MANAGEMENT DISCUSSION & ANALYSIS

November 13, 2017
For the three and nine months ended September 30, 2017

Legal Notice – Forward-Looking Information and Statements

*Certain statements in this Management's Discussion and Analysis ("**MD&A**") constitute forward-looking statements. Often, but not always, forward-looking statements use words or phrases such as "expects," "does not expect," "is expected," "anticipates," "does not anticipate," "plans," "planned," "estimates," "estimated," "projects," "projected," "forecasts," "forecasted," "believes," "intends," "likely," "possible," "probable," "scheduled," "positioned," "goal," or "objective." In addition, forward-looking statements often state that certain actions, events, or results "may," "could," "would," "might," or "will" be taken, may occur, or be achieved. Such forward-looking statements, including, but not limited to, statements with respect to anticipated levels of production, estimated costs, and timing of Frontera Energy Corporation's ("**Frontera**" or the "**Company**") planned work programs and reserves determination, involve known and unknown risks, uncertainties, and other factors that may cause the actual levels of production, costs, and results to be materially different from the estimated levels expressed or implied by such forward-looking statements.*

*The Company believes the expectations reflected in these forward-looking statements are reasonable, but the Company cannot assure that such expectations will prove to be correct, and thus, such statements should not be unduly relied upon. Factors that could cause actual results to differ materially from those anticipated in these forward-looking statements are described in the Company's Annual Information Form for the period ended December 31, 2016, dated March 14, 2017 (**"AIF"**). Although the Company has attempted to take into account important factors that could cause actual costs or operating results to differ materially, there may be other unforeseen factors that increase costs for the Company, and so results may not be as anticipated, estimated, or intended.*

Statements concerning oil and gas reserve estimates may also be deemed to constitute forward-looking statements to the extent that they involve oil and gas that will be encountered only if the property in question is developed. The estimated values disclosed in this MD&A do not represent fair market value. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates for all properties due to the effects of aggregation. Disclosure of well test results may be preliminary until analyzed or interpreted and are not necessarily indicative of long-term performance or ultimate recovery.

*This MD&A is management's assessment and analysis of the results and financial condition of the Company and should be read in conjunction with the accompanying unaudited Interim Condensed Consolidated Financial Statements and related notes for the three and nine months ended September 30, 2017 and 2016 (**"Q3 2017 Interim Financial Statements"**). The preparation of financial information is reported in United States dollars and is in accordance with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board ("**IASB**"), unless otherwise noted. This MD&A contains certain financial terms that are not considered in IFRS. These non-IFRS measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies, and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with IFRS. These measures are described in greater detail under the heading "Non-IFRS Measures" on page 17. All comparative percentages are between the quarters ended September 30, 2017 and 2016, unless otherwise noted.*

In order to provide shareholders with full disclosure relating to potential future capital expenditures, the Company has provided cost estimates for projects that, in some cases, are still in the early stages of development. These costs are preliminary estimates only. The actual amounts may differ, and these differences may be material. For further discussion of the significant capital expenditures, see "Capital Expenditures" on page 16.

Additional information with respect to the Company, including the Company's quarterly and annual financial statements and the AIF, have been filed with Canadian securities regulatory authorities and is available on SEDAR at www.sedar.com and on the Company's website at www.fronteraenergy.ca Information contained in or otherwise accessible through the Company's website does not form a part of this MD&A and is not incorporated by reference into this MD&A.

1. MESSAGE TO THE SHAREHOLDERS

During the third quarter of 2017, the Company remained focused on reducing costs and optimizing its current portfolio. In early 2017, the Company commenced a comprehensive reservoir optimization and technical review of its producing assets. During the third quarter, these studies began to exhibit successful results. Recently, drilled wells at existing fields (such as Quifa and Cajua) have shown initially higher production rates and the Company is implementing new pressure maintenance procedures and projects to help mitigate the impact of natural field declines.

Due to operational improvements and higher realized oil prices, the Company increased its 2017 Operating EBITDA guidance for the second time this year to $300 to $350 million, which represents a 13% increase (at the midpoint) from the previous guidance of $275 to $300 million and a 24% increase from the initial 2017 Operating EBITDA guidance of $250 to $275 million. The Company's 2017 guidance for exit production and annual capital spending remains unchanged at 70,000 to 75,000 boe/d and $250 to $300 million (before discounting exploration and evaluation sales), respectively.

The Company continues to operate its fields and facilities to maximize production while minimizing expenditures. During the third quarter of 2017, net production after royalties and internal consumption totaled 71,068 boe/d, remaining consistent with achievements in the previous quarter (72,370 boe/d). The slight decrease quarter over quarter was primarily due to maintenance downtime related to the Company's natural gas assets at La Creciente Block, as well as the impact of reduced spending on Colombian assets throughout the first half of 2017. Light and medium oil production in Peru was up 39% quarter over quarter to average 6,805 bbl/d; however, on September 18, 2017, production on the block was halted due to an indigenous blockade. Although the blockade has since been lifted, production has not yet resumed as the Company is currently evaluating the status of the assets within the block and is working with the local indigenous groups and the Peruvian government to ensure a safe and efficient restart of production.

The Company continues to create value through the execution of strategic initiatives, including recent agreements to acquire the remaining 36.4% ownership of Pacific Midstream Limited (**"PML"**) for $225.0 million (which, upon closing, will bring the Company's ownership of PML to 100%), and the sale of its total interest in Petroelectrica de los Llanos (**"PEL"**) for $56.0 million. These initiatives are part of a series of strategic transactions intended to reduce the Company's transportation costs by eliminating future take-or-pay commitments and increase annual adjusted EBITDA by over $100 million.

Looking forward, potential positive catalysts to unlock shareholder benefit include contract renegotiations, non-core asset dispositions, exploration drilling success, and continued cost control. The Company is excited to implement exploration and strategic activities designed to drive long term growth and unlock latent value. The balance sheet remains extremely strong with $599.9 million of total cash, cash equivalents and restricted cash offset by $250.0 million of long-term debt. Frontera also enjoys a strong oil hedge book with over 50% of production hedged at an average floor price over $50.6 per barrel Brent for the next 11 months.

Barry Larson
Chief Executive Officer
November 13, 2017

2. RESULTS FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2017

Financial and Operating Summary

					Nine Months Ended September 30	
		Q3 2017	Q2 2017	Q3 2016	2017	2016
Operating activities						
Total Production Volumes [1,2]	(boe/d)	71,068	72,370	75,096	71,982	114,982
Oil Production	(bbl/d)	65,641	66,448	67,128	66,041	105,696
Natural Gas Production	(mcf/d)	30,934	33,755	45,418	33,864	52,930
Combined Price (including hedging gains/losses)	($/boe)	47.86	46.28	40.83	46.68	40.02
Realized Oil & Gas Price	($/boe)	47.55	45.71	40.83	46.88	34.34
Realized hedging gain (loss)	($/boe)	0.31	0.57	—	(0.20)	5.68
Operating Cost	($/boe)	(24.32)	(25.97)	(24.06)	(25.22)	(21.46)
Production Cost	($/boe)	(10.85)	(9.93)	(9.39)	(10.07)	(7.63)
PAP royalties paid	($/boe)	(0.62)	(0.75)	(1.13)	(0.76)	(0.51)
Transportation (trucking and pipeline)	($/boe)	(11.77)	(14.19)	(12.69)	(13.31)	(11.68)
Diluent Cost	($/boe)	(1.08)	(1.10)	(0.85)	(1.08)	(1.64)
Operating Netback [3]	($/boe)	23.54	20.31	16.77	21.46	18.56
Adjusted Netback [3]	($/boe)	20.68	19.13	12.91	19.42	17.40
Adjusted FFO Netback [3]	($/boe)	12.64	11.76	2.55	12.58	11.78
Capital Expenditures	($M)	48,563	37,826	33,631	125,188	104,429
Financials						
Total sales	($M)	307,080	299,452	308,705	923,170	1,141,939
Net crude oil and gas sales and other income	($M)	278,137	273,377	307,587	842,881	1,138,941
Trading	($M)	28,943	26,075	1,118	80,289	2,998
Net loss [4]	($M)	(141,115)	(51,542)	(557,068)	(184,159)	(1,576,671)
Per share - basic and diluted [5]	$	(2.8)	(1.0)	(176,835.1)	(3.7)	(500,496.8)
Operating EBITDA [3]	($M)	105,885	86,857	89,846	285,184	400,362
Operating EBITDA margin (Operating EBITDA/revenues)	%	34%	29%	29%	31%	35%
Adjusted EBITDA [3]	($M)	44,203	87,389	37,689	246,650	255,586
Adjusted EBITDA margin (Adjusted EBITDA/revenues)	%	14%	29%	12%	27%	22%
Adjusted FFO	($M)	47,889	46,151	43,036	172,800	248,716
Per share - basic and diluted [5]	$	0.96	0.92	13,661.30	3.46	78,952.15
Total assets	($M)	2,546,631	2,621,871	2,403,602	2,546,631	2,403,602
Cash and cash equivalents	($M)	500,643	439,479	555,724	500,643	555,724
Total equity (deficit)	($M)	1,442,431	1,561,067	(4,518,434)	1,442,431	(4,518,434)
Debt and obligations under finance lease	($M)	270,222	271,181	5,838,557	270,222	5,838,557

1. *Total production volumes represents the Company's working interest volumes, net of royalties and internal consumption.*
2. *BOE has been expressed using the 5.7 to 1 Colombian Mcf/Bbl conversion standard required by the Colombian Ministry of Mines & Energy.*
3. *Refer to Non-IFRS Measures on page 17.*
4. *Net (loss) income attributable to equity holders of the parent.*
5. *The basic and diluted weighted average numbers of common shares for the three months ended September 30, 2017 and 2016 were 50,005,832 and 3,150, respectively (reflecting the impact of the November 2, 2016 share consolidation).*

