Company Note

Initiation & interims

29 September 2020

Corporate

Current price	27.0p
Sector	Oil & Gas
Code	SLE.L
AIM	AIM

Share Performance

	1m	3m	12m
SLE.L	-2.4%	+21%	-12.1%

Source: Fidessa, Allenby Capital

Share Data

Market Cap (£m)		135.1m
Shares in issue (m)		449.9
52 weeks	High	Low
	29.9p	11.1p
Financial year end		31 December

Source: Fidessa, Allenby Capital

Key Shareholders

Toscafund Asset Mgt LLP	50.85%
Oisín Fanning	23.89%
Midwestern Oil & Gas	13.18%

Source: Company Data, Allenby Capital

Peter J Dupont

0203 002 2078

p.dupont@allenbycapital.com

www.allenbycapital.com

Equity Research

San Leon Energy plc (SLE.L)

Powerful cash flow

SLE is a Nigeria focused mid-tier E&P independent. Its strategic move into the country in 2016 has been a great success story. Initially a significant indirect interest was secured in the operator of the Niger Delta licence OML 18. Meanwhile, substantial cash flow has derived from high yield loan notes obtained at the time of the acquisition. The OML 18 move has been followed by two recent investments which again focus on near-term cash flow. These are the interests taken in the new ACOES export pipeline linking the core of the OML 18 operations with an offshore FSO and in the Oza field development project in the northern Niger Delta. High yield debt is a feature of both investments. The stock is selling on an EV of a mere £29m net of cash and financial receivables. This implies that the equity interests in OML 18 and the ACOES pipeline are being assigned little value. Based on our sum-of-the parts calculation our valuation is 82p/share. Note SLE is leveraged to a potential recovery in oil prices in the coming months.

- **OML 18:** SLE has a 10.58% initial indirect interest in the OML 18 licence in the southern Niger Delta region via the 40% owned MLPL holding company. Eroton, the operator, led a $1.1bn buyout of 45% of the licence from a Shell operated consortium in 2015. Presently, the direct ownership interests in OML 18 are: NNPC (Nigeria state oil company) 55%, Eroton 27% and two indigenous companies 18%. SLE's indirect interest is through MLPL's indirect shareholding in Eroton. SLE has two members on the Eroton Board.

- **Reserves and production:** The Niger River Delta Province, is one of the world's largest petroleum systems. OML 18 lies at its heart and as per the 2016 CPR had 2P reserves of 1,112mm boe. The underlying oil production rate is 50,000 b/d but deliveries currently are nearer to 25,000 b/d reflecting OPEC quotas and losses and downtime on the export pipeline. The new ACOES pipeline should sharply cut delivery shortfalls. OML 18 production has the potential to reach 100,000 b/d with development.

- **Cash flow:** SLE's cash flow currently derives largely from its OML 18 high-yield (17%) loan notes. Between 2017 and August 2020 SLE received $191m in principal and coupon payments. Another $90m, approximately, is payable by end 2021. The payments are guaranteed by an influential member of the OML 18 consortium. The $15m investment in ACOES is through high-yield (14%) loan notes. SLE has recently announced a $7.5m investment via high yield (10%) debt and a 15% stake in Decklar Petroleum (subsidiary of TSX-V Decklar Resources) which is undertaking the development of the Oza field.

- **Valuation**: We have adopted a hybrid sum-of-the parts approach to valuation. In the case of the current cash balance and the financial receivables relating to OML 18 and the ACOES pipeline, we have valued these items dollar for dollar. Regarding the equity interests in OML 18 and Decklar, our valuation basis is price/boe multiplied by net reserves. We have used $3/boe and $1.5/boe for 2P reserves and 2C resources respectively. Our valuation overall is $482m or £371m, equivalent to 82p/share.

Year End: 31 December					
($'000)	**2018**	**2019**	**2020e**	**2021e**	**2022e**
EBITDA	(33,226)	(15,625)	(36240)	(11952)	(10270)
CASH FLOW (pre financing)	40,114	27,746	16649	72947	(1876))
NET CASH	40,762	36,697	20346	93293	91417

Allenby Capital acts as Nomad & Broker to San Leon Energy plc (SLE.L).

TABLE OF CONTENTS

Profile and background

Overview

Key assets are a 10.58% interest in OML 18 and high-yield loan notes: San Leon Energy (SLE) is an AIM listed oil and gas development and production company headquartered in Dublin. Presently, the company's key assets are its 10.58% initial indirect interest in the OML 18 River Niger Delta licence in south east Nigeria and the loan notes acquired at the time the investment was concluded in September 2016. Recently San Leon added to its Nigerian assets significantly. On August 3 the company announced a 10% stake in a new export pipeline in the Delta region. This was followed on September 1 by the announcement of planned 15% interest in Decklar Petroleum Ltd which is undertaking a major development of the Oza field towards the northern margin of the Niger River Delta Petroleum Province. The OML 18 investment has proven to be an inspired move and an excellent generator of cash via the loan notes. Public statements suggest Nigeria is likely to remain at the heart of San Leon's investment interests for the foreseeable future.

Mid-tier rather than a junior: With a market capitalisation of £115m ($161m) in early September 2020, San Leon arguably ranks as a mid-tier rather than a junior E&P concern. The company was founded in 2007 and was listed on AIM in late September 2008, against the challenging backdrop of the global financial crisis. The founders were a group of experienced oilmen and financiers including the current CEO, Oisín Fanning.

Shareholders

Tightly held shareholder base: San Leon Energy has a tightly held shareholder structure. As of late July-2020 the three largest shareholders owned 87.92% of the company with interests as follows: Funds managed by Toscafund Asset Management 50.85%, Oisín Fanning 23.89% and Midwestern Oil and Gas Co Ltd 13.18%. According to the 2019 Annual Report, there were no other shareholders owning 3% or more of the stock.

Toscafund owns slightly over 50% of the stock: Toscafund's involvement in San Leon as a significant shareholder stemmed from its holding in Aurelian Oil & Gas, the acquisition of which was completed in January 2013. At the end of 2012 the Annual Report showed Toscafund as owning 4.39% of the stock. The Toscafund's stake rose to 21.08% at the end of 2013 and to a recent high of 72.41% at end 2019. In a related company transaction on May 7, 2020 Toscafund sold Oisín Fanning 98.0m shares resulting in the shareholdings as indicated above. It should be noted that Toscafund was instrumental in financing San Leon's acquisition of the 10.58% initial interest in OML 18 in September 2016.

Midwestern, an influential OML 18 consortium member, owns over 13%: Midwestern Oil and Gas Ltd is an indigenous oil and gas company based in Nigeria owned by private individuals and the Delta State government. It is a very influential company in terms of the OML 18 consortium and apparently has significant oil production. Midwestern owns 70% and is the operator of the Umusadege Marginal Field located on OML 56 in Delta State. Since being awarded the licence in 2003, production has been boosted from about 3,000 b/d to 20,000 b/d according to San Leon. Midwestern and San Leon Energy own 60% and 40% respectively of the Mauritius holding company, Midwestern Leon Petroleum Ltd (MLPL). This, via the intermediate Nigerian holding company Martwestern Energy Ltd, currently has an initial 98% economic interest in the OML 18 operator, Eroton Exploration and Production. Midwestern's shareholding in San Leon Energy originates from 2018.

Headcount

San Leon's headcount is modest reflecting its role currently as essentially an investor and technical advisor rather than an operator of production assets. Based on the 2019 Annual Report, the average headcount including directors was 24, down 23% on the previous year. Employment costs in 2019 were $7.0m equivalent down 5% in absolute terms on a year earlier. Per head costs were $292,000.

Management

San Leon's management comprises a group of highly experienced petroleum industry professionals with a mix of backgrounds in technical, financial, commercial and administrative roles.

Mutiu Sunmonu, Non-Executive Chairman: Mutiu Sunmonu has been the San Leon Non-Executive Chairman since September 2016 following the acquisition of the indirect interest in OML 18. He is a former managing director of the Shell Petroleum Development Co (SPDC) and was Shell Nigeria Country Chairman from 2008 to February 2015. In this role he had a headcount of over 4,000. He has worked in the petroleum industry for over 36 years in Nigeria, UK and the Netherlands. Mutiu Sunmonu brings to San Leon a deep knowledge of Nigeria and valuable operating experience and relationships. He is also a member of the Board of Eroton, the OML18 operator. Mutiu Sunmonu holds a BSc in Mathematics and Computer Science from the University of Lagos.

Oisín Fanning, CEO: The longstanding CEO/Executive Chairman, is a founder of San Leon and has recently become a substantial shareholder in the company. He also sits on the board of Eroton Exploration and Production, the OML 18 operator and was the driving force behind the move into Nigeria. Oisín Fanning has an earlier background in stockbroking and corporate finance specialising in the oil and gas industry. Key highlights in his earlier career were the restructuring of Dana Petroleum in the early 1990's and the broking of Tullow Oil in its growth phase. The San Leon website describes Oisín as both a visionary and a practical person pursuing business goals on behalf of stakeholders.

Joel Price, COO: Joel Price was appointed to the Board as COO in September 2016. He joined San Leon via the Aurelian acquisition in 2013 and has academic backgrounds in both petroleum engineering and geology. Joel Price has broad operational, technical and commercial experience in the petroleum industry over 25 years. A highlight of his career was directing the drilling of the first horizontal multi-stage fracked wells in Poland. He has worked for both juniors and mid-tier E&P independents including Hess and Delta Hydrocarbons BV. Joel Price holds a BA (Hon) in Natural Sciences (Geology) from Cambridge University, an MEng Petroleum Engineering from Heriot-Watt University and an MBA from Durham University. Joel is a member of the Society of Petroleum Engineers (SPE) and a member of the Association of International Petroleum Negotiators (AIPN). He is also a member of the board of Energy Link Infrastructure (Malta) Ltd in which San Leon recently took a 10% stake and which owns the new ACOES pipeline.

Lisa Mitchell, CFO: Lisa Mitchell was appointed CFO in June 2019. She has over 25 years' experience in the finance function across the oil and gas, mining and pharmaceutical industries. Prior to joining San Leon, Lisa was the CFO and Executive Director of Lekoil (AIM: LEK) the Nigeria and Namibia focused E&P junior. Previously she was the CFO and Executive Director at Ophir Energy (LSE: OPHR) and had broad finance responsibility, including taxation, treasury and investor relations. At earlier stages in her career Lisa had finance roles at CSL Ltd and Mobil Oil Australia. Lisa is a Certified Practicing Accountant (CPA Australia) and holds a Bachelor of Economics degree from La Trobe University, Melbourne.

Alan Campbell, Director of Commercial & Business Development and Company Secretary: Alan Campbell joined San Leon in September 2010 following the acquisition of Island Oil & Gas Ltd. He was appointed to the Board in the above capacity in September 2016. Alan Campbell has 18 years' investment banking and oil and gas experience. He has expertise in commercial evaluation, strategy formulation and project management. Alan Campbell holds a Master's in Project Finance & Venture Management from the University of Ireland and a Bachelor Business degree from the Waterford Institute, Ireland. He is also a member of the AIPN.

Linda Beal, Independent NED: Linda Beal was appointed in January 2018 and has over 30 years' experience with PwC, including as a partner, specialising in the natural resources sector. She has extensive experience advising groups with African assets. Linda Beal is a Chartered Accountant and holds a degree in Mathematics from Nottingham University. She is currently a Non-Executive Director at Kropz plc, Orca Exploration Group Inc and i3 Energy plc.

Adekolapo Ademola, NED: Adekolapo Ademola, appointed in April 2020 is a marketing and business strategy specialist with over 30 years' experience, including oil and gas. He brings valuable regional knowledge, expertise and relationships to San Leon. Adekolapo Ademola is a Business Management graduate from the University of Jos, Nigeria.

European exploration focus, 2008-13

Several acquisitions post IPO: Prior to 2015, San Leon's strategy had been to focus on a combination of potentially high-impact exploration opportunities and lower risk development projects. The company was acquisitive between 2008 and 2013 with the key moves being as follows:

- Gold Point Energy Corporation in 2009. This provided shale acreage in the Baltic Basin, Poland.
- Island Oil & Gas in 2010. This provided exploration interests offshore Ireland, on and offshore Morocco and royalty interests in the Netherlands.
- Realm Energy International in 2011. This provided further Baltic Basin acreage.
- Aurelian Oil & Gas in 2013. This was the largest acquisition and provided exploration, development and modest production interests principally in Poland and Romania. Significantly Aurelian also brought cash resources and technical skills.

