MANAGEMENT'S DISCUSSION AND ANALYSIS
CRIUS ENERGY TRUST

March 14, 2019

This management's discussion and analysis ("**MD&A**") for Crius Energy Trust (the "**Trust**") dated March 14, 2019 has been prepared with all information available up to and including March 14, 2019. This MD&A should be read in conjunction with the Trust's audited consolidated financial statements and accompanying notes as at and for the years ended December 31, 2018 and 2017. The Trust's financial statements and other disclosure documents, including the Trust's Annual Information Form for the year ended December 31, 2018, dated March 14, 2019, are available on the System for Electronic Document Analysis and Retrieval ("**SEDAR**") under the Trust's issuer profile at www.sedar.com and on the Trust's website at www.criusenergytrust.ca. The Units (as defined herein) are listed for trading on the Toronto Stock Exchange ("**TSX**") under the symbol "KWH.UN".

The Trust prepares its consolidated financial statements in accordance with International Financial Reporting Standards ("**IFRS**"), as issued by the International Accounting Standards Board. The consolidated financial statements of the Trust are presented in United States dollars, which is the functional currency of the Trust. All figures within this MD&A are presented in United States dollars unless otherwise indicated. Certain totals, subtotals and percentages may not reconcile due to rounding.

Certain information contained in this MD&A constitutes non-IFRS financial measures and/or forward-looking statements (as defined herein). Investors are cautioned to read the sections entitled *"Non-IFRS Financial Measures"* and *"Forward-Looking Statements"* at the end of this MD&A. Certain key terms and abbreviations used in this MD&A are defined in the section entitled *"Key Terms and Abbreviations"* below.

Overview of the Trust

The Trust is an unincorporated, open-ended limited purpose trust established under the laws of the Province of Ontario on September 7, 2012, for the purpose of providing investors with a distribution-producing investment in the operating business of Crius Energy (as defined herein). The Trust has held, since the completion of the Remaining LLC Acquisition (as defined herein) in June 2016, a 100% interest in the operating business of Crius Energy, a provider of competitive electricity and natural gas products to approximately 1.2 million residential and commercial customers as at December 31, 2018.

Overview of Business

Crius Energy provides competitive electricity and natural gas products to residential and commercial customers in 19 states and the District of Columbia in the United States. The Company sells energy products through a family of brands strategy utilizing a multi-channel sales approach including exclusive partnerships, direct-to-consumer channels, and broker marketing channels. Crius Energy offers consumers a broad suite of energy products and services including fixed-rate and variable-rate contracts, renewable energy, and bundled products to support their energy needs beyond what is offered by their local utility.

The Company's revenues are earned primarily from electricity and natural gas sales and are recognized based on customer consumption. Seasonal variability of customer usage of electricity and natural gas may cause the Company's revenues and gross margins to fluctuate. In general, electricity consumption is highest during the summer months of July and August due to cooling demand and, to a lesser extent, during the winter months of January and February due to heating demand. Heating demand also influences natural gas consumption, which is typically highest between the months of November and March. The Company's revenues may also fluctuate based on retail rates charged to customers, customer growth and customer attrition. The Company also receives various other customer fees that are not tied to customer consumption.

The Company procures its electricity, natural gas and hedging requirements in various wholesale energy markets, including physical and financial markets, using both short-term and long-term contracts. For electricity and natural gas, the Company procures its wholesale energy requirements at various utility load zones for electricity and city gates for natural gas, based on the energy usage and geographic location of our customers. The Company manages its exposure to short-term and long-term movements in wholesale energy prices by hedging using derivative instruments. These derivative instruments are principally physical forward contracts and financial fixed-for-floating swaps, whereby the Company agrees to take physical delivery or cash settle the difference between the floating price and the fixed price on a notional quantity of electricity or natural gas for a specified timeframe, at a specified location. The Company remains subject to commodity risk for any volumetric differences between the actual quantities used by its customers and the forecasted quantities upon which such hedging instruments are based.

The Company's gross margin is primarily derived from the difference between the revenues received from its electricity and natural gas customers and the cost of sales paid to its energy and non-energy suppliers. The Company also incurs selling expenses through a mixture of upfront and residual-based payments. Such selling costs are either recognized as expenses in the period incurred, pursuant to the applicable contractual arrangements in place, or recognized over the term of the customer to which they relate. In addition, the Company incurs general, administrative, financing and other expenses to operate its business.

Key Terms and Abbreviations

"**Adjusted EBITDA**" means EBITDA adjusted to exclude certain non-operating and non-cash items. See the section entitled *"Reconciliation of Net income to EBITDA and Adjusted EBITDA"* in this MD&A for a reconciliation of EBITDA and Adjusted EBITDA to Net income as calculated under IFRS, the most directly comparable measure in the Trust's consolidated financial statements. Adjusted EBITDA is a non-IFRS financial measure. Refer to section entitled *"Non-IFRS Financial Measures"* at the end of this MD&A.

"**Adjusted Working Capital**" means current assets less current liabilities, excluding unrealized gains and losses on derivatives. See section entitled "*Adjusted Working Capital*" in this MD&A for a reconciliation of Adjusted Working Capital to the Trust's consolidated balance sheet as prepared under IFRS. Adjusted Working Capital is a non-IFRS financial measure. Refer to section entitled *"Non-IFRS Financial Measures"* at the end of this MD&A.

"**Administrator**" means Crius Energy Administrator Inc., or such other party as may be appointed as administrator of the Trust from time to time.

"**Board**" means the board of directors of the Administrator, the administrator for and on behalf of the Trust.

"**Customer**" or "**customer**" refers to an RCE (see definition of RCE below).

"**Cooling Degree Days**" means the number of degrees that a day's average temperature is above 65 degrees Fahrenheit (18 degrees Celsius), which is the temperature above which buildings need to be cooled.

"**Deferred Trust Units**" or "**DTUs**" means the deferred trust units of the Trust issued pursuant to the DTUP (as defined herein).

"**Deferred Trust Unit Plan**" or "**DTUP**" means the deferred trust unit plan of the Trust adopted by the Trust on January 6, 2016 as amended, supplemented or restated from time to time.

"**Distributable Cash**" means the amount of cash flow available to the Trust to meet its distribution obligations. See the section entitled *"Distributable Cash and Distributions"* in this MD&A for a reconciliation of Distributable Cash to cash flows provided by (used in) operating activities as calculated under IFRS, the most directly comparable measure in the Trust's consolidated financial statements. Distributable Cash is a non-IFRS financial measure. Refer to section entitled *"Non-IFRS Financial Measures"* at the end of this MD&A.

"**EBITDA**" means earnings before interest, taxes, depreciation and amortization. EBITDA is a non-IFRS financial measure. Refer to section entitled *"Non-IFRS Financial Measures"* at the end of this MD&A.

"**Embedded Margin**" represents a five-year non-discounted measure of Management's estimate of future electricity and natural gas gross margins based on forecasted volumes and unit margins for existing customers with appropriate assumptions for customer attrition and renewals. Embedded margin is not intended to take into account expenses such as selling, general and administrative or financing costs necessary to realize the gross margins. It is only calculated for existing customers and does not factor future customer additions. Embedded margin is a non-IFRS measure. Refer to section entitled "*Non-IFRS Financial Measures*" at the end of this MD&A.

"**Heating Degree Days**" means the number of degrees that a day's average temperature is below 65 degrees Fahrenheit (18 degrees Celsius), which is the temperature below which buildings need to be heated.

"**kWh**" means kilowatt hour and is a measurement of volume of electricity.

"**Maintenance Capital Expenditures**" consist of capital expenditures included within cash flows used in investing activities from the Consolidated Statement of Cash Flows, adjusted to exclude cash flows used in investing activities relating to acquisitions. Maintenance Capital Expenditures is a non-IFRS financial measure. Refer to section entitled "*Non-IFRS Financial Measures*" at the end of this MD&A.

"**Macquarie Energy**" means Macquarie Energy LLC.

"**MMBtu**" means one million British Thermal Units and is a measurement of volume of natural gas.

"**MWh**" means Megawatt hour and is a measurement of volume of electricity.

"**MW**" means Megawatt and is a measurement of capacity of electricity.

