OMV PETROM Bucuresti

Equity|Romania|Oil&Gas Sector

IEBATRUST Financial & Investment Services

Company Update

Regional expansion and Neptun Deep – longer term geared joint to offset valuation culprits incorporated by high capex and low RRR. Longer term expected changing capital structure would create some mixed effects, not yet entirely explored.

BUY

previous: BUY

TARGET PRICE 12M (RON)	0.3600
Previous Target price	0.4100
SHARE PRICE (RON)	0.3025

Performance	**1M**	**3M**	**12M**	**YTD**
Absolute (%)	2.5%	5.2%	-11.4%	-17.2%
Relative to BET (%)	2.2%	1.7%	-27.3%	-32.0%

RIC	SNPP.BX
Bloomberg	SNP RO
Index listed	BET, BET-C, BET-XT, BET-NG
Market Cap (RON m)	17,134
Market Cap (EUR m)	3,808
Shares Out (m)	56,644
52 Week Range (RON)	0.2175 / 0.3080
% from 52 Week range	39% / -1.8%
Avg. daily volume 6M (shares)	12,363,775

Shareholders (%)	
OMV AKTIENGESELLSCHAFT WIEN	51.01%
Ministry of Energy	20.64%
Fondul Proprietatea (FP RO)	12.56%
Free float	15.79%

(IFRS)	**15A**	**16A**	**17E**	**18E**
P/E(x) adj.	n/m	12.5	8.3	7.2
EPS adj. ch. (%)	n/m	n/m	102.9%	15.5%
EV/EBITDA(x)	4.1	4.7	3.3	3.1
Net debt/EBITDA	0.2	0.5	0.5	0.4
P/BV(x)	0.7	0.5	0.6	0.6
ROE(%)	-2.6%	4.1%	7.9%	8.5%
ROIC(%)	-2.4%	3.7%	7.0%	7.6%
P/S (x)	0.9	0.8	1.0	1.1
Div. Yield (%)	0.0%	6.5%	4.8%	5.5%
RON m				
Revenues	18,145	16,247	17,240	16,631
EBITDA	6,245	4,931	6,184	6,548
Net income	-687	1,039	2,109	2,436
EPS	-0.012	0.018	0.037	0.043
EPS adj.	-0.012	0.018	0.037	0.043
BVPS	0.454	0.448	0.494	0.494
DPS	0.000	0.015	0.015	0.017
FCF equity	0.025	0.017	0.002	0.002

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- **Surprisingly, valuation looks good** – OMV Petrom trades below historic multiples on 2017-18E earnings. Petrom trades at 8.3x P/E for 2017 and 7.2x for 2018E, at moderate discount to major oil companies. Petrom looks only slightly better also on EV/EBITDA, trading at 3.3-3.1x still implying a discount to last 2Y avg. of 4x. Our estimated 4.8-5.5% yield for 2017-2018E – which may be at further risk – but proves not very satisfactory on the longer term, under expectations for an upward sloping yield curve. We updated our 12M price target (TP) down by 12% to RON 0.36 (from RON 0.41).
- **Dividends.** OMV Petrom intends to keep an attractive dividend going onwards, we estimate a payout of 35% on avg. for the future, but to also maintain a strong balance sheet going onwards and a positive FCF after dividends. This is contingent to crude oil prices to generate cash-flow for capex, but also on the capex level required for the strategic objectives. For 2016, OMV Petrom proposed a pay-out ratio of slightly above 80%, or gross DPS of RON 0.015. For the next 3Y, we estimate avg. DPS at RON 0.016, as we think that, should the crude price stabilize at levels of around USD 55/bbl going onwards, the pay-out will not be that high as in 2016, in the context of Neptun FID release expectations, but management will choose a stable dividend policy, aligning the growth in DPS to that of EPS.
- **Is the capital structure to change – optimal financing structure ahead.** Overall, but again on the longer term, and with the new strategy drawn by management, a new picture sketches ahead eyeing for some new blend on the refining segment, i.e moving higher on the value chain by capturing some better value of each barrel and announcement of first polyfuel plant in RO. Economics behind the project detail about some EUR 60m capex initial deployment, a timetable of around 2Y for completion and first B/S gains starting 2019. OMV Petrom leverage should increase considerably after Neptun FID start – but no more in-depth details yet.
- **High capex and low RRR do not walk hand in hand, cost base is to come under review again?** We think yes, the cost base will come again under review, as the capex run in the past couple of years, turned to be only a marginal contributor to RRR, and its low efficiency generated, and lack of viable domestic alternatives, brought into picture the quest for new acquisitions, which should not be overlapping over OMV fields or countries of interest, admitted by management. Neptun deep project and additional fields acquired should increase costs base, instead, or maybe we should see a separate reporting manner for the two units cost base, fortunately.
- **Taxation side remains challenging but the picture seems not to be very troublesome, tough.** No changes implied in upstream taxation levels either, until furter notice, and no impact on estimates from volumes that could potentially flow from the Black Sea. Sensitivity-wise, the expected value add-on from Downstream Oil improvement in production mix cannot offset a much higher taxation impact.
- **Black Sea gas cannot come on stream without BRUA – pending FID.** Transgaz capex implementation seems to keep on hold RO gas market integration with more developed ones, but on-shore RRR ratios would move lower considerable, in lack of acquisitions. An additional pipeline coming from the Black Sea to Podisor (Marea Neagra-Podisor pipeline) will generate costs of EUR 278.3m. The gas reserves discovered in the Black Sea with importance for Romania are the joint ventures run by Lukoil/Romgaz and Petrom/Exxon Mobil for some 30bm cm and 42-84bn cm for the latter. The additional pipeline Marea Neagra-Podisor, should connect the shore with BRUA, and construction will be completed in parallel with BRUA, otherwise, there is no connection to the Black Sea, except for other projects like South Stream, although would keep Romania away from any Black Sea gas.

Please observe relevant disclosures at the end of the report

Financials & Valuation (Summary)

Financial Statements (IFRS)

Profit & Loss (RON Mn)	2014A	2015A	2016A	2017E	2018E
Revenues	21,541	18,145	16,247	17,240	16,631
EBITDA	8,245	6,245	4,931	6,184	6,548
EBIT	3,338	-530	1,472	2,604	2,976
Net financials	-429	-207	-204	-204	-204
EBT	2,909	-737	1,271	2,399	2,772
Net income	2,103	-687	1,039	2,109	2,436
IEBA net income	2,103	-687	1,039	2,109	2,436
Dividend	634	0	852	843	974

Cash flow (RON 000) - IEBA TRUST					
Net Cash flow from operations	7,718	5,295	2,407	4,698	5,098
Capex	6,203	3,906	1,435	4,565	3,800
FCFF	1,514	1,389	972	133	1,298
Other cash flows	-2,285	-2,799	-3,487	6,942	3,117
Cash flow used in investments	211	1,015	0	-4,565	-3,800
Change in debt	420	-60	3,239	242	242
Change in Capital	0	0	0	0	0
FCF	-140	-455	724	2,753	857

Balance Sheet (RON Mn)					
Net fixed assets	33,947	31,709	31,526	32,639	32,744
Current investments	3,296	4,311	4,311	4,311	4,311
Current assets	5,882	5,089	5,208	5,066	4,758
Cash & others	1,268	813	724	1,573	1,457
Total Assets	43,125	41,110	41,045	42,016	41,813
Current liabilities	6,160	5,040	5,589	5,701	5,199
Total debt	1,863	1,802	3,239	3,481	3,481
Net debt	595	990	2,515	2,902	2,902
Other L-T liabilities & provisions	8,097	8,579	6,897	4,944	3,796
Shareholders capital	5,664	5,664	5,664	5,664	5,664
Other reserves	21,377	20,079	19,724	22,307	23,769
Total Equity	27,042	25,743	25,388	27,971	29,433
Minorities	-36	-55	-69	-82	-96
EV	33,360	25,853	23,398	20,600	20,600
Market Cap	25,546	16,977	13,028	17,560	17,560
No of shares Year End (000)	56,644	56,644	56,644	56,644	56,644
No of shares Diluted (000)	56,644	56,644	56,644	56,644	56,644

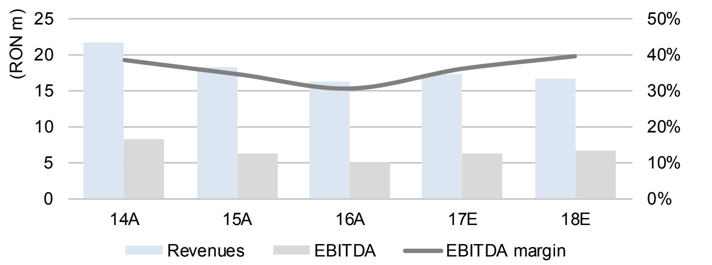
Per share	2014A	2015A	2016A	2017E	2018E
EPS	0.037	-0.012	0.018	0.037	0.043
IEBA EPS	0.037	-0.012	0.018	0.037	0.043
DPS	0.011	0.000	0.015	0.015	0.017
BVPS	0.477	0.454	0.448	0.494	0.494
FCFPS	0.027	0.025	0.017	0.002	0.002

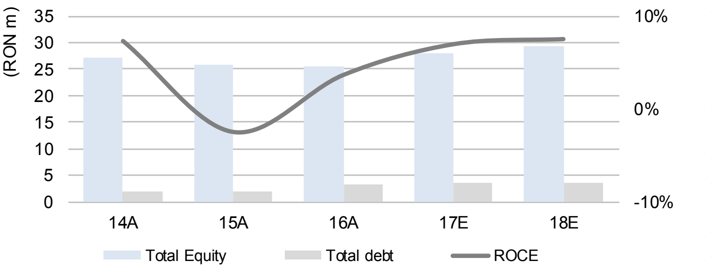
Growth rates & margins					
Revenues	-10.9%	-15.8%	-10.5%	6.1%	-3.5%
EBITDA	-11.5%	-24.3%	-21.0%	25.4%	5.9%
EBIT	-44.0%	-115.9%	-377.7%	76.9%	14.3%
EBT	-48.9%	-125.3%	-272.3%	88.8%	15.5%
Net Income	-56.4%	-132.7%	-251.2%	102.9%	15.5%
IEBA net Income	-56.4%	-132.7%	-251.2%	102.9%	15.5%
Dividend	-63.6%	-100.0%	n/a	n/a	n/a
EPS	-56.4%	-132.7%	-251.2%	102.9%	15.5%
IEBA EPS	-56.4%	-132.7%	-251.2%	102.9%	15.5%
DPS	-63.6%	-100.0%	n/a	n/a	n/a
EBITDA margin	38.3%	34.4%	30.3%	35.9%	39.4%
EBIT margin	15.5%	-2.9%	9.1%	15.1%	17.9%
Net margin	9.8%	-3.8%	6.4%	12.2%	14.6%
IEBA net margin	9.8%	-3.8%	6.4%	12.2%	14.6%