Pioneering shale gas activity in Poland: Post the Aurelian acquisition, San Leon had established a diverse portfolio of assets in low-risk jurisdictions in Europe and Morocco. Its onshore land position of about 49,560 km² was one of the largest in Europe. The company in the 2008-2015 period was perhaps best known for its pioneering natural gas development work in both conventional and unconventional shale formations in Poland. San Leon's unconventional programme in Poland has been the largest in terms of drilling intensity in Europe.

Move into Nigeria 2015/16

Fundamental change of strategy in 2015-----: Oisín Fanning announced a fundamental change of strategy in 2015 both operationally and geographically. The new policy emphasised development and production assets and near-term cash flow rather than exploration and the geographic focus switched from Europe to Nigeria. The drivers for the new strategic stance reflected three key factors as follows:

- A desire to opportunistically seek new business opportunities in the wake of the collapse in oil prices in the second half of 2014.
- A desire for a shorter cycle and lower risk route to cash flow than via exploration.
- A desire to reduce the heavy overhead burden of operating a diverse exploration programme across several jurisdictions. We note that in 2014 the administrative overhead was a hefty €16.9m or $19.4m.

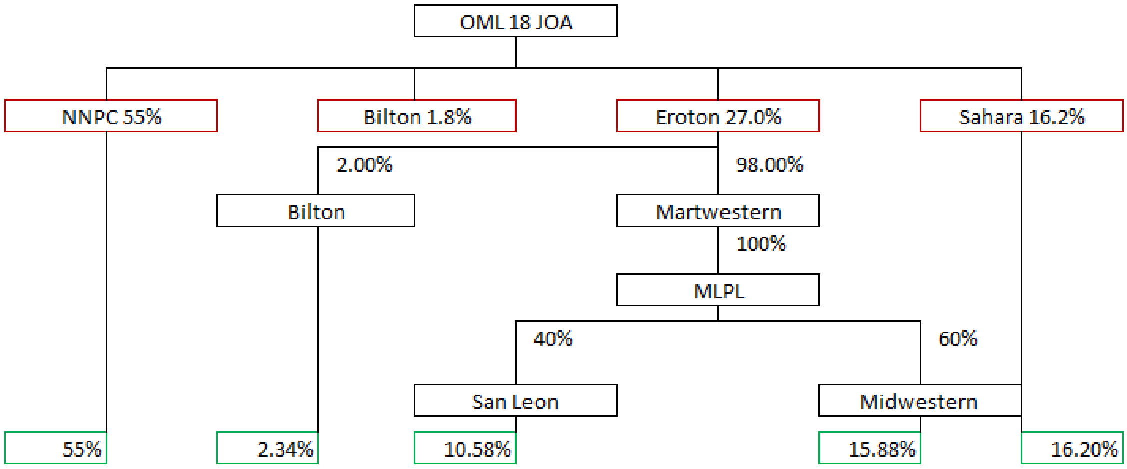
---------**followed by the move into Nigeria and the OML 18 investment:** Following the change of strategy, San Leon made a transformational move in 2015 consistent with its objective of gaining access to production and cash flow. This involved the acquisition of an initial indirect economic interest of 9.72% in the Nigerian OML 18 oil and gas production licence in the River Niger Delta Region of south east Nigeria. Subsequently, the economic interest increased to 10.58% reflecting a reassessment of the interests of the OML 18 consortium members. The deal was concluded in September 2016 and cost $174.5m. It followed two key developments:

- Acquisition for $1.1bn by an Eroton Exploration and Production Ltd led consortium of a 45% interest in OML 18 in 2015. Previously this licence had been operated by a Shell in a consortium that included Total, ENI and the state oil company NNPC.
- An apparent willingness of TSX-V listed Mart Resources, an indirect member of the Eroton consortium, to sell its stake.

Complicated route to joining the OML 18 consortium involved-----The route to concluding the deal was complicated and involved several stages in restructuring the ownership of Eroton Exploration and Production. The first involved the creation of a special purpose Mauritius-incorporated acquisition vehicle, Midwestern Leon Petroleum Ltd (MLPL). This was established to hold the combined interests of San Leon Energy and Midwestern Oil and Gas in the Nigerian holding company Martwestern Energy which in turn owns 98% of Eroton currently and 50% prospectively. Martwestern was originally owned 40% by Midwestern, 40% by Mart Resources and 20% by another Nigerian company, SunTrust. The Mart Resources interest in Martwestern was acquired by Midwestern and contributed to MLPL. The SunTrust interest in Martwestern was acquired by MLPL.

-----**establishing with Midwestern the MLPL holding company which controls the operator Eroton:** The upshot was that MLPL and Martwestern were both owned 60% by Midwestern and 40% San Leon. Martwestern presently has a 98% economic interest in Eroton which implies 39.2% for San Leon. Given Eroton's 27% direct interest in the OML 18 consortium, San Leon's indirect interest is 10.584%. It should be noted, however, that this will drop to 5.4% once Martwestern's interest in Eroton falls to the scheduled 50%. The other 50% is owned by a private indigenous Nigerian company, Bilton which also has a 1.8% direct interest in OML 18. Bilton's entry costs into the consortium were free carried by other members. Once various production and financial objectives are achieved Bilton's economic interest in Eroton will rise to 50%. We understand that this will be well into the future and probably not before ten years as the full carry plus a coupon will first need to be repaid.

Exhibit 1: OML 18 consortium initial economic interests



Source: Company and Allenby Capital.

Note: Boxes in red are direct shareholdings in OML 18; boxes in green are direct and indirect shareholdings in OML 18; JOA is Joint Operating Agreement

San Leon became the holder and beneficiary of high yield loan notes issued by MLPL: Importantly, the deal to acquire the indirect economic interest in Eroton also involved San Leon becoming the holder and beneficiary of the loan notes issued by MLPL to finance the acquisition. The par value was $174.5m and the coupon 17.0%. The acquisition was financed via a $221m San Leon share placing made in September 2016. Simultaneously San Leon and MLPL entered into a loan note repayment agreement that established a schedule for reimbursing principal and interest to the former. Between 2017 and end 2019 San Leon received $149.1m in principal and interest. A further $41.5m was paid in April 2020 which brought the running total to $190.6m.

San Leon has indicated that post the May payment the outstanding balance of principal on the loan notes was $82.1m. A further $10m payment is scheduled for October 2020. Earlier in 2020 the term for repaying the loan notes was extended to end 2021 with three payment dates scheduled in the second half in July, October and December. Payments of principal on these three dates will therefore be $24m.

The loan notes should contribute about $281m by end 2021: Including coupon interest at 17%, we estimate that the balance of all payments on the OML 18 loan notes is around $90m. This would bring the total contribution of the loan notes to about $281m of which $117m is interest.

Midwestern acts as guarantor for the loan notes: Originally the expectation was that payments under the San Leon-MLPL loan note agreement would be financed by Eroton dividends. In practice, Eroton has not been sufficiently profitable for this to occur, given also the need to pay down an RBL (reserve-based lending) facility so resort has had to be made to the guarantee clause in the MLPL loan note agreement. The guarantor is Midwestern Oil and Gas, a company with close links to Eroton and other members of the OML 18 consortium. Note, Midwestern and Eroton have a common chairman and Midwestern is the third largest shareholder in San Leon Energy.

What the OML 18 deal has provided

San Leon's OML 18 deal initially had four key attributes. These are as follows:

- Near instant gratification reflecting the cash flow stemming from the MLPL loan note agreement remembering here the high-yield coupon.

- Acquisition of a significant initial 10.584% economic interest in nine oil and gas fields in a world class petroleum system with considerable upside development potential. Deliverable production is currently running at 25,000 b/d to 30,000 b/d but is conceptually capable of over 100,000 b/d with development. Note, San Leon can influence events given its two seats on the Board of the operator, Eroton Exploration and Production and its right to nominate a senior technical manager and provide the head of the Finance Committee.

- Reflecting the above, access to a potentially large source of cash flow via Eroton and MLPL, assuming successful development of the OML 18 fields and a positive trend in commodity prices. Given San Leon's indirect shareholding, free cash flow at Eroton will need to be funnelled through to MLPL via dividend payments.

- The right to sell oilfield services to Eroton under a Master Services Agreement subject to competitive and anti-corruption considerations. This will probably largely revolve around sub-contract drilling. The San Leon oilfield services operation is still embryonic but could gain in significance, if drilling activity regains momentum at Eroton. Sub-surface consultancy services are already provided to Eroton separately.

San Leon acquires stake in new Nigerian export pipeline

10% equity interest in new ACOES export pipeline-----At the beginning of August 2020 San Leon announced an important strategic move that will strengthen its oil and gas interests in Nigeria and provide a near-term source of cash flow. The move concerned San Leon taking a 10% equity interest in the Malta-based holding company, Energy Link Infrastructure (Malta) Ltd (ELI). This owns the new 100,000 b/d ACOES (Alternative Crude Oil Evacuation System) export pipeline from the Niger Delta to an offshore FSO (floating, storage and offloading) vessel over a distance of about 60 km. We understand construction work is at an advanced stage with operations potentially commencing by end 2020. Midwestern Oil and Gas is indirectly a shareholder in ELI.

------using high-yield loan notes: In addition to the equity stake, the investment also included a $15m shareholder loan payable in two tranches. The first for $10m was in early August and the second for $5m is scheduled for October 2020 following an expected payment for $10m from MLPL. The loan has a coupon of 14% and a maturity of four years. Repayments of principal will commence on the first anniversary of loan and will be made quarterly along with coupon payments. The financial structure looks attractive with a payback of significantly less than four years allowing for the coupon. Note, the 10% working interest derives from granting the loan much in the same way as for the investment in Eroton.

Clearly, the elevated coupon reflects a combination of country and company credit risk, remembering that ELI is an unknown entity. The key near-term risk concerns the potential for delays in completing the pipeline and hence shortfalls in revenue for the pipeline operator, ELI.

Potential sharp drop in pipeline losses due to theft and downtime: Strategically the new pipeline resolves a major problem for the OML 18 Niger Delta production consortium, of which San Leon is a part. This concerns delivery losses with the existing export arrangements via the surface Nembe Creek Trunk Line (NCTL) to the Bonny Terminal associated with downtime due to theft, vandalism and technical issues. Very approximately, losses due to these factors might run to 35-40% which acts as a major depressant on OML 18 cash flow and profitability. The new pipeline, which will run under the bed of the Cawthorne Channel and the Bight of Bonny, should largely eliminate production losses and downtime in so doing greatly enhance the ability of the OML 18 operator to pay dividends. Note, the pipeline will also be available to third parties.

San Leon investment in Decklar Petroleum Ltd

The deal

Following hot on the heels of the ELI/ACOES pipeline deal, San Leon announced on September 1, 2020 another important strategic move in Nigeria. This time it concerned an investment in Decklar Petroleum Ltd, the Nigerian oil and gas arm of TSX-V listed Asian Mineral Resources (TSX-V:ASN, market capitalisation C$16m). Asian Mineral Resources acquired 100% of Decklar in July 2020 for C$8.55m in an all paper deal. Reflecting the metamorphosis of Asian Mineral Resources from a mineral exploration company focused originally on a Vietnam nickel project and more recently the British Columbia Holt gold-silver-copper project to a Nigerian oil and gas business, the company changed its name on September 9, 2020 to Decklar Resources. Its symbol on the TSX-V is DKL.

Decklar Petroleum's only asset is a Risk Sharing Agreement (RSA) covering the Oza field in Abia state in the northern Niger Delta region. Through the RSA, Decklar has an 80% economic interest in Oza. The RSA is with Millennium Oil & Gas Co, the operator and the original owner of the Oza field. Decklar is undertaking a major development of Oza and is responsible for all operational and other costs. In exchange, Decklar is entitled to priority recovery of its capital from 80% of distributable funds. This declines to 40% once production exceeds 10mm barrels.

San Leon's investment in Decklar comprises two component parts. Firstly, through the purchase of $7.5m of high yield (10% coupon) Decklar unsecured subordinated loan notes and secondly via taking a 15% equity interest in Decklar itself for the equivalent of $4,600. The latter clearly reflects nominal consideration.

The deal includes an option to increase San Leon's equity interest to 30% subject to Decklar drilling results. The option agreement would entail purchasing a further $7.5m high yield loan notes plus the equivalent of $6,500 for the equity. San Leon has sole discretion over triggering the option agreement and can do so 45 days after the well test results of the first development well on the Oza field.

