evaluation of the field's crude oil).

The field is divided by faults that create four reservoir compartments: Core Perth, NW Perth Terrace, NE Perth Terrace and East Perth. The Core Perth reservoir extends into an undrilled area called the Core Perth Extension, which is expected to be in pressure communication with Core Perth. Core Perth has been penetrated by five individual wells.

Fig 6: Perth Reservoir Compartments (Top of Claymore Structural Map)



Source: The Parkmead Group

Perth West is an exploration prospect premised on the immediate westward extension of the field. It is not shown in the above image.

According to a resource assessment prepared by Senergy (CPR, 2012), the Phase 1 development of Perth has proven and probable reserves of 41.3 mn barrels of oil (gross). We have used this estimate for Phase 1 in our valuation, which consists of the development of the Core Perth area (inclusive of Core Perth Extension). Senergy has not prepared a best estimate for Phase 2. We estimate that the Phase 2 development will produce 30.4 mn barrels of oil (gross) inclusive of 2.3 mn barrels from extending the field life of the Phase 1 development. We estimate that East Perth has a recoverable resource potential of circa 2.6 million barrels.

We believe that the two most noteworthy fields that produced from similar sands in the same area as Perth are the Claymore and Scapa fields. In our opinion, the analysis of the performance of these fields suggests that ultimate recovery of oil from the Perth Field could materially outperform our current assumptions for the field.

A study was carried out to assess the potential of undertaking a joint development of the Perth field with the neighbouring Lowlander field, which we estimate has a recoverable resource potential of 20.4 million barrels of oil (gross). The Lowlander field is under the stewardship of Parkmead's partner in Perth, Faroe Petroleum. The study concluded that a joint development of the two fields could significantly increase the value of the Perth project. The nearby Dolphin Field (circa 5.2 million barrels of recoverable gross oil resource), which is 52.03% held and operated by Parkmead, has also been assimilated into the joint project. The Perth and Lowlander interest holders have agreed on a joint framework to progress the project and the partners, in concert with the UK Oil & Gas Authority, have agreed that Parkmead will be the operator of the joint development. We anticipate that a definitive joint development agreement will be announced in due course. For now, in our valuation of Parkmead, we have not included any future benefit for the potential value gains that can be realised from a joint development.

Detailed and updated cost analysis:

We estimate that it will cost US$ 28.8 million to drill wells into the Perth field and its satellites, based on detailed line-by-line cost estimates and updated jack-up rig rates as per direct rig quotations (US$ 155,000/day). This is reflective of our estimate that rigs will be engaged for circa 58 days per well.

In respect of development costs we have applied cost estimates provided by Senergy (CPR, 2012) specifically in respect of the Perth field. They have qualified their cost estimates as "robust" and those estimates reflect the quality of materials required to tolerate H_2S levels of 6,500 ppm. Senergy's estimates were premised on the construction of an FPSO with topside modifications that would be able to accommodate significant production in excess of that for Perth Phase 1 and Phase 2 (at least 4,000 b/d of additional production capacity).

In our opinion, the FPSO cost estimates as provided by Senergy would require detailed analysis to assess the implications of developing the Perth field jointly with Lowlander due to the scale of that field and because Lowlander's H_2S concentration is higher than that of Perth.

We believe that the economics of Perth Phase 1 and Phase 2 cannot be assessed independently because the FPSO will be designed to accommodate both developments. We have separated Phase 1 from Phase 2 for the purposes of our target price only to allow for Phase 2 to be risked differently in terms of the subsurface until more is known about the fault blocks that are thought to contain the Phase 2 upside.

As per Senergy's assumption, the FPSO is assumed to be leased. We have directly applied their operating cost estimates inclusive of FPSO bare-boat (lease cost) estimates. Importantly, these costs are indicative of high crude oil price conditions as their estimates were made in May 2012.

According to Vincent Flores at Vallourec, which is a globally recognised specialist in drill-pipe engineering and manufacturing: "some highly sour oil and gas reservoirs are being explored with H_2S content beyond what could have been imagined a decade ago", this is due in large part to fit-for-purpose engineering and manufacturing undertaken on a private basis. This changes the costing and we have added US$ 5 million of additional capital expenditure charge to each well to reflect potential H_2S costs (drill string costs in particular). We expect the costs of production tubing to evolve favourably in the years ahead. Senergy's cost estimates reflect all capital spend above the sea bed.

The total capex required to bring the field to first oil (Phase 1) is circa US$ 308 million gross which is down 36% from the estimate prior to the collapse in crude oil prices. We expect additional wells (possibly deviated/horizontal wells) to be drilled prior to bringing Phase 1 onstream to test the North West and North East terraces which would be exclusive of the cited costs. Thereafter, we expect the project to be comfortably self-funding based on our commodity price assumptions and the assumption that Perth Phase 2 comes onstream in 2022, three years after Phase 1.

For perspective, based on our assumptions we do expect Perth to create profits for tax purposes. After incorporating the small field allowance, we estimate that the field will on average pay US$ 23 of tax for every barrel of oil produced (based on our long-term crude oil price assumption of US$ 70/b in 2018 inflated at 2% p.a.) with taxes becoming payable shortly after Phase 2 starts, which requires minimal capex other than drilling and sub-sea tie-ins.

Perth West:

Perth West is a step-out exploration prospect to the immediate west of the discovered Perth field. The company was awarded the block pursuant to the 28th Licensing Round (November 2014). Perth West has been identified by seismic on the upthrown and western side of a fault that forms the western boundary of the discovered Perth field. We believe that trap, seal and source risks are effectively nil for Perth West, with the only remaining technical risk being around reservoir presence and quality. To reflect this we have conservatively applied a 40% chance of geological success to the prospect in our valuation. We believe that Perth West is a natural and high-quality step-out exploration prospect.

Based on an oil in place estimate of 30.9 million barrels of oil for Perth West and a recovery rate of 30%, we estimate that the field will produce 9.2 million barrels (gross) if successful.

Sour Crude Oil Hub Strategy:

There are no existing facilities that allow for the production of sour crude oil in the area of the Perth Field; however, many sour crude oil fields have been discovered in the area. *As a technical note the Tartan field is able to produce a limited amount of low-H_2S sour crude oil but there is no material spare sour crude oil processing capacity in the area.*

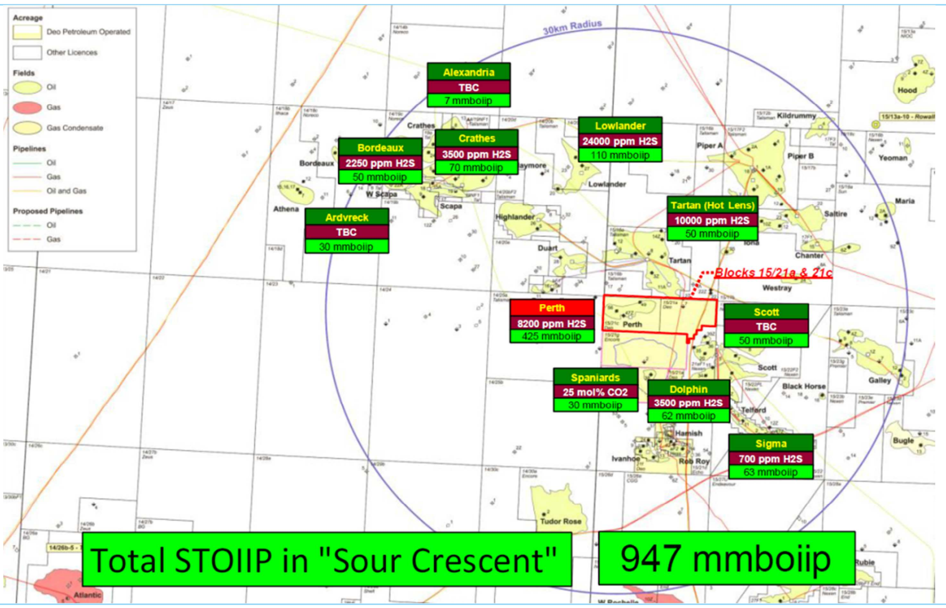
We believe that most of the costs to develop and operate the Perth field are fixed. Once the fixed costs have been borne, the costs of bringing new fields onstream consist only of drilling, completing and tying in new wells and variable operating costs. This greatly increases the economic attractiveness of fields that can be brought onstream using existing facilities.

The Perth Field is located in the central area of a very large fairway of sour oilfields. Parkmead refers to the area within a 30 km radius of the Perth Field as the "Sour Crescent", which is estimated to contain circa 947 million barrels of stranded crude oil in place within discovered but undeveloped fields. If the fields were developed a proportion of this estimate would be recoverable, depending on the recovery rate. Parkmead believes that oil fields within the 30 km radius could be produced through central facilities at Perth.