"**Payout Ratio**" means the proportion of Distributable Cash paid out as distributions to Unitholders over a defined period, expressed as a percentage. See the section entitled *"Distributable Cash and Distributions"* in this MD&A for the calculation of Payout Ratio. Payout Ratio is a non-IFRS financial measure. Refer to section entitled *"Non-IFRS Financial Measures"* at the end of this MD&A.

"**Phantom Unit Rights**" or "**PURs**" means cash-settled phantom unit rights granted under the PURP (see definition of PURP below.

"**Phantom Unit Rights Plan**" or "**PURP**" means the phantom unit rights plan of the Company adopted by the Company on November 13, 2012, as amended, supplemented or restated from time to time.

"**RCE**" or "**Residential Customer Equivalent**" is an industry-standard unit of measurement of energy consumption per annum equivalent to 10 MWh (or 10,000 kWh) in the case of the electricity and 100 MMBtu in the case of natural gas. The Company has estimated the number of RCEs in accordance with conventions adopted by the Company, in accordance with industry standards, based on information available regarding customers and their historical usage and are subject to adjustment based on updated available information.

"**Remaining LLC Acquisition**" means the acquisition by the Trust, directly or indirectly of all of the remaining membership units of Crius Energy, LLC not already owned by the Trust, which closed in June 2016.

"**Total Cash and Availability**" means the sum of cash and cash equivalents and any excess availability that is available to the Trust under its credit facilities. Total Cash and Availability is a non-IFRS financial measure. Refer to section entitled *"Non-IFRS Financial Measures"* at the end of this MD&A.

"**Total Distributions**" means the total distributions made to Unitholders, including both distributions to Unitholders of the Trust as well as, for the applicable periods, distributions to non-controlling interest. Total Distributions is a non-IFRS financial measure. Refer to section entitled *"Non-IFRS Financial Measures"* at the end of this MD&A.

"**Unitholder**" means a holder of Units (see definition of Units below).

"**Units**" means the trust units of the Trust, which are listed for trading on the TSX under the symbol "KWH.UN".

"**USG&E Acquisition**" means the acquisition by the Trust of U.S. Gas & Electric, Inc. in July 2017.

"**USG&E**" means U.S. Gas & Electric, Inc.

"**Verengo**" means Verengo, Inc.

"**Viridian International**" means Viridian International Management LLC.

Unless the context indicates otherwise, references in this MD&A to "volume", "usage" and "consumption" refer to MWh in the case of electricity and MMBtu in the case of natural gas.

Throughout this MD&A, for purposes of convenience, references to (i) the "**Trust**", the "**Company**", "**Crius Energy**", "**we**" or "**our**" refer to Crius Energy Trust and its subsidiaries and (ii) "**Management**" refer to the management of the Trust and its subsidiaries.

2018 AND FOURTH QUARTER 2018 HIGHLIGHTS

Financial Highlights

2018

- Revenue of $1,235.1 million in 2018, representing an increase of 41.0% from $875.9 million in 2017.
- Gross margin of $220.8 million in 2018, compared to gross margin of $184.0 million in 2017.
- Net income of $19.0 million in 2018, compared to a net income of $20.1 million in 2017.
- Adjusted EBITDA of $70.2 million in 2018, compared to $64.7 million achieved in 2017. During the year, the deregulated energy business contributed Adjusted EBITDA of $88.8 million after normalizing for non-recurring costs of $9.3 million and a negative $9.2 million contribution from the solar business (including $1.9 million in wind-down costs).
- Cash flows provided by operating activities of $48.6 million in 2018, compared to $13.2 million in 2017.
- Distributable Cash of $21.9 million representing a Payout Ratio of 167.9% in 2018, which is elevated over recent levels due to the impacts of negative contribution from the solar business and certain non-recurring costs as described below. Normalizing for these impacts, the Distributable Cash and Payout Ratio for the year were $40.4 million and 90.8%, respectively.
- Total Cash and Availability at the end of 2018 of $37.9 million, compared to $49.4 million at the end of 2017.

Fourth Quarter 2018

- Revenue of $284.8 million in the fourth quarter of 2018, representing an increase of 14.6% from $248.5 million in the fourth quarter of 2017.
- Gross margin of $54.0 million in the fourth quarter of 2018, compared to gross margin of $54.8 million in the fourth quarter of 2017.
- Net income of $1.7 million in the fourth quarter of 2018, compared to a net income of $36.0 million in the fourth quarter of 2017.

- Adjusted EBITDA of $19.1 million in the fourth quarter of 2018, compared to $18.0 million achieved in the fourth quarter of 2017. During the quarter, the deregulated energy business contributed Adjusted EBITDA of $22.4 million after normalizing for $1.9 million in non-recurring costs and negative contribution of $1.4 million from the solar business (including $0.8 million in wind-down costs).
- Cash flows from operating activities of $23.2 million in the fourth quarter of 2018, compared to $14.8 million in the fourth quarter of 2017.
- Distributable Cash of $10.0 million in the fourth quarter of 2018, representing a decrease from $13.0 million in the fourth quarter of 2017.

Operational Highlights

2018

- Embedded Margin of the customer portfolio increased by $36.0 million, or 7.6%, in 2018 to $510.0 million.
- Net customer attrition of 206,000 customers in 2018 with Crius Energy's customer count totaling 1,204,000 customers at the end of the year.
    - Added 478,000 customers during 2018 from sales and marketing channels and 40,000 through customer book acquisitions, compared to gross adds of 660,000 customers added organically and 360,000 added through acquisitions in 2017. Gross customer adds were lower during 2018 primarily due to the decision to no longer participate in the municipal aggregation segment and increased margin requirements across all sales channels.
    - Gross customer drops in 2018 of 724,000 customers, compared to gross drops of 592,000 customers in 2017. Gross customer drops were elevated during 2018 primarily due to the non-renewal of 215,000 municipal aggregation customers as a result of the decision to no longer participate in the segment. Excluding the impact of municipal aggregation non-renewals, customer drops were 509,000 in 2018.

Fourth Quarter 2018

- Embedded Margin of the customer portfolio increased by $14.6 million, or 2.9%, in the quarter to $510.0 million.
- Net customer attrition of 148,000 in the fourth quarter of 2018, with customer count totaling 1,204,000 at the end of the fourth quarter of 2018.
    - Added 73,000 customers organically from sales and marketing channels and 10,000 through the acquisition of a customer book in the fourth quarter of 2018, compared to average customer additions in the prior four quarters of 138,000, or 91,000 when excluding the customer additions from municipal aggregations.
    - Gross customer drops in the fourth quarter of 231,000 customers compared to the average in the prior four quarters of 169,000. Gross customer drops were elevated during the quarter primarily due to the non-renewal of 120,000 municipal aggregation customers as a result of the decision to no longer participate in the segment. Excluding the impact of municipal aggregation non-renewals, customer drops were 111,000 in the fourth quarter of 2018.

Growth and Corporate Highlights

2018

- Continued positive results from the integration of the USG&E business and broader cost-reduction initiatives
    - Based on activities achieved through the end of 2018, the Company achieved an annualized run-rate of $25.1 million in cumulative cost-synergies.

- Consolidated credit facilities and added an expanded syndicated working capital credit facility
    - In August 2018, the Company announced the combining of its existing credit facilities into a single consolidated credit facility ("**Credit Facility**") for the Company's wholesale energy supply requirements with a limit of $140 million, and adding a syndicated working capital facility with an initial limit of $110 million for cash advances and letters of credit.
    - The Credit Facility, which has a three-year term ending in August 2021, benefits Crius through improved trading terms and pricing, with lower volumetric energy fees and the interest rate on working capital advances of LIBOR plus 5.5% changing to a tiered pricing structure of between 1.75% and 4.25% plus the applicable LIBOR or prime rate, in the case of cash advances, based on leverage levels.

- Exiting the Solar business
  - As of the end of 2018, the Company had substantially wound down its solar business, with the exception of the Verengo solar installation business which it is winding down in the first half of 2019.

- Normal Course Issuer Bid
  - As of December 31, 2018, the Company had re-purchased 449,445 Units at an average price of C$7.23 per Unit under its normal course issuer bid, which became effective in March 2018.
  - As of the end of 2018, Crius had 56,605,607 Units outstanding.