Results

Operational Highlights

- Total production volumes after royalties and internal consumption for the third quarter of 2017 totalled 71,068 boe/d and was essentially flat compared with the previous quarter's volumes of 72,370 boe/d. The slight decrease quarter-over-quarter was primarily due to maintenance downtime on the Company's natural gas assets at La Creciente, as well as the impact of reduced spending on Colombian assets thus far in 2017.
- During the three months ended September 30, 2017, the Company drilled 24 development wells and four workovers in Colombia and spudded the first exploration well. The Company remains focused on optimizing its Colombian assets through modest capex investment concentrated on maintaining current production levels and mitigating the natural decline of certain fields. In the fourth quarter of 2017, the Company plans to drill approximately 35 - 45 wells.
- Oil production slightly decreased quarter over quarter. Light and medium net oil production in Colombia was 33,105 boe/d in the third quarter of 2017 compared with 34,174 boe/d in the second quarter. Heavy oil production from Quifa SW field and other fields averaged 23,501 bbl/d in the third quarter compared with 24,696 bbl/d in the second quarter of 2017.
- In Peru, light and medium oil production was up 39% quarter over quarter to average 6,805 bbl/d; however, on September 18, 2017, production at Block 192 was halted due to an indigenous blockade. Although the blockade has since been lifted, production has not yet resumed as the Company is currently evaluating the status of the assets within the block and is working with the local indigenous groups and the Peruvian government to ensure a safe and efficient restart of production. Offshore production at Block Z1 remains on production at approximately 1,000 bbl/d.

Financial Highlights

- Third quarter revenue increased 3% to $307.1 million compared with $299.5 million in the second quarter of 2017, primarily due to higher realized oil prices. Compared with the third quarter of 2016, revenue was in line year-over-year.
- Realized oil prices were 3% higher quarter-over-quarter, averaging $50.33/bbl in the third quarter versus $48.66/bbl in the second quarter of 2017. Benchmark Brent oil prices increased 3% to $52.17/bbl in the third quarter compared with $50.79/bbl in the second quarter of 2017. The slight outperformance of Frontera's realized prices versus Brent is primarily due to strong pricing for Vasconia heavy oil, which contributed to Frontera's overall commercial heavy oil differential to Brent, narrowing 14% to $1.84/bbl in the third quarter of 2017 versus $2.13/bbl in the second quarter of 2017.
- Operating EBITDA totalled $105.9 million ($2.12/share) for the third quarter of 2017, an increase of 22% compared with the $86.9 million ($1.74/share) achieved in the second quarter of 2017 (mainly due to strong realized oil pricing and lower total operating costs). In comparison with the third quarter of 2016, Operating EBITDA was $16.0 million higher.
- Adjusted Funds Flow from Operations ("**Adjusted FFO**") totalled $47.9 million ($0.96/share) for the third quarter of 2017, an increase of 4% compared with the $46.2 million ($0.92/share) achieved in the second quarter of 2017.
- Operating Netback was $23.54/boe for the third quarter of 2017, an increase of 16% compared with $20.31/boe in the second quarter of 2017 (mainly due to strong realized oil pricing and lower total operating costs). Year-over-year, the Company's third quarter Operating Netback was 40% higher than the $16.77/boe achieved in the third quarter of 2016.
- Total operating costs (including production, royalties paid in cash, transportation, and diluent costs) averaged $24.32/boe in the third quarter of 2017, an improvement of 6% compared with $25.97/boe in the second quarter of 2017. The largest driver of lower total operating costs was lower transportation costs, which improved 17% to $11.77/boe in the third quarter of 2017 from $14.19/boe in the second quarter of 2017, as increased volumes that could not utilize the Bicentenario pipeline were transported through the OCENSA pipeline. Another contributing factor was the revenue from subleasing tanks for fuel oil related to the mandate agreement signed with Puerto Bahia on August 17, 2017, was recognized retrospectively.
- G&A costs were in line at $4.06/boe in the third quarter of 2017 versus $3.96/boe in the second quarter of 2017. Year-over-year, the Company's third quarter G&A costs have improved by 23% from $5.27/boe in the third quarter of 2016. Frontera continues to look for additional opportunities to eliminate unnecessary costs.

- During the third quarter of 2017, net loss attributable to equity holders of the parent was $141.1 million, compared with a net loss of $51.5 million in the second quarter of 2017, mainly due to impairment charges of $74.0 million and unrealized risk management loss of $43.6 million in the third quarter of 2017.
- The Company continued to build cash and the balance sheet remains strong at the end of the third quarter of 2017, with a cash position (including cash equivalents and restricted cash) of $599.9 million, an increase of 11% from the previous period. Frontera also enjoys a strong oil hedge book with over 50% of its production hedged at an average floor price of approximately $50.6 per barrel Brent for the next 11 months.

Contract Renegotiations, Liability Reductions and Acquisitions

- On October 13, 2017, the Company signed an agreement to acquire the outstanding 36.36% ownership of PML from the International Finance Corporation ("**IFC**") and from funds related to the IFC (jointly, the "**IFC Parties**"). Following the acquisition, the Company will own 100% of PML, which will enable the Company to pursue initiatives related to the reduction and unwinding of various transportation commitments, including fixed rate take-or-pay arrangements. Consideration for the acquisition will be $225 million in cash paid in installments over a 36-month period, plus accrued interest on unpaid amounts. The completion of the transaction is subject to obtaining modifications to Frontera's take-or-pay contracts, which are expected to reduce tariffs, the consent of the Company's noteholders and secured lenders, and other customary conditions of closing.
- On October 25, 2017, the Company entered into an agreement to sell its interest in PEL to an affiliate of Electricas de Medellin-Ingeniería y Servicios S.A.S. Consideration for the sale will be $56.0 million in cash, of which $50.0 million will be used as the first payment to the IFC Parties in connection with the purchase of the IFC Parties' common shares in PML.
- The Company is currently undergoing an internal reorganization of its Colombian business units, in an effort to streamline its operations and eliminate legal entity redundancies. As of the date hereof, the Company is in the process of consolidating its four legal entities that hold its Colombian operational assets into one entity.
- On July 26, 2017, the Agencia Nacional de Hidrocarburos ("**ANH**") approved the assignment of interests, rights and obligations of the Company's 62.5% interest in the CPO-14 field contracts to Cepsa Colombia S.A. ("**Cepsa**").
- On September 22, 2017, the ANH approved the transfer of $6.0 million in commitment investments from the CPO-12 Block to two exploratory wells in the CPE-6 Block ($3.0 million for each well); the formalization of the transfer is pending.
- On September 22, 2017, the ANH approved the assignment of interests, rights and obligations under the PUT-9, Mecaya, Tacacho and Terecay Blocks contracts to Amerisur Exploracion Colombia Limitada ("**Amerisur**") subject to execution of a formal amendment.
- On October 3, 2017, the ANH approved the transfer of the San Jacinto 7 Block to CNE Oil & Gas S.A.S., a subsidiary of Canacol Energy Ltd. ("**CNE Oil**") in consideration for assuming all contractual exploration obligations of the Company, which total $7.8 million. The transaction is subject to CNE Oil's partner, ONGC Videsh Ltd., being accepted by the ANH.
- During the third quarter of 2017, Itaú BBA S.A. released an outstanding standby letter of credit related to the transfer of the Company's interest in the Queiroz Blocks in Brazil to Queiroz Galvão Exploração e Produção S.A., reducing Frontera's credit exposure by $42.5 million.

Assets Held for Sale (Executed/Closing) Summary

During the third quarter of 2017, the Company continued with its corporate strategy to monetize non-core assets. The Company received a standby letter of credit of $42.5 million related to the Queiroz Block, the Cerrito Block sale was finalized, and the Company received $0.1 million from Petrosouth Energy Corporation. During the nine months ended September 30, 2017, the Company received a total of $32.6 million of the $36.1 million net cash consideration from assets held for sale or sold in Peru (Blocks 126 and 131), Brazil (Karoon) and Colombia (Putumayo and Casanare Este). In addition to assets held for sale in the second quarter of 2017, the Company finalized an agreement with Interoil Corporation (now ExxonMobil Canada Holdings ULC) on the transfer of operating rights in Papua New Guinea for a total cash consideration of $57.0 million, net of outstanding liabilities. The Company expects to receive this amount in the fourth quarter of 2017 upon receipt of regulatory approval.

Below is a summary of certain non-core asset sales of exploration and production blocks executed within the past 12 months; many are pending final government approvals.

				(in millions of US$)				
Update	Assets	Country	Buyer	Net Cash Consideration	Enviromental Liabilities (1)	Exploration Obligations (1)	Bank Guarantees (2)	Status
Closed	Karoon blocks	Brazil	Karoon	15.5	0.0	50.8	0.0	Finalized
Closed	Queiroz blocks	Brazil	Queiroz	(10.0)	—	25.6	42.5	Finalized
Closed	Lot 131	Peru	Cepsa	17.1	1.6	7.2	—	Finalized
In progress	Major lands	Colombia	Ecopetrol S.A	6.3	—	—	—	Under negotiation
In progress	Putumayo Basin	Colombia	Amerisur	4.9	0.2	26.3	2.9	Pending signature of ANH amendment and return of the guarantees
In progress	Casanare Este	Colombia	Gold Oil	2.0	4.1	7.9	0.8	Pending Governmental approval; 50% of cash received
In progress	Lot 126	Peru	Maple Gas	0.2	10.3	3.6	2.8	Cash received. Pending Governmental approval
In progress	San Jacinto 7 block	Colombia	CNE Oil	Nominal	—	7.8	2.5	Pending Governmental approval
Closed	Cerrito	Colombia	Petrosouth	0.1	0.9	—	—	Finalized
				36.1	**17.1**	**129.2**	**51.5**	

1. *Estimated.*
2. *Standby Letter of Credit.*

Restructuring Transaction

On April 19, 2016, the Company, with the support of certain holders of its senior unsecured notes and lenders under its credit facilities, which totalled $5.3 billion, entered into an agreement with The Catalyst Capital Group Inc. ("**Catalyst**") with respect to implementing a comprehensive financial Restructuring Transaction (the "**Restructuring Transaction**"). Pursuant to the terms of the Restructuring Transaction, the claims of certain creditors ("**Affected Creditors**") were compromised in exchange for common shares in the Company. On November 2, 2016, the Company successfully completed the implementation of its Restructuring Transaction in accordance with its plan of compromise and arrangement which was approved by both the Affected Creditors and the Ontario Superior Court of Justice (Commercial List). The Restructuring Transaction substantially changed the capital structure of the Company, reducing financial debt to $250 million represented by five-year secured notes (the "**Exit Notes**") and a letter of credit facility, which at the time of the implementation of the Restructuring Transaction totalled $115.5 million. After completion of the Restructuring Transaction, the shareholders of the Company comprised the Affected Creditors with approximately 69.2% and Catalyst with approximately 30.8% of the common shares.