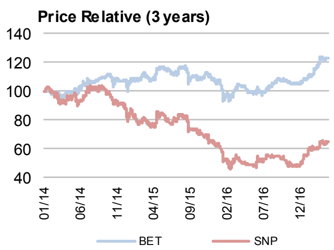
Key items

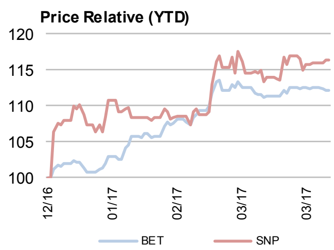
Ratios and multiples	2014A	2015A	2016A	2017E	2018E
P/E(x)	12.1	n/m	12.5	8.3	7.2
P/E(x) IEBA	12.1	n/m	12.5	8.3	7.2
P/E(x) IEBA at 52wks High	13.2	n/m	16.8	8.3	7.2
P/BV(x)	0.9	0.7	0.5	0.6	0.6
ROE	7.8%	-2.6%	4.1%	7.9%	8.5%
IEBA ROE	7.8%	-2.6%	4.1%	7.9%	8.5%
ROCE	7.4%	-2.4%	3.7%	7.0%	7.6%
IEBA ROCE	7.4%	-2.4%	3.7%	7.0%	7.6%
EV/EBITDA (x)	4.0	4.1	4.7	3.3	3.1
EV/EBITDA (x) at 52wks High	4.3	5.1	5.7	3.3	3.1
Net debt/EBITDA (x)	0.1	0.2	0.5	0.5	0.4
EBITDA/Net inter. Exp. (x)	17.3	-9.3	-4.3	-8.2	-8.2
EV/CE (x)	1.2	0.9	0.8	0.7	0.6
P/S (x)	1.2	0.9	0.8	1.0	1.1
P/FCFPS (x)	16.9	12.2	13.4	131.9	131.9
FCF Yield	5.9%	8.2%	7.5%	0.8%	0.8%
Dividend Yield	2.5%	0.0%	6.5%	4.8%	5.5%
Dividend payout	30.2%	0.0%	82.0%	40.0%	40.0%
Net debt/Equity	2.2%	3.8%	9.9%	10.4%	9.9%
T.debt/(T.debt + Equity)	6.4%	6.5%	11.3%	11.1%	10.6%

Stock's information			
Share price (RON)	0.3025	Target price /share	0.3637
52 weeks High price (RON)	0.3080	Mkt Cap (RON m)	13,028
52 weeks Low price (RON)	0.2175	EV (RON m) E	20,600
Country	Romania	Reuters	SNPP.BX
Sector	Oil&Gas Sector	Bloomberg	SNP RO









Source: SSIF IEBA Trust estimates; pricing as of 30 March 2017, unless otherwise specified

Investment case revisited – We view OMV Petrom moving forward the value chain on the refining segment via capturing additional value from its production mix, while Upstream side seems to be at a turning point – new acquisitions are on focus and most probably Neptun Deep FID will receive approval

Crude price decline lowers estimates. Earnings and dividends outlook seem not to be quite on the bright side for the short-to-medium term mostly due to lowering forecast for the crude oil price moving forward compared to the year start, when we briefly hiked target price (TP) to RON 0.41/share. We do consider that Downstream side will add more flexibility and value, on and from, its value chain from an improvement in the production mix. Neptun deep FID represents highest catalyst of OMV Petrom from the last couple of years, which should drag valuations and multiples much higher for the stock, but at the same time, the expected changing capital structure (higher debt), increasing capex and interest rate environment should not be neglected either.

Surprisingly, valuation looks good – Currently, OMV Petrom trades below historic multiples on 2017-18E earnings. Petrom trades at 8.3x P/E for 2017 and 7.2x for 2018E, at moderate discount to major oil companies. Petrom looks only slightly better also on EV/EBITDA, trading at 3.3-3.1x still implying a discount to last 2Y avg. of 4x. Our estimated 4.8-5.5% yield for 2017-2018E – which may be at further risk – but proves not very satisfactory on the longer term, under expectations for an upward sloping yield curve. We updated our 12M price target (TP) down by 12% to RON 0.36 (from RON 0.41).

Our estimates do not incorporate any of the regional expansion projects, or the Neptun area gas, due to lack of appropriate timing and main financial metrics.

Major valuation culprits remain the high capex needed to support current declining production which supports some 3% forecast for the production, suggesting mature fields and low efficiency, some increased risks for some new impairments to occur. For 2017E we estimated sales at RON 17.24bn, up 6.1% Y/Y, EBITDA around 6bn, an increase of 25% Y/Y, and net profit at RON 2.1bn, up 2x Y/Y but slightly higher than mgt. estimated at RON 1.8bn (unconsolidated basis). Q1'17 should benefit gas sales due to the cold weather and we expect some good results.

Dividends. OMV Petrom intends to keep an attractive dividend going onwards, we estimate a payout 35% on avg. for the future, but to also maintain a strong balance sheet going onwards and a positive FCF after dividends. This is contingent to crude oil prices to generate cash-flow for capex, but also on the capex level required for the strategic objectives. For 2016, OMV Petrom proposed a pay-out ratio of slightly above 80%, or gross DPS of RON 0.015. For the next 3Y, we estimate avg. DPS at RON 0.016, as we think that, should the crude price stabilize at levels of around USD 55/bbl going onwards, the pay-out will not be that high as in 2016, in the context of Neptun FID release expectations, but we consider that management will choose a stable dividend policy, aligning the growth in DPS to that of EPS.

Management targets. 2017 outlook and targets remain positive and well-embarked on a strong positive message about a good but flexible resource management, with focus on high capex, maintenance of positive FCF after dividends and some attractive dividends going ahead, but also speaks about some 3% annual production decline moving forward. Assumptions used are more positive on power demand and maybe for first year, some positive thoughts on avg. spark spreads, and a tight but manageable aspect of the gas market, which employs some high competition and increased margin pressure in

Downstream Oil. CAPEX for the next 5Y should reach some EUR 5bn cumulative figure, 85% in Upstream, but we do not know how much is directed toward acquisitions and, if it includes capex required for the Black Sea side either. Strategy does mention about regional expansion, but no further details.

Is the capital structure to change – optimal financing structure ahead. Overall, but again on the longer term, and with the new strategy drawn by management, a new picture sketches ahead eyeing for some new blend on the refining segment, i.e moving higher on the value chain by capturing some better value of each barrel and announcement of first polyfuel plant in RO. Economics behind the project detail about some EUR 60m capex initial deployment, a timetable of around 2Y for completion and first B/S gains starting 2019. OMV Petrom leverage is not expected to change due to this investment.

Market dynamics supported a mixed evolution for upstream EBIT. We have updated our forecast, which stands lower compared to first glance assessment, mostly due to the drop in the crude oil price, forecasted by EIA at 54 USD/bbl (Ural Avg.) on avg. for the next two years, which is lighter than management expectations at USD 55/bbl. Cash-flow prone stands the depreciation of the local currency, which comes to partially offset the drop in crude oil price, but Downstream should contribute higher too. DPS assumptions stands at RON 0.016 on avg over next 3Y, implying avg. dividend yield of 4.5% over FY'17-'20.

E&P segment – major concern for the company, RRR put forward as great milestone to overcome. The E&P segment should be affected by still a halt in prices onwards – crude oil price experienced a quite severe drop following some good and promising start for the year, volumes are expected to decline, until some major acquisitions will take place, contributing to a faster decline in the RRR, which was on the declining trend for the last 2 years. Production opex is at lowest level and asset tax is out starting this year, which should contribute to balancing the cash-flows required to support this year's capex, which is expected at RON 4.5bn. Sensitivity wise, some USD 1/bbl hike should add some EUR 20m to the company's EBIT, while a stronger USD against RON contributes the most, with some EUR 46m, as per management statements.

Temporary hike in crude oil price. First quarter of 2017 benefited from a good improvement in upstream market price although the story did not last much, but on the positive side, the power segment should see some reliable support from volumes and better spark spreads – some hikes were reached in extra consumption, all in all, the price increases lasted only for a marginal timeframe.

Main upstream caveats. On the longer term, FX should play a more important role, offsetting main caveats on upstream like lowering production volumes, estimated by management at some 3% per year, going onwards, and potential difficulties on the cost base.

High capex and low RRR do not walk hand in hand, cost base is to come under review again? We think yes, the cost base will come again under review, as the capex run in the past couple of years, turned to be only a marginal contributor to RRR, and its low efficiency generated, and lack of viable domestic alternatives, brought into picture the quest for new acquisitions, which should not be overlapping over OMV fields or countries of interest, admitted by management. Neptun deep project and additional fields acquired should increase costs base, instead, or maybe we should see a separate reporting manner for the two units cost base, fortunately.

Taxation side remains challenging but the picture seems not to be very troublesome, tough. No changes implied in upstream taxation levels either, until further notice, a no impact on estimates from volumes that could potentially flow from the Black Sea. Starting 2017E, the asset tax has expired, while windfall tax has been maintained – and, in our view, due to the political turmoil experienced in the beginning of the year, we think that some news flow could be available later during the year, maybe. This is one of major risks that affect OMV Petrom cash-flows, but as already acknowledged by the RO state, investments will be considered under new regulations, should they change much, but for sure on-shore and off-shore will receive different taxation levels, due to different economics/costs. The exclusion of the asset tax, will keep in treasury some RON 260m, annual basis.

Windfall tax will be maintained starting 1st April – for the moment the calculus method seems a bit confusing; we chose to keep the amounts paid at current levels for the forecasting horizon of around RON 360m on annual basis for Petrom. Our impression, at first glance, is that these amounts could drop, but for the time being, we find a little bit confusing media details about calculus methodology, thus we expect the official ruling and methodology to bring some clarifications with respect to the reference price, and assess a more accurate impact. Overall, we think it should be cash-flow neutral for our estimates, though, and with a minimal impact in valuation, also. The regulator could keep the cap at RON 72/MWh as currently, which makes no additional impact from taxation side, but could suggest that selling price should converge towards this cap, at least, putting some upward pressure on the gas prices for the short-to-medium time period.