- Implemented a Distribution Re-Investment Plan
  - In October 2018, the Company announced the implementation of a distribution re-investment plan ("**DRIP**"), which offers Canadian resident unitholders an opportunity to increase their investment in the Trust by receiving distribution payments in the form of Units, without paying additional transaction costs, broker commissions, administrative costs or other service charges.
  - Units available for the reinvestment of distributions under the DRIP may, at the discretion of the Trust, be (i) issued from treasury, or (ii) purchased on the open market at the applicable best efforts open market purchase price.
  - Initially, Units available for reinvestment of distributions under the DRIP will be purchased on the open markets at the applicable best efforts purchase price.

- Strengthened Board of Directors
  - Added three new highly-qualified members to the Board: Bob Gries, Ali Hedayat, and Marcie Zlotnik.
  - Long-serving director Brian Burden was appointed as the new Chairman of the Board following the retirement of the former Chairman, David Kerr.
  - Management and the Board own or control approximately 17% of the Company.

Fourth Quarter 2018

- Customer portfolio acquisition
  - In November 2018, the Company purchased the customer contracts and associated assets of approximately 10,000 residential electric customers in Massachusetts and New York from a New York-based energy retailer for an estimated purchase price of $0.7 million, subject to customary post-closing adjustments.

Highlights Subsequent to the End of 2018

- Announced change from a monthly to a quarterly distribution
  - In January 2019, the Board approved a change in the Trust's distribution schedule from a monthly distribution to a quarterly distribution. In conjunction with the change to a quarterly distribution schedule, the Board also approved a distribution of $0.209 per Unit for the first quarter of 2019.

Proposed Transaction

On February 7, 2019, the Company and Vistra Energy entered into a definitive agreement pursuant to which Vistra Energy will acquire the Company for cash consideration of C$7.57 per Unit, for the Company's 56,605,607 Units. On February 20, 2019, the Company and Vistra Energy announced they had agreed to amend the cash consideration to C$8.80 per Unit. In addition to the purchase price, Unitholders will receive the Company's previously-declared distribution for the first quarter of 2019, in the amount of C$0.209 per Unit, for total consideration in the amount of C$9.009 per Unit. The transaction is subject to certain customary closing conditions, including the approval of at least two-thirds of the Company's Unitholders and the regulatory approvals, including the expiration or termination of any applicable waiting period under the United States Hart-Scott-Rodino Antitrust Improvements Act, and approval by the Federal Energy Regulatory Commission. The acquisition is expected to close in the second quarter of 2019. The announcement of this transaction follows a competitive strategic review process led and unanimously recommended by the Independent Directors of Crius, and unanimously approved by Crius' Board of Directors.

2018 DISCUSSION

In 2018, Management focused on a transformational strategy that emphasized the improvement of the profitability of our deregulated energy business through cost-reduction, high-margin customer growth, and increasing customer lifetime value through portfolio optimization. Our strategic initiatives have contributed to the overall value of the portfolio, increasing by $36.0 million or 7.6% in 2018, as measured by Embedded Margin, which we believe contributes to long-term Unitholder value.

Overall revenues increased 41.0% in 2018 to $1,235.1 million from $875.9 million for the year ended December 31, 2017. The increase was largely driven by increased volumes due to higher average electricity customer numbers resulting from the acquisition of USG&E at the beginning of the third quarter of 2017.

Gross margin for 2018 was $220.8 million, up 20.0% from $184.0 million in 2017. The increase in gross margin was primarily attributable to the addition of the customer portfolio acquired from USG&E at the beginning of the third quarter of 2017. As a percentage of total revenue, gross margin was 17.9% in 2018, a decrease from the 21.0% achieved in 2017, with the year-over-year decrease resulting from the increased mix of commercial and municipal aggregation customers in the portfolio as well as regulatory changes resulting in significant incremental wholesale cost factors in New Jersey and Massachusetts, namely Regional Transmission Expansion Plan (RTEP) and Renewable Portfolio Standards (RPS) costs, which the Company was not able to fully pass through to customers as a result of how the customer contracts are structured.

Adjusted EBITDA in 2018 was $70.2 million, representing an 8.4% increase from $64.7 million reported in 2017. In 2018, Adjusted EBITDA results were comprised of a $79.4 million contribution from the deregulated energy business and a negative $9.3 million contribution from the solar business, which is inclusive of $1.9 million in costs incurred to wind-down the solar business. The deregulated energy contribution to Adjusted EBITDA in 2018 was adversely impacted by $9.3 million in non-recurring general and administrative expenses incurred in the year, primarily related to the achievement of cost-synergies. Normalizing for these non-recurring costs, Adjusted EBITDA from the deregulated energy business was $88.8 million in 2018, an increase of 25.9% from $70.5 million in Adjusted EBITDA contribution from the deregulated energy business in 2017.

Net income in 2018 was $19.0 million, representing a decrease of 5.3% from net income of $20.1 million in 2017, with the year-over-year decrease primarily attributable to the factors set out in the "*Discussion of Operations*" section of this MD&A.

Distributable Cash was $21.9 million in 2018 representing a Payout Ratio of 167.9% in 2018 compared to $45.0 million in 2017 and a Payout Ratio of 63.8% in 2017. The period-over-period decrease was a result of $9.3 million in non-recurring charges and $9.2 million in negative performance from the solar business (including $1.9 million in wind-down costs). As well, increased upfront selling costs of $25.9 million in 2018 reflected the channel mix of new sales with an increased contribution from residential customer-focused direct-to-consumer marketing channels which have higher upfront costs to acquire. The Company expects to benefit in the future from these increased upfront selling cost investments which are focused on higher-margin customers, as reflected in the $36.0 million increase in Embedded Margin during the year. Normalizing for the above-mentioned non-recurring costs and solar contribution, the Distributable Cash and Payout Ratio for 2018 were $40.4 million and 90.8%, respectively. Management are comfortable with a temporarily elevated Payout Ratio as the Company implements its strategic initiatives to refocus on the core deregulated energy business and benefit from achieved cost-reduction targets.

Cash flows provided by operating activities were $48.6 million in 2018, an increase of 268.1% from $13.2 million in 2017, with the year-over-year increase driven by changes in operating assets and liabilities after adjusting for the $29.9 million in contract initiation costs due to the implementation of IFRS-15 in 2018. Excluding changes in operating assets and liabilities, cash flow provided by operations was $86.9 million for the year ended December 31, 2018, compared to $50.8 million for the year ended December 31, 2017, impacted by $29.9 million in contract initiation costs, which are included in the changes in operating assets and liabilities in 2018 under IFRS-15.

At December 31, 2018, the Trust had Total Cash and Availability of $37.9 million, consisting of $16.7 million of cash and cash equivalents and $21.2 million available under the Company's credit facilities. This compares to the Total Cash and Availability as at December 31, 2017 of $49.4 million, consisting of cash and cash equivalents of $18.2 million and $31.2 million available under the credit facility. Crius Energy ended the year with net debt of $111.0 million, representing a leverage ratio of 1.6x based on net debt to 2018 Adjusted EBITDA. Both liquidity and leverage metrics were impacted by ongoing solar losses, non-recurring restructuring costs as well as settlement payments related to the legal reserve booked in 2017.

As at December 31, 2018, Crius Energy had 1,204,000 customers compared to 1,410,000 at the end of 2017, representing net customer attrition of 206,000 customers. The year-over-year decrease in customers was primarily driven by elevated non-renewals of municipal aggregation and large commercial customers that came up for renewal during the year that the Company chose not to renew. Gross additions of 478,000 customers, were lower than 660,000 in 2017 primarily due to the decision to not participate in the municipal aggregation segment, which was a key contributor to customer additions in 2017, and increased margin requirements across all sales channels. Gross customer drops in 2018 totaled 724,000 customers compared to gross customer drops of 592,000 in 2017. Gross customer drops were elevated during 2018 primarily due to the non-renewal of 215,000 municipal aggregation customers as a result of the decision to no longer participate in the segment.

While the Company experienced net attrition of 206,000 customers, or 14.6%, during the year, Embedded Margin of the customer portfolio increased by an estimated $36.0 million or 7.6% in the year, which is a direct result of our focus on higher-margin customer growth and portfolio optimization.

OUTLOOK

In 2018, Management executed on a “return to core” strategy focused on the improvement of the profitability of our deregulated energy business. It was a year of strategic shifts and resetting of our focus, and after achieving our cost reduction targets and substantially exiting the solar business, we are excited to enter 2019 with a simplified, streamlined organization that we believe will support the sustainability of our distribution, and enhance and strengthen our long-term value.