Additional information is included in Note 1: "Corporate Information" of the Company's audited annual financial statements as at December 31, 2016 (the **"2016 Audited Financial Statements"**).

Guidance Update

Due to operational improvements and higher realized oil prices, the Company is pleased to announce that it has raised its guidance for 2017 Operating EBITDA for the second time this year to $300 to $350 million, representing a 13% increase (at the midpoint) from the previous guidance of $275 to $300 million and a 24% increase from the initial 2017 Operating EBITDA guidance of $250 to $275 million. The Company's 2017 guidance for exit production and annual capital spending remains unchanged at 70,000 to 75,000 boe/d and $250 to $300 million (before discounting exploration and evaluation sales), respectively. The detailed reservoir study and technical review of the Company's portfolio undertaken earlier in 2017 has begun to deliver results. Initial production rates have been higher on new wells in existing fields (such as Quifa), pressure maintenance projects have been implemented, decline rates are being mitigated, and the Company spudded its first exploration well as a "new" company in September. Looking forward, potential positive catalysts to unlock shareholder benefit include contract renegotiations, non-core asset dispositions, exploration drilling success, and continued cost control. We are excited to implement exploration and strategic activities designed to drive long term growth and unlock latent value.

Principal Properties

	Working Interest	Operated	Gross Acres	Net Acres
Colombia Central				
Quifa	60.00%	Operated	265,954	159,572
Guatiquia	100.00%	Operated	14,372	14,372
Cubiro	100.00%	Operated	44,360	44,360
Cravo Viejo	100.00%	Operated	46,839	46,839
Casimena	100.00%	Operated	32,188	32,188
Arrendajo	97.50%	Operated	33,280	32,448
Neiva	55.60%	Non-operated	2,395	1,332
Corcel	100.00%	Operated	25,141	25,141
Cachicamo	100.00%	Operated	28,471	28,471
Canaguaro	87.50%	Operated	6,289	5,503
Dindal - Rio Seco	45.00%	Operated	47,689	21,539
Sabanero	100.00%	Operated	87,540	87,540
Llanos 7	100.00%	Operated	152,674	152,674
Llanos 55	100.00%	Operated	101,466	101,466
Llanos 83	100.00%	Operated	35,755	35,755
Llanos 25	100.00%	Operated	169,805	169,805
Casanare Este (1)	100.00%	Operated	18,476	18,476
Rio Ariari	100.00%	Operated	307,036	307,036
Mapache	100.00%	Operated	55,374	55,374
CPE-6	100.00%	Operated	593,018	593,018
CPO-12	57.00%	Operated	708,765	404,988
Abanico	25.00%	Operated	62,560	15,640
Buganvilles	49.00%	Operated	77,754	38,100
Cordillera-24	85.00%	Operated	619,817	526,844
Cordillera-15 (2)	50.00%	Non-operated	141,308	70,654
Muisca (2)	50.00%	Non-operated	585,126	292,563
Colombia North				
La Creciente	100.00%	Operated	26,650	26,650
Guama	100.00%	Operated	70,993	70,993
SSJN-3 (3)	100.00%	Operated	634,364	634,364
CR-1	60.00%	Operated	307,384	184,431
Cerrito (4)	80.00%	Operated	10,166	8,112
Colombia South				
Orito	79.00%	Non-operated	42,492	33,569
Caguan-5	50.00%	Operated	919,321	459,661
Caguan-6	60.00%	Operated	119,048	71,429
Portofino	40.00%	Non-operated	258,676	103,470
Tinigua	50.00%	Non-operated	105,467	52,734
Terecay (5)	100.00%	Operated	586,626	586,626
Tacacho (5)	50.50%	Operated	589,008	297,449
Putumayo-9 (5)	60.00%	Operated	121,452	72,871
Mecaya (5)	58.00%	Operated	74,127	42,993
Peru				
Block Z1	49.00%	Operated	554,443	271,677
Lot 126 (6)	100.00%	Operated	1,048,762	1,048,762
Lot 116 (7)	50.00%	Operated	1,628,126	814,063
Lot 192	84.00%	Operated	1,266,037	1,266,037

1. *Casanare Este Block held for sale to Gold Oil PLC Sucursal Colombia.*
2. *Includes investment in Maurel & Prom Colombia B.V. fields.*
3. *ANH approved termination contract, pending formalization.*
4. *Cerrito Block held for sale to Petrosouth Energy Corporation.*
5. *Blocks held for sale to Amerisur, pending formalization.*
6. *Peru block held for sale to Maple Gas Corporation del Peru SRL.*
7. *Lot 116 50% interest farmout from Maurel et Prom Perú S.A.C. is subject to Perupetro approval.*

3. FINANCIAL AND OPERATIONAL RESULTS

Production and Development Review

The following tables highlight the average daily total gross and net share production after royalties and internal consumption from all of the Company's producing fields in Colombia and Peru, reconciled to volume sold.

	Average Production (in boe/d)								
	Total field production		Gross share before royalties (1)		Net share after royalties				
	Three months ended				Three months ended			Nine months ended	
Producing fields in Colombia	September 2017	September 2016	September 2017	September 2016	September 2017	June 2017	September 2016	September 2017	September 2016
Rubiales / Piriri	—	—	—	—	—	—	—	—	31,873
Quifa SW (2)	43,306	44,934	25,783	26,692	23,501	24,696	24,299	24,396	26,087
	43,306	**44,934**	**25,783**	**26,692**	**23,501**	**24,696**	**24,299**	**24,396**	**57,960**
Other fields in Colombia									
Light and medium (3)	37,545	41,986	35,996	39,599	33,105	34,174	37,765	33,815	41,094
Gas (4)	6,139	8,884	5,427	7,968	5,427	5,922	7,968	5,941	9,286
Heavy oil (5)	3,185	4,000	2,307	3,008	2,230	2,665	2,882	2,628	3,191
	46,869	**54,870**	**43,730**	**50,575**	**40,762**	**42,761**	**48,615**	**42,384**	**53,571**
Total production Colombia	**90,175**	**99,804**	**69,513**	**77,267**	**64,263**	**67,457**	**72,914**	**66,780**	**111,531**
Producing fields in Peru									
Light and medium (6)	10,198	5,628	6,805	2,182	6,805	4,913	2,182	5,202	3,451
	10,198	**5,628**	**6,805**	**2,182**	**6,805**	**4,913**	**2,182**	**5,202**	**3,451**
Total production Colombia and Peru	**100,373**	**105,432**	**76,318**	**79,449**	**71,068**	**72,370**	**75,096**	**71,982**	**114,982**
Total production excluding Rubiales/Piriri	**100,373**	**105,432**	**76,318**	**79,449**	**71,068**	**72,370**	**75,096**	**71,982**	**83,109**

1. *Share before royalties is net of internal consumption at the field and before high-price clause ("**PAP**") at the Quifa SW field.*
2. *The Company's share before royalties in the Quifa SW and Cajua fields is 60% and decreases in accordance with the PAP that assigns additional production to Ecopetrol S.A.*
3. *Mainly includes Cubiro, Cravo Viejo, Casanare Este, Canaguaro, Guatiquia, Casimena, Corcel, CPI Neiva, Cachicamo, Arrendajo, and other producing fields. Subject to approval from the ANH, the Company is in the process of divesting its participation in Casanare Este.*
4. *Mainly includes La Creciente field.*
5. *Includes Cajua, Sabanero, CPE-6, Rio Ariari, Prospecto S, and Prospecto D fields.*
6. *Includes Block Z1, Block 192, and Block 131, which was sold to Cepsa; production was included until May 19, 2017.*

		Three months ended			Nine months ended	
		September 2017	June 2017	September 2016	September 2017	September 2016
Total Production Volumes (1)	**(boe/d)**	**71,068**	**72,370**	**75,096**	**71,982**	**114,982**
Oil Inventory Build (2)	(bbl/d)	(7,283)	(6,357)	7,811	(5,017)	(10,457)
Trading & Diluent Volumes Purchased (3)	(boe/d)	7,201	6,721	743	6,821	895
E&E Asset Volumes Sold (4)	(boe/d)	(1,075)	(1,502)	(1,483)	(1,343)	(1,248)
Trading Volumes Sold (5)	(boe/d)	(6,749)	(6,324)	(290)	(6,296)	(308)
Sales Volumes	**(boe/d)**	**63,162**	**64,908**	**81,877**	**66,147**	**103,864**
Oil Sales	(bbl/d)	57,808	59,191	74,268	60,419	94,943
Gas Sales (6)	(mcf/d)	30,518	32,587	43,371	32,650	50,850

1. *Total production volumes represents the Company's working interest volumes, net of royalties and internal consumption.*
2. *Produced volumes that were not sold in the period and instead resulted in an increase in crude inventories held in storage.*
3. *Volumes purchased for trading and diluent purposes to fulfill pipeline take-or-pay agreements and pipeline quality specifications.*
4. *Volumes from Exploration and Evaluation ("**E&E**") assets are excluded from total sales volumes because E&E revenues and costs are capitalized.*
5. *Trading volumes sold that were purchased to meet volumes required for pipeline take or pay agreements.*
6. *BOE has been expressed using the 5.7 to 1 Colombian Mcf/Bbl conversion standard required by the Colombian Ministry of Mines & Energy.*

Total production volumes after royalties and internal consumption for the third quarter of 2017 totalled 71,068 boe/d and was essentially flat with the previous quarter's volumes of 72,370 boe/d. The slight decrease quarter over quarter was primarily due to maintenance downtime on the Company's natural gas assets at La Creciente as well as the impact of lower spending on Colombian assets to date. During the three months ended September 30, 2017, the Company drilled 24 development wells and four workovers on the Colombian Blocks. In furtherance of the Company's strategy to prioritize economic value over production volumes, activity thus far in 2017 has been focused on keeping production flat between 70,000 and 75,000 boe/d with modest capex investment while growing and maximising Adjusted FFO and Operating EBITDA.