Black Sea gas cannot come on stream without BRUA – pending FID. Transgaz capex implementation seems to keep on hold RO gas market integration with more developed ones, but on-shore RRR ratios would move lower considerable, in lack of acquisitions. Neptun deep has reserves of 1.5-3tcf, and is expected to contribute the most to key RRR, as per management (most probably some 30% of company's probable oil and gas reserves with investments of around USD 1.5bn equally split between OMV Petrom and Exxon). Transgaz pipeline is expected to be finalized by 2019E, and given this aspect and any other potential delays, which could prolong the completion deadline, we think first volumes could come around 2020E-2021E.

Downstream Oil seen higher in full company EBITDA. Downstream Oil received higher weight in full EBITDA for next 3YE due to better margins showed in the past two years vs. historical avg., and macro side, although some local economists spoke about non-sustainable feature, but we think that the retail market will maintain an increased oil product demand despite some fierce competition. 2016 refining margins dropped by 8% due to higher costs of crude which offset the better products spreads. Earlier during the year, management was expecting some declining margins mostly on the back of the increasing crude oil price, but we as crude drops, margins should recover on the short term. Demand-wise, and excluding the more worrisome macro picture, OMV Petrom works close to full-capacity on refining side, and once with the completion of the polyfuel plant, that will enable the company to capitalize more on the value chain, we see risks but on the positive side, for Downstream Oil, to gain more in overall EBITDA.

A closer look at operating segments – All eyes on Upstream side, but Downstream should not be neglected either

The cost base came under review, as capex supported only decreasing growth rates in production

Upstream – past: On an annual basis, 2016 operating environment was affected by lower avg. realized crude oil price at USD 35.58/bbl (-21% Y/Y), hydrocarbon production dropped to 174kboe/day, down 3% Y/Y – crude oil production dropped faster by 4.21% Y/Y to 29.15m bbl, while gas production posted a marginal drop of 0.56% Y/Y to 5.29bn cm.
Production – cost base: The reserve replacement rate (RRR), was at 35% computed as avg. over last 3 years, was affected by reduction of investments, increased number of uneconomic wells due to mature profile, but some planned maintenance took place as well. 2015 marked the lowest RRR (in Romania), sending the cost base under review as capex and mostly, lack of self-sufficient capex, was in tandem with the evolution of the crude oil price. Opex/boe dropped a massive 10% Y/Y to USD 11.85/boe, mainly as a result of favorable FX effects and lower production levels. 2016 reported clean EBIT was the result of 15% Y/Y improvement in realized oil price, decreased production costs, royalties and depreciation by a cumulated 3% Y/Y, and lower exploration expenses due to lower activity in Neptun, which partially compensated a 3% Y/Y decline in total upstream production – mostly due to surface facility works in Totea Deep which were in part offset by production volumes in Lebada East NAG.

Upstream – CAPEX: CAPEX in Upstream activities was RON 2.1bn, and represented some 82% of 2016 total group capex, but was down 39% Y/Y, as a reaction to the crude oil price drop, which led to investments prioritization. The effect was in fact a drop in RRR, and proved once again the mature feature of upstream wells. Upstream investments were focused on activities related to workovers and subsurface operations, finalizing field redevelopments, surface facilities, drilling development wells, as well as investments related to the Neptun Deep project. For 2017E, capex should reach EUR 1bn, up 40% Y/Y, out of which approximately 85% will be directed to Upstream, which loosely speaking, is no change compared to past years, with respect to capex breakdown. Exploration expenditure are estimated to increase by 15% Y/Y, most probably largest part, as some six wells are planned for drilling.

Black Sea projects are pending Transgaz capex implementation – main reason for lacking FID, yet

Should production from the Black Sea start, Romania could double its annual production. Also, Romgaz will need to build some additional UGS facilities within the area, but both production of OMV Petrom and Romgaz, depend first on the infrastructure in the area. Two years seem a good timetable for the construction of the pipeline but without it being functional, neither Romgaz and/or OMV Petrom we view as front running Transgaz with some extra Upstream capex. OMV Petrom has no reasons to start production due to lack of infrastructure while Romgaz does not need any extra UGS for the moment in lack of production, so the key for this Black Sea gas to be put on stream is mostly in the hands of Transgaz. At the moment, FID for the Black Sea gas is missing, the commercial viability of the drilled area was not declared yet, but most probably, it will be, or at least messages from management look encouraging on this side. Infrastructure remains tough the main weak point.
In brief, the drilling activity for Black Sea ended, bringing the gas on-shore and capex required to do that is not cheap, which would imply some changing capital structure, should

the crude oil price remain under USD 50/bbl. Moreover, Petrom cannot build on its own this infrastructure, but depends on Transgaz and hopefully, the project will be completed in 2020, the earliest.

Due to the difficult economics of the project and changing financials of OMV Petrom should the pipeline be available, we choose not to incorporate the metrics behind into the planning model. We assume once with commercial viability declared, the capital structure of OMV Petrom should change, because, at current cash-flow levels, most of the capex goes to on-shore upstream fields, and should dividend policy be maintained, gearing ratio should be around 50%, depending funds needed for Black Sea.

Hydrocarbon production to remain in a range of an interesting 3% drop by 2020 – guidance

Hydrocarbon production at Group level should decline on avg. by 3% Y/Y, as per latest guidance, which should reach some 170kboe/day, with not too much deviation from current production split between oil and gas, which stands some 50% skewed towards crude oil production (54-56% historical average). Off-shore production should yield a portfolio of 56% gas production and 44% for oil side – unfortunately timing for commercial viability is yet unknown, similar to production flows.

Production cost remains a very sensitive issue, of prime focus for management going ahead – FY'16 major turnaround year for upstream costs, FX impact not very convincing either

A 3% Y/Y drop in total hydrocarbon production, under a stable gas production assumption going forward, means a larger drop on crude oil price, while it is unclear if, and how the cost base will be affected, but on the short-to-medium term, the trend should be at least constant. However, current plans – of approximately 1,000 capital works and drilling some 70 new wells, while on exploration side, six wells (onshore and shallow offshore) are planned for drilling, should raise costs again (it implies also production), but we assume these two approaches should balance each other toward a flat cost base, in our assumptions. On the other hand, a flat cost base could be a little bit forced, but we think that the mature profile of existing production wells should also bring some downwards adjustment in costs due to shut down initiatives.

CAPEX cuts mainly driven by focus on the most profitable barrels

OMV Petrom acknowledged the RRR issue, and intends to add some 80m boe in reserves via near-term acquisitions, prioritizing the Caspian and Western Black Sea. At the moment, we think that we have very few knowledge in order to incorporate any additional barrels into forecast. By 2021, the RRR should reach 100%, which is highly both optimistic and ambitious. We consider that the stabilization of crude oil price around USD 55/bbl, will contribute significantly to cash-flow and help these acquisitions, with less leverage.

We believe that acquisitions are possible and supported by the current financial picture of the company, but timing and potential barrels' flow remains, however uncertain and difficult to estimate and incorporate in the model for the time being. We estimated for a 5Y time period crude oil production will decrease some 5% on an annual avg., with gas production flows to drop only marginally, and support some overall hydrocarbon production at an annual 3% drop, in line with management guidance – in lack of any other details.

All in all, our estimated upstream EBITDA stands around RON 4.4bn on avg. over 5Y forecasted horizon, with upside arising from the USD 10/bbl premium above FY'16A avg. crude oil realized price, higher FX and assumed stable cost base, albeit for the latter we have the least insight about. We think of potential bottom to have been reached in this regard, but most probably should uneconomic wells come on stream again, drop should not be surprising.

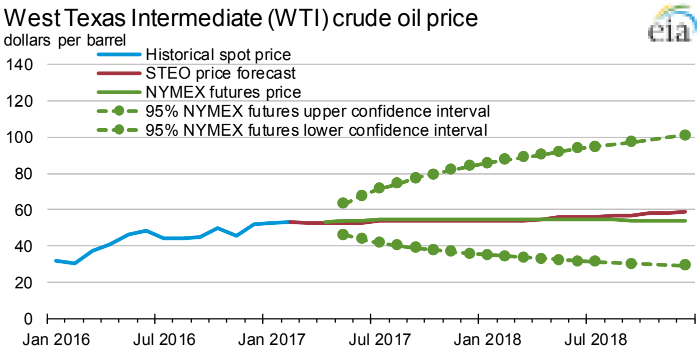
Crude oil price not too early on the positive trend, but we assume some gradual improvements to occur, however, a cap of USD 70/bbl will be difficult to reach too early – oil vs. metals are on a widening divergent gap since early 2017

U.S. crude oil production avg'd an estimated 8.9m bbl in 2016. U.S crude oil production is forecast to avg. 9.2m bbl in 2017 and 9.7m bbl in 2018.

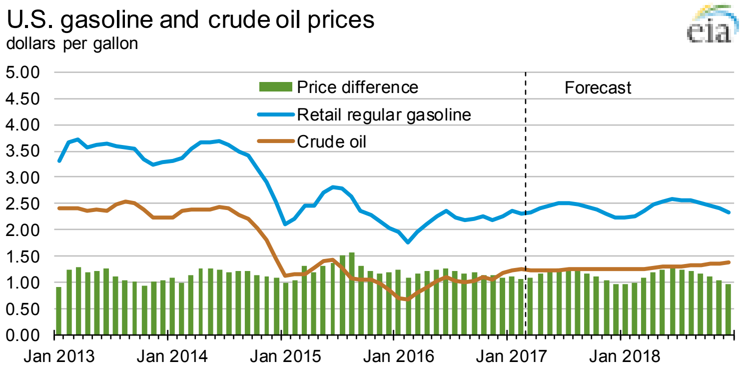
Benchmark North Sea Brent crude oil spot prices avg'd USD 55/bbl in February, largely unchanged from the avg. in January – as per EIA details.

The tables below detail about exact estimates from EIA with respect to WTI, middle distillate prices, Henry Hub natural gas price estimates, which mostly employ that for the short–to–medium term horizon, crude oil price is unlikely to recover to levels above USD 70/bbl.

EIA Short-Term Energy Outlook Figures, March 2017

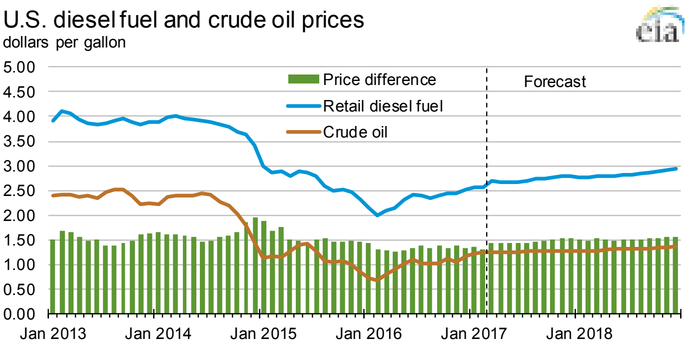


Note: Confidence interval derived from options market information for the 5 trading days ending Mar 2, 2017. Intervals not calculated for months with sparse trading in near-the-money options contracts.
Source: Short-Term Energy Outlook, March 2017.