In January 2019, the Board approved a change in the distribution schedule from a monthly distribution to a quarterly distribution to Unitholders. Concurrently, the Board announced a distribution for the first quarter of 2019 of $0.209 per Unit, which is equivalent to three months of the prior monthly distribution, essentially maintaining the distribution at the same level. Future distributions declared by the Board will follow a three-month payment schedule and will be declared on or about the 15th day of the month immediately following the end of the applicable quarterly period. The change from a monthly to a quarterly distribution schedule aligns the Company with industry peers, allows for better management of intra-quarter liquidity, and contributes to Management's priority to simplify operations. Management expects the annual improvements made through achieved cost reductions and exiting the solar business, along with liquidity levels in line with historic averages, will support the sustainability of the distribution.

While our total customer count has declined year-over-year as a result of attrition of low-margin large commercial and municipal aggregations, we believe the quality of our portfolio has improved and will continue to improve with the activities outlined above. Our focus on improving profitability and investing in growth, all while streamlining our operations, is contributing to consistent quarter-over-quarter growth in Embedded Margin as shown below - a key indicator that customer additions to the portfolio have been higher-margin than the customer drops from the portfolio.

As a management team, we use Embedded Margin to measure the quality of our portfolio of customers, and will use this as a key measurement to gauge our success and drive the activities of our people going forward. We are proud to share our progress on delivering on our strategic imperatives of growing the quality of our margins, operating an optimized business, and delivering on sales growth and innovation. We believe our previously stated target minimum steady-state base of Adjusted EBITDA of $100 million annually will be achievable in 2019, which positions Crius to deliver strong, long-term value to our Unitholders and supports the sustainability of our distribution.

Selected Consolidated Financial and Operational Data

The following selected historical financial information has been derived from the audited consolidated financial statements of the Trust as at and for the years ended December 31, 2018, 2017 and 2016 and the unaudited interim condensed consolidated financial statements of the Trust for the three months ended December 31, 2018 and 2017. The operating data has been prepared by Management based on the Company's records.

Statement of Comprehensive Income Highlights
(in millions)

	Quarter ended December 31, 2018 (unaudited)	Quarter ended December 31, 2017 (unaudited)	Year ended December 31, 2018	Year ended December 31, 2017	Year ended December 31, 2016
Revenue	$284.8	$248.5	$1,235.1	$875.9	$743.8
Cost of sales	230.8	193.7	1,014.3	691.9	585.3
Gross margin	54.0	54.8	220.8	184.0	158.5
Expenses					
Selling expenses	13.0	11.2	50.4	34.4	28.8
General and administrative	21.9	26.0	100.2	102.3	76.2
Unit-based compensation	0.0	0.1	1.8	5.9	4.9
Depreciation and amortization	12.8	12.0	52.3	58.3	39.4
Operating income (loss)	6.3	5.6	16.1	(17.0)	9.1
Other (expenses) income					
Finance costs	(5.4)	(5.2)	(22.6)	(15.3)	(10.3)
Distributions to non-controlling interest	—	—	—	—	(5.7)
Change in fair value of derivative instruments	0.1	32.2	(3.7)	30.2	46.1
Change in fair value of warrants	0.2	0.3	1.7	(0.4)	0.3
Change in fair value of non-controlling interest	—	—	—	—	6.7
(Loss) income before income taxes	1.3	32.8	(8.5)	(2.5)	46.2
(Benefit from) provision for income taxes	(0.4)	(3.2)	(27.5)	(22.6)	1.8
Net income	**$1.7**	**$36.0**	**$19.0**	**$20.1**	**$44.4**
EBITDA(1)	19.5	50.0	66.4	71.2	96.0
Adjusted EBITDA(1)	**$19.1**	**$18.0**	**$70.2**	**$64.7**	**$60.8**

Note:

(1) EBITDA and Adjusted EBITDA have limitations as analytical tools and should not be considered in isolation from, or as an alternative to, net income (loss) or other data prepared in accordance with IFRS. See the section entitled *"Non -IFRS Financial Measures"* in this MD&A. The following table is a reconciliation of net income to EBITDA and Adjusted EBITDA for the periods indicated.

Reconciliation of Net Income to EBITDA and Adjusted EBITDA
(in millions)

	Quarter ended December 31, 2018 (unaudited)	Quarter ended December 31, 2017 (unaudited)	Year ended December 31, 2018	Year ended December 31, 2017	Year ended December 31, 2016
Net income	**$1.7**	**$36.0**	**$19.0**	**$20.1**	**$44.4**
Excluding the impacts of:					
Finance costs	5.4	5.2	22.6	15.3	10.3
(Benefit from) provision for income taxes	(0.4)	(3.2)	(27.5)	(22.6)	1.8
Depreciation and amortization	12.8	12.0	52.3	58.3	39.4
EBITDA	19.5	50.0	66.4	71.2	96.0
Excluding the impacts of:					
Unit-based compensation	—	0.1	1.8	5.9	4.9
Distributions to non-controlling interest	—	—	—	—	5.7
Change in fair value of derivative instruments	(0.1)	(32.2)	3.7	(30.2)	(46.1)
Change in fair value of warrants	(0.2)	(0.3)	(1.7)	0.4	(0.3)
Change in fair value of non-controlling interest	—	—	—	—	(6.7)
Loss on sale of Viridian assets and related charges	—	—	—	—	7.3
Legal reserve and associated legal fees	—	0.4	—	17.5	—
Adjusted EBITDA	**$19.1**	**$18.0**	**$70.2**	**$64.7**	**$60.8**

Statement of Financial Position Highlights
(in millions)

	As at December 31, 2018	As at December 31, 2017	As at December 31, 2016
Current assets	$255.7	$227.7	$126.3
Total assets	581.2	567.0	299.3
Current liabilities	274.8	236.5	146.9
Long-term liabilities	66.2	81.8	12.8
Unitholders' equity	240.2	248.7	139.6

Statement of Cash Flows Highlights
(in millions)

	Quarter ended December 31, 2018 (unaudited)	Quarter ended December 31, 2017 (unaudited)	Year ended December 31, 2018	Year ended December 31, 2017	Year ended December 31, 2016
Cash flows provided by operating activities	$23.2	$14.8	$48.6	$13.2	$41.0
Cash flows used in investing activities	(0.4)	(6.6)	(8.7)	(102.5)	(20.5)
Cash flows (used in) provided by financing activities	(21.5)	(14.3)	(40.5)	96.5	(20.9)
Cash and cash equivalents at beginning of period	15.8	24.3	18.2	10.9	11.2
Cash and cash equivalents at end of period	16.7	18.2	16.7	18.2	10.9

Operational Highlights

	Quarter ended December 31, 2018 (unaudited)	Quarter ended December 31, 2017 (unaudited)	Year ended December 31, 2018	Year ended December 31, 2017	Year ended December 31, 2016
Electricity					
Volumes (MWh)	2,419,000	2,189,000	10,605,000	8,418,000	7,803,000
Revenue ($ million)	246.6	212.8	1,092.3	806.1	705.1
Gross margin ($ million)	38.7	41.1	162.3	155.2	138.4
Gross margin ($/MWh)	16.00	18.76	15.31	18.43	17.74
Gross margin as a % of revenue	15.7%	19.3%	14.9%	19.2%	19.6%
Natural gas					
Volumes (MMBtu)	5,212,000	5,120,000	19,057,000	9,783,000	5,817,000
Revenue ($ million)	35.3	33.3	130.2	58.7	28.2
Gross margin ($ million)	14.5	14.4	54.9	23.3	9.7
Gross margin ($/MMBtu)	2.79	2.82	2.88	2.38	1.66
Gross margin as a % of revenue	41.2%	43.3%	42.1%	39.6%	34.2%

Customer Aggregation

The following table summarizes the Company's gross additions and drops in electricity and natural gas customers from both organic growth and acquisition activity during the quarter ended December 31, 2018, and over the prior trailing four quarters.