Parkmead also has a 52.03% and operated stake in two nearby oil discoveries, namely Dolphin and Sigma, in addition to a 12.63% non-operated stake in the Spaniards discovery. These three discoveries are located about 6 km to the south of the Perth field.

The most obvious field that could be brought into a hub development is the Lowlander field which is about 16 km to the north west of Perth. Lowlander is a sour crude field with a H_2S concentration of approximately 12,000 ppm. Faroe Petroleum acquired a 50% interest in the field from Talisman in February 2013 and became field operator. Faroe acquired the remaining 50% from North Sea Ventures in November 2013.

Fig 7: The sour crescent (oilfields within 30km radius of Perth)



Source: Parkmead Group

Geology and Reservoir Characterisation:

The Perth field is a combined structural/stratigraphic trap consisting of Upper Jurassic Claymore sandstones onlapping the Tartan ridge to the north. The reservoir thickens and dips to the south.

The top and base of the Perth reservoir returns only a soft seismic response, which means that other sources of data need to be integrated with the seismic. Three 3D datasets have been used to interpret the field, one was acquired in 2001 and another in 2005. The third data-set, a high density campaign undertaken by TGSNopec, was acquired in 2011/2012 with final interpretation available in 2012. The seismic data has been tied to the five Perth wells which provides support to volumetric estimates.

The performance of producing wells and water injector wells may be reduced by the existence of faults that could cut across communicating reservoir compartments. According to Senergy, the 3D seismic images (correlated to five wells) suggest that each of the main independent reservoirs is internally unfaulted and that the risk of sealing faults is limited primarily to the immediate proximity of the main faults and to the northern extremities of the field where it thins (onlaps). Analysis of the 10 day extended well test suggests that fluid communication is good within the reservoir (no faulting). We are reassured that there is a total absence of affirmative data that suggests that any risk has materialised.

Water injection will be provided to maintain reservoir pressure, owing to Perth's limited aquifer support and gas saturation levels (the field has a GOR of circa 825 scf/bbl). The reservoir is a good candidate for water injection as proven by the injectivity test carried out on the 15/21b-47Y well, which injected water into the aquifer at a rate of up to 5,500 b/d.

The reservoir is thought to be comprised of deep water turbidite sands sourced from the Halibut Horst (to the west and south). The reservoir is heterogenous with variable net to gross ratios (ranging from 84% to 19% in wells drilled to date). Porosity in the reservoir averages between 12%-13%. Within the net pay, permeability ranges from 10mD to 600mD.

High permeability volumes (in excess of 60mD) are interpreted to result from diagenetic dissolution by acidic fluids expulsed from the underlying Kimmeridge Clay. The upward movement of these fluids appears to have been constrained by overlying mudstone horizons, creating good permeability beneath these horizons. This interpretation suggests that the high permeability streaks will be laterally extensive because the mudstones are also laterally extensive. The well logs also suggest that high permeability intervals are generally, but imperfectly, laterally extensive. As a base case we believe it is reasonable to assume that there is connectivity between the high permeability sands, creating a network of good permeability intervals. This will be important to ensure the effectiveness of the water injection strategy and to obtain a reasonable recovery of original oil in place.

For Phase 1, our economic valuation uses Senergy's conservative recovery rate of 24%. We expect the actual recovery rate to vary from this current estimate, perhaps materially because of the heterogenous nature of the Claymore reservoir. Recovery estimates for the Claymore and Scapa fields, which also produce from Claymore sands, increased over time to 40% and 56%, respectively (according to the operator Talisman Energy's most recent publicly available estimates).

We believe that the extended well test eliminates much of the risk of a downside case which could, if required, be remedied by operational strategies (more intensive drilling / sidetracks, increased water injection capacity, etc). In our opinion, the Claymore Sands, which are not widely distributed in the North Sea, have variable forecasts for expected ultimate recoveries due to the different sand qualities within that group. However, on balance we believe that the Perth Field's reservoir is more likely to over deliver than not relative to the expectations built into our target price.

The senior management team at Parkmead is experienced in producing from the regional Claymore sands as Dana Petroleum plc acquired a 7.25% interest in the Claymore Field from Centrica in 1998.

Development and Production:

We have valued the Perth Field on a stand-alone basis and have modelled first oil from Phase 1 (Perth Core and Perth Core Extension) to be achieved in C1H 2019. We have assumed Phase 2 (NW Perth Terrace and NE Perth Terrace) achieves first oil in C2H 2022.

According to the original field development plan the field will be produced with a dedicated floating production storage and offloading (FPSO) vessel with a swivel turret. Once on production, crude oil will flow from a single subsea drill centre to the FPSO via a primary 8 inch flowline. A secondary 8 inch production flowline will also be installed in addition to an 8 inch water injection line, a 4 inch gas lift flowline and a control umbilical.

It is anticipated that the sour gas will be treated in an amine unit to remove the hydrogen sulphide before the gas is used for gas lift.

We expect Phase 1 to consist of four deviated wells and two water injection wells that will be drilled to penetrate the reservoir near the interpreted oil water contact (based on pressure data) at 12,993 feet tvdss.

We believe that the development concept for Phase 2 will depend on the results of the Phase 1 development. We anticipate first oil from Phase 2 to start flowing three years after first oil from Phase 1.

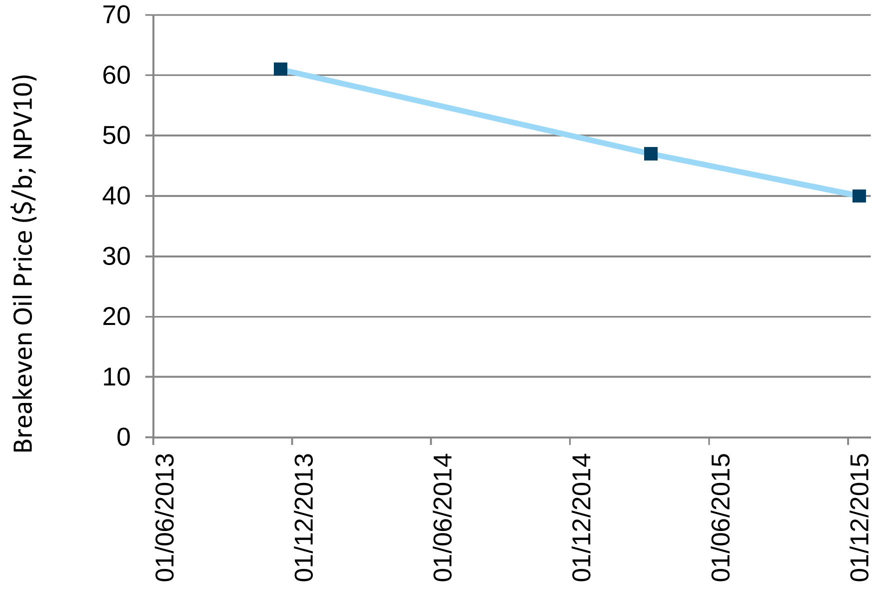
Economic Analysis:

A detailed economic analysis is provided on page 5 of this note, which provides key assumptions, valuations, risking factors for our target price and breakeven commodity prices.

Our Central North Sea oil valuation reflects our long-term Brent oil price assumption of US$ 70/b starting in 2018, which we inflate at 2% p.a.

As indicated on page 3 of this note, we estimate that the economic (NPV10) breakeven oil price (inflated at 2% p.a.) for Perth (Phases 1 and 2) is US$ 41 per barrel.

Fig 8: Evolution of Perth Breakeven Oil Price



Source: WH Ireland

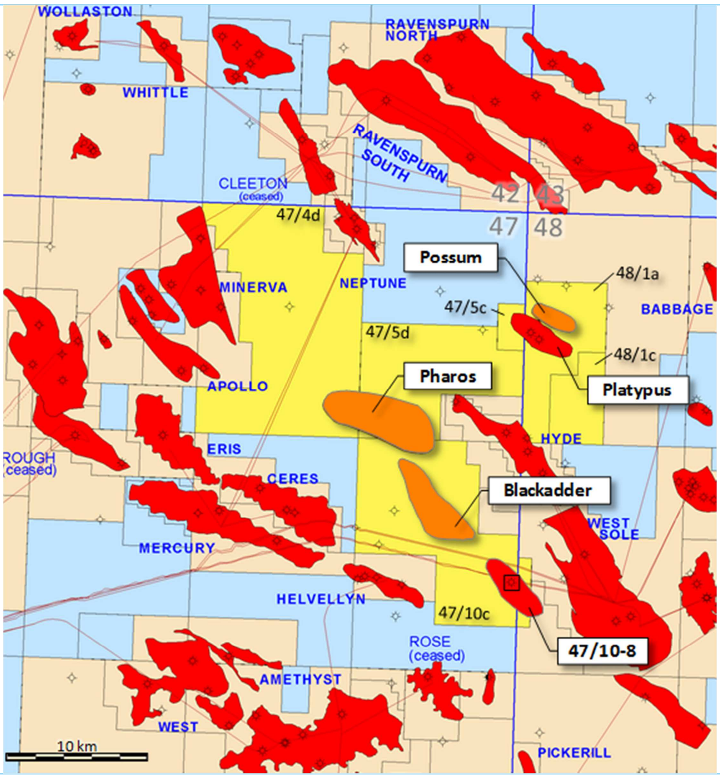
Southern North Sea Gas Assets

Overview:

In our opinion, Parkmead has five key assets in the Southern North Sea. These assets consist of two discoveries (Platypus and Pharos) and two associated step-out exploration targets (Blackadder and Possum), in addition to an independent exploration target (Selene).