The loan notes have a maturity of five years. Payments are scheduled to be made quarterly. Unlike the OML 18 loan note deal there is no guarantor for the payments on the notes but San Leon does have a cash sweep facility relating to all available funds in Decklar until the principal and coupon payments are made. The subscription agreement with Decklar is expected to become effective by September 30, 2020. San Leon will have the right to one seat on the Decklar Board.

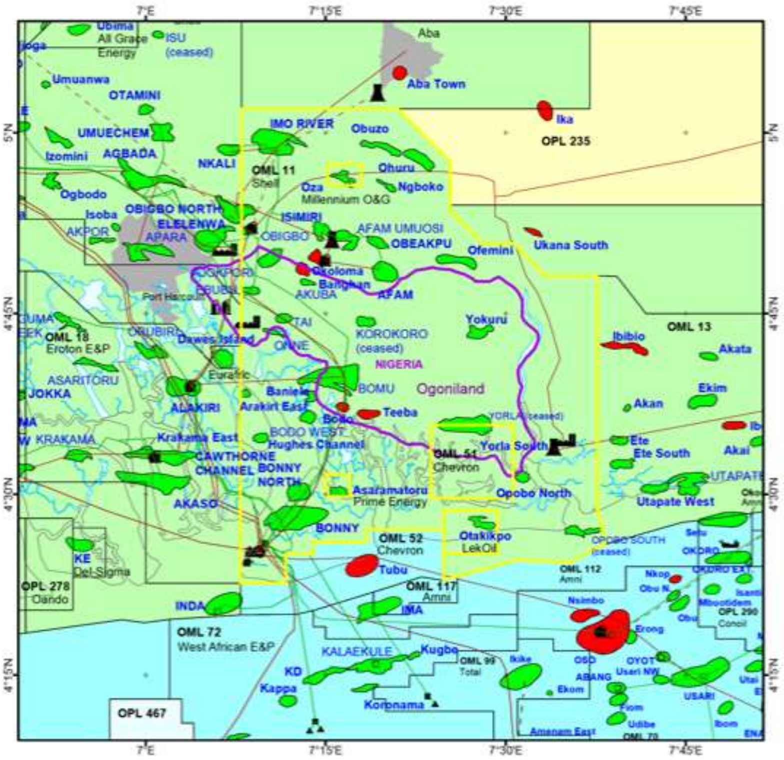
To help fund the work programme in the meantime San Leon has forwarded an initial deposit of $750,000. If a subscription agreement is not reached by September 30, 2020, Decklar will be required to repay the amount within three months.

The asset

History: The Oza field is located on dry ground towards the northern margin of OML 11 about 100 km north east of the OML 18 operations. It covers about 20 km². The field was discovered by Shell in 1959 and three wells and one side-track were drilled between then and 1974. Shell undertook some test production during this period but did not undertake commercial development. Cumulatively around 1mm barrels have been produced from Oza, according to Asian Mineral Resources/Decklar. Significantly, well tests on two wells have run at 2,000 boe/d yielding high quality 35-43° API gravity oil.

The Oza field was acquired by Millennium Oil & Gas in 2003 as part of Nigeria's marginal field development programme. The marginal field concept was conceived in the early 2000s and related to fields owned by the international oil companies which had laid dormant for more than ten years. With the agreement of the IOC, marginal fields were then awarded by the regulatory authorities to indigenous companies. Millennium spent about $45m in recent years on new infrastructure including pipelines, metering systems and production facilities. The field is now linked to the Trans Niger Pipeline and the Bonny Island export terminal.

Exhibit 2: Location of Oza field



Source: Decklar Petroleum

Resources and reserves: Oza is surrounded by other fields. The petroleum system in the region is therefore well understood and is based on multiple stacked reservoir sands generally accessed by vertical wells. Reserves for Oza have been given by Decklar Petroleum as 2.6mm barrels gross for 2P. There are also 23mm barrels of contingent and 10mm barrels of prospective resources respectively. The 2P reserve position is modest but given the prospectivity of the region and significant resources is probably capable of expansion with infill drilling.

Well production potential: Key indicators suggest that Oza field wells should be capable of production of several thousand barrels per day. The conclusion is supported by well test results, production performance elsewhere in the Niger River Delta Petroleum Province and the presence of multi-stacked sandstone reservoir formations.

Oza development plan: According to the Asian Mineral Resources' August 2020 presentation, Decklar is planning to fast track a major development programme at Oza. This will be financed in part by San Leon and in part by Millennium supported by a Nigerian bank and the trading arm of a major oil company. All told, the financing available could be up to $26m from the two sources.

Initially the plan is to re-enter the existing Oza-1 well and test two of the three oil-bearing zones. The third zone is expected to be laterally drilled. Subsequently the well will be brought on-stream. The indications are that production can be brought on-stream within three to four months of the commencement of workovers and drilling. Assuming work commences in early October following the drawdown of cash this would probably imply early to mid-first quarter 2021. Over the next six to 12 months the development programme outlined by Decklar is scheduled to include workovers of the three existing wells plus one new development well. We believe workovers could cost $2.5-3.0m depending on the condition of the well while completed well costs based on intimations from San Leon are about $8.5m.

Following the initial Oza-1 workover and side-track, we believe production could run at about 2,000 b/d. Assuming success with the remaining workovers and a development well we think production might climb to around 8,000 b/d by late 2021. Note, the new 15,000 b/d production processing facilities already installed at Oza should be capable of handling this volume. The second phase of the Oza development programme possibly commencing in 2022 could see the drilling of another two or three development wells, according to Asian Mineral Resources/Decklar. This could conceivably take production to around 15,000 b/d. At $45/barrel Brent the implied annual revenue would be $246m. Note that as a marginal field Oza would attract a more favourable fiscal regime than mainstream fields. This applies particularly to federal royalties which for production up to 5,000 b/d are 2.5% against 20%. In addition, there is an overriding royalty of 3% payable to the owners of the licence.

Rationale for the Decklar/Oza investment

The proposed investment in Decklar Petroleum is consistent with San Leon's key strategic objectives. These are near term cash generation, low technical and financial risk and the potential for material long term returns. The Decklar deal provides near term cash flow via the high-yield loan notes. Financial risk is mitigated considerably by the cash sweep facility in the loan note covenants. Infrastructure is also largely in place at Oza so capital outlays per barrel of production should be relatively low. Technical risk is arguably modest given that the wells have performed solidly under test and the well understood geology of the Niger River Delta Petroleum Province.

Assuming that the Oza development programme achieves production broadly as indicated above, it would have the potential for solid long term returns at plausible commodity prices. Based on production of 15,000 b/d and Brent at $45-50/barrel, for example, free cash flow before petroleum profits tax could be $110-135m gross. While less than a bonanza after allowing for PPT (petroleum profit tax) cash flow after tax might still be sufficient to pay a meaningful dividend. Clearly, Decklar's financial performance long term will be leveraged to international oil prices.

Exhibit 3: Oza field infrastructure - new production facilities

Source: Company

Where does San Leon go from here?

Nigeria will remain the focus: San Leon has clearly stated that its future lies in Nigeria reflecting the scale of the resources available and the business relationships developed. Public statements suggest that its high-level corporate objective is to be one of the leading independent E&P's in the country. San Leon has indicated that it believes its investment in the OML 18 consortium could provide the template for further moves into the Nigerian upstream petroleum industry. The template has, indeed, been applied in the case of Decklar.

Significantly, the Department of Petroleum Resources (DPR), the Nigerian petroleum regulatory body, announced a marginal field onshore and shallow offshore licencing round in June 2020. This is the first such round since 2003 and relates to discoveries on IOC (international oil company) licences where there has been no activity for at least ten years. With the agreement of the IOC, an area of land is carved out surrounding the discovery which becomes the marginal field. There are 57 marginal fields available for bidding. Applications for marginal fields are open to indigenous companies and foreign companies in conjunction with local partners.

The new licencing round is part of the state-owned Nigeria National Petroleum Corporation's plan to boost oil production from about 2mm b/d currently to 3mm b/d by 2023.

Disposal of non-core interests:

European assets non-core and largely spun-off: Since the move into Nigeria, San Leon has been spinning off its non-core assets in Europe. Following the sale in 2019 of four Polish concessions to Horizon Petroleum Ltd San Leon has two projects remaining in Europe. These are the Durresi block offshore Albania and the Barryroe undeveloped offshore Ireland oil and gas field about 60km south of Cork Harbour. San Leon has a 100% participating interest in Durresi and a 4.5% NPI (net profit interest) in Barryroe.

Durresi contains a gas and light oil discovery and is a potential farm-out candidate. Barryroe has had six hydrocarbon wells successfully drilled and the operator, Providence Resources, continues to seek a farm-in partner for appraisal and potentially development purposes. We believe that pre farm-out it is doubtful if either Durresi or Barryroe have significant value.

Niger River Delta Petroleum Province

Geological and historical overview

Nigerian oil production concentrated in the Niger River Delta Petroleum Province: The production of oil and gas in Nigeria is concentrated onshore and offshore in the Niger River Delta Petroleum Province or Basin in the south east of the country. Oilfield development was initially undertaken onshore in the Delta region and subsequently in shallow water at depths of <200m along the continental shelf up to around 60km from the shoreline.

Exhibit 4: Niger River Delta Petroleum Province

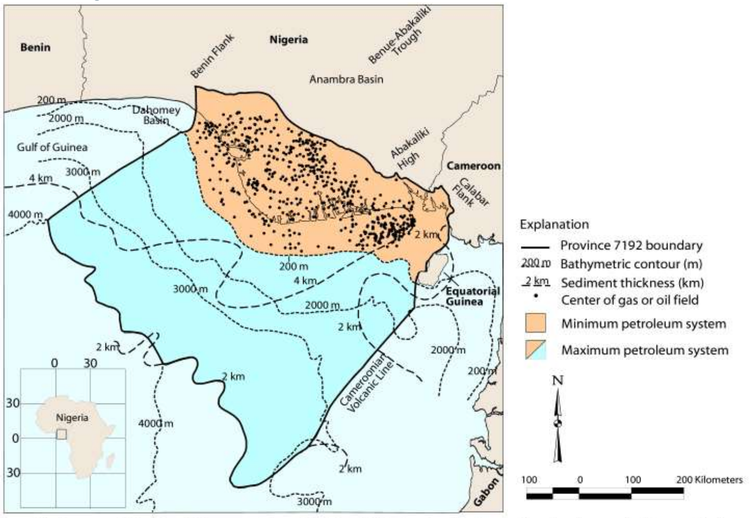


Figure 1 Index map of Nigeria and Cameroon. Map of the Niger Delta showing Province outline (maximum petroleum system); bounding structural features; minimum petroleum system as defined by oil and gas field center points (data from Petroconsultants, 1996a); 200, 2000, 3000, and 4000 m bathymetric contours; and 2 and 4 km sediment thickness.

Source: USGS

The Province covers a large area on and offshore: Broadly, the Province extends for about 500 km east to west while the oil producing zone extends for about 100 km north of the shoreline. The southern margin of the Province is defined by the 4,000m water depth contour or the 2km sedimentation thickness line. This is roughly 200 km from the shoreline. The offshore eastern margin is formed by the Cameroon Volcanic Belt while in the west the boundary is the Dahomey Basin. The northern margin is defined by various Cretaceous outcrops such as the Abakaliki High.

Cenozoic petroleum system based on the Akata shales and the Akbada sandstone reservoirs: OML 18 is at the heart of the onshore sector of the Niger River Delta Petroleum Province. The Niger River Delta basin was originally formed as a result of rifting in the late Jurassic and early to mid-Cretaceous periods 150-100mya associated with the opening of the South Atlantic. It contains one known petroleum system stemming from sedimentation during the Cenozoic era starting about 66mya and continuing to the present day. Deposition commenced in earnest during the Paleocene with the ingress of marine shales. These are contained in the Akata formation and are the primary source rock for the petroleum system. Deltaic sandstones started to be deposited during the Eocene and provide the main reservoir material based on the Akbada formation. Upper Akata formation turbidite sands may, however, also have reservoir potential in deep water offshore locations and beneath currently producing intervals onshore. Sedimentation in the Delta region is now over 10 km thick.

The seal rock in the Niger River Delta province is primarily interbedded shale in the Akbada formation. Oil traps within the system are largely structural in nature and stem from the syn-sedimentary deposition of large quantities of material leading to features such as faulting and folding.