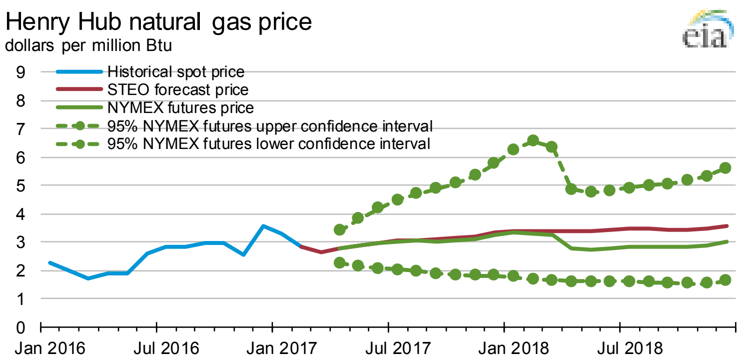
Crude oil price is composite refiner acquisition cost. Retail prices include state and federal taxes.

Source: Short-Term Energy Outlook, March 2017.

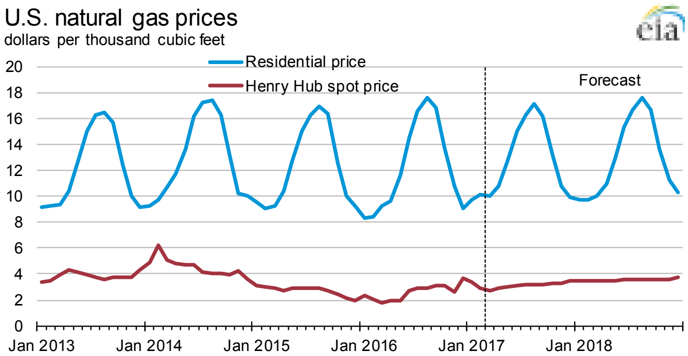


Crude oil price is composite refiner acquisition cost. Retail prices include state and federal taxes.

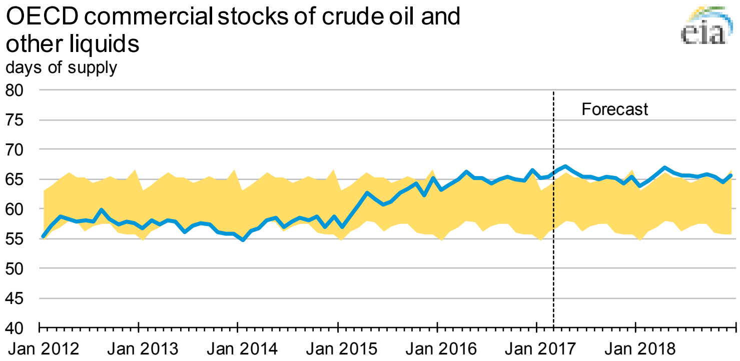
Source: Short-Term Energy Outlook, March 2017.



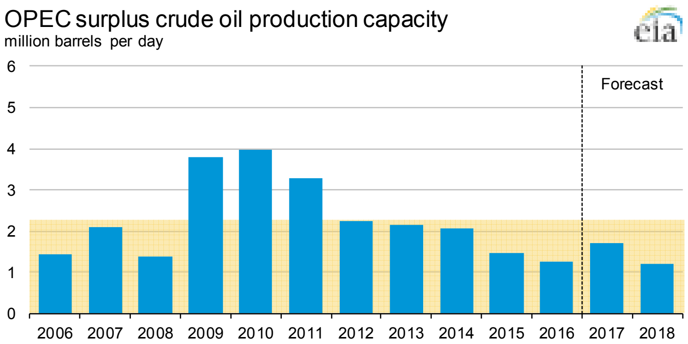
Note: Confidence interval derived from options market information for the 5 trading days ending Mar 2, 2017. Intervals not calculated for months with sparse trading in near-the-money options contracts.
Source: Short-Term Energy Outlook, March 2017.



Source: Short-Term Energy Outlook, March 2017.



Note: Colored band around days of supply of crude oil and other liquids stocks represents the range between the minimum and maximum from Jan. 2012 - Dec. 2016.
Source: Short-Term Energy Outlook, March 2017.



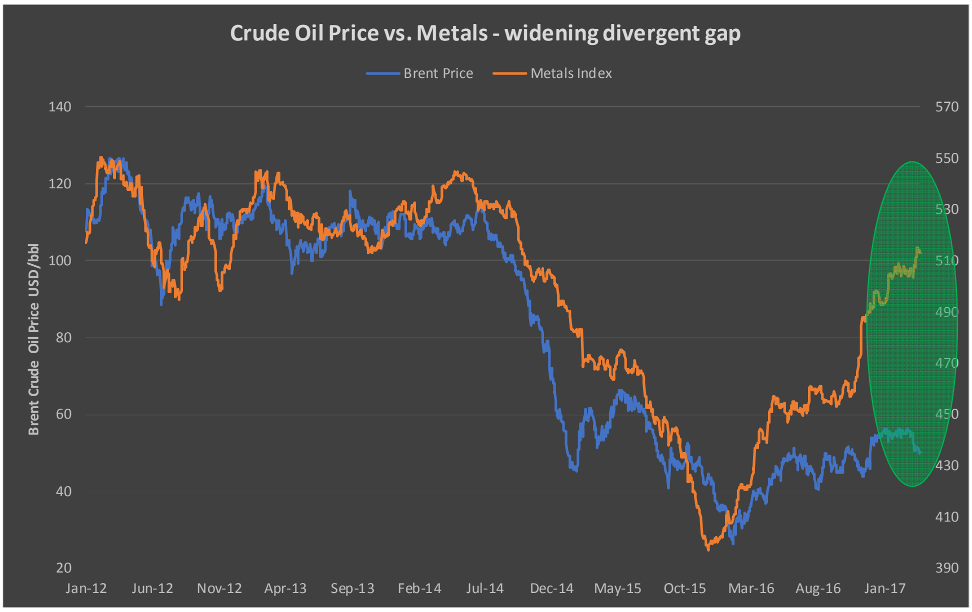
Note: Shaded area represents 2006-2016 average (2.3 million barrels per day).
Source: Short-Term Energy Outlook, March 2017.

	2015	2016	2017	2018
Crude Oil prices	(dollars per barrel)			
WTI Spot Average	48.67	43.33	53.49	*56.18*
Brent Spot Average	52.32	43.74	54.62	*57.18*
Imported Average	46.34	38.78	49.97	*52.67*
Refiner Average Acquisition Cost	48.4	40.72	52.5	*55.2*

Source: EIA, Short-Term Energy Outlook March 2017

Promising start for the year, but recent abrupt decline, may expose the Upstream side for additional impairments for the year, pending no revival in Brent price, but this is a wait-and-see issue

EIA forecasts Brent crude oil prices to avg. USD 55/bbl in 2017 and USD 57/bbl in 2018. West Texas Intermediate (WTI) crude oil prices are expected to avg. about USD 1/bbl less than Brent prices in the forecast. Another quite unexpected pattern that got featured since early January 2017, is the widening divergent gas between oil and metals, suggesting again that expectations for crude supply is to remain sufficient for covering demand (short–to–medium term).



Source: Bloomberg, IEBA TRUST

Please observe relevant disclosures at the end of the report

Investments-crude oil price congruence. For the time being, the business model is planned to become cash-flow neutral with crude oil price at USD 40/bbl; should the crude oil price increase, capex should also jump, but within the limits of a positive cash-flow, therefore the investments-crude oil price mutual congruence. With lower capex, the company can engage to workovers of existing wells, infill drilling campaigns and selected field redevelopment programs, to secure minimal production declines, which are estimated up to 3% on an annual basis. During 2012-2016, OMV Petrom managed to reduce production decline by 4.7%, while dropping capex by 45%, opex was declined by USD 3/bbl, from USD 15/bbl to USD 12/bbl and crude price more than halved from above USD 100/bbl to below USD 40/bbl. No hedging announced for 2017, either. In Q1'16, clean EBIT in Upstream was negative at RON 73m, having achieved an avg. realized crude oil price at USD 27/bbl.

Downstream: What's new on business operations: OMV Petrom eyes moving higher on the value chain via the construction of a polyfuel project to upgrade production mix

Downstream Oil historical performance. In 2016, higher retail sales volumes were offset by weaker refining margins, with company full CCS EBIT al RON 1.7bn implying also higher Downstream contribution; clean EBIT CCA was at RON 1.3bn in 2015 and RON 1.1bn in 2016 due to positive CCS effects at RON 120m on higher crude oil price. Avg. utilization rate of the Petrobrazi refinery was at 90%.

Downstream Oil seen higher in full company EBITDA. Downstream Oil received higher weight in full EBITDA for next 3YE due to better margins showed in the past two years vs. historical avg., and macro side, although some local economists spoke about non-sustainable feature, but we think that the retail market will maintain an increased oil product demand despite some fierce competition. 2016 refining margins dropped by 8% due to higher costs of crude which offset the better products spreads. Earlier during the year, management was expecting some declining margins mostly on the back of the increasing crude oil price, but we as crude drops, margins should recover on the short term. Demand-wise, and excluding the more worrisome macro picture, OMV Petrom works close to full-capacity on refining side, and once with the completion of the polyfuel plant, that will enable the company to capitalize more on the value chain, we see risks but on the positive side, for Downstream Oil, to gain more in overall EBITDA.

Refining margin higher, but in-depth modeling obstructed by condensed reporting way. OMV Petrom does not disclose the portion of Marketing segment contribution to Downstream Oil segment side – which makes pointless the reporting of the refinery margin – it cannot be computed going forward, but obviously, the fact that in 2015 reported refining margin was reported at USD 8.71/bbl, is without doubt the effect of improvement in middle distillate spreads and volumes sold, higher energy efficiency of the refinery. The pricing at which crude is transferred from Upstream to Downstream is not very clear either, if the current cost of supply, as mentioned in the official reporting, is the current production cost and/or some discounts apply, which would be an artificial margin uplift.

Negatives over positives, and excluding the reporting issue, the results of the Downstream segment are the result of the EUR 600m completed upgrade, which boosted efficiency due to better yield structure, and in a sensitivity-like case, we estimate that the refining margin should remain within a range of USD 5-to-7/bbl for the next 3Y, at least.