Customer Aggregation
(in customers)[1]

	Opening Customer Count	Customer Adds	Customer Drops	Net Change	Closing Customer Count
Electricity	1,258,000	131,000	(167,000)	(36,000)	1,222,000
Natural Gas	188,000	14,000	(14,000)	—	188,000
Quarter ended December 31, 2017	**1,446,000**	**145,000**	**(181,000)**	**(36,000)**	**1,410,000**
Net Change % of Opening Customer Count				***(2.5)%***	
Electricity	1,222,000	138,000	(152,000)	(14,000)	1,208,000
Natural Gas	188,000	17,000	(24,000)	(7,000)	181,000
Quarter ended March 31, 2018	**1,410,000**	**155,000**	**(176,000)**	**(21,000)**	**1,389,000**
Net Change % of Opening Customer Count				***(1.5)%***	
Electricity	1,208,000	160,000	(156,000)	4,000	1,212,000
Natural Gas	181,000	17,000	(23,000)	(6,000)	175,000
Quarter ended June 30, 2018	**1,389,000**	**177,000**	**(179,000)**	**(2,000)**	**1,387,000**
Net Change % of Opening Customer Count				***(0.1)%***	
Electricity	1,212,000	90,000	(122,000)	(32,000)	1,180,000
Natural Gas	175,000	13,000	(16,000)	(3,000)	172,000
Quarter ended September 30, 2018	**1,387,000**	**103,000**	**(138,000)**	**(35,000)**	**1,352,000**
Net Change % of Opening Customer Count				***(2.5)%***	
Electricity	1,180,000	72,000	(208,000)	(136,000)	1,044,000
Natural Gas	172,000	11,000	(23,000)	(12,000)	160,000
Quarter ended December 31, 2018	**1,352,000**	**83,000**	**(231,000)**	**(148,000)**	**1,204,000**
Net Change % of Opening Customer Count				***(10.9)%***	

Note:
(1) Customer counts in the above table refer to RCEs or residential customer equivalents, an industry standard unit of measurement of consumption per annum equivalent to 10 MWh (or 10,000 kWh) in the case of the electricity and 100 MMBtu in the case of natural gas. We have estimated the number of RCEs in accordance with industry conventions based on information available regarding customers and their historical usage and are subject to adjustment based on updated available information. Customer adds and customer drops do not always reflect a customer's service commencement date or service end date due to time lags following the customer's enrolment date and termination request date.
(2) Customer Adds in the quarter ended September 30, 2017 include 350,000 RCEs acquired from USG&E in July 2017, comprising 216,000 electricity customers and 134,000 natural gas customers.

Embedded Margin[1]

The following table summarizes the Company's Embedded Margin related to its electricity and natural gas customers as at December 31, 2018, and for the prior trailing four quarters.

	Embedded Margin ($ Million)	Customers
Quarter ended December 31, 2017	474.0	1,410,000
Quarter ended March 31, 2018	480.7	1,389,000
Quarter ended June 30, 2018	486.2	1,387,000
Quarter ended September 30, 2018	495.4	1,352,000
Quarter ended December 31, 2018	**510.0**	**1,204,000**

Note:
(1) Embedded Margin represents a five-year non-discounted measure of Management's estimate of future electricity and natural gas gross margins based on forecasted volumes and unit margins for existing customers with appropriate assumptions for customer attrition and renewals. Embedded margin is not intended to take into account expenses such as selling, general and administrative or financing costs necessary to realize the gross margins. It is only calculated for existing customers and does not factor future customer additions.

Summary of Quarterly Results
Quarterly Results (unaudited)
(in millions)

	Quarter ended December 31, 2018	Quarter ended September 30, 2018	Quarter ended June 30, 2018	Quarter ended March 31, 2018	Quarter ended December 31, 2017	Quarter ended September 30, 2017	Quarter ended June 30, 2017	Quarter ended March 31, 2017
Revenue	$284.8	$359.4	$269.1	$321.8	$248.5	$269.9	$180.2	$177.4
Cost of sales	230.8	306.6	215.0	262.0	193.7	214.9	143.0	140.3
Gross margin	54.0	52.9	54.1	59.9	54.8	54.9	37.2	37.0
Expenses								
Selling expenses	13.0	14.1	11.3	12.1	11.2	12.2	6.1	4.9
General and administrative	21.9	23.6	26.8	27.9	26.0	24.8	24.9	26.7
Unit-based compensation	—	1.4	0.5	(0.2)	0.1	1.0	2.1	2.6
Depreciation and amortization	12.8	13.5	12.9	13.1	12.0	14.3	14.3	17.7
Operating income (loss)	6.3	0.2	2.7	6.9	5.6	2.6	(10.2)	(14.9)
Other (expenses) income								
Finance costs	(5.4)	(6.1)	(5.3)	(5.8)	(5.2)	(5.5)	(2.4)	(2.3)
Change in fair value of derivative instruments	0.1	14.2	8.2	(26.3)	32.2	7.1	(0.8)	(8.3)
Change in fair value of warrants	0.2	0.1	0.7	0.7	0.3	0.4	(0.4)	(0.6)
Income (loss) before income taxes	1.3	8.5	6.3	(24.6)	32.8	4.7	(13.8)	(26.1)
(Benefit from) provision for income taxes	(0.4)	0.8	1.0	(28.9)	(3.2)	(20.3)	0.8	0.2
Net income (loss)	**$1.7**	**$7.7**	**$5.3**	**$4.3**	**$36.0**	**$25.0**	**$(14.6)**	**$(26.3)**

Reconciliation of Net Income to EBITDA and Adjusted EBITDA

Net income (loss)	**$1.7**	**$7.7**	**$5.3**	**$4.3**	**$36.0**	**$25.0**	**$(14.6)**	**$(26.3)**
Excluding the impacts of:								
Finance costs	5.4	6.1	5.3	5.8	5.2	5.5	2.4	2.3
(Benefit from) provision for income taxes	(0.4)	0.8	1.0	(28.9)	(3.2)	(20.3)	0.8	0.2
Depreciation and amortization	12.8	13.5	12.9	13.1	12.0	14.3	14.3	17.7
EBITDA	19.5	28.1	24.5	(5.6)	50.0	24.5	2.8	(6.1)
Excluding the impacts of:								
Unit-based compensation	—	1.4	0.5	(0.2)	0.1	1.0	2.1	2.6
Change in fair value of derivative instruments	(0.1)	(14.2)	(8.2)	26.3	(32.2)	(7.1)	0.8	8.3
Change in fair value of warrants	(0.2)	(0.1)	(0.7)	(0.7)	(0.3)	(0.4)	0.4	0.6
Legal reserve and associated legal fees		—	—	—	0.4	0.3	7.9	9.0
Adjusted EBITDA	**$19.1**	**$15.2**	**$16.1**	**$19.8**	**$18.0**	**$18.3**	**$14.0**	**$14.4**

Distributable Cash and Payout Ratio

Cash flows provided by (used in) operating activities	**$23.2**	**$(3.8)**	**$8.4**	**$20.8**	**$14.8**	**$5.3**	**$1.3**	**$(8.2)**
Adjusted to:								
Exclude: Changes in select operating assets and liabilities	(8.0)	15.1	2.0	(9.5)	4.8	13.7	13.6	19.1
Include: Finance costs - included in financing activities	(5.1)	(6.0)	(5.1)	(5.8)	(5.0)	(5.3)	(2.7)	(2.3)
Include: Maintenance Capital Expenditures - included in investing activities	(0.1)	(0.9)	(1.6)	(1.8)	(1.6)	(0.5)	(0.8)	(0.9)
Distributable Cash	**$10.0**	**$4.4**	**$3.8**	**$3.6**	**$12.9**	**$13.2**	**$11.4**	**$7.7**
Distributions to Unitholders	**$9.0**	**$9.0**	**$9.3**	**$9.2**	**$8.9**	**$8.2**	**$5.8**	**$5.8**
Payout Ratio	**90.0%**	**204.5%**	**244.7%**	**255.6%**	**69.0%**	**62.1%**	**50.9%**	**75.3%**

Discussion of Operations
For the years ended December 31, 2018 and December 31, 2017

Revenue

For the year ended December 31, 2018, revenue was $1,235.1 million, representing an increase of 41.0% from $875.9 million for the year ended December 31, 2017, with the period-over-period increase being primarily due to revenues associated with the acquisition of USG&E at the beginning of the third quarter of 2017.