Colombia

During the third quarter of 2017, light and medium net oil production in Colombia was 33,105 bbl/d, lower by 3% in comparison with 34,174 bbl/d in the second quarter of 2017. Two wells were drilled in each of the Guatiquia and Mapache blocks; in both wells, basic sediment water was found.

Heavy oil production levels from Quifa SW field and other fields decreased during the third quarter of 2017, in comparison with the previous quarter's 27,361 bbl/d. The Company drilled 18 development in the Quifa SW field, and one well was drilled in each of the Cajua and CPE-6 blocks.

Natural gas production declined in the third quarter of 2017 compared with the previous quarter, reflecting the lack of capital investment as the Company continues to evaluate future activity on La Creciente Block.

Peru

During the third quarter of 2017, total production volumes after royalties and internal consumption was 6,805 bbl/d, a 39% increase from 4,913 bbl/d in the second quarter of 2017 due to Block 192's production ramp-up after the reactivation of the Norperuano pipeline on January 31, 2017. On September 18, 2017, production on the block was halted due to indigenous actions.

2017 Operational Update

During the third quarter of 2017, after integration of various technical studies and detailed reservoir management work, the Company has made significant progress towards increasing the effective management of its producing assets and took significant steps towards slowing production decline. Furthermore, the Company evaluated the use of new reservoir optimization technologies to assist with increasing production, reducing development costs and optimizing operating costs. In addition, the Company completed reservoir injectivity tests to prove the potential for secondary recovery and reservoir pressure support. These studies and optimization activities have positioned the Company to accomplish more cost-efficient development and production operations. The following producing blocks were positively affected:

- Quifa SW and Cajua Blocks - Reservoir studies have been completed to facilitate optimization and the placement of future development wells and evaluate the potential for more efficient well designs such as multi-laterals. Now that these studies have been completed, the Company will continue to accelerate the development program in the fourth quarter of 2017 with the arrival of additional drilling rigs in Quifa SW and Cajua. Initial results from the accelerated drilling program are proving to be very encouraging.
- Guatiquia Block - Development drilling was reduced in early 2017 due to required reservoir studies to ensure prudent reservoir management and preparations for the drilling of injector wells for reservoir pressure maintenance. The first injector well in the Ardilla field will be drilled in the fourth quarter of 2017 in conjunction with the acceleration of the development drilling. Additional injection wells will be drilled as required, which will assist with arresting production decline and increasing the recovery factor. New development wells were drilled and completed, adding production and new reserves. The Company is now considering the implementation of dual-completions for the two producing reservoirs, which would reduce drilling costs and increase well productivity.
- CPI Blocks (Orito and Neiva) - The Company implemented a new water injection program at the Neiva block in an effort to enhance recovery. Initial results have been promising and to date there has been a 20% increase in production. Based on these positive results, the Company is considering an expansion of this program. Reservoir studies to assess the production potential of the "A" Limestone in the Orito Field have also been completed and the Company is now evaluating the potential for recompletion of an existing well to test the potential productivity of the "A" Limestone.

- Cubiro Block (Copa field) - Through various reservoir injectivity tests, the Company has been able to confirm that injector wells will be able to effectively provide reservoir pressure support by being able to receive significant volumes of water. This, in turn, will increase production by raising the recovery factor from the Copa field.

Netbacks

The Company's netbacks are summarized below. For discussion on the definitions of how the Company uses Operating Netback, Adjusted Netback, and Adjusted FFO Netback, please refer to Note 3 entitled "Financial and Operational Results - Non-IFRS Measures" on page 17.

	Q3 2017		Q2 2017		Q3 2016	
Combined Operating Netback	**($/boe)**	**$M**	**($/boe)**	**$M**	**($/boe)**	**$M**
Crude oil and natural gas sales price [(1)]	**47.86**	**278,137**	**46.28**	**273,377**	**40.83**	**307,587**
Production cost of barrels	(10.85)	(70,940)	(9.93)	(65,390)	(9.39)	(64,896)
Royalties paid in cash	(0.62)	(4,047)	(0.75)	(4,922)	(1.13)	(7,798)
Transportation (trucking and pipeline)	(11.77)	(76,931)	(14.19)	(93,435)	(12.69)	(87,704)
Diluent cost	(1.08)	(7,052)	(1.10)	(7,225)	(0.85)	(5,870)
Total Operating Cost [(2)]	**(24.32)**	**(158,970)**	**(25.97)**	**(170,972)**	**(24.06)**	**(166,268)**
Operating Netback	**23.54**	**119,167**	**20.31**	**102,405**	**16.77**	**141,319**
Fees paid on suspended pipeline capacity [(2)]	(5.33)	(34,838)	(3.38)	(22,237)	(6.23)	(43,032)
Share of gain of equity-accounted investees - pipelines [(3)]	2.47	16,135	2.20	14,506	2.37	16,344
Adjusted Netback	**20.68**	**100,464**	**19.13**	**94,674**	**12.91**	**114,631**
General and administrative expenses [(4)]	(4.06)	(26,569)	(3.96)	(26,098)	(5.27)	(36,398)
Cash finance costs [(5)]	(0.96)	(6,250)	(0.95)	(6,250)	(2.17)	(15,000)
Other cash costs [(6)]	(3.02)	(19,756)	(2.46)	(16,175)	(2.92)	(20,197)
Adjusted FFO Netback	**12.64**	**47,889**	**11.76**	**46,151**	**2.55**	**43,036**
Total Production volume (boe/d) [(7)]	71,068		72,370		75,096	
Sales volume (D&P) (boe/d) [(8)]	63,162		64,908		81,877	

For reconciliation to IFRS figures:

1. *Per boe price calculated over sales volume D&P, refer to page 11.*
2. *Operating costs, refer to page 12.*
3. *Share of gain of equity-accounted investees, refer to page 14.*
4. *General and administrative costs, refer to page 14.*
5. *Finance costs, refer to page 14.*
6. *Mainly includes: Dividends from associates, Frontera's share of gain of equity-accounted investees - pipelines, current income tax, equity tax paid, realized foreign exchange, inventory fluctuation, overlift/underlift and uses of asset retirement obligation.*
7. *Production and development review, refer to page 7.*
8. *Sales volumes D&P excludes E&E as the revenues and costs are capitalized.*

During the three months ended September 30, 2017, the Company's crude oil and natural gas sales price from commercial development and production fields increased to $47.86/boe from $46.28/boe in the second quarter of 2017 and $40.83/boe in the third quarter of 2016, mainly as a result of the improvement in oil market prices and better price differentials.

Per barrel total operating costs, including production, royalties paid in cash, transportation, and diluent costs, decreased from $25.97/boe in the second quarter of 2017 to $24.32/boe in the third quarter of 2017. The decrease is attributable to lower transportation cost as a result of more disrupted capacity days at Bicentenario; another factor was the revenue from subleasing tanks for fuel oil related to the mandate agreement signed with Puerto Bahia on August 17, 2017 - the revenue was recognized retrospectively.

Adjusted Netback in the third quarter of 2017 was $20.68/boe, 8% higher than $19.13/boe in the second quarter of 2017 and $12.91/boe in the third quarter of 2016. An increase in realized oil prices offset higher fees paid on suspended pipeline capacity as the Bicentenario system was not operational for 75 days. However, the Company was able to source available operational capacity from the OCENSA pipeline at a lower cost per barrel. The cost redundancy from unused pipeline take-or-pay commitments affected Adjusted Netback by $5.33/bbl ($34.8 million) in the third quarter of 2017.

	Nine months ended September 30			
	2017		2016	
Combined Operating Netback	**($/boe)**	**$M**	**($/boe)**	**$M**
Crude oil and natural gas sales price (1)	**46.68**	**842,881**	**40.02**	**1,138,941**
Production cost of barrels	(10.07)	(197,857)	(7.63)	(240,340)
Royalties paid in cash	(0.76)	(14,842)	(0.51)	(16,376)
Transportation (trucking and pipeline)	(13.31)	(261,618)	(11.68)	(367,851)
Diluent cost	(1.08)	(21,146)	(1.64)	(51,823)
Total Operating Cost (2)	**(25.22)**	**(495,463)**	**(21.46)**	**(676,390)**
Operating Netback	**21.46**	**347,418**	**18.56**	**462,551**
Fees paid on suspended pipeline capacity (2)	(4.28)	(84,175)	(2.74)	(86,481)
Share of gain of equity-accounted investees - pipelines (3)	2.24	44,021	1.58	49,712
Adjusted Netback	**19.42**	**307,264**	**17.40**	**425,782**
General and administrative expenses (4)	(4.09)	(80,373)	(3.33)	(104,898)
Cash finance costs (5)	(0.95)	(18,750)	(3.63)	(114,418)
Other cash costs (6)	(1.80)	(35,341)	1.34	42,250
Adjusted FFO Netback	**12.58**	**172,800**	**11.78**	**248,716**
Total Production volume (boe/d) (7)	71,982		114,982	
Sales volume (D&P) (boe/d) (8)	66,147		103,864	

For reconciliation to IFRS figures:

1. *Per boe price calculated over sales volume D&P, refer to page 11.*
2. *Operating costs, refer to page 12.*
3. *Share of gain of equity-accounted investees, refer to page 14.*
4. *General and administrative costs, refer to page 14.*
5. *Finance costs, refer to page 14.*
6. *Mainly includes: Dividends from associates, Frontera's share of gain of equity-accounted investees - pipelines, current income tax, equity tax paid, realized foreign exchange, inventory fluctuation, overlift/underlift and uses of asset retirement obligation.*
7. *Production and development review, refer to page 7.*
8. *Sales volumes D&P excludes E&E as the revenues and costs are capitalized.*

During the nine months ended on September 30, 2017, the combined crude oil and gas Operating Netback was $21.46/boe, $2.90/boe higher compared with $18.56/boe in the same period of 2016. The increase was mainly attributable to the oil market price improvement during 2017 and better price differentials.