New polyfuel plant will allow conversion of LPG components into gasoline and middle distillates. OMV Petrom intends to invest some EUR 60m in a polyfuel plant that will allow conversion of LPG components into gasoline and middle distillates, and is expected to be fully operational beginning of 2019 – refinery capacity will remain at 4.5m tonnes/year. Construction will start in 2017.

Downstream Gas: 2016 gas sales were lower by 3% Y/Y at 43.86TWh (third party sales) as Brazi gas consumption was higher, generating some 2.93TWh energy production, up 11% Y/Y. Clean EBIT was positive at RON 11m, due to better contribution of Q4'16, which generated half of end-of-period profitability.

Black Sea gas cannot come on stream without BRUA – pending FID. Transgaz capex implementation seems to keep on hold RO gas market integration with more developed ones, but on-shore RRR ratios would move lower considerable, in lack of acquisitions. Neptun deep has reserves of 1.5-3tcf, and is expected to contribute the most to key RRR, as per management (most probably some 30% of company's probable oil and gas reserves with investments of around USD 1.5bn equally split between OMV Petrom and Exxon). Transgaz pipeline is expected to be finalized by 2019E, and given this aspect and any other potential delays, which could prolong the completion deadline, we think first volumes could come around 2020E-2021E.

Modest spark spreads ahead, volumes not very impressive either, but managed to gradually improve – however results are not spectacular. Gas demand to remain broadly unchanged.

2017 gas pricing evolution could be a slender topic, but on the longer term, the trend is positive. Starting 1st of April, the gas price for households is considered deregulated, but some further steps are needed to be done in order to achieve full liberalization of the gas market, which is rather a long-term process.

Some more technical issues were brought under discussion related to a more flexible gas trading platform that needs to be secured and some more legislation to support trading should be implemented. A 5-6% increase from current RON 60/MWh will mean some RON 64/MWh price for domestic producers, which means some EUR 14/MWh, which is only EUR 3/MWh below import price which stands around EUR 17/MWh, on average for the next three quarters according to the data provided by CEGH Quarterly Futures. All in all, we think that, at least for the upcoming two summer quarters, the impact will be marginal on financials due to seasonal low volumes, while the crude oil price needs room to climb, on the longer term, above a more sustainable USD 55/bbl to produce larger cash-flow effects.

Pricing: We have considered, as in the case of Romgaz, that OMV Petrom would sell some equally volumes of 50% to households and 50% to households. On the short term, some skewing towards households could occur, since we do not estimate some major impact from resumption of demand from the industrial sector.

In more detail, for households' gas price we used the figures from the new gas price deregulation calendar until April 2017, while for the industrials side we used spot and forward quotations available on CEGH OTC market – main platform for gas trading in Central Europe. Since the market for households is considered deregulated after 1st April 2017, the gas price for households should follow the trend in import gas prices or at least those on international markets, aligning gradually to those for industrials, if not suddenly, and perhaps more abrupt, following an upward move.

CEGH Czech Monthly Futures				CEGH Czech Seasons			
Trading Day	**Contract**	**Settlement Price EUR/MWh**	**Last Price EUR/MWh**	**Trading Day**	**Contract**	**Settlement Price EUR/MWh**	**Last Price EUR/MWh**
29.03.2017	Apr-17	15.75	15.30	29.03.2017	Summer 2017	15.95	16.23
29.03.2017	May-17	15.80	-	29.03.2017	Winter 2017	17.15	-
29.03.2017	Jun-17	15.85	-	29.03.2017	Summer 2018	16.075	-

CEGH Czech Quarterly Futures				CEGH Czech Yearly Futures			
Trading Day	**Contract**	**Settlement Price EUR/MWh**	**Last Price EUR/MWh**	**Trading Day**	**Contract**	**Settlement Price EUR/MWh**	**Last Price EUR/MWh**
29.03.2017	Quarter 2/2017	15.80	15.95	29.03.2017	2018	16.73	18.2
29.03.2017	Quarter 3/2017	16.10	-	29.03.2017	2019	16.70	-
29.03.2017	Quarter 4/2017	16.88	-				
29.03.2017	Quarter 1/2018	17.43	-				

Source: http://www.cegh.at, IEBA TRUST

Transgaz capex implementation seems to keep on hold RO gas market integration with more developed ones, but on-shore RRR ratios would move lower considerable, in lack of acquisitions

Romania consumes an annual 10-11bn cm, of which almost equally produced by Romgaz and OMV Petrom. Romania ranks fifth in Europe based on annual production of gas (10.9bn cm), Norway has an annual production of 115bn cm, followed by Holland with 64bn cm, UK with 41 bn cm and Ukraine with a much smaller production at 18.6bn cm, but almost double compared to Romania. Should production from the Black Sea start, Romania could double its annual production. Also, Romgaz will need to build some additional UGS facilities within the area, but both production of OMV Petrom, depend first on the infrastructure in the area. Two years seem a good timetable for the construction of the pipeline but without its being functional, neither Romgaz and/or OMV Petrom we view as front running Trangaz with some extra Upstream capex. OMV Petrom has no reasons to start production due to lack of infrastructure while Romgaz does not need any extra UGS for the moment in lack of production, so the key for this Black Sea gas to be put on stream is mostly in the hands of Transgaz.

- **Transgaz projects pending to set new competitive features to the local gas market:**
    - **BRUA (Bulgaria-Romania-Hungary-Austria):** EU decided to include this project on main list of major interest in order to provide an alternative diversification source for those member states that were affected by deselecting of Nabucco project; deadline for completion is FY'19 with an estimated cost of EUR 560m.
    - **Development on the Romanian territory of the Southern Transmission Corridor for taking over the Black Sea gas:** Development of an infrastructure on RO territory in order to transport natural gas from the Black Sea to the boarder of Romania-Hungary; included in the Ten Year Network Development Plan (TYNDP 2015) it aims at building a pipeline from the Black Sea to the technological plateau in Giurgiu County to make the connection between the offshore gas available in Black Sea and the corridor Bulgaria - Romania - Hungary – Austria (BRUA). Deadline for finalization is FY'19 with an estimated cost at EUR 262.4m.

- **Interconnection with international transport pipelines:** this project consists in upgrading Silistea compression station, upgrading and scaling Onesti compression station, changes inside the metering station Isaccea and rehabilitation of sections of pipelines Cosmesti - Onesti (66.2 km) and Silistea - Sendreni (11.3 km). Currently, Transgaz started a pre-feasability study, with completion works estimated by FY'18 with a total cost of EUR 65m.

- **Development of national transportation grid (NTS) in the north-eastern Romania:** new pipeline interconnection between Romania and Moldova to provide transport capacities to Moldova; the first phase of the project includes the construction of natural gas pipeline Gheraeşti - Letcani and the second phase of the project is to develop transport capacity of NTS in order to provide natural gas flow on the direction Romania – Republic of Moldova. Deadline for the project is FY'17 and investment value is EUR 110m.

- **Development of Central Corridor:** interconnection with the transmission system and ensuring international Isaccea reverse flow; ensuring reverse flow on interconnection Romania – Hungary and develop NTS between Onesti and Bacia. Deadline is FY'23 and investment value is EUR 544m.

Summarizing, Romania needs some financing worth EUR 1.54bn in order to complete these interconnection projects that secure flow and reverse flow to Europe, while the deadlines implied look very optimistic and currently Transgaz is a laggard in terms of budgeted CAPEX compliance. We consider these deadlines quite near the corner on paper and we believe there are few chances for them to materialize while given also the delayed upstream capex of OMV Petrom for the Black Sea gas, we could see first flow much later than FY'19. On the other hand, considering current demand on the gas market, Romania does not need additional volumes, hence, the Black Sea is only a source of exports and supply to domestic market only when on-shore fields will be completely depleted and redevelopment will produce low IRR compared to available flows.

Recent news from the Ministry of Energy are related to BRUA (Bulgaria – Romania – Hungary – Austria) gas interconnector – at the end of 2017, preparatory works will start and expectations are for 2020 for the pipeline to be functional. This gas interconnector is a major infrastructure milestone for OMV Petrom to be able to bring on-shore the gas from the Black Sea. The new gas interconnector will have a total length of 500 km, and will have an annual capacity of 1.5bn cm with Bulgaria and 4.4bn cm/annual with Hungary, for a cost of EUR 560m. Transgaz already signed the agreement to access the EUR 179m grant for the construction of the interconnector on the Romanian territory. Cost is EUR 560m, thus the grant from the EU stands for only 31%. The difference will be financed by Transgaz either via own sources or through additional borrowing. An additional pipeline coming from the Black Sea to Podisor (Marea Neagra-Podisor pipeline) will generate costs of EUR 278.3m. The gas reserves discovered in the Black Sea with importance for Romania are the joint ventures run by Lukoil/Romgaz and Petrom/Exxon Mobil for some 30bm cm and 42-84bn cm for the latter.

The additional pipeline Marea Neagra-Podisor, should connect the shore with BRUA, and construction will be completed in parallel with BRUA, otherwise, there is no connection to the Black Sea.

Source: Transgaz

BRUA project will reduce dependence on Russian gas, in the context of materialization of new projects aimed at diversification of gas transportation routes from the Caspian region to Europe Central, and new sources of natural gas in offshore perimeters in the Black Sea. This new gas transport corridor will ensure exploitation of natural gas volumes related to these sources Romanian and European market and the possibility of permanent physical bidirectional flow interconnections with Bulgaria and Hungary.

Bulgaria started building the interconnector with Greece

In December 2016, Sofia and Athens signed the agreement to build a pipeline that will connect the natural gas networks of the two countries, a gas interconnector that will allow Bulgaria to diversify gas supply and Greece, to connect to the rest of the European network. The pipeline will become operational in 2018 and has an estimated cost EUR 220m, out of which, the European Union will provide a grant of EUR 45m.

Romania could receive gas from Azerbaijan

Romania could receive gas from Azerbaijan via the interconnector between Bulgaria and Romania so we can buy gas from Azerbaijan, which is developed by national operators in the two states, Transgaz and Bulgartansgaz. The project has an estimated value of EUR 24m, of which EUR 9m are secured by the European Commission. Bulgartansgaz will contribute some EUR 14m while Transgaz is expected to participate with an additional EUR 10m.