The locations of Pharos, Blackadder, Platypus and Possum are shown in the map below.

Fig 9: Parkmead's Southern North Sea Discoveries and Step-out Targets



Source: Parkmead

The Pharos discovery and associated Blackadder prospect are held by Hanza Hydrocarbons (46.154% and operator), Parkmead (30.769%) and Dyas (23.077%).

Platypus and its nearby prospect, Possum, are held by Dana Petroleum (59% and operator), Parkmead (15%), Cal Energy (15%) and First Oil (11%).

The Selene prospect is held by Parkmead (50% and operator) and Atlantic Petroleum (50%).

We expect that the abundant surrounding infrastructure in the area will allow for a low-cost and operationally straightforward development of Parkmead's Southern North Sea gas assets.

The scale of Selene, being 234 bcf (or 38.9 million boe) on a gross basis, is particularly interesting. In many ways the prospectivity of Selene compares well to that of the company's highly successful Diever West discovery in the Netherlands, given that both reservoir rocks consists of Rotliegendes sands and the principal pre-drill reservoir risk relates to the accuracy of structural mapping, a discipline in which Parkmead's technical team has many years of experience and success.

Detailed and updated cost analysis and development plan:

Based on updated cost estimates, we assume that it will cost approximately US$ 21.2 million to drill Southern North Sea gas wells at current jack-up rig rates. This reflects our estimate that a rig will be in service for 67 days per well and that the company's Southern North Sea gas assets will be developed with horizontal wells. We have assumed that jack-up rigs suitable for the area's shallow water depths can be contracted for US$ 95,000/d, which is based on actual rig quotations for shallow water jack-ups. Prior to the collapse in crude oil prices, we estimate it would have cost circa US$ 33 million to drill the same wells. We see scope for further cost savings as warm and cold-stacking of jack-up rigs continues into 2016.

Platypus (discovery) / Possum (prospect):

Platypus is situated in water depths of 43m allowing for wells to be drilled with jack-up rigs. The discovery well, 48/1a-5 (operated by Dana Petroleum), was drilled to a measured depth of 3,367m. In April 2010, Dana Petroleum announced that the well successfully encountered 66m of high quality gas bearing reservoir. The well was suspended for re-entry as a producer.

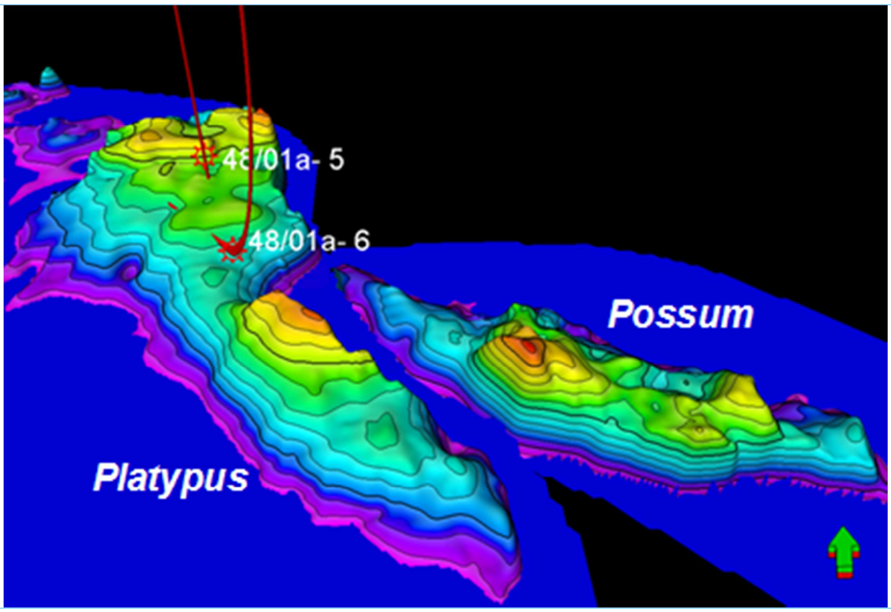
On 11 April 2012, an appraisal well (48/1a-6) was spudded at Platypus. The well reached a total measured depth of 4,320m on 19 June 2012 after drilling a 944m horizontal section within the reservoir. A drill stem test was completed which recorded a flow rate of 27 mmscf/d (equivalent to 4,500 boe/d) on a 96/64" choke.

Parkmead's best estimate of recoverable gas reserves for Platypus is circa 112 bcf (gross). Possum is expected to improve the economics of the Platypus development by contributing an additional c43 bcf of recoverable gas resources (gross) to the project. In any event, our economic evaluation indicates that Platypus is commercially viable as a standalone project.

We assume that the Platypus/Possum joint development achieves first gas in C1H 2019. This is premised on field development approval by the oil & gas authority in C2016. Parkmead expects to submit a Field Development Plan to OGA in the near-term.

Possum and Platypus have the same reservoir and trap type (fault/dip closure) as shown in Figure 10.

Fig 10: Platypus and Possum Structural Map



Source: Parkmead

Platypus and Possum are expected to be developed conjointly. The first well drilled into Possum will both confirm the existence of the field and produce the gas within it.

Parkmead estimates that the Possum prospect has a circa 50% chance of success, with the two primary geological risks relating to the presence of an effective trap and the quality of the reservoir.

Pharos (discovery) /Blackadder (prospect):

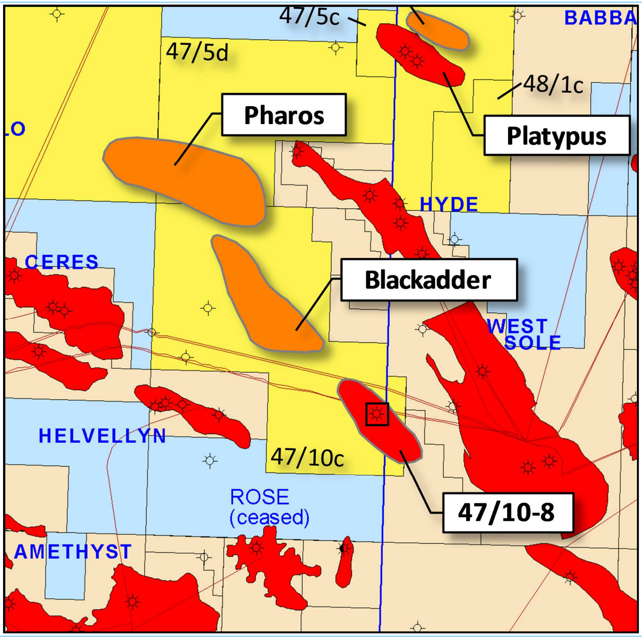
In November 2013, Parkmead announced that the Pharos exploration well had made a successful gas discovery. Extensive downhole data was gathered from the well, including wireline logs, gas samples, reservoir pressures and substantial coring of the reservoir.

In December 2014, Hansa Hydrocarbons (Parkmead's partner in the area) stated that "detailed evaluation of the Pharos well data is progressing well with the objective of determining the optimum forward plan for appraising the discovery" and "prospect maturation studies are ongoing on the significant Blackadder prospect with the aim of making a decision to drill an exploration well by mid-2015".

We believe it is likely that the Pharos discovery and Blackadder extension/prospect both consist of the same reservoir and we have modelled it as a joint development, with a combined gross best estimate of recoverable resources standing at 360 bcf.

From a timing perspective, we assume that development planning for the Pharos/Blackadder field will begin in earnest after the Blackadder prospect is drilled. We assume that first gas from Pharos/Blackadder occurs in 1H 2020.