According to the USGS (US Geological Survey), the prolific nature of the Niger River Delta petroleum system reflects several key characteristics as follows:

- The voluminous nature of the source rock which in the Akata formation is up to 7,000 m thick according to the USGS.
- High permeability thick sandstone reservoir formations.
- Rapid hydrocarbon generation reflecting high sedimentation rates.
- Excellent migration pathways.

Mature production zone onshore: From a production standpoint, the Niger River Delta Province is mature. Production first commenced at a Shell-BP joint-venture in 1958 and onshore development activity mainly took place over the following 20-30 years. Over the past 15 years or so oilfield development has moved into deep and ultra-deep-water locations in the Gulf of Guinea at depths of 1,000m plus and around 150 km from the shoreline. The move into the deep-water reflects the discovery of largescale fields with annual production rates of up to 200,000 b/d of liquids. Typically, onshore fields are much smaller. Regulatory burdens may also be less onerous offshore than onshore while the equity interest of the state owned NNPC tends to be smaller. Theft is also much less of a problem than onshore.

Oil quality

Light low-sulphur oil: The Niger River Delta province is primarily a producer of mid and light duty crude with a low sulphur content of between 0.1% and 0.3%. According to the USGS, 56% of Niger River Delta reserves has an API gravity of between 30° and 40° while heavy oil of less than 26° accounts for only 15% of the total. Reflecting its high-quality characteristics, particularly in terms of sulphur content, benchmark Nigerian crude Bonny Light historically sold at a premium to Brent of a dollar or two/barrel. Since the advent of large quantities of light US crude coming on stream in recent years this premium has evaporated and at times reversed. In early September, however, 2020 Bonny was selling at a premium of $1.27/barrel to Brent.

Petroleum reserves and production

One of the world's largest petroleum systems: The Niger River Delta Petroleum Province is one of the world's largest petroleum systems with hydrocarbons reserves of 69 bn boe based on the BP Statistical Review. It accounts for virtually all Nigeria's oil and gas production. The principal exception is the offshore Dahomey Basin close to the border with Benin which hosts the Aje field. For the purposes of reserves and production we use Nigeria and the Niger River Delta Petroleum Province as being synonymous in this report.

Proved oil reserves are 37mm barrels the second highest in Africa: At end 2019 proved petroleum reserves for Nigeria were shown in the 2020 BP Statistical Review at 37.0 bn barrels. This was equivalent to 2.1% and 22% of the world and OPEC totals respectively. Nigeria ranked in 2019 as having the second largest proved petroleum reserves in Africa after Libya's 48.4 bn barrels. Over the past ten years the trend in Nigerian reserves has been flat. In all probability reserves are capable of uplift given that deep-water exploration is relatively recent, mainly having commenced in earnest in the 1990s. According to industry sources, there is also the potential to increase onshore reserves, although prospective fields are considerably smaller than in the deep-water.

Signs of a revival in production in 2019----- Nigerian oil production has been on a declining trend over the past ten years. However, there were signs of a revival in 2019 reflecting the coming on-stream at the beginning of the year of the Total operated large, deep water Egina field. Oil production in 2019 averaged 2.11mm b/d, up 5% on a year earlier but still down 17% on the recent high of 2.53mm b/d in 2010. Industry estimates suggest that

2.5mm b/d is around full capacity currently. According to the Nigerian National Oil Co, deep water production in 2019 was about 0.85mm b/d thereby implying 1.26mm b/d for the onshore and shallow water operations in the Niger River Delta Petroleum Province. Production has been depressed in recent years by a combination of factors including theft, vandalism of onshore equipment, civil strife and terrorist induced outages and OPEC production constraints.

------but a substantial fall likely in 2020: In 2020 Nigerian oil production is likely to be down substantially on 2019 reflecting OPEC orchestrated cutbacks and weak demand in the wake of severe recessionary influences post the covid-19 pandemic. Based on first half trends, we believe there could be a year-on-year drop in 2020 of around 20% to 1.70mm b/d.

Where does the oil go?

Presently largely an export orientated industry but this could change with Dangote refinery: The vast bulk of Nigerian oil production is exported via five onshore terminals and over 20 FSO's (floating, storage and offloading) and FPSO's (floating, production, storage and offloading). The domestic petroleum market is significant at around 500,000 b/d but the four local refineries, which according to the BP Statistical Review have a capacity of 350,000 b/d, are largely out of action for refurbishment or have been mothballed. Refined product, therefore, is largely imported. The situation should change post 2021 when the giant 650,000 b/d Dangote refinery near Lagos is scheduled to come on-stream. The refinery and associated petro-chemical facilities will also use substantial quantities of natural gas both as a fuel and as a feedstock.

Natural gas and LNG

Substantial natural gas reserves: The Niger Delta Petroleum Province has substantial proved natural gas reserves. Overall, proved reserves for Nigeria were given in the 2020 BP Statistical Review as 190.4 tcf in 2019. This constitutes 2.7% of the world total and is the largest reserve base in Africa. Production, although significant, is less than might be expected given the scale of reserves. In 2019 the production of dry gas was 49.3 bcm (1.74 tcf), 1.2% of the world total and up 2.1% on a year previously. The longer-term growth trend is 3.9% pa based on BP Statistical Review data.

Historically LNG export orientated but pipeline gas offers a major domestic opportunity: Significantly, natural gas production historically has been export orientated in the form of LNG. In 2019 LNG shipments of 28.8bcm accounted for 58% of natural gas production. The LNG weighting was however down from nearer 70% ten years earlier. Nigeria ranked number six globally in LNG exports in 2019. We believe there is a major domestic market opportunity in the years ahead for the commercialisation of natural gas in Nigeria particularly for power generation applications. This reflects a combination of factors as follows:

- Government electrification schemes including a plan to provide universal access to electricity by 2030.
- The substitution of diesel-powered gen-sets by price advantaged mains electric power.
- Major industrialisation programmes such as the Dangote refinery.
- Rapid population growth of 2.5-3.0% pa.
- The potential for solid trend economic growth.
- The liberalisation of gas market prices and fiscal investment incentives for gas producers including lower royalty and corporate tax rates.

Nigeria petroleum industry participants

Dominance of the IOC's being eroded by indigenisation: Historically, the petroleum and more widely the hydrocarbons industry in Nigeria has been dominated by the major international oil companies (IOC's). Over the past ten or 15 years, however, the industry has become significantly more diverse with the emergence of indigenous participants, including Eroton. Some of the indigenous concerns such as Seplat Petroleum, Lekoil and ADM Energy are publicly listed in London as well as Lagos. This development was encouraged by the 2010 Nigeria Oil & Gas Industry Content Development Act which was designed to enhance the participation of Nigerians and Nigerian companies in the nation's oil and gas industry. According to Seplat Petroleum, one of the largest local E&P concerns, indigenous companies now control about 19% (400,000 b/d in 2019) of oil and 18% of gas production in Nigeria.

Africa Oil Corp has recently invested in the deepwater licence OML 127: The IOC's present in Nigeria with major operated oil and gas concessions are Shell, Total, Chevron, ExxonMobil and ENI. Shell is the longest standing participant with downstream operations dating back to the late 1930s. Despite divestments, Shell still has a wide range of energy interests in Nigeria from upstream through midstream. Shell also remains the largest player upstream with operated output capacity of over 1mm b/d of oil, according to their website. Interestingly, in early 2020 Toronto-listed Africa Oil acquired a 50% interest in Prime Oil and Gas BV (formerly Petrobras) and thereby an 8% interest in the deepwater licence OML 127 licence. This contains the Chevron deepwater Agbami field.

Shell continues to be the largest of the IOC's: Shell's Nigerian production in 2019 from operated joint-ventures was 678,000 boe/d, up 9% from a year previously. Production was split 514,000 b/d onshore and shallow water Niger Delta (SPDC subsidiary) and 164,000 boe/d from the deepwater Bonga field (SNEPCo subsidiary). Significantly, Shell pioneered deepwater operations offshore Nigeria with the commissioning of the Bonga field in 2015. The Niger Delta joint-venture interests are Shell 30%, NNPC 55%, Total 10% and ENI 5%. The Bonga field interests are Shell 55%, ExxonMobil 20%, ENI 12.5% and Total 12.5%. Shell also has two other non-operated deepwater interests, a gas distribution business and two LNG interests. The LNG interests comprise the wholly owned entity Shell Nigeria Gas Ltd (Bonny LNG plant) and a 25.6% interest in the NNPC controlled Nigeria Liquified Natural Gas Ltd.

Total could be number two: Total also has wide ranging upstream, midstream and downstream interests in Nigeria. Its upstream interests relate to both the onshore Delta region and deepwater fields. We believe following the coming on-stream of the Egina field that Total is now the second largest operator in Nigeria with production of perhaps 400,000 boe/d gross. The other three IOC's, we believe, have significantly lower operated production of around 250,000 boe/d gross each.

Exhibit 5: Nigeria independent E&Ps

				2P reserves net			Production net		
				Oil	Gas	Total			
Company	Asset	Location	Interest %	mm barrels	Gas boe mm	boemm	Oil b/d	Gas boe/d	Total boe/d
Eroton Exploration and Production	OML 18	Niger Delta	27	156	145	301	10530	2250	12780
San Leon Energy	OML 18	Niger Delta	10.58	60.9	57	117.9	4228	903	5131
ADM Energy	OML 113	Dahomey Basin	9.2	16.4			273		
	Aje field	Offshore							
Africa Oil Corporation	OML 127	Deepwater	4			85.1	33887	5063	38950
	Agbami field	Gulf of Guinea							
	OML 130		8						
	Akpo and Egina fields								
Lekoil	Otakikpo Marginal field	Niger Delta	40	19.4		19.4	2329		2329
	OPL 310	Dahomey Basin	70						
	OPL 325	Dahomey Basin	62						
Oando	OML 56 Ebenor field	Northern Niger	42.75	292	179	471			43045
		Delta							
Seplat Petroleum	OML 38	Niger Delta	45	252	257	509	23935	22563	46498
	OML 283		40						
	OML53		40						
	OML 40		45						
	OML 4		45						
	OML 41		45						

Source: Allenby Capital & Company reports

Note: Reserves and production are for the most periods reported.

Gas conversion rate 6000 cf=1 barrel of oil

Eroton and San Leon 2P reserves data are based on gross estimates for the licence of 576 mm barrels for oil and 3123 bcf for gas.

San Leon working interest shown is the net initial indirect interest in OML 18 via MLPL and Eroton.

Africa Oil's interest in OML 127 and OML 130 is indirect via its 50% holding in Prime Oil and Gas BV.

OML 18 and Eroton

Consortium ownership and Eroton financing background

Former Shell operated licence: Before the acquisition by Eroton Exploration and Production in March 2015, OML 18 was operated by Shell (SPDC Nigerian subsidiary) in a joint venture that included the state oil company NNPC, Total and ENI (local subsidiary Agip). Shell and its oil major partners had a 45% interest and NNPC 55%. Eroton itself was incorporated in Nigeria in 2013. The divestment by Shell and its partners followed a strategic review of its onshore assets in the Niger Delta. Significantly, it was also consistent with government policy on indigenisation.

Eroton acquired a 45% stake in OML 18 for $1.1m from a Shell led consortium: The 45% interest was acquired by Eroton for $1.1bn. This was financed by a $663m RBL (reserve backed loan) facility and $437m of equity. Subsequently, an 18% interest was spun-off to the Nigerian privately owned oil and gas company, Sahara Field Production Ltd. A final adjustment came with Sahara transferring a 1.8% interest to the indigenous Bilton, a company established for handling community relations. The current direct ownership status for OML 18 is therefore as follows: NNPC 55.0%, Eroton 27.0%, Sahara 16.2% and Bilton 1.8%. Eroton is the operator of the licence which expires in 2039 but may be extended.

Eroton RBL facility

RBL loan covenants constrain dividend payments: The covenants relating to the RBL facility are critical in governing Eroton's ability to pay dividends. In January 2019 Eroton announced that Lagos headquartered Guarantee Trust Bank (GRTB: LN) had granted more favourable RBL terms than hitherto. The current status is as follows:

- A terminal date for repayment of end 2025.
- Two quarter's repayments to be maintained in a designated Debt Service Reserve Account (DSRA) before dividends can be paid. San Leon has indicated that two quarter's payments are about $50m against more than $100m prior to the change in covenants.
- A coupon of 11% pa.

We believe the balance of principal on the RBL is currently $210m.