For the nine months ended on September 30, 2017, per barrel total operating costs, including production, royalties paid in cash, transportation, and diluent costs, increased to $25.22/boe from $21.46/boe during the same period of 2016. The increase was mainly due to lower volumes after the expiration of Rubiales block which, as a mature field, had lower costs than other fields.

Adjusted Netback for the nine months ended on September 30, 2017 increased to $19.42/boe from $17.40/boe during the same period in 2016, mainly due to an improved Operating Netback.

Realized and Reference Prices

	Q3 2017	Q2 2017	Q3 2016	YTD 2017	YTD 2016
Reference prices					
Brent ($/bbl)	52.17	50.79	46.99	52.51	43.17
Average realized prices					
Realized oil price ($/bbl)	50.33	48.66	42.21	47.72	41.37
Realized natural gas price ($/Mcf)	3.73	3.79	4.81	3.76	4.49
Realized natural gas price ($/boe) (1)	21.26	21.63	27.43	21.45	25.62
Combined price before hedging/other ($/boe)	**46.33**	**44.51**	**40.01**	**45.99**	**34.06**
Realized hedging gain (loss) ($/boe)	0.31	0.57	—	(0.44)	5.68
Other revenue ($/boe) (2)	1.22	1.20	0.82	1.13	0.28
Combined Realized price ($/boe)	**47.86**	**46.28**	**40.83**	**46.68**	**40.02**

1. *Refer to the section entitled "Further Disclosures" on page 23 for conversion factor.*
2. *Mainly includes income from infrastructure asset.*

Greater expectations of the effectiveness of the Organization of the Petroleum Exporting Countries ("**OPEC**") output cut agreement led to a significant crude oil price recovery during the first quarter of 2017. However, through the second quarter of the year, the OPEC deal failed to impress the market and oil prices deteriorated as OPEC exports have not fallen by as much as production, while a recovery in Libyan and Nigerian output has partially upset efforts by others to reduce production.

After crude oil prices tested the low of $44.00/bbl in June, oil prices started to recover in July as OPEC's data indicated higher levels of compliance with the agreed production cuts. By late August, oil prices slipped approximately 5% as the hurricane season significantly affected the U.S. Gulf Coast refineries, terminals and ports, leading to a crude oil demand destruction. At its peak, Hurricane Harvey closed around 4.8 MMbbl/d of refining capacity in the U.S. Gulf Coast, triggering crude trade bottlenecks within the U.S. and resulting in overtightening of the rest of the world's crude market. By mid-September, as refineries in the U.S. Gulf Coast started coming back online, trade flows started to recover. At the same time, oil prices increased due to expectations for higher global oil demand growth in the near term (EIA, IEA, OPEC, etc.) and geopolitical events.

Between the second and third quarters of 2017, Brent prices increased by $1.38/bbl to an average of $52.17/bbl. Year over year, the Brent price increased by $5.18/bbl (11%) in the third quarter of 2017 compared with the average of $46.99/bbl in the same period of 2016.

Sales

	Three Months Ended September 30		Nine Months Ended September 30	
(in thousands of US$)	**2017**	**2016**	**2017**	**2016**
Net crude oil and gas sales and other income	$ 276,344	$ 307,595	$ 846,529	$ 977,384
Realized gain (loss) on hedges	1,793	(8)	(3,648)	161,557
Trading revenue	28,943	1,118	80,289	2,998
Total sales	**$ 307,080**	**$ 308,705**	**$ 923,170**	**$ 1,141,939**
Total sales excluding trading revenue	278,137	307,587	842,881	1,138,941
$/per volume sold	47.86	40.83	46.68	40.02

Total sales during the third quarter of 2017 were $307.1 million, 1% lower than the same period of 2016. This reduction is the result of the lower volumes sold. Revenue for the nine months ended September 30, 2017 was $923.2 million, 19% lower than the same period of 2016, which had revenues of $1,141.9 million, mainly due to the expiration of the Rubiales block and higher realized gains from risk management activities.

The following is an analysis of the price and sales volume movements for the third quarter of 2017 compared with the same period of 2016, and for the nine months ended September 30, 2017 and 2016:

	Three Months Ended September 30
(in thousands of US$)	2017 - 2016
Total sales for the three months ended September 30, 2016	$ 308,705
Decrease due to 23% (18,715 boe/d) reduction in produced and sold volume	(68,888)
Increase due to 6,459 bbl/d higher volume of trading	24,833
Hedge effect	1,801
Increase due to 16% higher realized prices	38,981
Other revenue increase	1,648
Total sales for the three months ended September 30, 2017	**$ 307,080**

	Nine Months Ended September 30
(in thousands of US$)	2017 - 2016
Total sales for the nine months ended September 30, 2016	$ 1,141,939
Decrease due to 37% (37,717 boe/d) lower produced and sold volume	(354,240)
Increase due to 5,963 bbl/d higher volume of trading	57,917
Hedge effect	(165,205)
Increase due to 35% higher realized prices	228,403
Other revenue increase	14,356
Total sales for the nine months ended September 30, 2017	**$ 923,170**

Operating Costs

	Three Months Ended September 30		Nine Months Ended September 30	
(in thousands of US$)	2017	2016	2017	2016
Production costs	$ 70,940	$ 64,896	$ 197,857	$ 240,340
Royalties paid in cash	4,047	7,798	14,842	16,376
Transportation costs	76,931	87,704	261,618	367,851
Diluent cost	7,052	5,870	21,146	51,823
Total operating cost	**$ 158,970**	**$ 166,268**	**$ 495,463**	**$ 676,390**
Average operating cost per boe	**24.32**	**24.06**	**25.22**	**21.46**
Fees paid on suspended pipeline capacity	34,838	43,032	84,175	86,481
Trading purchase cost	28,719	905	79,174	2,411
Other costs [1]	(17,527)	15,269	(21,463)	(7,306)
Overlift / (underlift)	106	19	81	(34,816)
Post-termination Rubiales Block	4,358	—	4,358	—
Total cost	**$ 209,464**	**$ 225,493**	**$ 641,788**	**$ 723,160**

1. *Other costs mainly correspond to inventory fluctuation.*

Total operating costs for the three and nine months ended September 30, 2017 were $159.0 million and $495.5 million, respectively, a 4% and 27% decrease from $166.3 million and $676.4 million in the same periods of 2016 and mainly due to the expiry of the Rubiales block which, as a mature field, had lower costs than other fields.

During 2017, the Company increased activities related to its oil trading business, taking advantage of its transportation capacity and stronger financial position, which allowed for better negotiations with suppliers.

Depletion, Depreciation, and Amortization

	Three Months Ended September 30		Nine Months Ended September 30	
(in thousands of US$)	2017	2016	2017	2016
Depletion, depreciation and amortization	$ 87,802	$ 113,802	$ 287,184	$ 490,285
$/per boe production	13.43	14.79	14.61	17.03

Depletion, depreciation, and amortization ("**DD&A**") decreased to $87.8 million in the third quarter of 2017 compared with $113.8 million in the same quarter of 2016; additionally, year to date, DD&A decreased to $287.2 million from $490.3 million in 2016. The decrease was mainly due to the lower depletable base after the impairments recorded in 2016 and the change in the depletion calculation over the Company's proved and probable reserves in 2017 (2016: proved reserves). Unit DD&A for the third quarter of 2017 was $13.43/boe, a 9% decrease compared with the same period of 2016, mainly due to lower production compared with the previous year.

Impairment and Impairment Reversal

	Three Months Ended September 30		Nine Months Ended September 30	
(in thousands of US$)	2017	2016	2017	2016
Impairment expenses of oil & gas properties and plant and equipment	$ 74,000	$ 281,272	$ 95,896	$ 885,270
Impairment expenses (reversal) of exploration and evaluation assets	—	13,115	(10,362)	45,941
Impairment of other assets (advances and Bicentenario prepayments)	—	120,851	—	173,446
Loan, taxes and others	—	8,675	1,178	8,942
Total impairment and exploration expenses	**$ 74,000**	**$ 423,913**	**$ 86,712**	**$ 1,113,599**

The Company continued its strategy to divest certain non-core assets in 2017. As part of this process, the Company received various bid offers below carrying value. In accordance with IFRS, the Company considered this to be an indicator of impairment and, accordingly, was required to estimate the recoverable amount of the Cash Generating Unit ("**CGU**"). As a result of this analysis, the Company recognized impairment expenses of $74.0 million and $97.1 million during the three and nine months ended September 30, 2017, respectively.

In the third quarter of 2017, an impairment charge of $56.0 million was recognized with respect to natural gas field assets located in the Colombia North CGU. The carrying value was written down to a recoverable amount consistent with the bid offer received to purchase these assets.