Fig 11: Pharos and Blackadder



Source: Parkmead

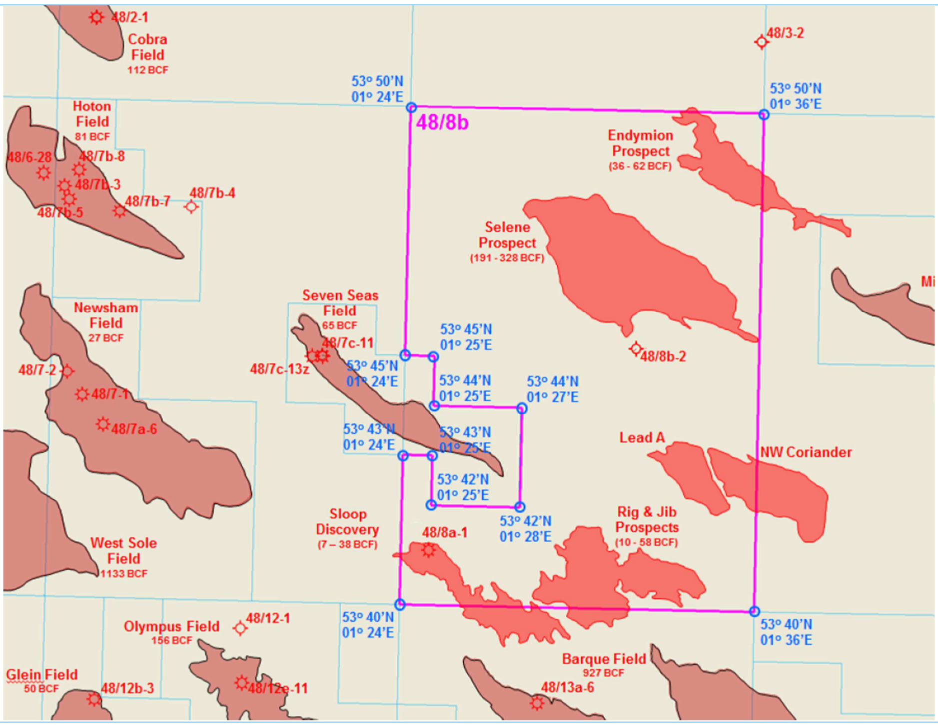
If Blackadder is successfully drilled up, the nearby 47/10-8 gas discovery (c. 86 bcf of gas in place) will be developed in tandem as the development of 47/10-8 is contingent on development sanction at Blackadder.

Selene:

We believe that the Selene gas prospect is a geologically attractive/robust exploration target in a well understood petroleum basin. The gross P50 (best) estimate of recoverable gas is 234 bcf.

Selene is located in an area of the Southern North Sea where a number of successful discoveries have been made with relatively few dry holes as seen in the image below.

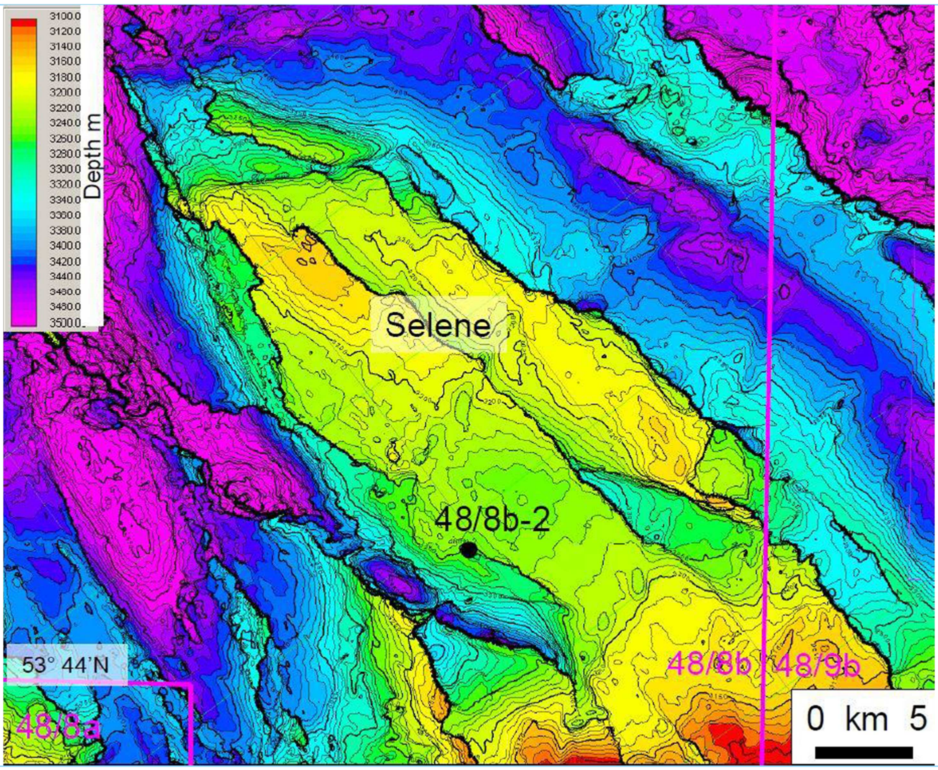
Fig 12: Selene location relative to other fields.



Source: Parkmead

The Selene prospect is a massive uplifted fault/dip bounded structure as seen in Figure 13.

Fig 13: Selene Structural Map



Source: Parkmead

The 48/8b-2 well was drilled by Amerada Hess in 1989 and it was drilled on the outskirts of the structure which meant that testing the well did not provide conclusive results. It is thought that the nearby fault introduced complications inclusive of diagenesis (a deterioration of the reservoir quality due to mineralisation). The 5.4% porosity encountered by the well is not considered to be representative of what can be expected in Selene itself. Sands in the area typically have porosities of between 10% and 15%. It is uncertain whether gas or water was present in the targeted formation, but gas shows were recorded while tripping the well.

Based on our detailed geological assessment of the prospect, we estimate that the chance of success for Selene is 38%.

Geology and Reservoir Characterisation:

The Platypus, Possum, Pharos, Blackadder and Selene reservoir rock is a Lower Permian Lower Leman sandstone formation of the Rotliegend Group. The Lower Leman is a major producing reservoir in the Southern North Sea. The sands consist primarily of desert deposits that are interbedded with mudstones *(source: British Geological Survey).*

Based on the Platypus well test production rate and the length of the horizontal leg of the appraisal well, we believe there is potential for the Platypus reservoir to have its permeability increased through fracture stimulation.

Economic Analysis:

A detailed economic analysis is provided on page 5 of this note, which provides key assumptions, valuations, risking factors for our target price and breakeven commodity prices.

Our valuation reflects our long-term gas price assumption of 50p/therm (circa US$ 7.71/mcf) starting in 2018, which we inflate at 2% p.a.

Netherlands Onshore

Overview

The Netherlands has provided Parkmead with i) cash flow ii) excellent returns on invested capital and iii) diversification into natural gas.

On 8 March 2012, Parkmead announced the acquisition of a portfolio of oil & gas assets in the Netherlands from Dyas B.V. for €7.5 million, of which €3.5 million is payable on the first sale of oil from the Papekop field.

A summary of the company's Dutch assets based on our estimates is provided below. We have assumed that a single additional well is drilled into each of Papekop and Geesbrug and that Diever West does not benefit from drilling an additional well. We believe that this is a conservative approach to valuing these assets, all of which in our opinion would benefit from more drilling.

Fig 14: Parkmead's discovered resource portfolio in the Netherlands

Asset	Description	Status	Operator	PMG Working Interest	Estimated Remaining Recoverable Resource Gross *(mn boe)*	Estimated Remaining Recoverable Resource PMG Share *(mn boe)*
Brakel, Geesbrug, Grolloo	gas	producing	Vermillion	15.0%	1.2	0.4
Diever-West	gas	producing	Vermillion	15.0%	6.9	1.0
Geesbrug 2nd Well	gas	pending	Vermillion	15.0%	1.7	0.3
Papekop	oil	planning phase	Vermillion	15.0%	3.5	0.5
Total					13.3	2.2

Sources: Parkmead Group, WH Ireland

The company discovered the Diever West field with the Diever-2 well in September 2014. Diever-2 was drilled to a total depth of 7,457 feet and discovered a 157 foot gas column in Rotliegendes sandstone. The well was flow tested at 29 mmcf/d (circa 4,800 boe/d), which is an extraordinary result for a low-cost onshore well. For perspective, we estimate that the producing Diever-2 well has a net value to Parkmead of circa US$ 7.6 million which compares to a net cost of circa US$ 1.6 million to drill the well.