Table. OMV Petrom Group Estimated Operational Indicators & selected P&L figures (RON Mn)

Operational segment	Q1'15A	Q2'15A	Q3'15A	Q4'15A	FY'15A	Q1'16A	Q2'16A	Q3'16A	Q4'16A	FY'16A	FY'17E	FY'18E	FY'19E	FY'20E
Upstream														
E&P Sales, net of intersegment	**141**	**170**	**223**	**148**	**682**	**111**	**105**	**96**	**123**	**436**	**579**	**576**	**555**	**535**
Total hydrocarbon production (mn boe)	16.52	16.48	15.97	16.22	65.19	15.94	15.83	15.99	15.66	63.7	58.8	57.0	55.3	53.6
Total hydrocarbon production (kboe/day)	184	181	174	176	178.75	175	177	174	170	174.0	161	156	151	147
Crude oil production (mn bbl)	7.67	7.74	7.6	7.42	30.43	7.37	7.36	7.25	7.16	29.1	25.2	24.2	23.0	21.8
Natural gas production (bn cm)	1.36	1.34	1.28	1.35	5.33	1.31	1.34	1.34	1.30	5.29	5.14	5.02	4.95	4.87
Natural gas production (bn cf)	47.85	47.23	45.26	47.53	187.87	46.36	47.43	47.23	45.93	187	181	177	175	172
Average Ural Price (USD/bbl)	52.89	61.42	49.75	42.26	51.58	32.29	43.91	44.10	47.89	42.10	52.62	55.18	55.18	55.18
Average crude price realized (USD/bbl)	45.37	53.5	44.7	36.07	44.91	26.69	36.86	37.41	41.55	35.58	45.62	48.18	48.18	48.18
Exploration investment (mn RON)	365	401	321	312	1,399	275	-34	40	57	338	1,399	560	560	560
Exploration expenditure (mn RON)	66	133	62	315	576	57	87	19	99	262	400	400	240	240
Production cost (USD/boe)	14.23	13.16	13.11	12.1	13.16	12.25	12.09	11.27	11.77	11.85	12.00	12.00	12.00	13.00
USD/RON	4.09	3.98	3.94	4.07	4.01	4.07	3.98	4.00	4.18	4.01	4.05	4.04	4.02	4.02
EUR/RON	4.43	4.47	4.42	4.46	4.45	4.49	4.50	4.47	4.51	4.49	4.46	4.44	4.42	4.42
EBITDA	**854**	**1,313**	**1,062**	**870**	**4,099**	**569**	**876**	**819**	**829**	**3,093**	**4,176**	**4,249**	**4,221**	**3,834**
margin (%)	***20%***	***29%***	***23%***	***18%***	***n/m***	***16%***	***24%***	***18%***	***18%***	***19%***	***24%***	***26%***	***26%***	***24%***
Production related OPEX	962	863	825	798	**3,448**	**795**	**777**	**721**	**742**	**3,034**	2,859	2,761	2,666	2,802
Depreciation	690	782	1,469	2,973	5,914	649	725	648	670	2,692	2,700	2,704	2,708	2,712
Impairment	-3	-5	786	1,879	3,133	0	58	0	0	58	0	0	0	0
Clean depreciation	693	787	683	1,094	2,781	649	667	648	670	2,634	2,700	2,704	2,708	2,712
Clean EBIT	**175**	**551**	**416**	**-223**	**919**	**-73**	**210**	**193**	**246**	**576**	**1,476**	**1,545**	**1,513**	**1,122**
EBIT	**164**	**531**	**-407**	**-2,103**	**-1,815**	**-80**	**151**	**171**	**159**	**401**	**1,476**	**1,545**	**1,513**	**1,122**
margin (%)	***4%***	***12%***	***-8%***	***n/m***	***n/m***	***n/m***	***4%***	***4%***	***3%***	***2%***	***9%***	***9%***	***9%***	***7%***
Downstream														
Downstream Gas														
G&E Sales, net of intersegment	**1,302**	**765**	**914**	**1,224**	**4,206**	**1,158**	**804**	**966**	**1,190**	**4,118**	**4,486**	**4,486**	**4,486**	**4,486**
Gas sales (mn cm)	1,541	983	1,009	1,235	4,768	1,297	987	1,051	1,302	4,637	4,682	4,682	4,682	4,682
Gas sales (TWh)	16.69	10.57	10.85	10.70	48.81	12.89	10.75	11.44	14.17	43.86	50.00	50.00	50.00	50.00
Gas sold from UGS (TWh)	0.00	1.80	2.70	1.90	6.4	0.00	2.10	3.30	2.50	7.9	6.0	6.0	6.0	6.0
Gas production (TWh)	16.69	8.77	8.15	8.80	42.4	12.89	8.65	8.14	11.67	35.96	44.00	44.00	44.00	44.00
Net electricity production (TWh)	0.3	0.1	1.1	1.1	1.0	0.42	0.48	1.2	0.8	0.4	3.4	3.4	3.4	3.4
EBITDA	**35**	**-56**	**-16**	**33**	**-4**	**73**	**-2**	**25**	**25**	**121**	**104**	**104**	**104**	**104**
margin (%)	***1%***	***-1%***	***0%***	***1%***	***0%***	***2%***	***0%***	***1%***	***1%***	***1%***	***1%***	***1%***	***1%***	***1%***
Depreciation	32	28	38	41	212	26	28	35	29	118	100	100	100	100
EBIT	**3**	**-84**	**-54**	**-8**	**-216**	**47**	**-30**	**-10**	**-4**	**3**	**4**	**4**	**4**	**4**
Downstream Oil														
R&M Sales, net of intersegment	**2,822**	**3,599**	**3,673**	**3,130**	**13,224**	**2,282**	**2,713**	**3,390**	**3,270**	**11,655**	**12,138**	**11,531**	**11,300**	**11,074**
Refining margin (USD/bbl)	8.24	8.95	9.87	7.75	**8.7**	8.06	6.82	5.96	7.14	**7.0**	6.50	6.50	6.50	6.50
Refining input (mn tons)	1.00	0.96	1.13	1.09	**4.2**	1.10	0.81	1.16	1.15	**4.2**	0.68	0.68	0.68	0.68
Refinery Capacity Utilization rate (%)	86	81	94	92	**88.3**	94	68	97	96	**85.3**	85	85	85	85
Total sales of refined products (mn tons)	1.1	1.22	1.37	1.34	**5.0**	1.14	1.13	1.39	1.27	**4.6**	4.4	4.4	4.4	4.4
Distribution stations	778	777	776	788	**788**	783	784	786	783	**783**	783	783	783	783
EBITDA	**487**	**663**	**323**	**368**	**1,841**	**462**	**462**	**535**	**457**	**1,916**	**1,950**	**2,241**	**2,162**	**2,293**
margin (%)	***11%***	***15%***	***7%***	***8%***	***10%***	***13%***	***13%***	***12%***	***10%***	***12%***	***11%***	***13%***	***13%***	***14%***
Depreciation	145	157	148	161	**611**	150	157	161	158	**626**	604	592	596	596
EBIT	**342**	**506**	**175**	**207**	**1,230**	**312**	**305**	**374**	**299**	**1,290**	**1,346**	**1,649**	**1,566**	**1,697**
margin (%)	***8%***	***11%***	***4%***	***5%***	***7%***	***9%***	***8%***	***8%***	***7%***	***8%***	***8%***	***10%***	***10%***	***11%***

Source: OMV Petrom, SSIF IEBA Trust

VALUATION – Rating remains at BUY – TP 12% lower to RON 36/share due to drop in crude oil price – valuation remains very sensitive to volumes and pricing ahead. Excluding short term fluctuations in both variables, trend should remain positive on the longer term due to expected acquisitions and Neptun FID

We arrive at a fair value of RON 36/share (20% upside potential to current price levels) and BUY rating. The stock currently trades at lower EV/EBITDA (17E) of 4.8x (at target price), but estimated multiples still trade below peers.

P&L Estimates	Q1'15A	Q2'15A	Q3'15A	Q4'15A	FY'15A	Q1'16A	Q2'16A	Q3'16A	Q4'16A	FY'16A	FY'17E	FY'18E	FY'19E	FY'20E
Total Group sales	*6,458*	*7,071*	*6,897*	*6,518*	*26,943*	*5,200*	*5,508*	*6,280*	*6,549*	*23,652*	*25,517*	*24,867*	*24,324*	*23,819*
Intersegment sales	***2,187***	***2,530***	***2,081***	***1,999***	***8,798***	***1,641***	***1,875***	***1,819***	***1,954***	***7,406***	***8,277***	***8,236***	***7,946***	***7,686***
Group sales	*4,271*	*4,540*	*4,819*	*4,518*	*18,148*	*3,559*	*3,633*	*4,461*	*4,595*	*16,247*	*17,240*	*16,631*	*16,379*	*16,133*
EBIT Corporate	-26	-10	-23	-16	-75	-17	-8	-20	-27	38	38	38	38	38
Consolidation	11	-156	343	148	346	80	-200	58	-91	-153	-153	-153	-153	-153
EBITDA Group	**1,367**	**1,760**	**1,696**	**1,408**	**6,231**	**1,173**	**1,135**	**1,424**	**1,202**	**4,933**	**6,184**	**6,548**	**6,442**	**6,185**
margin (%)	***32%***	***39%***	***35%***	***31%***	***34%***	***33%***	***31%***	***32%***	***26%***	***30%***	***36%***	***39%***	***39%***	***38%***
Group Depreciation, o/w	873	974	1,662	3,252	6,761	830	917	851	867	3,463	3,428	3,424	3,424	3,436
Additional depreciation/impairment	-3	-5	-786	2,253	1,459	0	63	-1	0	0	0	0	0	0
Group Normalized Depreciation	870	969	876	999	3,714	830	854	852	867	3,463	3,428	3,424	3,424	3,436
EBIT Group	**494**	**786**	**34**	**-1,844**	**-530**	**343**	**218**	**573**	**335**	**1,472**	**2,604**	**2,976**	**2,862**	**2,601**
margin (%)	***12%***	***17%***	***1%***	***n/m***	***n/m***	***10%***	***6%***	***13%***	***7%***	***9%***	***15%***	***18%***	***17%***	***16%***
Clean EBIT	502	704	867	86	2,256	232	273	562	528	1,514	2,715	3,087	2,973	2,712
Special items, o/w	-8	-15	-833	-1,930	-2,786	111	-55	11	-193	42	111	111	111	111
Personnel&restructuration	-8	-5	-41	8	-46	-8	-8	-37	-39	-29	-7	-7	-7	-7
Additional depreciation	-3	-5	-786	-1,997	-2,791	0	-63	-1	0	-	-	-	-	-
Litigation provisions	-	-	-	-	-	-	0	0	0	-	-	-	-	-
Other	-92	102	5	74	89	118	0	49	-154	134	118	118	118	118
CCS effects	-92	47	-194	-125	-364	-177	44	-40	75	121	121	121	121	121
E&P clean EBIT	**175**	**551**	**416**	**-223**	**919**	**-73**	**210**	**193**	**246**	**575**	**1,425**	**1,494**	**1,462**	**1,071**
G&E clean EBIT	3	-84	-54	-8	-143	47	-31	-10	5	10	4	4	4	4
R&M clean EBIT CCS	174	304	560	277	1,315	255	166	403	288	1,112	1,225	1,528	1,445	1,576
Corporate clean EBIT	-26	-10	-23	-17	-76	-17	-8	-19	-25	-69	-69	-69	-69	-69
Consolidation	*268*	*-104*	*164*	*181*	*509*	*196*	*-108*	*36*	*-60*	*-64*	*-64*	*-64*	*-64*	*-64*
EBIT clean CCS	**594**	**657**	**1,061**	**211**	**2,523**	**408**	**229**	**602**	**454**	**1,692**	**2,521**	**2,893**	**2,779**	**2,518**
Net profit	**345**	**691**	**-43**	**-1,680**	**-690**	**288**	**117**	**473**	**160**	**1,039**	**2,109**	**2,436**	**2,336**	**2,107**
margin (%)	***8%***	***15%***	***-1%***	***n/m***	***n/m***	***8%***	***3%***	***11%***	***3%***	***6%***	***12%***	***15%***	***14%***	***13%***