In the second and third quarters of 2017, a total impairment charge of $41.2 million was recognized with respect to the transmission line assets of PEL based on bid offers received in the second quarter and a final offer received in the third quarter. Based on the final offer, an agreement to sell PEL for proceeds of $56.0 million was entered into on October 25, 2017.The carrying value was ultimately written down to a recoverable amount consistent with the sale consideration.

The Company did not classify the above assets as held-for-sale as the criteria for classification, such as formal approval to sell, were not met as at September 30, 2017.

In the first quarter of 2017, the Company recognized a reversal of impairment of $11.6 million on certain assets classified as held for sale. The Company assessed the fair value of those assets and reversed the following impairment charges previously recognized: exploration and evaluation assets in the Peru CGU by $10.3 million and oil and gas properties in the Colombia Central CGU by $1.3 million.

General and Administrative Costs

(in thousands of US$)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	2016	2017	2016
General and administrative	$ 26,569	$ 36,398	$ 80,373	$ 104,898
$/per boe production	4.06	5.27	4.09	5.37

G&A costs for the three and nine months ended September 30, 2017 decreased to $26.6 million and $80.4 million, respectively, in comparison with the same periods of 2016, mainly due to continuing efforts to minimize discretionary spending.

Finance Costs

(in thousands of US$)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	2016	2017	2016
Cash finance costs	$ 6,250	$ 15,000	$ 18,750	$ 114,418
Non-cash finance cost (income)	957	7,943	(60)	10,330
Total finance costs	**$ 7,207**	**$ 22,943**	**$ 18,690**	**$ 124,748**
Cash finance costs $/per boe production	0.96	2.17	0.95	3.63

Finance costs include interest on the Company's long-term debt, working capital loans, finance leases, and fees on letters of credit, net of interest income received.

During the third quarter of 2017, finance costs decreased to $7.2 million from $22.9 million in the same period of 2016, mainly due to the change in the Company's capital structure, in which financial debt was reduced to $250.0 million as part of the Restructuring Transaction.

Share of Gain of Equity-Accounted Investees

(in thousands of US$)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	2016	2017	2016
Share of gain of equity-accounted investees - pipelines	$ 16,135	$ 16,344	$ 44,020	$ 49,712
Share of gain (loss) of equity-accounted investees - other	11,317	(5,624)	17,357	17,381
Total share of gain of equity-accounted investees	**$ 27,452**	**$ 10,720**	**$ 61,377**	**$ 67,093**
Share of gain of equity-accounted investees - pipelines $/per boe production	2.47	2.37	2.24	1.58

During the third quarter of 2017, the Company's share of gain of equity-accounted investees increased to $27.5 million from the same period of 2016, mainly due to the equity pick-up of Pacific Infrastructure Ventures Inc., which had lower foreign exchange losses in 2017 compared to 2016.

Foreign Exchange

(in thousands of US$)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	2016	2017	2016
Foreign exchange gain	$ 6,511	$ 17,541	$ 5,348	$ 22,720

Foreign exchange gains or losses primarily result from the movement of the Colombian peso ("**COP**") against the U.S. dollar. A significant portion of the Company's working capital and expenditures are denominated in COP. During the third quarters of 2017 and 2016, the COP appreciated against the U.S. dollar by 3% (foreign exchange close rate COP–U.S. dollar was COP$2,936.67 for the third quarter of 2017, and COP$3,038.26 for the second quarter of 2017). The foreign exchange gain in the third quarter of 2017 was $6.5 million compared with a gain of $17.5 million in the same period of 2016 primarily due to the impact of the COP's appreciation on the translation of the Company's net working capital.

(Loss) Gain on Risk Management

	Three Months Ended September 30		Nine Months Ended September 30	
(in thousands of US$)	2017	2016	2017	2016
(Loss) gain on risk management	$ (43,567)	$ (18,514)	$ 9,012	$ (125,986)

As part of its risk management strategy, the Company entered into several oil price risk management contracts to hedge against oil price volatility; as of September 30, 2017, the Company had hedged some of its production up to July 2018. The hedging portfolio consists of zero-cost collars and put spread instruments. As of September 30, 2017, the Company had outstanding finance hedge positions for approximately 12.7 MMbbl with average floor and ceiling strike prices of $50.55/bbl and $56.53/bbl Brent, respectively, with a net liability of $23.0 million.

None of the risk management contracts outstanding as of September 30, 2017 have been designated as accounting hedges.

					Carrying amount	
Type of Instrument	**Settlement Month**	**Benchmark**	**Notional Amount / Volume (bbl/d)**	**Put/ Call Strike**	**Assets**	**Liabilities**
Commodities Price Risk						
Collar	October 2017	Brent	1,440,000	51.56 / 59.60	—	309
Collar	November 2017	Brent	1,440,000	50.28 / 56.32	—	3,174
Call	November 2017	Brent	465,000	51.45 / 54.00	946	—
Collar	December 2017	Brent	1,440,000	49.52 / 54.18	—	5,152
Call	December 2017	Brent	690,000	52.15 / 54.18	992	—
Collar	January 2018	Brent	1,200,000	49.11 / 55.45	—	3,282
Collar	February 2018	Brent	1,200,000	49.95 / 55.28	—	3,194
Collar	March 2018	Brent	1,200,000	50.06 / 55.37	—	3,074
Collar	April 2018	Brent	1,200,000	50.77 / 55.73	—	2,512
Collar	May 2018	Brent	1,200,000	51.10 / 55.86	—	2,283
Collar	June 2018	Brent	1,200,000	51.23 / 55.91	—	2,157
Collar	July 2018	Brent	1,200,000	52.00 / 59.31	295	69
Total as at September 30, 2017					**$ 2,233**	**$ 25,206**

Income Tax Expense

	Three Months Ended September 30		Nine Months Ended September 30	
(in thousands of US$)	2017	2016	2017	2016
Current income tax expense	$ (12,134)	$ (21,321)	$ (25,703)	$ (41,409)
Deferred income tax recovery	—	940	—	2,456
Total income tax expense	**$ (12,134)**	**$ (20,381)**	**$ (25,703)**	**$ (38,953)**

The current income tax expense during the third quarter of 2017 was $12.1 million, which includes minimum income tax ("presumptive tax") for the period of $9.6 million; a reduction in expected income tax receivables of $2.37 million; and the current tax in countries other than Colombia of $0.12 million. Current income tax totalled $25.7 million for the nine months ended September 30, 2017 compared with $41.4 million in the same period in 2016. The variation is mainly attributable to the decrease in profits before tax in the Colombian entities, which are subject to presumptive tax. The income tax consists of $24.9 million of current tax in Colombia; a write-off of the income tax receivables for $0.09 million, and the current tax in countries other than Colombia of $0.62 million. During 2017, the Company paid $11.7 million related to the Colombian wealth tax.

Restructuring and Severance Costs

	Three Months Ended September 30		Nine Months Ended September 30	
(in thousands of US$)	2017	2016	2017	2016
Restructuring cost	$ —	$ 26,795	$ —	$ 91,515
Severance	2,393	5,307	10,181	8,306
Total restructuring and severance costs	**$ 2,393**	**$ 32,102**	**$ 10,181**	**$ 99,821**

For the three and nine months ended September 30, 2017, the Company incurred $2.4 million and $10.2 million, respectively, in costs related to restructuring, lower than $32.1 million and $99.8 million for the same periods in 2016 due to the closing of the Restructuring Transaction.

Following the Restructuring Transaction, the Board of Directors and management have embarked on a project to transform operations both from an efficiency and controls perspective. A key aspect of the project has been continuous improvement in the areas of people, process, controls and technology. To that end, several key new management personnel have been recruited to contribute and help drive improvements, particularly as it relates to controls, compliance and operational efficiency. The Board of Directors and senior management team are committed to this transformation project and believe that it will be of significant benefit to the Company and its stakeholders.

Capital Expenditures

	Three Months Ended September 30		Nine Months Ended September 30	
(in thousands of US$)	2017	2016	2017	2016
Development drilling	$ 33,950	$ 16,873	$ 99,868	$ 32,489
Exploration activities	7,602	7,021	9,788	32,006
Production facilities	4,342	4,691	9,596	24,517
Administrative assets and prepaid expenses	2,622	3,570	5,762	7,213
Other projects	47	1,476	174	8,204
Total capital expenditures	**$ 48,563**	**$ 33,631**	**$ 125,188**	**$ 104,429**

During the third quarter of 2017, capital expenditures totalled $48.6 million compared with $33.6 million in the third quarter of 2016. During the third quarter of 2017, a total of $34.0 million was invested in the expansion and construction of production infrastructure, primarily in the Quifa, Guatiquia, La Creciente, Cravo Viejo and Neiva blocks; $7.6 million was invested in exploration activities, mainly in Colombia; and $4.3 million went into development drilling, mainly in the Quifa, Guatiquia, Mapache, Cubiro, and Orito blocks.