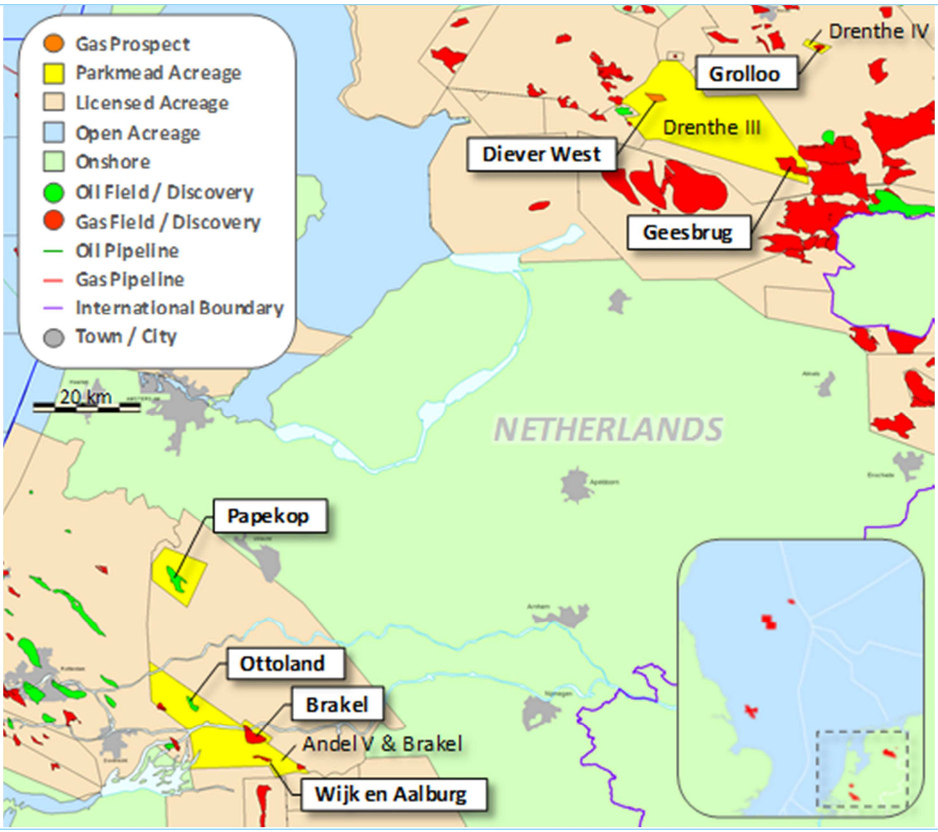
In November 2015, only 14 months after its discovery, Parkmead announced that the Diever-2 well was tied into local infrastructure producing commercial natural gas.

Natural gas prices in the Netherlands have essentially been linked directly to UK natural gas prices since 2013 as logistical infrastructure now allows for even modest price differentials to create arbitrage opportunities. We have therefore applied our UK natural gas price estimates (50p/therm or US$ 7.71/mcf in 2018, inflated at 2% thereafter) to value Parkmead's Dutch gas assets. Oil in the Netherlands trades on par with UK prices.

Parkmead's core Dutch oil & gas fields are held in four licence areas, Drenthe III (Diever West and Geesbrug), Drenthe IV (Grolloo), Brakel, Andel V (Ottoland and Wijk en Aalburg) and Papekop (Papekop). Each of the licences represents an autonomous entity for tax purposes.

A map of the fields and licence areas is provided in Figure 15.

Fig 15: Field and Licence Map in the Netherlands



Source: Parkmead

The company holds 15% working interests in each of the licence areas, although for all the licences excluding Papekop the effective revenue interest is 7.5% pursuant to a commercial agreement with NAM (a 50/50 joint venture between ExxonMobil and Shell).

The assets are 45% held by Vermillion Energy (TSX/NYSE listed with a market capitalisation of circa US$ 3.3 billion) who operates the licence areas and 40% by Energie Beheer Nederland (EBN), which is owned by the Dutch state.

We have not included any value for the company's exploration prospectivity in the Netherlands. However, the company has identified a prospect, De Mussels, in which it has a 7.5% effective interest as a potential near-term target. The stacked (Rotliegendes/Carboniferous) targets could discover 12 bcf (gross) based on the best estimate of recoverable resources on a pre-drill basis (assuming the fields are dip closed). We will include this in our valuation upon a successful discovery.

Detailed and updated cost analysis:

Vermillion Energy provided an updated drilling, completion, equip and tie-in gross cost estimate for wells in the Netherlands of US$ 10.4 million each in their November 2015 investor presentation. We have applied this estimate to all future wells.

Operating costs in the Netherlands are very low, particularly for highly efficient gas production. We have estimated operating costs based on US conventional onshore gas wells where infrastructure is abundant. We estimate that operating costs average circa US$ 2.69/boe (US$ 0.45/mcfe).

In our opinion, tax analysis is much more material than field operating costs to accurately value the company's Dutch assets. We estimate that the company's tax costs in the Netherlands will amount to US$ 12.33/boe (US$ 2.05/mcfe).

The Netherlands applies royalties to onshore licence areas that produce oil & gas over certain thresholds. We estimate that the Drenthe III licence will have production such that a modest (2%) royalty will be payable for a limited amount of time once the Geesbrug-2 well comes onstream.

The corporate income tax rate (CIT) is 25%. A supplemental state profit tax (SPS) is also payable and is a deductible expense for the purposes of determining corporate tax. Ultimately, the marginal tax rate on oil & gas production the Netherlands is approximately 50% *(source: Deloitte, Dutch Ministry of Economic Affairs)*.

Further deductions to the oil & gas tax base in the Netherlands come from a 10% uplift in costs for the purposes of calculating the supplemental state profit share tax.

Asset Description:

The productive horizon(s) for each of the assets is provided below.

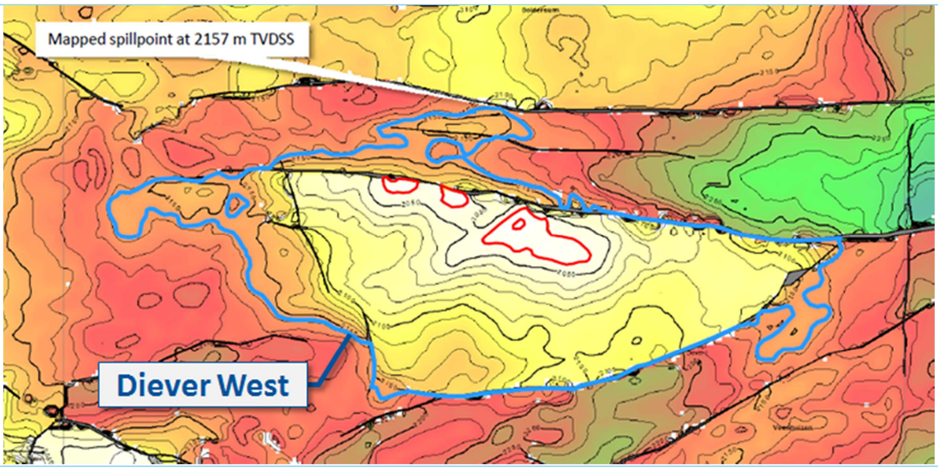
Fig 16: Productive Horizon by Field

Field	Productivie Horizon(s)
Brakel	Low er Triassic Bunter
Geesbrug	Carboniferous
Grolloo	Upper Carboniferous
Ottoland	Low er Triassic Bunter
Papekop	Middle Triassic Bunter
Diever West	Low er Permian Rotliegend

Source: Wood Mackenzie

The Diever West field is a classic fault and dip bound structure as seen in Figure 17. Due to the high quality 3D seismic data obtained over the discovery (which has been calibrated against the actual Diever-2 discovery well), and the known quality of the Rotliegendes reservoir, we believe that Diever West will be a low-risk and prolific natural gas field.

Fig 17: Diever West Structural Map

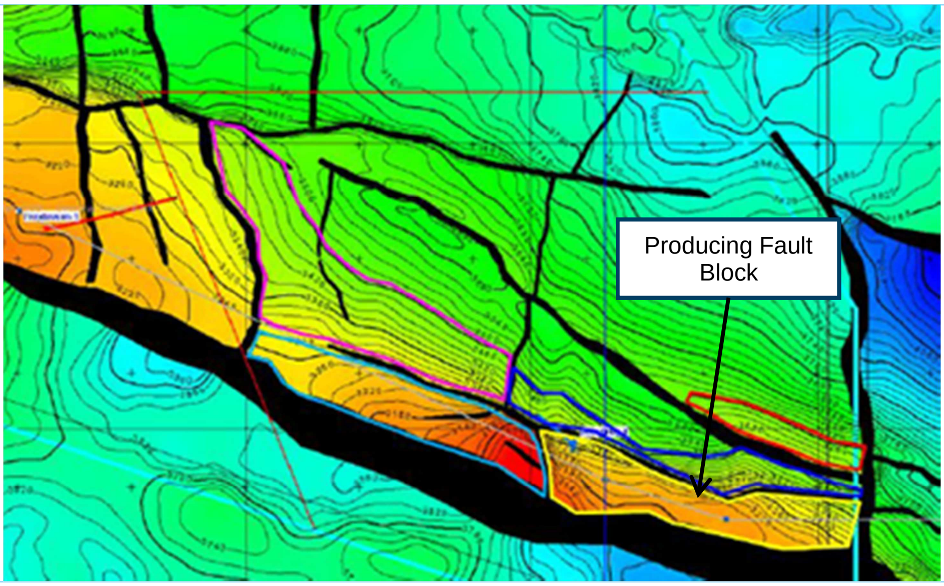


Source: Wood Mackenzie

We have only included the benefit of drilling a single additional well into the producing Geesbrug field, although we believe drilling additional wells would be feasible. The field is currently producing from a single well and we assume that a second well will commence production in C1H 2017.