Electricity

Electricity revenue for the year ended December 31, 2018 was $1,092.3 million, representing an increase of 35.5% from $806.1 million for the year ended December 31, 2017, as a result of a 26.0% increase in volume and a 7.6% higher average retail rate per unit. Electricity volumes for the year ended December 31, 2018 were 10,605,000 MWh representing an increase of 26.0% from 8,418,000 MWh for the year ended December 31, 2017, with the increase being primarily due to higher average customers associated with the acquisition of USG&E.

Natural Gas

Natural gas revenue for the year ended December 31, 2018 was $130.2 million, representing an increase of 121.9% from $58.7 million for the year ended December 31, 2017, as a result of a 94.8% increase in volume and a 13.9% increase in average retail rate per unit. Natural gas volumes for the year ended December 31, 2018 were 19,057,000 MMBtu, representing an increase of 94.8% from 9,783,000 MMBtu for the year ended December 31, 2017, with the increase being primarily due to higher average customers associated with the acquisition of USG&E.

Solar Revenue

Solar revenue for the year ended December 31, 2018 was $12.6 million, representing an increase from revenues of $11.2 million for the year ended December 31, 2017. The prior comparable period benefited by $5.0 million in revenue associated with the community solar initiative launched in the second quarter of 2017 for the aggregation of community solar customers. Excluding the community solar revenues, solar revenues were up by $6.4 million over the prior comparable period, due to the acquisition of the Verengo solar installation business in mid-2017.

Gross Margin

For the year ended December 31, 2018, gross margin was $220.8 million, representing an increase of 20.0% from $184.0 million for the year ended December 31, 2017, with the increase being attributable to the addition of the customer portfolio acquired from USG&E at the beginning of the third quarter of 2017. Gross margin for the year ended December 31, 2018 was 17.9% of total revenue, representing a decrease from 21.0% of total revenue for the year ended December 31, 2017 for the reasons detailed below.

Electricity

Electricity gross margin for the year ended December 31, 2018 was $162.3 million, representing an increase of 4.6% from $155.2 million for the year ended December 31, 2017. For the year ended December 31, 2018, electricity gross margin per unit was $15.31/MWh and electricity gross margin was 14.9% of electricity revenues, compared to $18.43/MWh and 19.2%, respectively, for the year ended December 31, 2017. Gross margins in the current year were higher than the prior year comparable period, primarily due to the higher average customer numbers due to the addition of the customer portfolio acquired from USG&E at the beginning of the third quarter of 2017 but unit gross margins and gross margins as a percentage of revenue were lower due to the increased mix of commercial and municipal aggregation customers in the portfolio, including the commencement of service of a large municipal aggregation in Massachusetts in January 2018. Specifically, gross margins in our municipal aggregation portfolio, which Crius intends to run-off, were negatively impacted by regulatory changes resulted in significant incremental wholesale cost factors in New Jersey and Massachusetts, namely RTEP and RPS costs, which the Company was not able to fully pass through to customers as a result of how the customer contracts are structured.

Natural Gas

Natural gas gross margin for the year ended December 31, 2018 was $54.9 million, representing an increase of 135.9% from $23.3 million for the year ended December 31, 2017. For the year ended December 31, 2018, natural gas gross margin per unit was $2.88/MMBtu and natural gas gross margin was 42.1% of natural gas revenues representing an increase from $2.38/MMBtu and 39.6%, respectively, for the year ended December 31, 2017. The increase in gross margin and gross margin per unit in the year were primarily attributable to the addition of the customer portfolio acquired from USG&E at the beginning of the third quarter of 2017.

Solar

Solar gross margin for the year ended December 31, 2018 and December 31, 2017 was $3.6 million and $5.6 million, respectively, reflecting the partial wind-down of the solar business throughout the year.

Selling Expenses

Selling expenses consist of commissions due to our various sales channels including independent contractors, commercial and residential brokers, telemarketing and door-to-door vendors, partners in our strategic partnerships, employees both for customer consumption and enrolling new electricity, natural gas and solar customers, vendors used in the Company's direct mail and other direct marketing campaigns as well as other sales and marketing costs directly associated with customer enrolment.

Selling costs in the deregulated energy business are divided into two categories: (i) upfront selling costs, which are primarily based on the successful enrollment of customers; and (ii) residual commissions, which are primarily based on customer consumption and receipt of customer payments. Residual-based commissions are expensed over the life-of-customers based on customer consumption and receipt of customer payments. In all reporting periods prior to the implementation of the new IFRS-15 revenue recognition accounting standard in first quarter of 2018, upfront selling costs were expensed in the period incurred, typically at the time of enrolment of the customer. Commencing in the first quarter of 2018, certain upfront selling costs that meet the definition of contract initiation and fulfillment costs under the standard, are deferred and amortized/expensed over the expected life of the customer to which they relate, with costs that do not meet this definition continuing to be expensed as incurred.

The commission structures utilized are summarized below:

- Commissions due to independent contractors in our direct marketing channels primarily comprise upfront commissions, based on successful customer enrollments, and may be subject to a partial or full repayment of such commission for customers who terminate their service within certain time frames, or paid under hourly contracts. Selling costs also include costs from various vendors used in direct mail and other direct marketing campaigns.

- Commissions due to brokers in our commercial broker channel are primarily residual commissions, which are based on energy usage over a customer's term of enrollment.

- Commissions due for customers acquired through our strategic partnerships are calculated primarily based on upfront commissions calculated per customer enrolled, and may be subject to a partial or full repayment of such commission for customers who terminate their service within certain time frames and a residual-based commission based on revenue or energy usage over a customer's term of enrollment.

- Commissions due to employees and independent contractors based on customer enrolments and/or the size and pricing of the solar systems sold.

For the year ended December 31, 2018, selling expenses were $50.4 million, representing an increase from $34.4 million for the year ended December 31, 2017, with the increase primarily attributable to the acquisition of USG&E in the third quarter of 2017, offset by the accounting benefit of the new IFRS-15 accounting standard as detailed below. Selling expenses for the year ended December 31, 2018 amounted to 4.1% of revenue compared to 3.9% of revenue for the year ended December 31, 2017. These expenses consist of:

(i) Deregulated energy selling costs for the year ended December 31, 2018 of $47.6 million (amounting to 3.9% of deregulated energy revenues), representing an increase from $31.6 million for the year ended December 31, 2017 (amounting to 3.7% of deregulated energy revenues). Deregulated energy selling costs were higher in the year ended December 31, 2018 primarily due to the addition of selling costs related to the USG&E business which was acquired in the third quarter of 2017 and the channel mix of sales being impacted by the residential focused direct-to-consumer channels, which are associated with higher selling costs. Additionally, accounting changes resulted in a net $14.0 million reduction to selling costs in the year ended December 31, 2018 as compared to the prior comparable period, consisting of a reduction to selling costs of $17.3 million as a result of the deferral of certain upfront selling costs with the implementation of the new IFRS-15 accounting standard in 2018, partially offset by a period-over-period increase to selling costs of $3.3 million due to the acquisition accounting treatment of residual-based commissions associated with acquired customers (as opposed to organic customer additions). By way of background, residual-based commissions owed to brokers based on usage of the customers acquired are treated under acquisition accounting as an assumed liability and are included in the purchase price allocation for the acquisition, based on estimated customer usage and contracted commission rates. Thus, ongoing payment of residual-based commissions associated with the customers acquired from acquisitions such as USG&E, TriEagle Energy or Kona Energy, relieve the liability on the consolidated statement of financial position rather than be expensed as a selling cost. The reduction to selling costs as a result of this acquisition accounting treatment, was greater in 2017 than it is in 2018, primarily due to the increased amount of residual-based commissions associated with the commercial customer-focused TriEagle Energy and Kona Energy acquisitions, than for the more residential customer-focused USG&E acquisition in 2017.

(ii) Solar selling costs for the year ended December 31, 2018 of $2.8 million, compared to $2.9 million for the year ended December 31, 2017.

General and Administrative Expenses

General and administrative expenses for the year ended December 31, 2018 were $100.1 million compared to $102.3 million for the year ended December 31, 2017. The period-over-period comparison is set out in tables below and was impacted by the certain one-time costs including the legal reserve and associated legal fees in the prior period, as well as the impact of the acquisition of USG&E cost-base from the third quarter of last year.