Source: OMV Petrom, SSIF IEBA Trust

Discounted Cash Flow Model

Our DCF valuation exercise results to an absolute target price of RON 0.36/share. Overall, we assume over 10-year forecasted model FY(15-26E) with a mere revenues CAGR of -7% reflecting mostly the drop in crude oil production since we did not include yet in estimates the upstream acquisitions and Neptun project. Our avg. WACC stands on avg. at 12% and a perpetuity growth of a negative 2% due to fields mature characteristics and above details. We implied still high CAPEX at approximately EUR 1bn, in line with management, that overall should weigh some 63% over the next 4y estimated Group EBITDA. We remind that our valuation is very sensitive to capex, and crude oil price as well as to the newly announced project on the upstream side (acquisitions, Neptun deep). Due to expected changing capital structure with impact on WACC as well, we consider that the outcome of the DCF analysis should be regarded only on the short term, and rather in isolation as a sensitivity to assumptions made, since we cannot incorporate yet the major impacting projects, and thus it does not capture accurately the exact future cash-flows of the company. We think that the short-term volatility of future cash-flows could alter significantly the long-term perspectives and TP, but on the other hand, excluding the additional leverage and the lacking infrastructure for the gas projects, future stream of income should remain positive.

Discounted Stream of Cash-Flows	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	TV
											+
Sales	17,240	16,631	16,379	16,133	16,024	16,018	16,012	16,006	16,001	15,996	
EBIT	**2,604**	**2,976**	**2,862**	**2,601**	**2,263**	**2,130**	**2,185**	**2,076**	**1,992**	**1,912**	
Depreciation	3,427	3,419	3,427	3,431	3,451	3,471	3,483	3,503	3,503	3,503	
EBITDA	**6,031**	**6,395**	**6,289**	**6,032**	**5,714**	**5,601**	**5,668**	**5,579**	**5,495**	**5,415**	
EBITDA margin (%)	*35%*	*38%*	*38%*	*37%*	*36%*	*35%*	*35%*	*35%*	*34%*	*34%*	
NOPLAT	**2,288**	**2,616**	**2,515**	**2,286**	**1,989**	**1,872**	**1,920**	**1,825**	**1,751**	**1,681**	
Wcapital	1,332	1,297	1,276	1,251	1,234	1,231	1,232	1,228	1,226	1,223	
Wcapital in sales (%)	*8%*	*8%*	*8%*	*8%*	*8%*	*8%*	*8%*	*8%*	*8%*	*8%*	
Change in Wcapital	(132.41)	35.18	21.46	24.71	16.70	3.86	(0.97)	3.20	(2.56)	(2.43)	
CAPEX	4,565	3,800	3,424	3,436	3,460	3,476	3,492	3,500	3,508	3,508	
% in EBITDA	76%	59%	54%	57%	61%	62%	62%	63%	64%	65%	
FCFF	**1,283**	**2,200**	**2,497**	**2,256**	**1,963**	**1,863**	**1,912**	**1,825**	**1,748**	**1,678**	
WACC	11.9%	12.0%	12.4%	12.6%	12.4%	12.4%	12.7%	12.6%	13.3%	13.4%	
PV of FCFF	1,183	1,947	2,197	1,983	1,718	1,631	1,667	1,592	1,515	1,451	**10,669**
Net income	2,109	2,436	2,336	2,107	1,809	1,693	1,658	1,562	1,571	1,501	
Pay-out estimated	40%	40%	40%	30%	30%	30%	30%	30%	30%	30%	
DPS	843	974	934	632	543	508	497	469	471	450	
y-o-y growth in DPS	*-1%*	*16%*	*-4%*	*-32%*	*-14%*	*-6%*	*-2%*	*-6%*	*1%*	*-4%*	
Sum PV of FCFF	16,885										
Terminal growth rate	-2%										
TV	**10,669**										
PV of TV	9,226										
Total FCFF	**26,111**										
(+) BV investments (-) minorities (17E)	2,637										
EV	**28,748**										
(-) net debt (17E)	(240)										
(-) other adjustments	(7,057)										
(-) dividends to be paid	(852)										
Shareholder's value (RON m)	**20,599**										
Shareholder Value per share	0.36										
Premium/(Discount) %	20%										

Source: SSIF Iebatrust estimates.

Multiples range at target price	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2025E	2025E
P/E (x)	9.77	8.46	8.82	9.78	11.39	12.17	12.43	13.18	13.11	13.72	13.72
P/BV (x)	0.74	0.70	0.67	0.64	0.61	0.59	0.57	0.56	0.54	0.53	0.51
EV/EBITDA (x)	4.77	4.50	4.57	4.77	5.03	5.13	5.07	5.15	5.23	5.31	5.31
DIVY	4.1%	4.7%	4.5%	3.1%	2.6%	2.5%	2.4%	2.3%	2.3%	2.2%	2.2%
EV/Sales (x)	1.67	1.73	1.76	1.78	1.79	1.79	1.80	1.80	1.80	1.80	1.80
ROE (%)	7.5%	8.3%	7.6%	6.5%	5.4%	4.9%	4.6%	4.2%	4.1%	3.8%	3.7%
EPS growth (%)	102.9%	15.5%	-4.1%	-9.8%	-14.1%	-6.4%	-2.1%	-5.8%	0.6%	-4.5%	-4.5%

Source: SSIF Iebatrust estimates.

Main risks to our estimates and TP:

- Taxation side
- Negative trend in crude oil prices – recall that a sensitivity provided by management speaks about EUR 20m jump in full company EBIT should Brent oil price add USD 1/bbl, and risk for impairments
- Mature fields lower production lead to lower estimates regarding oil and gas reserves; significant variance from actual quantities of oil and natural gas that can be recovered
- Material decreases in the price of crude oil/natural gas and/or electricity could severely damage the company's cash-flows
- Higher or lower than implied growth rates in production and pricing level could also severely
- OMV Petrom must maintain elevated level of capital expenditure in order to increase its production level, while the lack of acces to such financing sources could jeopardize the activity of the company
- Certain petroleum agreements of the company may no longer be in force, albeit OMV Petrom continues operating under normal course of activity (similar issue to Romgaz)
- Current reserves and forward production data may be only estimates and not match actual production flow rates, thus revenues of the company may be overvalued
- Operational risks on drilling side could potentially result on additional charges which are currently not implied in our cash-flow
- The tax regime is still uncertain and could potentially overweigh upon estimated cash-flows – exposure on changing taxes and royalties' system imposed on its operations
- The state continues to exert significant influence upon the company – via taxation side

RELATIVE VALUATION

OMV Petrom trades below historic multiples on 2017-18E earnings. Petrom trades at 8.3x P/E for 2017 and 7.2x for 2018E, at moderate discount to major oil companies. Petrom looks only slightly better also on EV/EBITDA, trading at 3.3-3.1x still implying a discount to last 2Y avg. of 4x. Our estimated 4.8-5.5% yield for 2017-2018E – which may be at further risk – but proves not very satisfactory on the longer term, under expectations for an upward sloping yield curve.

All in all, a relative valuation on OMV Petrom, looks not very conclusive, mostly due to the business model that is expected to change more towards a gas producer, and because of difficulties to find a quite similar business model (upstream and refining/power), whilst our peer group is comprised of rather pure refiners. Size is also not negligible.

Table. Relative valuation

Company name	Mkt Cap	YTD	1 Year	P/E		P/B		ROE		EPS Growth		DIV Yield	
	(in EUR m)	(%)	(%)	2017E	2018E	2017E	2018E	2017E	2018E	2017E	2018E	2017E	2018E
Tatneft PJSC	177,430	-17	-1	7.9	6.0	1.2	1.0	16.2	18.3	2.3	32.6	1.2	18.3
Surgutneftegas OJSC	233,405	-5	-25	4.2	5.1	0.4	0.4	2.7	6.5	-66.7	-17.7	0.4	6.5
Novatek OJSC	489,839	-8	22	12.3	10.7	2.9	2.4	26.5	24.5	-30.6	14.7	2.9	24.5
Societatea Nationala de Gaze N	2,464	16	8	10.2	9.6	1.1	1.1	10.6	11.1	n/av	6.2	1.1	11.1
MOL Hungarian Oil & Gas PLC	457,757	-2	23	8.2	7.5	1.1	1.0	14.0	13.7	-19.3	8.1	1.1	13.7
Lukoil PJSC	576,012	-11	17	5.5	4.7	0.6	0.5	11.6	13.1	90.8	18.0	0.6	13.1
Tupras Turkiye Petrol Rafineri	4,978	27	14	9.5	9.2	2.4	2.2	26.0	24.0	31.5	3.2	2.4	24.0
Aygaz AS	963	21	19	9.2	8.2	1.5	1.4	16.3	17.1	14.3	12.3	1.5	17.1
Gazprom Neft PJSC	211,156	-6	34	4.0	3.6	0.6	0.5	17.4	17.1	18.7	12.3	0.6	17.1
Grupa Lotos SA	2,277	46	98	12.8	11.2	1.1	1.0	9.1	9.0	-28.9	14.4	1.1	9.0
Bashneft PJSC	129,032	3	43	9.4	8.9	1.9	1.6	22.4	21.7	27.2	5.0	1.9	21.7
Polski Koncern Naftowy ORLEN S	9,817	22	41	9.7	10.7	1.4	1.3	15.6	12.5	-13.4	-8.6	1.4	12.5
Rosneft PJSC	755,472	-20	5	6.6	5.3	0.9	0.8	14.4	15.6	n/av	24.3	0.9	15.6
Unipetrol AS	9,067	23	27	4.0	7.5	0.8	0.7	22.4	10.4	29.7	-46.8	0.8	10.4
KOC Holding AS	8,685	12	6	10.4	8.7	1.4	1.2	13.1	13.4	9.4	19.0	1.4	13.4
Median	**129,032**	**3.1**	**19.1**	**9.2**	**8.2**	**1.1**	**1.0**	**15.6**	**13.7**	**9.4**	**12.3**	**1.1**	**13.7**
OMV Petrom	**3,802**	**15.7**	**25.6**	**8.3**	**7.2**	**0.6**	**0.6**	**7.9**	**8.5**	**103.0**	**15.5**	**4.8**	**5.5**
Premium/Discount to peers	-97%	n/m	34%	-9%	-12%	-47%	-42%	-49%	-38%	n/m	26%	n/m	-60%
At target price - OMV Petrom	**3,802**	**38.0**	**51.0**	**9.7**	**8.4**	**0.7**	**0.7**	**7.5**	**8.3**	**103.0**	**15.5**	**4.1**	**4.7**
Premium/Discount to peers	-97%	n/m	n/m	6%	3%	-35%	-33%	-52%	-39%	n/m	26%	n/m	-66%