Selected Quarterly Information

(in thousands of US$ except as noted)	2017 Q3	2017 Q2	2017 Q1	2016 Q4	2016 Q3	2016 Q2	2016 Q1	2015 Q4
Financial and Operational results:								
Average daily oil and natural gas production (boe/d)	71,068	72,370	72,524	69,432	75,096	127,951	142,337	159,831
Average daily oil production (boe/d)	65,641	66,448	66,035	62,229	67,128	118,526	131,856	149,368
Average daily natural gas production (mcf/d)	30,934	33,755	36,987	41,057	45,418	53,723	59,742	59,639
Net oil and natural gas sales (boe/d)	63,162	64,908	70,452	67,470	81,877	109,736	120,220	171,039
Combined realized sales price – oil and natural gas ($/boe)	47.86	46.28	45.95	41.92	40.83	37.60	41.67	41.22
Realized oil and gas price ($/boe)	47.55	45.71	47.34	43.44	40.83	37.60	26.90	32.75
Realized oil hedging ($/boe)	0.31	0.57	(1.39)	(1.52)	—	—	14.77	8.47
Brent ($/bbl)	52.17	50.79	54.57	51.06	46.99	47.03	35.21	44.69
Operating cost ($/boe)	(24.32)	(25.97)	(25.36)	(27.40)	(24.06)	(20.30)	(21.13)	(21.73)
Operating Netback ($/boe) (1)	23.54	20.31	20.59	14.52	16.77	17.30	20.54	19.49
Adjusted Netback ($/boe) (1)	20.68	19.13	18.49	13.89	12.91	17.25	19.81	17.71
Adjusted FFO Netback ($/boe) (1)	12.64	11.76	13.38	2.48	2.55	9.17	18.93	(4.60)
Total sales ($)	307,080	299,452	316,638	269,772	308,705	376,403	456,831	651,970
Net (loss) income attributable to equity holders of the parent for the period ($)	(141,115)	(51,542)	8,498	4,025,194	(557,068)	(118,654)	(900,949)	(3,895,908)
Per share - basic and diluted ($)	(2.82)	(1.03)	0.17	80.50	(176,835)	(37,665)	(285,996)	(1,236,796)
Operating EBITDA ($) (1)	105,885	86,857	92,442	44,275	89,846	120,452	190,064	224,911
Adjusted EBITDA ($) (1)	44,203	87,389	115,058	(1,967)	37,689	126,083	91,814	257,584
Adjusted FFO ($) (1)	47,889	46,151	78,760	8,256	43,036	44,314	161,366	(24,853)
Capital expenditures ($)	48,563	37,826	38,799	64,707	33,631	50,044	20,755	160,154
Total assets (end of period) ($)	2,546,631	2,621,871	2,772,423	2,741,719	2,403,602	2,990,699	2,687,858	3,986,121

1. *Refer to Non-IFRS Measures on page 17.*

Non-IFRS Measures

This report contains the following financial terms that are not considered in IFRS: Operating and Adjusted EBITDA, Operating Netback, Adjusted Netback, Adjusted FFO Netback, and Adjusted FFO. These non-IFRS measures do not have any standardized meaning and, therefore, are unlikely to be comparable to similar measures presented by other companies. These non-IFRS measures should not be considered in isolation or as a substitute for measures of performance prepared in accordance with IFRS. These financial measures are included because management uses this information to analyze operating performance and liquidity. These measures are different from those measures disclosed in prior periods, reflecting the Company's new strategic focus on operational efficiency and capital discipline.

Operating and Adjusted EBITDA

Management believes that EBITDA is a common measure used to assess profitability before the impact of different financing methods, income taxes, depreciation and impairment of capital assets, and amortization of intangible assets.

- Operating EBITDA represents the operating results of the Company's primary business, excluding the effects of capital structure, other investments (infrastructure assets), non-cash items that depend on accounting policy choices, and one-time items that are not expected to recur.

- Adjusted EBITDA excludes items of a non-recurring nature (one-time items) or items that could make the period-over-period comparison of results from operations less meaningful, but includes results from the Company's other investments (infrastructure assets).

A reconciliation of Operating and Adjusted EBITDA to Net loss is as follows:

	Three Months Ended September 30				Nine Months Ended September 30			
(in thousands of US$)		2017		2016		2017		2016
Net loss [1]	$	(141,115)	$	(557,068)	$	(184,159)	$	(1,576,671)
Adjustments								
Income tax expense		12,134		20,381		25,703		38,953
Depletion, depreciation and amortization		87,802		113,802		287,184		490,285
Impairment and exploration expenses		74,000		423,913		86,712		1,113,599
Finance costs		7,207		22,943		18,690		124,748
Restructuring and severance costs		2,393		32,102		10,181		99,821
Equity tax		—		—		11,694		26,901
Other expense/(income)		8,487		2,792		639		(41,628)
Foreign exchange unrealized gain		(6,705)		(21,176)		(9,993)		(20,422)
Adjusted EBITDA		**44,203**		**37,689**		**246,651**		**255,586**
(Gain) loss valuation of unrealized hedge contracts		43,567		18,514		(9,012)		125,986
Share of gain in equity-accounted investees		(27,452)		(10,720)		(61,377)		(67,093)
Gain (loss) attributable to non-controlling interest		10,302		(2,304)		19,616		10,203
Share based compensation		233		—		486		(8,503)
Foreign exchange realized loss (gain)		194		3,635		4,646		(2,298)
Fees paid on suspended pipeline capacity		34,838		43,032		84,175		86,481
Operating EBITDA	**$**	**105,885**	**$**	**89,846**	**$**	**285,185**	**$**	**400,362**

1. *Net loss attributable to equity holders of the parent.*

Netbacks

Management believes that Netback is an useful measure to assess the net profit after subtracting all the costs associated with bringing one barrel of oil to the market. It is also commonly used by the oil and gas industry to analyze financial and operating performance expressed as profit per barrel.

- Operating Netback represents realized price per barrel plus realized gain or loss on financial derivatives and less production costs, royalties paid in cash, transportation and diluent costs, and shows how efficient the Company is at extracting and selling its product.
- Adjusted Netback represents Operating Netback plus the results from corporate investments such as our pipeline investments that are in addition to oil and gas production and the take-or-pay tariffs paid on disrupted pipelines.
- Adjusted Funds Flow from Operations Netback ("**Adjusted FFO Netback**") represents Adjusted Netback less corporate cash expenses (general and administrative expenses and cash finance costs) and other cash items (mainly includes: dividends from associates, Frontera's share of gain of equity-accounted investees - pipelines, current income tax, equity tax paid, realized foreign exchange, inventory fluctuation, overlift/underlift and uses of asset retirement obligation).

The third quarter of 2017 marks the first time the Company has disclosed Adjusted FFO and Adjusted FFO Netback given the increasing significance of these metrics to evaluate operational results. The Company changed from Cash Netback to Adjusted FFO Netback as it provides stakeholders with greater insight on the Company's ability to generate funds from continuing operations.

Refer to "Netbacks" on page 9.

Adjusted Funds Flow From Operations

Adjusted Funds Flow From Operations ("**Adjusted FFO**") is a non-IFRS financial measure that adjusts a IFRS measure - cash flow provided by (used in) operating activities - for changes in non-cash working capital, which management uses to analyze operating performance and liquidity. Changes to non-cash working capital can include differences in timing of cash flows related to accounts receivable and accounts payable, which management believes reduces comparability among periods. The indicator excludes asset retirement obligations settlements, one-time expenses for the Company not related to the ongoing operations such as restructuring and severance costs, and expense/revenue from past assets.

	Three Months Ended September 30		**Nine Months Ended September 30**	
(in thousands of US$)	**2017**	**2016**	**2017**	**2016**
Net cash provided (used) by operating activities	110,306	(12,414)	189,287	(56,450)
Changes in non-cash working capital	(65,733)	22,846	(27,873)	128,037
Deferred revenue net proceeds	—	—	—	75,000
Restructuring and severance costs	2,393	32,102	10,181	99,821
Settlement of asset retirement obligations	1,565	502	1,847	2,308
Loss (gain) from past assets	(642)	—	(642)	—
Adjusted FFO	**47,889**	**43,036**	**172,800**	**248,716**

Financial Position

Upon completion of the Restructuring Transaction and as of September 30, 2017, the only long-term borrowing of the Company consisted of Exit Notes due in 2021 bearing interest at 10% per annum.

Covenant/Limitation on Indebtedness

Under the indenture for the Exit Notes due in 2021 (the "**Indenture**"), the Company may not incur, with some exceptions, directly or indirectly, any additional indebtedness prior to November 2, 2018. Subsequent to November 2, 2018, and after giving effect to certain conditions provided under the Indenture, the Company may incur additional indebtedness provided that the Company complies with the following financial covenants:

Covenant	**Ratio**
Consolidated Debt to Consolidated Adjusted EBITDA (1)	< 2.5 : 1.0
Consolidated Fixed Charge (2)	> 3.25 : 1.0

1. *Consolidated Debt to Consolidated Adjusted EBITDA Ratio is defined in the Indenture as the Consolidated Total Indebtedness as of such date divided by Consolidated Adjusted EBITDA for the most recently ended period of four consecutive fiscal quarters. Consolidated Adjusted EBITDA is defined as the Consolidated Net Income (as defined in the Indenture) plus: i) consolidated interest expense; ii) income tax and equity tax; iii) depletion and depreciation expense; iv) amortization expense; and v) impairment charge, exploration expense, and abandonment costs.*
2. *Consolidated Fixed Charge Ratio means, the Consolidated Adjusted EBITDA for the most recent ended period of four consecutive fiscal quarters divided by the consolidated interest expense for such period.*

Other covenants under the Indenture limit, with some exceptions, the Company's ability to sell assets, incur liens, declare dividends, and enter into lease-back transactions.

On November 2, 2017, Fitch Ratings, Inc. raised its corporate credit rating on the Company to "B+" from "B" and the Exit Notes' debt rating to "BB-" from "B+". The rating outlook is stable.

Letters of Credit

The Company has various guarantees in place in the normal course of business. As at September 30, 2017, the Company had issued letters of credit and guarantees for exploration and operational commitments for a total of $107.1 million.

On June 22, 2016, as a part of the Restructuring Transaction, the Company entered into a letter of credit facility that was amended and restated on November 2, 2016 (the "**Letter of Credit Facility**").The facility matures on June 22, 2018, and the Company pays a credit facility fee of 5% per annum on the issued and maintained amounts, and will pay 8% per annum on amounts drawn under the facility. If any event of default exists, these rates will increase by an additional 2% per annum until such default is cured. As of September 30, 2017, letters of credit totalling $103.1 million were issued and maintained under the Letter of Credit Facility (December 31, 2016: $111.7 million).

Outstanding Share Data

Common Shares

As at November 13, 2017, 50,005,832 common shares were issued and outstanding.