Ultimately, additional wells at Geesbrug could be drilled to develop three additional fault blocks. It is currently anticipated that the next well drilled into the structure will target the South East Fault Block which contains the producing well, which is currently only accessing part of the gas contained within this fault panel. A structural map is provided in Figure 18.

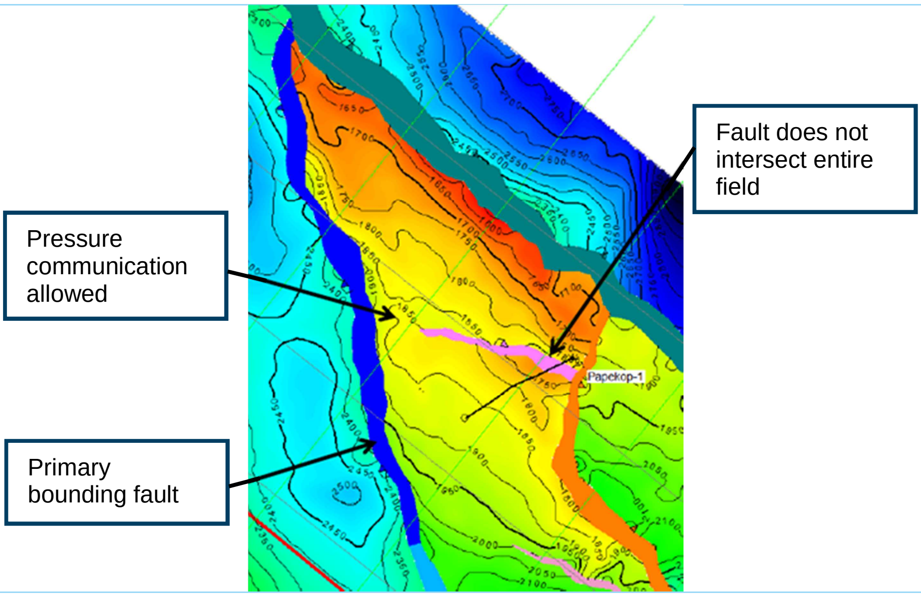
Fig 18: Geesbrug Structural Map



Source: Parkmead Group

The Papekop oil and gas discovery is bounded by three faults and a dip closure. We have assumed that the field is produced by a single well and that as such only two thirds of the recoverable oil & gas is produced. We believe that in due course another well will be drilled if the first well cannot deplete the recoverable resource by exceeding our assumed production profile. The well location of the discovery can be seen in the structural map below. We assume that Papekop provides first oil & gas production in C2H 2017. Due to the setting of the well location in a relatively populated area there is a possibility that planning and permitting may be delayed, in our opinion.

Fig 19: Papekop Structural Map



Source: Parkmead Group

Production profiles:

We have applied a 22% decline rate to all of the company's wells in the Netherlands. This is consistent with Vermillion Energy's average decline rate in the Netherlands (source: Vermillion Energy November 2015 Investor Presentation).

Economic Analysis:

In respect of the Netherlands, we have included only the value of discovered assets in our target price. However, the successful discovery of Diever West indicates that exploration in the area has the potential to create material shareholder value.

A detailed economic analysis is provided on page 5 of this note, which provides key assumptions, valuations, risking factors for our target price and breakeven commodity prices.

Athena

Overview:

Parkmead acquired a 10% interest in the Athena oil field through its acquisition of Lochard Energy Group Plc ("Lochard") which received court approval in July 2013. In April 2014, the company completed the acquisition of an additional 20% interest in the field from EWE Vertrieb GmbH ("EWE").

Parkmead's acquisitions of Athena were completed prudently so as to minimise cash outflows. Lochard Energy was acquired entirely for shares, which valued the acquired company at £14.5 million based on the prevailing Parkmead share price of 189 pence (factoring in the subsequent 15:1 share consolidation in December 2013). EWE's 20% equity interest in Athena was acquired for US$ 2.7 million of cash and 228,016 Parkmead shares (valued at £0.5 million at the date the acquisition was closed). The notional consideration for the EWE deal amounted to US$ 11.2 million (comprising US$ 8.0 million of cash and the remainder in shares); however, revenue generated by the field between the effective date of the acquisition and its completion reduced the actual cash and share considerations to just a fraction of the headline consideration amount.

For the purposes of valuing Athena we have assumed that the field will cease production in 1H 2016 *(the author of this note has not changed this assumption since his first equity research coverage of Parkmead).* We have therefore ascribed no value to Athena in our target price.

Based on our estimates, Athena will have recovered only 10% of the oil in place by 1H 2016, which is less than half of what is typically recovered from Lower Cretaceous oil fields in the North Sea. We believe that production from Athena did not reach maximum capacity for the following reasons: i) the field's development operator drilled a series of productive wells that were too close to one another, leaving much of the field undeveloped ii) the single water injector well currently does not provide optimal pressure support for the reservoir and iii) drilling fluid may be affecting reservoir contact at this time.

The field's four productive wells have electrical submersible pumps, which tend to have a useful life of two and half years each. The electrical submersible pump in the P4 well was replaced in 2H 2014, which required a rig intervention.

Partners in the field are Ithaca (22.5% and operator), Parkmead (30%), Dyas (17.5%), Jersey Oil & Gas pursuant to Trap Oil's reorganisation (15%) and Spike Exploration (15%).

Athena is located in the Outer Moray Firth approximately 135 km northeast of the Aberdeenshire coastline in water depths of circa 130-140m in the Central North Sea. The field lies approximately 35km to the north west of the Perth Field. Producing the Athena field via Perth would be significantly more economically attractive, in our opinion, than producing it through a relatively costly standalone FPSO.

Lochard, which was acquired by Parkmead in 2013, received US$ 12 million in funding to develop the Athena field from Gemini Oil & Gas Fund II ("Gemini"). In return, Lochard granted Gemini a royalty interest in respect of its 10% share in the field. The funding was provided on a non-recourse basis at the asset level. The royalty earned by Gemini consisted of 50% of the revenue from Lochard's 10% working interest in Athena until Gemini received cumulative revenues of US$ 14 million. After this, the royalty would reduce to 20% until Gemini receives cumulative revenues of US$ 24 million and after this, the royalty reduces to 5% until the field produces 20 million barrels of oil (gross). At this stage the royalty reduces once again to 2%. We estimate that Gemini will have received cumulative revenues of circa US$ 20 million in H1 2016.

Should Parkmead and its partners decide to relinquish the field in accordance with the timeline we have assumed (*no change to the author's prior assumption)* we believe the timing would coincide with the increase in gas production expected in the Netherlands, which has already started with 700+ boe/d from a single well net to Parkmead, generating revenue and positive cash flows from 2015 onwards.

Detailed and updated cost analysis:

Up until 30 June 2015, we believe that the cash operating costs for Athena have been in-line with expectations, generally speaking. This is because the bulk of the costs have related to the FPSO day rate (US$ 130,000 in the first calendar half of 2015). We estimate that additional daily operating costs amount to circa US$ 63,000 consisting of duty holder opex (61%), standby vessel costs (21%), diesel (5%), subsea inspection (3%) and other opex (10%), which includes maintenance, logistics and onshore support. When measured on a dollar per barrel basis, costs have risen as the field's production has declined.

Parkmead and its partners negotiated the reduction of the FPSO day rate to nil starting in C2H 2015. As part of this agreement the partners agreed to provide the FPSO owner, BW Offshore, with a profit share (which varies from a 40:60 to a 50:50 split in line with a ratchet mechanism based on crude oil prices). Additionally, the partners in the field agreed to pre-pay demobilisation costs of £12.9 million (gross) for the FPSO and to cover the demobilisation costs of insolvent Trap Oil, in return for additional equity in the Athena field.

The company and its partners had already effectively pre-paid for other relinquishment costs through the funding of an associated escrow account (Parkmead's current cash balances in escrow amount to £8.0 million).

The company expensed a large portion of the demobilisation and relinquishment costs in the last half of financial 2015, which is a non-cash accounting entry.

Our expectation is that that the total abandonment costs that have been factored into our valuation, US$ 61.2 million gross (US$ 19.5 million net), should be more than sufficient to cover related costs and potential options to re-use Athena infrastructure in the event that Parkmead brings Athena back into production by tying the field into nearby infrastructure at PDL (the Perth area FPSO). These balance sheet adjustments are fully reflected in our target price.

Economic Analysis:

Details of our economic analysis are provided on page 5 of this note.

We have ascribed no value to Athena in our target price.

Exploration

West of Shetland

Parkmead holds exploration targets West of Shetland, of which we believe Davaar is the centre-piece. Sanda North and Sanda South are obvious associated exploration targets that would be substantially derisked by success at Davaar. The prospects are located about 100 km west of the Shetland Islands in water depths of around 500m.

Our pre-drill best estimates of gross recoverable resources for Davaar, Sanda North and Sanda South are 175, 69 and 54 million barrels of oil respectively.