Source: SSIF IEBA Trust, Bloomberg

Source: SSIF IEBA Trust, Bloomberg

Q4'16 results and opinion:

- OMV Petrom reported Q4'16 and full year financial results on February 16 – clean CCS net profit landed at RON 263m (RON 1.16bn for 2016) impacted by positive result in all segments, particularly Downstream, where a clean CCS EBIT of RON 292m was reported, slightly higher compared to clean CCS EBIT in Upstream of RON 246m.

- In Upstream, Q4'16 EBIT landed at RON 159m, lower compared to our estimate of RON 238m due to some RON 87m booked as special items (mainly reflecting the reassessment of receivables and personnel restructuring charges), which put clean CCS EBIT at RON 246m. Aside from the upstream key production items that were already announced in the Trading Statement, the Group production cost landed at USD/bbl of 11.77, down 3% Y/Y mainly due to lower services, personnel and favorable FX rates, partly offset by lower production available for sale. Exploration expenses decreased to RON 99m vs. Q4'15, mainly due to lower write-offs, while exploration expenditure decreased to RON 57m, mainly due to finalized drilling activities in the Black Sea. Full year EBIT landed at RON 401m, RON 575m in clean figures with operational metrics much improved Y/Y due to 10% Y/Y drop in opex/bbl to 11.85 USD/bbl, which offset the 4% Y/Y drop in production of crude oil and NGL to 29.15m bbl and 21% Y/Y drop in avg. group realized crude price to 35.58 USD/bbl – FX positive impact as 1% USD appreciation against RON for the full year was boosted mainly in Q4'16 when the USD appreciated by 3% Y/Y (avg. figures).

- In Downstream, full year clean CCS EBIT landed at RON 1.12bn, o/w Q4'16 contribution was at RON 288m for Downstream Oil and RON 5m for Downstream Gas, an improved operational performance, mainly from better gas sales and good refining margin indicator of 7.14 USD/bbl in Q4'16 and improved sales volume. Some RON 103m were also booked in special items, reflecting the reassessment of receivables and provisions. RON 8m was additional cost triggered by the unavailability of one gas turbine of the Brazi power plant, as the unplanned outage of one gas turbine, led to 29% lower net electrical output.

- Due to FCF after dividends of RON 1.6bn, supported by cost savings which offset the NWC negative developments, declining prices and margins, the BOD proposed a gross dividend of RON 0.015/share, which means a payout of 82% of FY'16 net profit and a dividend yield around 5.2%, last intra-day market price – subject to approval by shareholders with next GSM.

- The Group also presented the **2021+ Strategy** which details upon capex to be employed for the next 5y+ at EUR 0.8bn (of which around 85% in Upstream), a production decline of only 3% Y/Y, a positive FCF after dividends which means actually continuing strenghtening the B/S and maintaing a good yield for the dividends. Actually, the 2021+ startegy was centered around three pillars (enhancing competitiveness in the existing portfolio, developing growth options and a regional expansion). Upstream segment carries some increased focus, targeting an improvement in the RRR ratio to 100% via either acquisitions and/or maximizing the economic recovery rate of existig fields (infill driling campaigns), focusing on the most profitable barrels and further reduction in unit costs. In Downstream, there will be a focus in the maximization of the availability and utilization of downstream plants and increasing throughput per filling station, but also some increased customer focus, as increasing brand loyalty measures will be in place – partnerships with Waze, Auchan, Subway.

- Some additional opportunities are to be captured in retail and refining via the construction of a polyfuel project to upgrade production mix (operative 2019) and modernization of a fuel storage network by end-2018.

- Moreover, in Upstream, the Group is settled to capture synergies with existing operations, and around 80mn boe reserves are targeted from near-term acquisitons, with prioritisation in the Caspian and Western Black Sea without competing with OMV main interest areas; 2017 includes drilling of six wells, onshore and shallow offshore, E&A expenditure estimated at RON 0.4bn, with Group capex including capitalized E&A at RON 3.6bn.

- All in all, above measures should lead to RRR of 100% by 2021, clean CCS ROACE higher than 10% (consider that currently OMV Petrom has investments made that bear no return yet), a strong balance sheet and positive FCF after dividends for the majority of the period.

We consider the reported results better than estimated in terms of Downstream result mainly, Upstream, more or less was already expected, due to the fact that the key operational metrics were already made public before the announcement of the full year results. If we are to exclude that Q4 is usually lower due to lack of driving season and adjust for the RON 193m in special items the clean CCS EBIT for the group is only RON 148m lower vs. Q3 and slightly higher than Q1'16 reported figure of RON 408m.

Opex/bbl for the year was also a surprise starting Q3'16, which was the first quarter with the figure dropping below 12 USD/bbl and track record maintained, which could not be achieved unless cost reduction measures and close monitoring of the operating environment to offset both the maturing feature of its operated fields and rather volatile crude oil price during the year. Also, gas sales were more flexible compared to peer Romgaz, most probably due to higher flexibility assumed on the entire selling chain and risk management productive measures, we assume.

We had slightly higher estimates mostly due to the fact that we did not imply any of the one-offs booked during Q4'16 while the consolidation line is often quite burdensome, mostly due to lack of availability of volumes remaining in inventory/unrealized profits among divisions that are to be eliminated upon consolidation associated with the magnitude of the change in related pricing, either for processed or raw feedstock.

With respect to the strategy 2021+, we find it quite challenging with some new milestones and targets set forth, eyeing for organic growth but also some acquisitions in the Upstream field in order to maintain its integrated business profile.

in RON mn	Q1'16A	Q2'16A	Q3'16A	Q416'E	Q416'A	FY'16E	FY'16A	Y/Y %	QoQ %
Clean EBIT Upstream	-73	210	193	268	246	598	575	-37%	27%
Clean EBIT Downstream Gas	47	-31	-10	-10	5	-4	11	n/m	n/m
Clean CCS EBIT Downstream Oil	255	166	403	219	288	1,043	1,112	-15%	-29%
EBIT Group	343	218	573	620	335	1,754	1,469	n/m	-42%
Clean CCS EBIT	408	229	602	495	454	1,734	1,694	-33%	-25%
Net profit	288	117	473	498	160	1,375	1,038	n/m	-66%

Source: IEBA TRUST, OMV PETROM

RECOMMENDATION SYSTEM

SSIF IEBA TRUST uses a Relative recommendation system. Such system indicates that each stock is rated on a basis of the excess return, measured by the relative value of the target (calculated) price and the current price, over a 12 months period of time.

The range of recommendations for each stock consists of 4 elements: Buy (B), Accumulate (A), Hold (H), Reduce (R).

SSIF IEBA TRUST RATINGS	
BUY	The stock is expected to generate potential excess return over 15%
ACCUMULATE	The stock is expected to generate potential excess return of 5 to 15%
HOLD	The stock is expected to generate potential excess return of -5% to 5%
REDUCE	The stock is expected to generate potential excess return below 5%

Excess return: Target price/current price − 1

For the cases of Initial Public Offering, the above-mentioned recommendation system is not applied. In such cases, the recommendation is based on the comparison between the price of the Offering, and the fair value estimated by SSIF IEBA TRUST.

OMV PETROM

Ratings and target price history

#	Date	Rating	Target price (in RON)
1	25/05/2012	BUY	0.47
2	26/09/2012	BUY	0.50
3	31/01/2013	BUY	0.55
4	15/03/2013	BUY	0.55
5	12/09/2014	ACCUMULATE	0.46
6	19/05/2015	HOLD	0.41
7	03/04/2017	BUY	0.36

Measures Definitions

IEBA Net Income	Adjusted Net Income for one-off items	
Net Cash Flow from operations	EBITDA (+/-) other provisions (+/-)(Increase)/Decrease in Working Capital	
FCF Equity	Net Cash Flow from operations (-) CAPEX	
Net debt	Total short-term and long-term bank debt (-) cash	
EV	Market Cap (avg historic or current) + book value of minorities + Net debt	
FCFPS	FCF Equity	Diluted no of shares
EPS (or IEBA)	Reported (or IEBA) Net Income	Diluted no of shares
BVPS	Total Equity	Year end no of shares
P/E (or IEBA)	Share Price (avg historic or current)	Reported (or IEBA) EPS
P/E IEBA at 52wks High	52 weeks High price (avg historic or current)	IEBA EPS / Diluted IEBA Earnings Per Share
P/BV	Share Price (avg historic or current)	BVPS
ROE	Reported Net Income	Avg. Total Equity
ROCE	Reported Net Income	Avg. (Total debt + Total Equity)
EV/EBITDA	EV (with avg historic or current)	Reported EBITDA
EV/EBITDA (x) at 52wks High	EV using 52 weeks High market cap (avg historic or current)	Reported EBITDA
EBITDA/Net financials	Reported EBITDA	Net financials: Net interest (+/-) Net financials
EV/CE (x)	EV (with avg historic or current)	CE: Total bank debt + Total Equity
FCF Yield	FCFPS	Share Price (avg historic or current)
Dividend Yield	DPS	Share Price (avg historic or current)
Dividend Payout	Dividend	Reported Net Income

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