Eroton management and headcount

Based on the San Leon Admission document in 2016, Eroton's headcount was over 200 which points to the significant scale of operations. The top management has considerable petroleum and related industry experience. The backgrounds of the three top members of management are given below:

Onajite Okoloko, Chairman: Onajite Okoloko has an entrepreneurial background. He was a founding member of Oando plc a leading Nigeria focused E&P and trading concern. In addition to his role at Eroton, Onajite Okoloko is Chairman at Midwestern and Managing Director of Notore Chemicals Industries. Notore is an integrated producer of fertiliser and agri-chemicals based near Port Harcourt and indeed the Eroton operations. Mr Okoloko has a degree in economics from the University of Benin.

Ebiaho Emafo, CEO: Ebiaho Emafo has almost 30 years' oil and gas industry experience in procurement, supply management and administration. He holds MBA and a master's Degree in Logistics and Supply Chain Management from Cranfield, UK.

Dr Theo Okeke, Chief Technical Officer: Dr Okeke has over 30 years' experience in the petroleum and mining industries in engineering and project management roles in Nigeria, Europe, Middle East, South America and the US. He has worked for Shell and Vancouver-based Rio Alto Mining Ltd. Dr Okeke has an M.Eng and a PhD in civil engineering from the University of Calgary in Canada.

As we noted earlier, San Leon has two members on the Eroton Board and can appoint and remove the technical manager and Head of the Finance Committee.

OML 18 location

Southern onshore Niger Delta location: OML 18 lies in Rivers State in the southern onshore Niger River Delta region approximately 500 km east of Lagos and a similar distance south of the Nigerian capital, Abuja. The northern boundary of the licence lies immediately to the south of the Rivers state capital and Nigerian oil and gas centre of Port Harcourt (population approximately 1.9m). OML 18 covers a very large area of 1,035 km² (larger than the country of Bahrain) much of which is comprised of mangrove swamp.

3-D shot widely over licence: Geologically OML 18 is located within the core of the Cenozoic age River Niger Delta Petroleum Province as discussed previously. 3-D seismic has been shot widely over the licence and has revealed three megastructures in the north, centre and south. The nine fields so far discovered are based on the north and central structures.

Exhibit 6: OML 18 Nigeria location

Source: Company

Asset and operational review

Fields and well production

Cumulative production of over 1bn of oil and 1.8 tcf of gas: The underlying asset base on OML 18 is mature. Development commenced in the late 1960s and early 1970s. The first fields to come on-stream were Alakiri and Cawthorne Channel in 1970. In total nine fields have been discovered with five (Alakiri, Buguma Creek, Orubiri, Asaritoru) based on the northern and four (Krakama, Cawthorne Channel, Akaso and Awoba) on the central structures. Across the nine fields 146 wells have been drilled to date. The cumulative output across the nine fields has been over 1bn barrels of oil, including condensate and 1.8 tcf of gas. By far the most prolific field has been Cawthorne Channel which has produced over 615,000 barrels of oil and 925 bcf of gas cumulatively since coming on-stream. Presently, four fields are on-line comprising Akaso, Alakiri, Awoba, and Cawthorne Channel.

Around 50 wells producing on average 1,000 b/d but new wells capable of much higher production rates: Eroton's fields currently have about 50 operating wells with each producing on average an underlying 1,000 b/d. The well infrastructure is mature and subject to a high decline rate of over 10%. Thanks to the excellent reservoir characteristics and dual well string operation (production from two different reservoir zones in each well), however, we understand new wells have the potential to yield a up to 10,000 b/d. This is highly competitive internationally and offers the potential for superior economics. We also understand that due to the well understood geology in the Delta region and 60 years of production infill well drilling is low risk.

Exhibit 7: OML 18 field status

Field	Discovery year	First production	Last production or current status	No of wells drilled	Cumulative production: Oil mm barrels	Cumulative production: Gas bcf	Oil & condensate 2P reserves mm barrels
Akaso	1979	1980	Producing	14	112.5	157.2	88.1
Alakiri	1959	1970	Producing	37	100.8	480.3	107.6
Asaritoru	1990	1992	Aug-00	1	3.4	3.8	1.4
Bille	1971	-		1	0	0	5.5
Buguma Creek	1960	1972	Dec-00	10	18.8	47.0	63.8
Cawthorne Channel	1963	1970	Producing	52	614.0	925.0	206.6
Krakama	1958	1972	Jan-08	16	44.9	31.6	57.3
Orubiri	1971	1973	Nov-07	11	32.7	35.4	14.1
Awoba	1981	1992	Producing	4	75.6	97.8	31.4
Total				146	1002.7	1778.1	575.8

Source: Petro Vision CPR
Note: Reserves are shown gross
Production data is cumulative to January 2016
Awoba straddles OML 18 and OML 24. Production is split 50:50 between the two licences. Data for Awoba refers to OML 18 only.

Oil evacuation

Shell operated NCTL pipeline to the Bonny terminal used presently: Oil is presently evacuated from the central structure fields via the Nembe Creek Trunk line (NCTL) from Cawthorne Channel to the Shell operated Bonny Terminal on Bonny Island about 20 km to the south east. The northern structure fields are tied back to Cawthorne Channel. Eroton has an offtake agreement with Shell and all oil is currently being sold spot. Bonny Light and Brent are the key benchmark grade for pricing purposes.

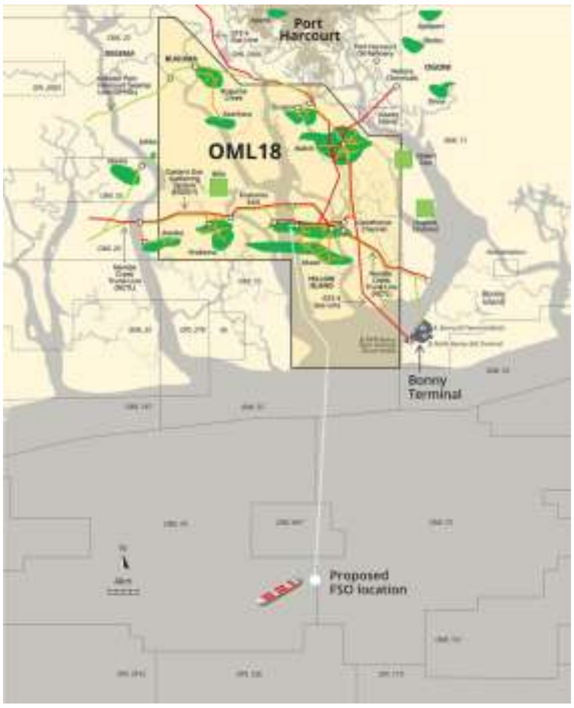
Changeover to the new ACOES pipeline to an offshore FSO scheduled by 2021: In the coming months the evacuation route for OML 18 oil is scheduled to change reflecting the pending start-up of the new 100,000 b/d Alternative Crude Oil Evacuation System (ACOES) pipeline. This will run from just east of the Cawthorne Channel hub for about 60km to an FSO (floating storage and offloading) vessel located in the Gulf of Guinea. Compared with the NCTL, the ACOES offers the potential for less down time and substantially fewer losses to theft and vandalism since the new line will be under the seabed. San Leon has indicated that pipeline downtime and allocated losses should be cut from up to 35% presently to less than 10%.

According to San Leon, the ACOES pipeline tariff will be $5/barrel or in line with that of NCTL.

Natural gas evacuation

50mm cf/d of gas shipped to the Notore fertiliser plant: Typically, oil produced in the Niger Delta Petroleum Province has a high gas content. By-product gas historically was flared but since 2016 Eroton has reduced the need for this practice due to a gas supply contract with the Notore chemical a fertiliser plant about 16 km north east of Cawthorne Channel. Existing infrastructure includes gas gathering and processing facilities. We understand that gas is being sold to Notore for an internationally competitive \$1.5/mcf currently. Natural gas deliveries to Notore are presently running at around 50mm cf/d.

Exhibit 8: OML 18 fields and infrastructure



Source: Company

Reserves and production

Reserves

Substantial 1P and 2P reserves of oil and gas: OML 18 has substantial reserves both at the 1P and 2P levels. This reflects the scale of the licence in a core part of a prolific basin and the deep knowledge of the sub-surface gained from over 50 years of production and extensive 3-D seismic coverage. Based on the last CPR in 2016, 1P and 2P gross reserves for liquids, including condensates, were put at 389mm barrels and 576mm barrels respectively. In addition, natural gas reserves were given as a hefty 3,119 bcf at the 1P level and 3,213 bcf at the 2P level. The implied oil and gas 2P reserve position was 1.11 bn boe. San Leon's implied share of 2P reserves based on its 10.58% indirect initial economic interest in the OML 18 licence is 61 mm barrels for liquids and 340 bcf for gas. Combined, the 2P position would be 118mm boe.

OML 18's reserves are also long-life. The reserves: production ratio (R/P) for OML 18 is a comfortable 32 years using an underlying production rate of 50,000 b/d and 2P reserves for liquids. Even on a 1P basis the R/P ratio would be 21 years.

There are also sizeable 3P reserves: The 2016 CPR, unusually, also gave 3P (proved, probable and possible) reserves for OML 18. The possible element in the estimation reflects 10% probability of commercial extraction as opposed to 90% and 50% for proved and probable respectively. For liquids and gas, the 3P reserves were given as 777mm barrels and 5,080 bcf gross respectively which would take the combined total to 1.62bn boe gross. San Leon's share of 3P would be 82mm barrels for liquids, 537 bcf for gas and 171mm boe combined.

Given the scale of reserves, the key issue now for Eroton is not so much adding to them but rather developing cost effectively what is already in existence.

Exhibit 9: OML 18 reserves

	1P	2P	3P
Oil and condensate (mm barrels) gross	389	576	777
Natural gas (bcf) gross	3119	3213	5080
Natural gas (boe mm) gross	520	536	847
Oil and gas (boe mm) gross	909	1112	1624
San Leon Oil and gas (boe mm) net 10.58% interest	96	118	172

Source: Company; Allenby Capital

Production trends

Production peaked at around 100,000 b/d in the early 1970s and 1990's-----: In OML 18's 50-year history peak production levels of about 100,000 b/d for oil and 200 cf/d of gas were achieved in the early 1970's and early 1990's. The former coincided with the start-up of five fields including the largest, Cawthorne Channel, while the latter coincided with the commencement of operations at the Awoba field.

------ but was under heavy pressure in the early 2000's: Oil production trended sharply downward between the early 1990's and 2015 reflecting issues of vandalism and the poor operating performance of the Nembe pipeline which resulted in high levels of well downtime. At the beginning of 2015 only four fields were in operation and production was briefly down to about 5,000 b/d. Following a well and field rehabilitation programme post the Eroton acquisition in March 2015, production trended strongly upward over the balance of the year. For 2015, oil production averaged 17,751 b/d based on the 2016 CPR. Gas shipments to the Notore fertiliser plant also commenced in March 2015. Production continued to move ahead in 2016 as more rehabilitated wells were brought on-stream. The CPR referred to production averaging 52,093 b/d in April 2016.

Between 2016 and 2019 the trend was flat at about 50,000 b/d during uptime: Since mid-2016 the underlying trend in oil production has flattened at 45,000 to 50,000 b/d during field uptime but before taking into account losses due to theft and pipeline downtime. In 2019 oil production during uptime was 50,000 b/d up 11% on a year earlier. The actual level of production was, however, significantly lower at 39,000 b/d due to downtime while sales ex the Bonny terminal were 29,500 b/d or slightly less than the 30,069 b/d of a year earlier. The variance between deliveries and actual production was 24% and mainly reflected the impact of pipeline disruptions, leakages and theft. Reducing allocated losses to less than 10% with the new ACOES pipeline could boost oil deliveries by 15,000 b/d to 45,000 b/d.

Production and deliveries are likely come under pressure in 2020 from OPEC quota restrictions: We believe Eroton's production will dip significantly in 2020 despite the drilling of and completion of three wells and workover activity in 2019 and early 2020. The key issue is OPEC quota restrictions which we believe may have taken delivered output down to about 25,000 b/d in the second and third quarters. There should however be a partial recovery in the fourth quarter of 2020 as quota restrictions are relaxed. Very approximately we think Eroton's delivered production in 2020 could average about 27,000 b/d, down 8% on 2019. We believe it will probably be challenging to lift oil production at the wellhead substantially in 2021 given the likelihood of the lingering impact of OPEC quotas. Deliveries could be a different story assuming that the new ACOES pipeline comes on-stream as scheduled.