General and Administrative Expenses
(in $ millions and % of revenue)

	Year ended December 31, 2018		Year ended December 31, 2017	
	$	%	$	%
Variable Costs				
POR fees / bad debt	$13.3	1.1%	$9.0	1.0%
Gross receipts taxes and other taxes	11.2	0.9%	9.2	1.1%
Total Variable Costs	**24.5**	**2.0%**	**18.2**	**2.1%**
Fixed Costs				
Processing costs	5.4	0.4%	5.5	0.6%
Human resources	31.7	2.6%	30.4	3.5%
Professional and consultant fees	2.5	0.2%	4.3	0.5%
Legal and regulatory	1.9	0.2%	1.8	0.2%
Other fixed costs	14.8	1.2%	16.1	1.8%
Total Fixed Costs	**56.3**	**4.6%**	**58.1**	**6.6%**
Solar & Non-operating Costs				
Solar operating expenses	10.0	0.8%	7.3	0.8%
Legal reserve and associated legal fees	—	—%	17.5	2.0%
Other costs	9.3	0.8%	1.2	0.1%
Total Other Costs	**19.3**	**1.6%**	**26.0**	**2.9%**
Grand Total	**$100.1**	**8.1%**	**$102.3**	**11.7%**

General and administrative expenses incurred during the year ended December 31, 2018 were made up of the following categories:

Variable Costs

Variable costs, consisting of expenses directly driven by revenues, were $24.5 million for the year ended December 31, 2018, representing 2.0% of revenues. Variable costs were $18.2 million for the year ended December 31, 2017, representing 2.1% of revenues.

(a) POR fees/bad debt represent fees paid to the local distribution companies ("**LDCs**") pursuant to Purchase of Receivables ("**POR**") programs, under which the LDCs assume credit risk associated with customer non-payment and bad debt costs incurred in markets where the Company does not operate under a POR program, which exposes the Company to customer credit risk. The POR fees/bad debt costs for the year ended December 31, 2018 was $13.3 million, representing 1.1% of revenue, compared to $9.0 million for the year ended December 31, 2017, representing 1.0% of revenue.

(b) Gross receipts taxes and other taxes for the year ended December 31, 2018 of $11.2 million, representing 0.9% of revenue, represent operational taxes in various states and jurisdictions and are primarily driven by revenue, and compared to 9.3 million, representing 1.1% of revenue in the prior comparable period.

Fixed Costs

Fixed costs, consisting of operating expenses not directly driven by revenues, were $56.3 million for the year ended December 31, 2018, representing 4.6% of revenues, compared to $58.1 million for the year ended December 31, 2017, representing 6.6% of revenues.

(c) Processing costs for the year ended December 31, 2018 of $5.4 million include various data processing and information technology costs incurred to service our customers and salesforce, compared to $5.5 million for the year ended December 31, 2017.

(d) Human resource costs for the year ended December 31, 2018 of $31.7 million, consist of costs incurred in relation to the Company's employee base, temporary staff and independent contractors compared to costs in the prior comparable period in 2017 of $30.4 million, with the increase primarily due to the USG&E Acquisition, partially offset by headcount reductions associated with the cost-reduction initiatives implemented in 2018.

(e) Professional and consultant fees for the year ended December 31, 2018 of $2.5 million represent audit, tax, investor relations, share registry, valuation, due diligence, internal controls consulting and other fees, compared to $4.3 million in the prior comparable period in 2017.

(f) Legal and regulatory costs for the year ended December 31, 2018 of $1.9 million represent external legal fees and compares to $1.8 million in the prior comparable period in 2017.

(g) Other costs for the year ended December 31, 2018 of $14.8 million represent the balance of corporate, operational and marketing related expenses incurred to operate our business. These costs compare to $16.1 million in the prior comparable period in 2017, with the decrease attributable to the cost-reduction initiatives implemented in 2018.

Solar and Non-Operating Costs

(h) Solar operating expenses for the year ended December 31, 2018 of $10.0 million represent costs associated with the operation of the solar business, including certain wind-down costs of $1.9 million, and compares to $7.3 million in the prior comparable period in 2017.

(i) No legal reserve and associated legal fees were incurred by the Company for the year ended December 31, 2018, compared to $17.5 million, in the prior comparable period in 2017, which consisted of a reserve for certain litigation and regulatory matters relating to sales and marketing practices together with associated legal fees. The charges incurred in the prior comparable period were excluded from Adjusted EBITDA and Distributable Cash.

(j) Other costs for the year ended December 31, 2018 of $9.3 million represent certain non-recurring costs primarily related to restructuring charges, such as employee severance costs, associated with workforce rationalizations. Other costs in the prior comparable period amounted to $1.2 million which included transaction costs in connection with the USG&E Acquisition, partially offset by gain relating to prior acquisitions.

Unit-Based Compensation

For the year ended December 31, 2018, unit-based compensation expense amounted to $1.8 million, representing a decrease from $5.9 million for the year ended December 31, 2017. The expense reflects the fair value of the unit-based compensation based on the vesting schedule, applicable performance expectations and the market price of the Units at the end of the period and the applicable vesting period.

Depreciation and Amortization

Depreciation and amortization for the year ended December 31, 2018 was $52.3 million, representing a decrease from $58.3 million for the year ended December 31, 2017. The higher amortization in the prior comparable period is primarily attributable to the amortization associated with the acquisitions of TriEagle Energy and Kona Energy completed in 2015 and 2016, respectively, as well as the impact of changes in estimates of useful lives of certain intangible assets, all of which expired in 2017, partially offset by amortization of newly established intangible assets related to the USG&E Acquisition in the second half of 2017.

Finance Costs

Finance costs for the year ended December 31, 2018 were $22.6 million, representing an increase from $15.3 million for the year ended December 31, 2017. The higher finance costs period-over-period were attributable to the higher energy volumes as a result of the USG&E Acquisition at the beginning of the third quarter of 2017, increased usage on the Credit Facility and interest on the Term Loans, both which were partially used to fund the cash portion of the USG&E Acquisition.

Change in Fair Value of Derivative Instruments

The change in fair value of derivative instruments consists of changes in unrealized gains or losses on derivatives, which represent the estimated amount that the Trust would need to pay or receive to dispose of the remaining notional commodity or currency positions in the market if the derivative contracts to which the Company are party were to be terminated at the respective period end (see the section entitled *"Financial Instruments and Risk Management"* in this MD&A).

For the year ended December 31, 2018, the changes in unrealized gains or losses associated with derivative contracts were net losses of $3.7 million compared to net gains of $30.2 million for the year ended December 31, 2017.

Change in Fair Value of Derivative Instruments
(in millions)

	Year ended December 31, 2018	Year ended December 31, 2017
Forward electricity positions	$(0.8)	$33.1
Forward natural gas positions	1.2	(3.3)
Weather derivative positions	(0.1)	0.1
Forward currency positions	(4.0)	0.2
Change in fair value of derivative instruments	**$(3.7)**	**$30.2**

These gains and losses represent non-cash gains and losses associated with mark-to-market movements on forward hedge positions that are outstanding at period end. These hedges are put in place to hedge either the fixed price exposure of customers on fixed price contracts, the expected short-term exposure of variable priced customers, or the impacts of currency movements on the Trust's distributions, thereby minimizing the impact of these unrealized mark-to-market gains and losses.

Change in Fair Value of Warrants

The change in fair value of warrant liability for the year ended December 31, 2018 was a gain of $1.7 million compared to a loss of $0.4 million for the year ended December 31, 2017. These gains and losses represents the mark-to-market valuation of the 750,000 warrants to purchase Units ("**Warrants**") issued to Macquarie Energy in connection with the legacy supplier agreement. The valuation of these Warrants is based on an option valuation model, and accordingly the non-cash gains and losses are the result of changes in the Unit price, volatility, yield, time to maturity and the risk-free rate over the period.

Benefit from Income Taxes

For the years ended December 31, 2018 and December 31, 2017, the Trust recorded a benefit from income taxes of $27.5 million (consisting of $1.1 million in current tax expense and $28.6 million in deferred tax benefit) and a benefit from income taxes of $22.6 million (consisting of $0.8 million in current tax expense and $23.4 million in deferred tax benefit), respectively. The Trust's (benefit from) provision for income taxes relates to the Trust's U.S. subsidiaries. Deferred tax assets are recognized to the extent that the Trust believes that the likelihood of recognition is probable. The benefit from income taxes during the year was impacted by the recognition of deferred tax assets meeting the recognition criterion during the period primarily related to NOLs and intangibles that are expected to be utilized against current and future taxable income of USG&E.