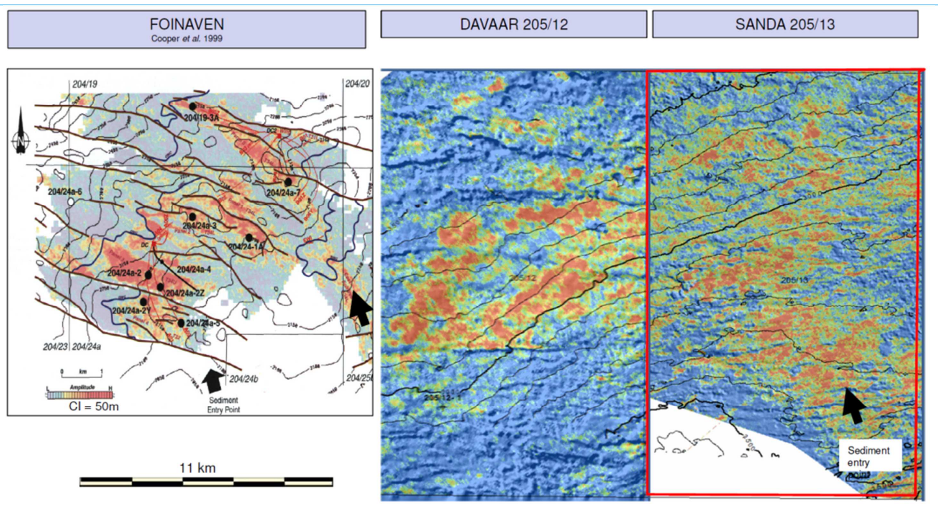
The Davaar prospect is held by Parkmead (30% and operator), Atlantic (30%), Dyas (14%) and Summit Petroleum (26%). The Sanda North and Sanda South prospects are held by Parkmead (56% and operator), Atlantic Petroleum (30%) and Dyas (14%).

The scale of these prospects is such that any success would be transformational for the company.

In a success case, Davaar and its associated satellite fields would be comparable to the BP operated Foinavan-Schiehallion-Loyal hub, where BP and its partners (Shell and OMV) commenced a back-to-back seven year drilling programme with a purpose built rig in April 2015. In total, the refurbishment of the hub is expected to involve a capital investment of £3 billion. The existence of that hub will allow for Davaar and its satellites to be developed using existing infrastructure on a cost-effective basis.

We have undertaken a detailed geological assessment of these assets and believe that the prospects share the same geology and direct hydrocarbon indicators as the neighbouring giant Foinaven field, which is now expected to produce 450 million barrels – twice the original estimate. We are particularly encouraged by the fact that Davaar, Sanda North and Sanda South exhibit the same seismic amplitude anomalies as Foinaven and that those anomalies tend to terminate at regional fault boundaries, which is symptomatic of the presence of hydrocarbons rather than a change in lithology (Figure 20).

Fig 20: Amplitude anomalies conform to faults



Source: Parkmead Group

Based on our detailed geological assessment of the prospects, we estimate that the geological chances of success for Davaar and Sanda North/South are 25% and 12.5% respectively.

We believe that major oil companies will remain interested in large scale capital projects in the West of Shetland area even as they withdraw from mature areas in the UK North Sea. A farm-out would represent a major price-material catalyst, especially if farm-out terms included a cost carry and/or the introduction of a major into the partnership.

The valuation on page 5 provides details relating to the value of Davaar.

Skerryvore

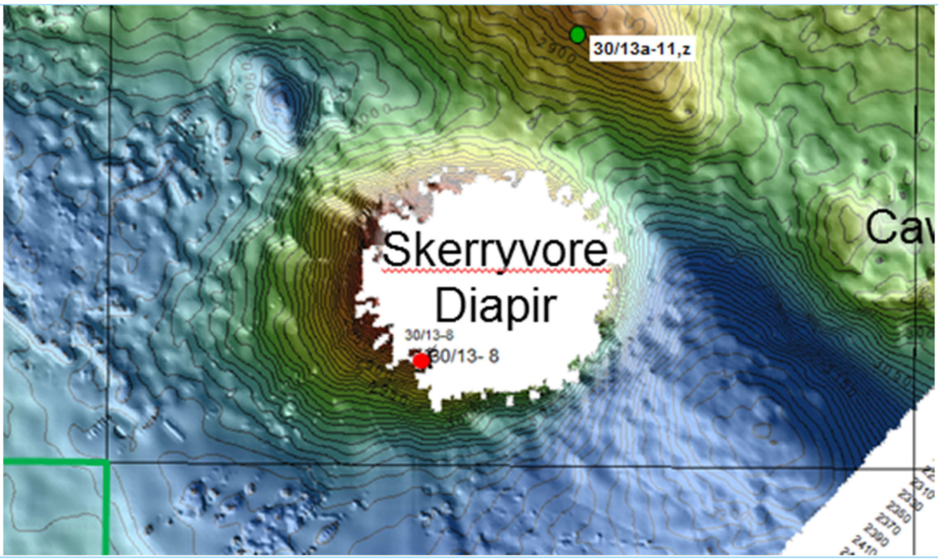
Skerryvore is located in the Central Graben of the Central North Sea, approximately 250km East of Aberdeen in water depths of circa 80m.

Skerryvore is an exploration prospect held by Parkmead (30.5%), Verus Petroleum (25%) and Dyas (14%).

The prospect is a stacked target, of which the principal target is the Upper Cretaceous Chalk, which we expect will produce 66 million barrels (gross) in a success case, based on our pre-drill best estimate.

The target is to the south-west of a salt diapir. The location of the salt diapir and the 30/13-8 exploration well are shown in the map below. Well 30/13-8 targeted the prospect but drilled updip of the pinch-out edge and missed the high-quality reservoir.

Fig 21: Skerryvore Diapir (Depth: Top of Mey Sands)



Source: Parkmead Group

The target is on the flank of a salt dome. From a geological perspective, it is similar thematically to the super-giant Ekofisk oil field (expected to produce circa 1.2 billion barrels of oil).

Based on our detailed geological assessment, we estimate that the field has a 38% chance of geological success.

The valuation on page 5 provides details relating to the value of Skerryvore.

Financial Analysis

The company has a 30th June financial year-end.

Parkmead had a cash balance of £41.1 million at 30 June 2015. Of that amount, we consider £8 million to be ring-fenced for the eventual relinquishment liabilities in respect of Athena, which is reflected in our valuation and target price. We expect that liability will only be payable when the field is conclusively abandoned after producing through the PDL hub facilities. The timing of abandonment costs have no bearing on our valuation or target prices as we consider these costs ring-fenced.

Parkmead has no debt having repaid the £4.7 million outstanding on an £8 million working capital facility in F2015. This facility is provided by Tom Cross and we consider it to be akin to a long-term stand-by facility that increases liquidity for the company.

At 30 June 2015, the company had trade payables of £14.6 million and trade receivables of £6.0 million, we have reduced our valuation and target price by the difference to reflect this liability.

The company holds 3.8 million shares in Faroe Petroleum, which we value at £2.0 million based on a Faroe Petroleum share price of £0.52.

We believe that Parkmead is very well positioned to access bank finance due to the prudent management of its balance sheet, its high quality assets and the track record of its management team.

The company completed a successful equity placing and debt for equity conversion in January 2013, providing finance for growth of £19.925 million (US$ 32.9 million). Of that amount, £15.925 million (US$ 26.3 million) was raised via an oversubscribed placing of 8.7 million shares at 183.75 p/share (allowing for a subsequent 15:1 share consolidation).

The company completed an oversubscribed equity placing for £40.0 million (US$ 66.0 million) in January 2014, offering 15.7 million shares at 255 p/share.

The company completed a successful equity placing for £13.4 million (US$ 21.1 million) in May 2015 in a period where very few oil & gas companies had access to capital. This placing was priced at 120 p/share, a 1.4% discount to the prior closing price.

Due to the nature of Parkmead's intended capital programme on its key assets there will be onward funding requirements. However, it is important to appreciate that the company is operator of its most capital intensive projects and that it therefore has discretion over capex timing.

We have provided detailed financial projections in the Financial Projections section.

Shareholder Structure

At 30 June 2015, the company had 98.9 million shares outstanding. At the same date the company had 7.8 million options and shareholder appreciation rights outstanding with an average exercise price of £1.62 p / share.

Fig 22: Significant Shareholders

Shareholder	(mn)	(%)
Tom Cross and affiliates	18.9	19.1%
Fidelity International	8.9	9.0%
BlackRock	4.6	4.6%
Hargreave Hale	4.1	4.1%
Polar Capital Partners	3.9	3.9%
Henderson Global Investors	3.6	3.7%
Legal & General	3.4	3.4%

Source: Parkmead Group

Directors

Tom Cross – Executive Chairman

Tom is a Chartered Director and petroleum engineer with extensive energy sector experience, spanning projects in more than 20 countries. Tom was the founder and Chief Executive of Dana Petroleum plc through until its sale to the Korea National Oil Corporation in 2010. Prior to Dana, he held senior positions with Conoco, Thomson North Sea, Louisiana Land and Exploration and was Director of Engineering at the UK Petroleum Science and Technology Institute. Tom is a former Chairman of BRINDEX, the Association of British Independent Oil Companies, a former adviser to the BBC on energy affairs and a Fellow of the Institute of Directors.