Medium-term field development programme

The original plan

Eroton announced an ambitious development programme in 2016 to boost production to 115,000 b/d: Following the acquisition of the Shell led consortium's interest in OML 18, Eroton proposed a major medium-term programme to unlock undeveloped reserves and accelerate the recovery of reserves at existing operations starting in 2017. The key objectives based on the development of 2P reserves was over a five-year period to boost oil production from an underlying 50,000 b/d to about 115,000 b/d and to raise gas deliveries from 50mm cf/d to 485mm cf/d. Overall the production objective was an increase to 196mm boe/d gross over five years.

The capital cost of the development programme on the 2P reserves scenario was given in the 2016 CPR as $1.59bn split $1.04bn oil and $0.55bn gas. Operational cash flow was expected to provide the financing. The NPV 10 attributable to San Leon was quoted in the CPR as $429m. Events clearly overtook what was, in our view, a very ambitious development programme. Among the issues encountered were permitting and regulatory delays, depressed commodity prices, the RBL repayment constraint and delays in the state oil company, NNPC, meeting cash calls.

An alternative programme

A new less ambitious more measured programme is likely in due course: Although a new development programme has not been announced, we believe it is very likely that a new one will surface in due course albeit less ambitious than in 2016. Key drivers include the following:

- The need to offset the natural decline curve for the existing wells.
- Low risk highly productive drilling opportunities.
- Low risk well rehabilitation opportunities.
- The ability to leverage the cost base with greater volume.
- Major domestic market opportunities in natural gas (power generation and petrochemicals) and possibly oil (refining).

Visibility on $50/barrel will probably be required for approval: In addition to scale, one of the key questions is when a new programme might start. We believe, particularly if the intention is to fund internally, the earliest starting point is late 2021 or early 2022. Rather than a grandiose plan we also think that it will be flexible in nature and dependent on commodity prices. In our view, it is likely that to justify a significant development programme involving drilling multiple wells that a Brent price of at least $50/barrel will be required. We think this is a plausible assumption quite possibly as early as the fourth quarter of 2020. Assuming the Notore gas price of $1.5/mcf ($9/boe), we believe it will be difficult if not impossible to justify new standalone gas wells. Producing by-product gas from oil wells could, by contrast, provide a viable option.

A 50 well drilling programme would cost $1.05bn based on 2016 CPR well costs of $21m: Clearly, the cost of a development programme will be largely dependent on the number of wells to be drilled and the cost/well. Based on the average well cost given in the 2016 CPR of $21m and a 50 well programme expenditure would be $1.05bn. We believe the well cost is high internationally for an onshore location and probably also allows for some infrastructural outlays. It is not clear from the CPR the ratio of horizontal to vertical wells. Assuming one rig operation and a spud-spud time of 60 days a significant 5-6 wells could be drilled per year. One rig might be adequate for a 25 well programme but two-rig operation would probably be required for an ambitious 50 well project.

Economics

Cash costs could be c. $23/barrel at current depressed volumes: Based on the 2020 interim statement, the hefty loss of $14.1m reported for equity accounted investments clearly implied a sizeable deficit for Eroton on a fully accounted basis. This may have been c. $35m. The situation, however, on a cash operating basis should have been more marginal given likely substantial charges for depreciation and depletion. Operations in the H1 2020 may indeed have been modestly cash positive before maintenance and capex.

We estimate that at delivered production rate of 25,000 b/d cash operating costs could be around $23/barrel. The breakdown is as follows: well site fixed and variable costs $16/barrel, pipeline tariff $5/barrel and central G&A $2/barrel. Based on experience elsewhere, we believe the fixed to variable split for well site costs might be 75:25.

A 20% royalty takes a hefty slice out of revenues: In calculating the cash contribution account also needs to be taken of the 20% federal government royalty. This equates to $8/barrel at $40/barrel which Brent averaged in the first half of 2020. The cash contribution at $40/barrel, assuming a 25,000 b/d production rate, would therefore be $9/barrel. In practice, workovers and maintenance would reduce this contribution. If we were to assume depreciation and depletion north of $15/barrel, which we believe is plausible, we would arrive at broadly the hefty fully accounted loss mentioned above.

At $45/barrel Brent and current production rates the cash contribution may be about $13/barrel: If we apply the same model, assuming the mid-August Brent price of $45/barrel, the cash contribution would be $13/barrel. The comparable contributions for $50 and $60/barrel oil would be $17/barrel and $25/barrel respectively. Note, these calculations are very approximate and exclude by-product gas sales. Allowing for gas would boost the contributions slightly particularly bearing in mind a lower royalty rate of 7%. Eroton's current production rate during uptime is about 50,000 b/d. If we were to assume this rate, cash costs/barrel would drop by a highly significant $7/barrel to $16/barrel. Assuming $45 oil, the cash contribution would therefore rise to $20/barrel.

Exhibit 10: Eroton operational cash economics model

$/barrel	**25000 b/d production scenario**					
Brent/Bonny price	25	30	40	45	50	60
Royalty	-5	-6	-8	-9	-10	-12
Net revenue	20	24	32	36	40	48
Well site variable costs	-4	-4	-4	-4	-4	-4
Well site fixed costs	-12	-12	-12	-12	-12	-12
Pipeline tariff	-5	-5	-5	-5	-5	-5
Central G&A	-2	-2	-2	-2	-2	-2
Cash contribution	**-3**	**1**	**9**	**13**	**17**	**25**

$/barrel	**50,000 b/d production scenario**					
Brent/Bonny	25	30	40	45	50	60
Royalty	-5	-6	-8	-9	-10	-12
Net revenue	20	24	32	36	40	48
Well site variable costs	-4	-4	-4	-4	-4	-4
Well site fixed costs	-6	-6	-6	-6	-6	-6
Pipeline tariff	-5	-5	-5	-5	-5	-5
Central G&A	-1	-1	-1	-1	-1	-1
Cash contribution	**4**	**8**	**16**	**20**	**24**	**32**

Source: Allenby Capital

Note: Royalty 20%; Pipeline tariff as per SLE; Central G&A $18m/pa as per 2016 CPR

Financials

Recent years in retrospect

Marginal revenues historically: San Leon Energy was primarily an exploration company until the acquisition in 2016 of the indirect interest in the OML 18 licence via the operator, Eroton. Between 2008 and 2015 revenues were marginal peaking in 2013 at €3m following the acquisition of Aurelian. Cash outflows related largely to exploration activity and G&A and were mainly financed by share issues.

Hefty cash inflows from the high yield loan notes since 2017: The acquisition of the indirect interest in Eroton and the subsequent disposal of legacy exploration assets transformed the company. Effectively, San Leon evolved as an investment vehicle via its 40% interest in the Mauritius holding company MLPL. Significantly, San Leon Nigeria had title to $174m (principal) of high-yield loan notes. Between 2017 and 2019 San Leon received $149.1m in repayments of principal on the loan notes and interest. Looking at the three years to 2019 San Leon's net operational and investment related cash flow was a hefty $67m. In 2019 cash flow on this metric was $27.7m. This, however, was more than offset by a $33.0m share buy-back which combined with some miscellaneous items resulted in a corporate cash outflow for 2019 of $4.1m. Corporately San Leon swung between end 2016 and 2019 from net debt of $5.6m to a cash position of $36.7m.

Bullet proof balance sheet: San Leon's balance sheet was bullet proof at end 2019. Equity represented no less than 96% of financing sources, the current ratio (current assets:current liabilities) was 27.5X and cash plus financial assets (loan notes) accounted for 71% of total assets. At the EBITDA level adjusted for exceptional items, San Leon has in recent years been heavily in loss albeit on a declining trend. In 2019 the loss on this basis was $15.6m, down 53% on the previous year and 60% on 2017. The downward trend reflects declining G&A and miscellaneous expense items. At the PBT level in 2019 there was a loss of $52.7m. To a considerable extent this reflected an impairment of $48.3m in the carrying value of San Leon's profit interest in the Barryroe oilfield offshore Ireland.

Hefty H1 2020 loss but strong underlying cash flow: San Leon reported a hefty after-tax loss of $20.3m in the first half of 2020. This reflected a considerable widening from the $6.8m loss of a year earlier and was primarily attributable to an adverse swing on the contribution from equity accounted investments, a loss on disposals and a provision for loan note losses. Administrative expense in the first half of 2020 came in at $7.7m, up 30% on a year previously driven by a combination of higher employee remuneration, and fees for advisors and consultants and a foreign exchange debit. Higher spending on advisors and consultants stemmed from M&A activity.

The largest contributor to the 2020 first half deficit related to the equity accounted loss. For the period the loss from this source was $14.1m against a marginal profit of $97,000 a year previously. Overwhelmingly the loss was attributable to San Leon's 40% interest in MLPL, the holding company that indirectly has a 98% initial interest in Eroton, the operator of OML 18. In the first half of 2020, Eroton's financial performance was heavily impacted by the toxic mix of sharply lower price realisations and deliveries. For the period deliveries at 25,200 b/d were down 22% on a year earlier while we believe realisations were probably off by about 40%. Deliveries were hit by OPEC quota restrictions while pipeline losses and downtime have remained a depressing influence.

In reviewing the 2020 first half income statement data three points should be noted as follows:

- The equity accounted loss of $14.1m, the loan loss provision of $5.9m and the loss on disposals of $1.0m were all non-cash items and partly offset by a $7.8m contribution from financial income.

- San Leon has historically been an operating company and continues to have this capability. Currently, however, its interests are indirectly held with the emphasis on cash flow. The key metric by which it should be judged is cash flow before dividends and share buybacks. On this basis San Leon performed powerfully in the first half of 2020 with a cash inflow of $32.5m against $1.5m a year earlier. We also note that the balance sheet remains bullet proof with shareholders' equity accounting for 96% of total financing sources at the end of the first half of 2020.

- San Leon reported a cash balance on September 18, 2020 of $15.8m excluding the $6.75m of restricted cash held in escrow for the Decklar/Oza transaction.

2020 and beyond

2020

Loan note principal repayments and coupon payments look like buoying underlying cash flow in 2020----San Leon's underlying cash flow looks like remaining strong in 2020 driven by principal repayments and coupon interest on the OML 18 loan notes. In April $41.5m was received including both the repayment of principal and interest. A further payment of $10m is scheduled for early October. This would bring total payments on the loan notes in 2020 to $51.5m and the cumulative total to about $200m.

-----but net of the dividend payment and investments cash flow could be modestly negative: On the combined operational and investment related metric we look for a cash inflow of about $17m in 2020. This is net of the loans made to the pipeline concern ELI and Decklar of $15m and $7.5m respectively. Allowing for the special $33m dividend (6p/share) paid at the end of May there would be an approximate $16m outflow on an overall corporate basis for the full year. This would take the end year cash balance down to $20m.

The outflow at the operating level could narrow in 2020: In addition to the sizeable inflow from the loan notes, we see the operational cash outflow in 2020 narrowing to $12.0m from $15.7m. This mainly reflects a significant contribution from consultancy fees of $3m related to the drilling and completion of three Eroton wells in 2019/20 and the assumption of unchanged working capital requirements. In terms of administrative expense, we are assuming a broadly unchanged picture between the first and second halves of 2020.

Potential for very strong cash flow in 2021 driven by the final payments on the OML 18 loan notes: We would expect San Leon's cash flow to be very buoyant in 2021 with the key driver being the concluding principal and coupon payments on the OML 18 loan notes. For the year, we forecast a corporate cash inflow of $72.9m comprising an outflow of $12.0m on operations and a substantial inflow of $84.9m on investing activities of which the contribution from the OML 18 loan notes is the major part. Operational cash flow includes a further $3m of consultancy fees related to anticipated Eroton drilling activity.

Note, during 2021 San Leon should start receiving payments of principal and coupon on its ELI and Decklar loan notes. We have allowed $7.2m for this factor. Our forecast 2021 cash inflow would take the year end San Leon cash position to about $93m. This would give the company considerable discretion over share buybacks, dividends and M&A activity.

Weaker cash flow performance likely in 2022 assuming existing structure: We believe that net cash flow will weaken significantly in 2022 given the completion of OML 18 loan receivable payments at end 2021 and the sizeable central G&A overhead. Our net corporate cash flow forecast calls for an outflow of $1.88m. This comprises an outflow from operations of $10.27m and an inflow from investing activities of $8.39m. Our operational cash flow forecast assumes $5m of income in consultancy fees related to

Eroton drilling. We have assumed five wells. Note, the forecast of weaker cash flow in 2022 assumes the existing business and asset structure.