The Company does not have shares subject to escrow restrictions or pooling agreements.

Deferred Share Units ("DSUs")

As at November 13, 2017, there were 42,971 DSUs outstanding. DSUs are instruments that may be settled in cash or common shares and are payable to eligible participants (limited to directors of the Company) upon their departure from the Board of Directors of the Company.

Liquidity and Capital Resources

As at September 30, 2017, the Company had cash and cash equivalents of $500.6 million, an increase of $111.5 million from the balance as at December 31, 2016, primarily due to net operating cash inflows of $189.3 million and the receipt of gross cash proceeds of $32.6 million related to the sale of assets held for sale, offset by net capital expenditures of $112.9 million. As at September 30, 2017, working capital was $313.3 million, an increase of $107.7 million compared with December 31, 2016, mainly due to the Company's ability to generate operating cash flow in excess of capital expenditures for the nine months ended September 30, 2017.

4. COMMITMENTS AND CONTINGENCIES

The Company is involved in various claims and litigation arising in the normal course of business. Since the outcome of these matters is uncertain, there can be no assurance that such matters will be resolved in the Company's favour. The Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these and other matters, or any amount which it may be required to pay by reason thereof, would have a material impact on its financial position, results of operations, or cash flows.

In Colombia, the Company is participating as a shipper in a project to expand the OCENSA pipeline, which commenced operations in July 2017. As part of the expansion project, the Company, through its Colombian branches, entered into separate crude oil transport agreements with OCENSA for future transport capacity. The Company started paying ship-or-pay fees once the expansion project was completed and operational.

Except as noted above, no material changes have occurred with respect to the matters disclosed in "Note 25 - Contingencies and Commitments" of the 2016 Audited Financial Statements, and no new contingencies have occurred that are material to the Company since the issuance of those financial statements.

5. RELATED-PARTY TRANSACTIONS

The following table provides the total balances, loans, interest balance outstanding, and commitments with related parties as at September 30, 2017 and December 31, 2016:

		Accounts Receivables	Accounts Payables	Commitments	Cash Advance	Loan Receivable	Interest Receivable	Convertible Debentures
Oleoducto de los Llanos Orientales S.A.	2017	$ —	$288	$143,282	$ —	$ —	$ —	$ —
	2016	638	341	176,442	—	—	—	—
Bicentenario	2017	11,918	501	938,164	87,753	—	—	—
	2016	13,400	—	1,164,251	87,753	—	—	—
Pacific Infrastructure Ventures Inc.-Sociedad Portuaria Puerto Bahia S.A	2017	4,795	1,568	165,921	17,867	76,552	24,241	—
	2016	828	905	199,859	17,867	74,279	18,097	—
Interamerican Energy - Consorcio Genser Power - Proelectrica - Termomorichal	2017	—	107	—	—	—	—	—
	2016	174	555	—	—	—	—	—
CGX Energy Inc.	2017	110	—	—	—	13,650	515	1,500
	2016	—	—	—	—	10,000	1,500	1,500
Paye Foundation (1)	2017	—	35	—	—	—	—	—
	2016	—	1,737	—	—	—	—	—
Fupepco Foundation (1)	2017	—	217	—	—	—	—	—
	2016	—	—	—	—	—	—	—

1. *The Paye Foundation (formerly Pacific Rubiales Foundation) was in liquidation as of September 30, 2017, and the Company established the new charitable Fupepco Foundation in Colombia in 2017. The foundation has the objective of advancing social and community development projects in the country.*

The following table provides the total amount of transactions that were entered into, and the interest income earned, with related parties during the three and nine months ended September 30, 2017 and 2016:

		Three months ended September 30			Nine months ended September 30		
		Sales	Purchases / Services	Interest Income	Sales	Purchases / Services	Interest Income
Oleoducto de los Llanos Orientales S.A.	2017	$ —	$16,700	$ —	$ —	$37,995	$ —
	2016	—	23,794	—	217	75,260	—
Bicentenario	2017	—	28,991	—	—	95,196	—
	2016	—	50,129	—	—	129,447	—
Pacific Infrastructure Ventures Inc.-Sociedad Portuaria Puerto Bahia S.A	2017	—	5,823	2,094	—	25,793	6,143
	2016	123	9,750	—	2,715	29,814	
Interamerican Energy - Consorcio Genser Power - Proelectrica - Termomorichal	2017	—	293	—	495	312	—
	2016	1,915	1,766	—	9,575	16,960	—
CGX Energy Inc.	2017	—	—	30	—	—	45
	2016	—	—	—	—	—	—
Paye Foundation (1)	2017	—	64	—	—	1,779	—
	2016	—	1,958	—	—	7,242	—
Fupepco Foundation (1)	2017	—	17	—	—	71	—
	2016	—	—	—	—	—	—

1. *The Paye Foundation (formerly Pacific Rubiales Foundation) was in liquidation as of September 30, 2017, and the Company established the new charitable Fupepco Foundation in Colombia in 2017. The foundation has the objective of advancing social and community development projects in the country.*

On April 26, 2017, the Company entered into a secured bridge loan facility with CGX Energy Inc. ("**CGX**"). The principal amount of up to $3.1 million is divided into tranches payable within 12 months of the first draw-down. The loan carries an annual interest rate of 5% and is secured by the assets of CGX. During the quarter ended September 30, 2017, the Company advanced $1.8 million under this facility. On October 30, 2017, the Company amended the secured bridge loan facility to increase the principal amount by $0.3 million with all other terms unchanged and as of the date hereof, the Company has advanced the full amount of the loan to CGX.

6. ACCOUNTING POLICIES, CRITICAL JUDGMENTS, AND ESTIMATES

Significant Accounting Judgments, Estimates, and Assumptions

The accounting policies used in preparation of the Q3 2017 Interim Financial Statements are consistent with those disclosed in the 2016 Audited Financial Statements, except for the adoption of minor amendments and interpretations effective January 1, 2017 that had little or no impact on the Q3 2017 Interim Financial Statements. The Company has not early adopted any standard, interpretation or amendment that has been issued but is not yet effective. Recent accounting pronouncements of significance or potential significance are described in Note 2 of the Q3 2017 Interim Financial Statements, including management's evaluation of impact and implementation progress.

The preparation of the Q3 2017 Interim Financial Statements in accordance with IFRS requires the Company to make judgments in applying its accounting policies and estimates and assumptions about the future. These judgments, estimates and assumptions affect the reported amounts of assets, liabilities, revenues and other items in net operating earnings or loss, and the related disclosure of contingent assets and liabilities included in the consolidated financial statements. The Company evaluates its estimates on an ongoing basis. The estimates are based on historical experience and on various other assumptions that the Company believes are reasonable under the circumstances. These estimates form the basis for making judgments about the carrying value of assets and liabilities and the reported amounts of revenues and other items. Actual results may differ from these estimates under different assumptions or conditions.

In preparing the Q3 2017 Interim Financial Statements, the significant judgments made by management in applying the Company's accounting policies and the key sources of estimation uncertainty were consistent with those that were applied in the 2016 Audited Financial Statements, except as described below:

- ***Oil and Gas Properties:*** Oil and gas properties are depreciated using the unit-of-production method. As of January 1, 2017, oil and gas properties were depleted over proved and probable reserves, compared with 2016, when they were depleted over proved reserves. This change is a result of the Company's ability to finance its near-term capital programs included in the updated reserve estimates.

7. INTERNAL CONTROL - RISKS AND UNCERTAINTIES

In accordance with National Instrument 52-109 - Certification of Disclosure in Issuers' Annual and Interim Filings ("**NI 52-109**") of the Canadian Securities Administrators, the Company issues a "Certification of Interim Filings." This Certification requires certifying officers to certify, among other things, that they are responsible for establishing and maintaining Disclosure Controls and Procedures ("**DC&P**") and Internal Controls Over Financial Reporting ("**ICFR**") as those terms are defined in NI 52-109.

The Company's ICFR are designed to provide reasonable assurance regarding the reliability of the Company's financial reporting for external purposes in accordance with IFRS. The Company's ICFR may not prevent or detect all misstatements because of inherent limitations. Additionally, projections of any evaluation of effectiveness in future periods are subject to the risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with the Company's policies and procedures.

The Company's DC&P is designed to provide reasonable assurance that:

- Material information relating to the Company is made known to the Company's certifying officers by others, particularly during the period in which the annual filings are being prepared.
- Information required to be disclosed by the Company in its annual filings, interim filings, and other reports filed or submitted by the Company under securities legislation is recorded, processed, summarized, and reported within the time period specified in securities legislation.

There have been no significant changes during the nine months ended September 30, 2017 to the risks and uncertainties identified in the Company's AIF. The AIF is available at www.sedar.com and readers are urged to read the discussion in its entirety.

8. FURTHER DISCLOSURES

Boe Conversion

The term "boe" is used in this MD&A. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of cubic feet to barrels is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In this MD&A, boe has been expressed using the Colombian conversion standard of 5.7 Mcf: 1 bbl required by the Colombian Ministry of Mines and Energy.

Abbreviations

The following abbreviations are frequently used in the Company's MD&A.

1P	Proved reserves	**Mbbl**	Thousand barrels
2P	Proved reserves + Probable reserves	**Mbbl/d**	Thousand barrels per day
Adjusted FFO	Adjusted Funds Flow from Operations	**Mboe**	Thousand barrels of oil equivalent
Adjusted FFO Netback	Adjusted Funds Flow from Operations Netback	**Mboe/d**	Thousand barrels of oil equivalent per day
bbl	Barrels	**MMbbl**	Million barrels
bbl/d	Barrels per day	**MMbbl/d**	Million barrels of oil per day
boe	Barrels of oil equivalent	**MMboe**	Million barrels of oil equivalent
boe/d	Barrels of oil equivalent per day	**$**	U.S. dollars
D&P	Development and producing	**$M**	Thousand U.S. dollars
E&E	Exploration and evaluation		