Ryan Stroulger – Finance Director

Ryan served as Commercial Director of the Group before becoming Finance Director. He has been responsible for identifying and driving forward numerous asset and corporate opportunities, such as the acquisitions of DEO Petroleum plc and Lochard Energy Group PLC. Prior to this, he served as Group Finance Manager, responsible for all aspects of Parkmead's external financing, from strategic planning through to successful execution. He is a member of the UK's Institute of Directors (IoD) and was awarded the Corporate Finance Qualification by the Institute of Chartered Accountants in England and Wales (ICAEW).

Dr. Colin Percival – Technical Director

Colin has more than 30 years of experience in the oil & gas industry. He began his career as a sedimentologist with BP in international operations and went on to lead a series of BP exploration teams evaluating various plays across the UKCS, which resulted in a number of significant discoveries. Colin was a member of the Dana Petroleum plc management team from 2003 to 2011, with responsibility for the technical work on all Dana operated assets and new ventures. He joined Parkmead in 2011, where he leads the Company's experienced exploration and technical group. Colin played a key role in Parkmead's success in the UKCS 27th and 28th Licensing Rounds.

Philip Dayer – Non-Executive Director

Philip has over 25 years of corporate finance, public company and stock market experience. He has worked with a number of prominent City institutions and advised a wide range of public companies including UK and international groups active in the oil and gas sector. Philip qualified as a Chartered Accountant and went on to gain extensive experience as Director or Head of Corporate Finance with Barclays de Zoete, Citigroup Scrimgeour Vickers, ANZ Grindlays and Société Générale. Latterly, whilst focusing on the energy sector, Philip was Director of Corporate Finance at Old Mutual Securities and Executive Director at Hoare Govett Limited. Philip was a non-executive director of Dana Petroleum plc from 2006 through to its successful sale.

Ian Rawlinson – Non-Executive Director

Ian has over 25 years of experience in the banking and investment industries and in advising public and private companies, including working with Lazard Brothers, Robert Fleming, Fleming Family & Partners and Dana Petroleum plc. Ian read law at Cambridge and was called to the Bar in 1981. From 1995 to 2000 he was a member of the senior management team of Flemings in Southern Africa, and was Chief Operating Officer of Fleming Family and Partners on its establishment in 2000. From 2005 he has held various independent appointments in the business and charitable sectors and was Executive Chairman of The Monarch Group from 2009 to 2014. Ian was a non-executive director of Dana Petroleum plc from 2005 through to its successful sale.

Financial Statements

It is known that commodity prices, acquisitions, dispositions, farm-outs, discoveries and unforeseen growth opportunities will evolve in ways that are not possible to predict. Investors should consider that our financial estimates are for indicative purposes only.

Balance sheet (£m)

Year to June	2013A	2014A	2015A	2016E	2017E
Cash and equivalents	13.3	46.3	41.1	37.1	12.3
Trade receivables	4.0	11.6	6.0	6.5	7.0
Inventories	-	-	-	-	-
Other current assets	-	-	0.2	0.2	0.2
Investments	4.4	4.8	3.3	3.3	3.3
Long-term assets	31.7	64.7	54.9	50.5	70.0
Total assets	**53.4**	**127.4**	**105.6**	**97.6**	**92.8**
Trade payables	8.7	8.0	14.6	14.6	14.6
Other current liabilities	0.4	0.5	0.4	0.4	0.4
Debt	2.0	6.2	-	-	-
Long-term deferred taxes	1.6	1.6	1.3	1.3	1.3
Other long-term liabilities	3.3	11.4	8.8	8.8	8.8
Total liabilities	16.0	27.7	25.1	25.1	25.1
Equity	37.3	99.7	80.5	72.5	67.8
Liabilities and equity	**53.4**	**127.4**	**105.6**	**97.6**	**92.8**

Income statement (£m)

Year to June	2013A	2014A	2015A	2016E	2017E
Revenue	**4.1**	**24.7**	**18.6**	**7.3**	**3.5**
Cash opex	(2.1)	(12.4)	(33.0)	(6.7)	(0.3)
Gross profit in cash	**2.0**	**12.3**	**(14.4)**	**0.7**	**3.2**
G&A costs	(7.7)	(5.7)	1.2	(2.1)	(2.2)
EBITDA	**(5.6)**	**6.6**	**(13.1)**	**(1.5)**	**1.0**
Depreciation	(0.7)	(9.0)	(6.4)	(5.3)	(3.9)
EBITA	**(6.3)**	**(2.4)**	**(19.5)**	**(6.7)**	**(2.9)**
Other	1.2	4.5	(13.2)	-	-
Financial expenses	(0.1)	(1.0)	1.9	-	-
Profit (loss) on investments	(0.0)	-	-	-	-
Income tax	(0.3)	0.2	(0.5)	(1.3)	(1.8)
Earnings	**(5.6)**	**1.2**	**(31.4)**	**(8.0)**	**(4.7)**
Minority interests	-	-	-	-	-
Earnings for shareholders	**(5.6)**	**1.2**	**(31.4)**	**(8.0)**	**(4.7)**

Cash flow statement (£m)

Year to June	2013A	2014A	2015A	2016E	2017E
Earnings	(5.6)	1.2	(31.4)	(8.0)	(4.7)
Depreciation	0.4	9.0	6.4	5.3	3.9
Other	3.5	(1.6)	6.5	-	-
Deferred tax	0.3	-	0.1	-	-
Cash flow from operations	**(1.4)**	**8.7**	**(18.4)**	**(2.7)**	**(0.8)**
Changes in working capital	(3.4)	(2.0)	15.1	(0.5)	(0.5)
Cash from operations	**(4.8)**	**6.7**	**(3.3)**	**(3.2)**	**(1.3)**
Disposals	0.7	-	-	-	-
Investments	(8.4)	(8.6)	(12.3)	(0.8)	(23.4)
Cash from investments	**(7.6)**	**(8.6)**	**(12.3)**	**(0.8)**	**(23.4)**
Cash from equity raised	15.6	39.5	13.0	-	-
Net cash from debt capital	2.5	(4.6)	(2.4)	-	-
Cash from financing	**18.1**	**35.0**	**10.6**	**-**	**-**
Net change in cash	**5.6**	**33.1**	**(5.0)**	**(4.0)**	**(24.7)**

Disclosures

WH Ireland Recommendation Definitions

Buy
Expected to outperform the FTSE All Share by 15% or more over the next 12 months.

Outperform
Expected to outperform the FTSE All Share by 5/15% over the next 12 months.

Market Perform
Expected to perform in line with the FTSE All Share over the next 12 months.

Underperform
Expected to underperform the FTSE All Share by 5/15% or more over the next 12 months.

Sell
Expected to underperform the FTSE All Share by 15% or more over the next 12 months.

Speculative Buy
The stock has considerable level of upside but there is a higher than average degree of risk.

Share Price Target

The share price target is the level the stock should currently trade at if the market were to accept the analyst's view of the stock and if the necessary catalysts were in place to effect this change in perception within the performance horizon.

Stock Rating Distribution

As at the quarter ending 31 Dec 2015 the distribution of all our published recommendations is as follows:

Recommendation	Total Stocks	Percentage %	Corporate
Buy	53	73.6	40
Speculative Buy	15	20.8	14
Outperform	1	1.4	0
Market Perform	1	1.4	1
Underperform	1	1.4	0
Sell	1	1.4	0
Total	72	100	55

This table demonstrates the distribution of WH Ireland recommendations. The first column illustrates the distribution in absolute terms with the second showing the percentages.

Conflicts of Interest Policy

This research is classified as being "non-independent" as defined by the FCA's Conduct of Business Rule 12.3. Please refer to www.wh-ireland.co.uk for a summary of our conflict of interest policy.

Analyst Certification

The research analyst or analysts attest that the views expressed in this research report accurately reflect his or her personal views about the subject security and issuer.

Companies Mentioned

Company Name	Recommendation	Price	Price Date/Time
Vermillion Energy	N/A	36.03	17:55 01 February 2016

Share Price Date/Time

Company Name	Recommendation	Price	Price Date/Time
Parkmead	BUY	52.0	17:55 01 February 2016

Summary of Company Notes

Headline: Accelerated Dana - Initiation	**1 February 2016**

Summary of Security Recommendations

Recommendation	From	To	Analyst
Buy	1 February 2016	n.a.	CA

Current Analyst (CA), Previous Analyst (PA)

WHIreland

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