The gross cash inflow largely reflects payments of principal and coupon on the ELI loan and Decklar notes. On our scenario, we have assumed Eroton pays dividends in neither 2021 nor 2022. This reflects our view that Eroton will prioritise field development rather than dividend payments. Furthermore, we think it unlikely that commodity price trends will be sufficiently robust in 2021 to enable Eroton to combine field development, dividends and paying down the RBL facility.

Exhibit 11: Income Statement

Year-end December						
$000s	**2017**	**2018**	**2019**	**2020e**	**2021e**	**2022e**
Revenue from contracts	366	198	266	0	0	0
Cost of sales	-165	-95	-148	0	0	0
Gross profit	201	103	118	0	0	0
EBITDA	-38730	-33226	-15625	-36240	-11952	-10270
Administrative expense	-19156	-16439	-14899	-15600	-15912	-16230
Share of loss of equity investments	-7999	-14693	-3204	-24100	0	0
(Loss)/profit on disposals	0	-13133	-13770	-1044	0	0
Impairments/write-offs	-51888	-3074	-1407	-86	0	0
Decommissioning of wells	266	485	0	0	0	0
Other	-9077	-3532	1400	2500	3000	5000
Loss from operating activities	-87653	-50283	-31762	-38330	-12912	-11230
Dividend received	0	0	0	0	0	0
Finance expense	-7431	-2417	-144	0	0	0
Finance income	18333	44082	24123	4700	15547	1994
Expected credit losses	0	4212	3465	0	0	0
Fair value movements in financial assets	0	2281	-48373	-5857	0	0
Other	-3583	0	0	0	0	0
Loss before tax	-80334	-2125	-52691	-39487	2635	-9236
Tax	-2485	-3777	14079	0	0	0
Loss after tax	-82819	-5902	-38612	-39487	2635	-9236
Average shares in issue m	454.5	504.8	466.3	449.9	449.9	449.9

Source: Company; Allenby Capital

Note: EBITDA includes losses from equity investments. These largely relate to the 40% interest in in the Mauritius-based holding company, Midwestern Leon Petroleum Ltd (MLPL).

Exhibit 12: Balance sheet						
Year-end December						
$000s	**2017**	**2018**	**2019**	**2020e**	**2021e**	**2022e**
Assets						
Non-currents						
Intangible assets	2864	0	0	0	0	0
Equity accounted investments	69763	55070	51866	27766	27766	27766
Property, plant and equipment	2745	1964	4344	3484	2624	1764
ELI receivable	0	0	0	15000	12500	7500
Decklar receivable	0	0	0	7500	6000	4500
Decklar equity	0	0	0	5	5	5
Financial assets	134998	124876	2963	2963	2963	2963
Other	206	206	1718	588	588	588
Total	**210576**	**182116**	**60891**	**57306**	**52446**	**45086**
Current assets						
Inventory	323	272	180	180	180	180
Trade and other receivables	4976	2440	987	987	987	987
Other financial assets	0	0	0	0	0	0
Financial assets	70743	57611	112252	59595	-5857	-5857
Cash and cash equivalents	9311	40762	36697	20346	93293	91417
Assets held for sale	0	0	0	0	0	0
Total	**85353**	**101085**	**150116**	**81108**	**88603**	**86727**
Total assets	**295929**	**283201**	**211007**	**138414**	**141049**	**131813**
Non-current liabilities						
Provisions	0	0	2501	2501	2501	2501
Derivative	488	659	128	0	0	0
Deferred tax	8630	12404	0	0	0	0
Total	**9118**	**13063**	**2629**	**2501**	**2501**	**2501**
Current liabilities						
Trade and other payables	17895	8228	5406	5500	5500	5500
Loans and borrowings	4747	0	0	0	0	0
Provisions	1789	760	56	0	0	0
Liabilities held for sale	1145	0	0	0	0	0
Total	**25576**	**8988**	**5462**	**5500**	**5500**	**5500**
Total liabilities	**34694**	**22051**	**8091**	**8001**	**8001**	**8001**
Net assets	**261235**	**261150**	**202916**	**130413**	**133048**	**123812**
Net cash/(debt)	**4564**	**40762**	**36697**	**20346**	**93293**	**91417**
Shareholders' equity				5156	5156	5156
Share capital	150600	150600	5172	125257	127892	118656
Reserve	110635	110550	197744	130413	133048	123812
Total equity	**261235**	**261150**	**202916**	**138414**	**141049**	**131813**
Total equity and liabilities	**295929**	**283201**	**211007**	**449.9**	**449.9**	**449.9**
Shares outstanding year end m	500.3	500.3	451.3	0	0	0

Source: Company; Allenby Capital

Exhibit 13: Cashflow

Year-end December

$000s	2018	2019	2020e	2021e	2022e
Loss from continuing operations	-5812	-38612	-39487	2635	-9236
Depletion and depreciation	850	960	960	960	960
Finance expense	2417	144	0	0	0
Finance income	-44082	-24123	-4700	-15547	-1994
Share-based payments charge	1275	1069	0	0	0
Foreign exchange	-552	-403	0	0	0
Income tax	3777	-14079	0	0	0
Impairments	3074	1407	86	0	0
Expected credit losses	-680	-3465	0	0	0
Loss on disposals	13133	13770	1044	0	0
Decommissioning	-981	-702	0	0	0
Fair value movements in financial assets	-2281	48373	5857	0	0
Share of loss of equity accounted investments	14693	3204	24100	0	0
Other	-54	-18	0	0	0
Total	**-15223**	**-12475**	**-12140**	**-11952**	**-10270**
Inventory (inc)/dec	50	92	0	0	0
Trade and other receivables (inc)/dec	-132	532	0	0	0
Trade and other payables inc/dec	-8737	-3876	94	0	0
Net operating cash flow	**-24042**	**-15727**	**-12046**	**-11952**	**-10270**
Cash flows from investing activities					
Expenditure on exploration and evaluation assets	-210	-466	0	0	0
ELI investment	0	0	-15000	0	0
Decklar investment	0	0	-7500	0	0
Decklar equity	0	0	-5	0	0
Purchase of property, plant and equipment	-75	-82	-100	-100	-100
Lease prepaid rents	0	-231	0	0	0
Loans advanced	458	0	0	0	0
Loans repaid by directors		727	0	0	0
Loans issued to directors	-724	0	0	0	0
Interest and investment income received	103	279	0	0	0
OML 18 loan notes principal received	31572	23361	46800	65452	0
OML 18 loan notes interest received	33032	19885	4700	12300	0
ELI loan note principal	0	0	0	2500	5000
ELI loan interest	0	0	0	2581	1487
Decklar principal	0	0	0	1500	1500
Decklar interest	0	0		666	507
Other	0	0	-200	0	0
Net cash flow from investing activities	**64156**	**43473**	**28695**	**84899**	**8394**
Cash flows from financing activities					
Share buybacks	0	-32048	0	0	0
Share issues	0	99	0	0	0
Dividend payments	0	0	-33000	0	0
Effect of exchange rate fluctuations	771	474	0	0	0
Other	-9434	-336	0	0	0
Net cash outflow from financing activities	**-8663**	**-31811**	**-33000**	**0**	**0**
Corporate net cash flow	**31451**	**-4065**	**-16351**	**72947**	**-1876**
Opening net cash/(debt)	**9311**	**40762**	**36697**	**20346**	**93293**
Closing net cash/(debt)	**40762**	**36697**	**20346**	**93293**	**91417**

Source: Company; Allenby Capital

Risks and challenges

Operational and financial

Remaining payments on the OML 18 loan notes are the main risk: Near-term, the key risk for San Leon surrounds the remaining payments on the OML 18 licence loan notes. The payments are guaranteed by Midwestern but in extremis, perhaps due to adverse trends in commodity prices, it is possible that the repayment schedule might need to be extended to the detriment of San Leon's cash flow. We believe, however, that such a scenario is unlikely at this stage given particularly the firming trend in benchmark oil prices from the ultra-depressed levels experienced early in the second quarter of 2020.

Eroton's dividend paying ability is uncertain----: Medium to long-term, we see the principal risk facing San Leon in Nigeria as being Eroton's dividend paying ability. San Leon's OML 18 business model, with its indirect interest in the consortium, necessitates the regular payment of dividends through to MLPL and San Leon Nigeria. Ultimately Eroton's dividend paying ability is largely contingent on commodity price developments, volume, operational cost trends and Nigerian government petroleum industry fiscal policy.

-----particularly given the RBL covenants: Eroton's ability to pay dividends has been severely constrained over the past five years by a combination of weak volume and commodity price trends plus the need to pay down the RBL facility. There is a possibility that trends in these key variables will remain adverse over an extended period, although we suspect the outlook is more bullish. Shipments of oil should receive a boost in 2021 from a potentially highly significant reduction in pipeline related losses with the advent of the new ACOES pipeline and probably from an easing of OPEC quota restrictions. Crude prices, we believe, will trend higher going into 2021. This reflects our expectation of a tightening market as oil demand returns to the semblance of normality subsequent to the covid crisis lessening in intensity at a time when production in both the OPEC and non-OPEC worlds will still be heavily constrained by earlier cutbacks.

As noted earlier, uncertainty inevitably surrounds the priority that Eroton will give to development activity vis-à-vis dividends. An absence of development activity over a sustained period would be reflected in decline curve induced falls in production and rising per barrel costs.

Uncertainty surrounding Decklar/Oza field development project: The investment in Decklar Petroleum and the development of the Oza field inevitably carry risks. Near term the chief risk relates to Decklar being unable to service the quarterly principal and coupon payments on the $7.5m loan note possibly due to delays in bringing production on-stream at the Oza field. San Leon has recourse to a cash sweep facility as previously discussed but this will only be of use if cash resources are available. We note that Asian Mineral Resources (Decklar Resources) had a modest cash balance of C$1m at end June 2020.

Longer term there is a question mark over just how quickly Decklar Petroleum will be able to raise production at the Oza field to meaningful levels. Financial and geological constraints could slow progress and leave production well short of theoretical levels of 10-15,000 b/d. This would clearly adversely impact dividend paying ability. As in the case of Eroton, once the debt is paid down San Leon needs a flow of dividends from Decklar Petroleum to continue to generate cash flow.

Although there is a risk surrounding Decklar, it should be noted that the odds in favour of a successful Oza development programme appear high from a technical perspective as discussed earlier.

Business and political environment

Perceptions of a high-risk environment may now be exaggerated: Historically, the Nigerian business environment has been considered by investors as high-risk in large part due to perceptions of a high incidence of ethnic tension, vandalism, terrorism, theft, corruption and military rule. While these factors have presented very real challenges, particularly for those businesses operating in the Delta region, risks related to at least some them do appear to have diminished of late.

Seplat points to an improving backdrop in terms of criminality and militancy: According to one of the leading indigenous Nigerian petroleum companies, Seplat Petroleum, a policy of engagement and dialogue by politicos and the petroleum industry have reduced criminality and militancy significantly in the Delta region in recent years. Seplat also argues that as democracy has taken root in Nigeria, along with the emergence of governments that emphasise social and economic development, the regulatory and political backdrop has become more secure for foreign investors. Given the desire of governmental authorities to boost oil and gas production medium term in support of broader economic development objectives, it would appear unlikely that present internationally high petroleum industry tax and royalty rates will be boosted near-term.

Political background

Democracy has taken root: Democracy was restored in Nigeria in 1999 and since then there have been regular elections every four years for the federal President and members of the Senate and House of Representatives. The last was in February 2019. This was won by the APC (All Progressive Congress), a broadly centre-left party favouring economic nationalism and drawing support from the central and northern parts of the country. The opposition PDP (Peoples Democratic Party) tends to be more popular in the southern states and philosophically is centre right and more liberal in economic matters than the APC. Until 2015 the PDP was the governing party. Significantly, there was a peaceful transition between the two political parties. This was a first for Nigeria.

Currency and exchange control

Capital controls have excluded the payment of petroleum industry dividends and interest: The Nigerian authorities have operated a dual exchange rate system for the local currency, the naira, since 2014. The system was established in response to an acute shortage of dollars in the wake of the collapse in oil prices in the second half of that year. There is also a thriving parallel market in the naira where it sells at a discount to the official rate of about 20%. Government agencies and certain favoured importers have access to dollars on a more favourable basis than the official rate. To encourage foreign investment the remittance by the petroleum industry of dividends and interest has also continued to be allowed in recent years despite a deteriorating economic backdrop driven by the malaise in oil markets and the covid crisis.

Capital controls could be tightened but tightened but we think this unlikely: Dollar shortage has remained a problem for the authorities which has led to periodic downward adjustments in the peg against the dollar. Conceptually capital controls could be tightened in an attempt to limit outflows, including dividend and interest payments. Clearly this would adversely impact San Leon. Arguably, however, tighter capital controls are unlikely, given the importance of the foreign owned petroleum industry in Nigeria and the government's objective of boosting oil and gas output. Achievement of the objective will require the free flow of capital. In the absence of a surge in oil prices the authorities will probably have to revert to a unified official rate with a frequently adjusted peg or a floating currency. It should be noted that the bulk of the petroleum industry's costs in Nigeria, as elsewhere, are dollar denominated.

Share price performance and valuation

Some thoughts on the share price and valuation

Sharp rebound from the March low----: San Leon has rebounded sharply from the more than five-year closing low in late March 2020 of 11.1p/share. This reflects in part the broader petroleum sector trend but particularly the very positive developments in recent months surrounding the stock. The latter included the maiden dividend in May (a yield of 30% at the time), strong cash flow courtesy of the high-yield OML 18 loan notes, the still sizeable cash position post the dividend payment and the ELI pipeline deal. The recent high for the stock was 27.9p in mid-August 2020, an approximate six-month peak. At this level the San Leon market capitalisation was £126m. Since mid-August the stock has trended broadly flat. In late September it was trading at about 27p for a market capitalisation of £121m. This left the stock 2.3X the March low. By contrast, the two largest stocks in our peer group of Nigerian plays, Africa Oil Corporation and Seplat, were up on the same basis by about 25% and 45% respectively.

------but the EV/2P is decidedly lowly: Despite the rebound from the March lows, San Leon remains significantly below the recent highs of 43p/share and 56p/share in mid-March 2019 and late March 2017 respectively. The former peak roughly coincided with the buy-back announcement while the latter occurred at the time Toscafund was increasing its stake in the company.

The failure to regain earlier highs reflects partly negative market sentiment concerning the petroleum sector and partly, we believe, uncertainty concerning the outlook for future cash flows/dividends via the indirect interest in the OML 18 licence and the operator Eroton. Indeed, the EV/2P is a mere $1.1/barrel adjusting purely for estimated early September cash. If the receivables relating to OML 18, ELI and Decklar are treated as cash equivalents the EV/2P would drop to a nominal $0.3/barrel currently. In making comparisons internationally it should be noted that dollar/barrel valuations for Nigerian assets are substantially lower than in many other regions reflecting perceived higher risk.

The stock assigns little value to the interests in OML 18 and ELI: At a market capitalisation of $147m or £113m, it is worth noting that the enterprise value as of late-September 2020 was only around $38m or £29m after adjusting for the estimated cash balance and the OML 18 and ELI loan receivables. Effectively, the 10.58% interest in the OML 18 equity, the 10% interest in ELI and the prospective 15% interest in Decklar are only assigned nominal value by the share price.

Exhibit 14: Nigeria E&P peer group valuation

			Market cap		2P reserves	EV/2P
Stock	**Symbol**	**Price**	**US$m**	**EV US$m**	**boe mm**	**$/barrel**
San Leon	SLE: AIM	25p	146.2	38	118	0.3
ADM Energy	ADME: AIM	5.00p	5.0	5.0	16	0.3
Africa Oil	AOI: TSX	C$0.95	350	508	85.1	6.0
Lekoil	LEK: AIM	2.25p	15	28	19.4	1.4
Oando						
Seplat Petroleum	SEPL: LSE	61p	595	1007	509	2.0

Source: Thomson Reuters & Allenby Capital

Note: Prices as at 22nd September

Valuation methodology and estimate

Cash and other financial assets valued dollar for dollar, OML 18 interest $3/barrel of 2P and ELI interest $15m investment cost: We believe a hybrid sum-of-the parts approach to valuation can be usefully applied in the case of San Leon. This reflects on the one hand the company's sizeable financial assets in the form of cash and loan receivables and on the other exposure to operational assets as represented by the working interests in OML

18, ELI and prospectively Decklar Petroleum. In the case of cash, we have included San Leon's reported status as at September 18, 2020 of $15.8m. For the financial receivables we have included $82m for the balance on the OML 18 loan notes and $10m for the initial portion of the ELI loan. As far as the working interests are concerned in the equity of OML 18, ELI and prospectively in Decklar Petroleum we have adopted the following approach:

- OML 18 has been valued on a dollar/2P basis. We have used $3/boe for the purpose which reflects a compromise between the high-quality nature of the OML 18 assets and the low prevailing valuations/barrel on Nigerian assets. Based on San Leon's share of OML 18's 2P reserves of 117.7m boe (10.58% initial interest) the valuation is $353.1m

- The ELI equity interest valuation reflects the $15m investment that San Leon made in the company.

- The Decklar equity interest has been valued on a dollar/2P and dollar/2P contingent basis. We have used $3/boe for San Leon's share of 2P reserves and $1.5/boe for 2P contingent resources of 0.39mm barrels and 3.45mm barrels respectively. This would imply a valuation of $6.35m. Note here in reviewing the valuation quotients the Oza field is already well endowed with infrastructure.

Using the above approach our valuation for San Leon is $482m, £371m or 82.5p/share at an exchange rate of £1=$1.30. This valuation reflects San Leon's initial 10.58% interest in OML 18. Assuming the potential 5.4% OML 18 interest, the valuation would drop to 52.9p/share. It should be noted, however, that San Leon's interest in OML 18 is unlikely to drop to 5.4% for around ten years or so based on the likely time required for the indigenous carry vehicle to repay its carry plus coupon costs. The higher valuation is therefore more reflective of the near to medium term reality. Arguably, the key issues surrounding valuation are just how quickly Eroton can embark on a development programme at OML 18 to boost output and ultimately the dividend paying potential of the licence. Near to medium term the speed and success of development at Oza and the direction of commodity prices also have valuation implications.

Exhibit 15: San Leon Energy valuation

	Initial status OML 18 10.58% interest			Final status OML 18 5.4% interest		
	$m	£m	p/share	$m	£m	p/share
September 18, 2020 cash balance	15.80	12.15	2.70	15.80	12.15	2.70
OML 18 loan note balance	82.00	63.08	14.02	82.00	63.08	14.02
ELI loan note coupon receivable	10.00	7.69	1.71	10.00	7.69	1.71
Total cash and cash equivalents	**107.80**	**82.92**	**18.43**	**107.80**	**82.92**	**18.43**
OML 18 10.58% working interest	353.08	271.60	60.37	179.98	138.45	30.77
ELI 10% working interest	15.00	11.54	2.56	15.00	11.54	2.56
Decklar Petroleum 15% equity interest	6.35	4.88	1.09	6.35	4.88	1.09
Total	**482.23**	**370.95**	**82.45**	**309.13**	**237.79**	**52.85**

Source: Allenby Capital

Note: September 18 2020 cash balance is net of $6.75m of restricted cash held in escrow for the Decklar transaction

OML 18 loan note balance September 2020: $82m

OML 18 10.58% working interest reflects net 117.69 boe x $3/boe.

ELI working interest reflects loan note receivable principal.

Decklar Petroleum 15% equity interest reflects net 0.39mm boe 2P x $3/boe + 3.45mm boe 2C x $1.5/boe

Exchange rate £1=US$1.30.

Share price catalysts

Potential San Leon share price catalysts in the months ahead have already been signalled by the company. They largely relate to the repayment schedule on the OML 18 loan notes. We see the following items of news flow which could act as share price catalysts in the coming months:

- The scheduled early October 2020 payment of $10m on the OML 18 loan notes. This has already been signalled in advance but should nevertheless provide some comfort to investors. At roughly the same time San Leon will also be providing the final $5m of financing for the ELI pipeline.
- A possible dividend announcement in April 2021.
- Further strategic moves in Nigeria at any time over the coming year.
- The 2020 results announcement probably in June 2021. The key issues will be Eroton production, the prospects for a recommencement of the development programme at OML 18 and strategic. We think that it would not be totally surprising if San Leon announces another major strategic initiative in 2021.
- The concluding payments on the OML 18 loan notes in the third and fourth quarters of 2021. The timetable has already been provided.
- A continuing recovery in international oil prices. The oil market is in significant supply deficit and likely to remain so going into 2021. Strengthening economic growth combined with further progress on the covid-19 vaccine front could pave the way for a surprisingly strong upward trend in oil prices in the coming months. Bearing in mind its status as a close to pure play on oil production, San Leon would be a clear beneficiary of such a trend.

Disclaimer

Allenby Capital Limited ("Allenby") is incorporated in England no. 6706681; is authorised and regulated by the Financial Conduct Authority ("FCA") (FRN: 489795) and is a member of the London Stock Exchange. This communication is for information only it should not be regarded as an offer or solicitation to buy the securities or other instruments mentioned in it. It is a marketing communication and non-independent research and has not been prepared in accordance with the legal requirements designed to promote the independence of investment research, and is not subject to any prohibition on dealing ahead of the dissemination of investment research. The cost of Allenby research product on independent companies is paid for by research clients.

This communication is for the use of intended recipients only and only for distribution to investment professionals as that term is defined in article 19(5) of The Financial Services and Markets Act 2000 (Financial Promotion) Order 2005. Its contents are not directed at, may not be suitable for and should not be relied upon by anyone who is not an investment professional including retail clients. Any such persons should seek professional advice before investing. For the purposes of this communication Allenby is not acting for you, will not treat you as a client, will not be responsible for providing you with the protections afforded to clients, and is not advising you on the relevant transaction or stock. This communication or any part of it do not form the basis of and should not be relied upon in connection with any contract.

Allenby uses reasonable efforts to obtain information from sources which it believes to be reliable. The communication has been prepared without any substantive analysis undertaken into the companies concerned or their securities, and it has not been independently verified. No representation or warranty, express or implied is made, or responsibility of any kind accepted by Allenby its directors or employees as to the accuracy or completeness of any information in this communication. Opinions expressed are our current opinions as of the date appearing on this material only and are subject to change without notice. There is no regular update series for research issued by Allenby.

No recommendation is being made to you; the securities referred to may not be suitable for you and this communication should not be relied upon in substitution for the exercise of independent judgement. Neither past performance or forecasts are a reliable indication of future performance and investors may realise losses on any investment. Allenby shall not be liable for any direct or indirect damages including lost profits arising from the information contained in this communication.

Allenby and any company or persons connected with it, including its officers, directors and employees may have a position or holding in any investment mentioned in this document or a related investment and may from time to time dispose of any such security or instrument. Allenby may have been a manager in the underwriting or placement of securities in this communication within the last 12 months, have received compensation for investment services from such companies within the last 12 months, or expect to receive or may intend to seek compensation for investment services from such companies within the next 3 months. Accordingly, recipients should not rely on this communication as being impartial and information may be known to Allenby or persons connected with it which is not reflected in this communication. Allenby has a policy in relation to management of conflicts of interest which is available upon request.

This communication is supplied to you solely for your information and may not be reproduced or redistributed to any other person or published in whole or part for any purpose. It is not intended for distribution or use outside the European Economic Area except in circumstances mentioned below in relation to the United States. This communication is not directed to you if Allenby is prohibited or restricted by any legislation or registration in any jurisdiction from making it available to you and persons into whose possession this communication comes should inform themselves and observe any such restrictions.

Allenby may distribute research in reliance on Rule 15a-6(a)(2) of the Securities and Exchange Act 1934 to persons that are major US institutional investors, however, transactions in any securities must be effected through a US registered broker-dealer. Any failure to comply with this restriction may constitute a violation of the relevant country's laws for which Allenby does not accept liability.
By accepting this communication, you agree that you have read the above disclaimer and to be bound by the foregoing limitations and restrictions.

Research Recommendation Disclosure
Peter J Dupont is the author of this research recommendation and is employed by Allenby Capital Limited as an Equity Analyst. Unless otherwise stated, the share prices used in this publication are taken at the close of business for the day prior to the date of publication. Information on research methodologies, definitions of research recommendations, and disclosure in relation to interests or conflicts of interests can be found at www.allenbycapital.com. Allenby Capital acts as Nomad and broker to San Leon Energy plc.

Allenby Capital, 5 St Helen's Place London EC3A 6AB, +44 (0)20 3328 5656, www.allenbycapital.com