Net Income

For the year ended December 31, 2018, net income was $19.0 million, compared to net income of $20.1 million for the year ended December 31, 2017, with the changes being attributable to the factors noted above. Net income is impacted by numerous non-cash items, some being a result of the industry in which we operate. Accordingly, Management believes the additional non-IFRS financial measures of Adjusted EBITDA and Distributable Cash are useful metrics to be considered together with net income for evaluating the Trust's financial and operating performance, as they are measures that Management uses internally to assess performance.

Liquidity and Capital Resources

The Trust expects to have sufficient liquidity to fund its planned operations for the foreseeable future. The following are the primary sources of funding for future expenditures that are expected by Management to be available: (i) internally generated cash flow from operations; (ii) existing cash and working capital; (iii) borrowing capacity under our credit facilities; and (iv) existing external debt financing. Additionally, Management may seek to raise capital through further debt or equity financing.

Cash Flow provided by Operations

Cash flow provided by operations for the year ended December 31, 2018 amounted to $48.6 million compared to $13.2 million for the year ended December 31, 2017, with the year-over-year increase primarily attributable to lower cash used in changes in operating assets and liabilities excluding the $29.9 million in contract initiation costs, which are included in changes in operating assets and liabilities in 2018 following the implementation of IFRS-15 as detailed in the *"Selling Expenses"* section of this MD&A. Excluding changes in operating assets and liabilities, cash flow provided by operations was $86.9 million for the year ended December 31, 2018, compared to $50.8 million for the year ended December 31, 2017, with the year-over-year variance being attributable to the above-noted $29.9 million in contract initiation costs that were included in changes in operating assets in 2018, but not in 2017, due to the implementation of the IFRS-15 accounting standard.

Cash flow provided by operations for the three month period ended December 31, 2018 amounted to $23.2 million compared $14.8 million for the three month period ended December 31, 2017, with the year-over-year increase primarily attributable to the changes in operating assets and liabilities. Excluding changes in operating assets and liabilities, cash flow provided by operations was $24.9 million for the three month period ended December 31, 2018, compared to $19.1 million for the three month period ended December 31, 2017.

Distributable Cash and Distributions

Distributable Cash for the year ended December 31, 2018 was $21.9 million and Total Distributions paid for the year were $36.7 million, which represented a Payout Ratio of 167.9% of Distributable Cash. This compares to Distributable Cash of $45.0 million, Total Distributions of $28.7 million and a Payout Ratio of 63.8% for the year ended December 31, 2017. The year-over-year decrease in Distributable Cash of $23.3 million was impacted by increased upfront selling costs of $25.9 million reflecting the channel mix of new sales in the year ended December 31, 2018, with increased contribution from residential customer-focused direct marketing channels which have higher upfront costs to acquire. Upfront selling costs averaged $81 per customer in the year ended December 31, 2018, compared to $21 per customer in the prior comparable period. The company expects the benefit in future quarters from these increased upfront selling cost investments which are focused on higher-margin residential customers, and this benefit is reflected in the increase in Embedded Margin during the year of $14.6 million.

Distributable Cash for the year ended December 31, 2017 exclude charges of $17.5 million for legal reserve and associated legal fees relating to the certain litigation and regulatory matters. Including these costs would have resulted in Distributable Cash of $27.5 million (representing a Payout Ratio of 104.3%) for the year ended December 31, 2017.

Distributable Cash for the three month period ended December 31, 2018 was $10.0 million and Total Distributions paid for the quarter were $9.0 million, which represented a quarterly Payout Ratio of 90.2% of Distributable Cash. This compares to Distributable Cash of $13.0 million, Total Distributions of $8.9 million and a Payout Ratio of 69.0% for the three month period ended December 31, 2017. The period-over-period decrease in Distributable Cash was attributable to the same above-mentioned non-recurring items as well as the impact of increased upfront selling costs associated with the change in channel mix of new sales.

The following table provides a reconciliation of Cash flows provided by operating activities to Distributable Cash and shows the Payout Ratio of Total Distributions as a percentage of Distributable Cash.

Distributable Cash and Payout Ratio (unaudited)
(in millions)

	Year ended December 31, 2018	Year ended December 31, 2017	Quarter Ended December 31, 2018	Quarter Ended December 31, 2017
Cash flows provided by (used in) operating activities	**$48.6**	**$13.2**	**$23.2**	**$14.8**
Adjusted to:				
Exclude: Changes in select operating assets and liabilities	(0.3)	50.9	(8.0)	4.8
Include: Finance costs - included in financing activities	(22.0)	(15.3)	(5.1)	(5.0)
Include: Maintenance Capital Expenditures - included in investing activities	(4.4)	(3.8)	(0.1)	(1.6)
Distributable Cash	**$21.9**	**$45.0**	**$10.0**	**$13.0**
Total Distributions	**$36.7**	**$28.7**	**$9.0**	**$8.9**
Payout Ratio	**167.9%**	**63.8%**	**90.2%**	**69.0%**

Note:

(1) The exclusion of changes in select operating assets and liabilities from Distributable Cash is based on the temporary and highly seasonal nature of these net changes, as well as the Trust's ability to use the Credit Facility to fund such net changes. See *"Credit Facility"* and *"Cash Flow Provided by Operations"* sections of this MD&A. Refer to table below labeled "*Changes in select operating assets and liabilities"* for a reconciliation to the changes in operating assets and liabilities based on the Trust's consolidated cash flow statement as prepared under IFRS.

The table below shows the calculation of the changes in select operating assets and liabilities which are excluded from Distributable Cash and a reconciliation to the Changes in operating assets and liabilities based on the Trust's consolidated cash flow statement as prepared under IFRS. The exclusion of these changes in select operating assets and liabilities from Distributable Cash is based on the temporary and highly seasonal nature of these net changes, as well as the ability to utilize Crius Energy's structured borrowing based Credit Facility to fund these changes. Changes in operating assets and liabilities primarily arise due to the time lag associated with the cash conversion cycle or the period between the time the Company pays for wholesale energy and the time it receives payments from our customers for the energy it sells, which is also impacted by the business' growth and seasonality. The Credit Facility in place is a borrowing base facility and, as such, provides access to cash needed to fund changes in operating assets and liabilities associated with the build-up of customer accounts receivables and trade payables.

Changes in select operating assets and liabilities
(in millions)

	Year ended December 31, 2018	Year ended December 31, 2017	Quarter Ended December 31, 2018	Quarter Ended December 31, 2017
Changes in operating assets and liabilities	(38.3)	(37.6)	(1.7)	(4.4)
Adjusted to exclude:				
Contract initiation and fulfillment payments	29.9	—	6.2	—
Unit-based compensation payments	8.7	4.2	3.5	—
Legal reserve and associated legal fees	—	(17.5)	—	(0.4)
Changes in select operating assets and liabilities	**$0.3**	**$(50.9)**	**$8.0**	**$(4.8)**

The adjustments in the above reconciliation are made to exclude certain longer-term or permanent items (which are accordingly included in the calculation of Distributable Cash) as well as items considered to be non-recurring in nature (which are accordingly excluded from the calculation of Distributable Cash) from the changes in operating assets and liabilities that are excluded from the calculation of Distributable Cash.

Credit Facility

In August 2018, the Company's separate supplier agreements and credit facilities with Macquarie Energy and Vantage Commodities Financial Services II ("**Vantage**") were replaced with a single consolidated supplier agreement and credit facility with Macquarie Energy and National Bank of Canada (collectively **"Credit Facility"**). The Credit Facility provides for the exclusive supply of the Company's wholesale energy needs and hedging requirements for a term ending in August 2021. Under the Credit Facility, Macquarie Energy assumes the responsibility for meeting all the credit and collateral requirements with each Independent System Operator. Further, the Company's customers and the LDCs serving the Company's customers are directed to remit all customer payments into a designated restricted bank account (the "**Lockbox**"), and the funds in that account are used to pay Macquarie Energy for energy supplied and other fees and interest due under the Credit Facility. The trade payables are secured by funds pledged in the Lockbox, accounts receivable, natural gas inventory and all other Company assets.

Under the wholesale energy supply component of the Credit Facility, Macquarie Energy extends trade credit to buy wholesale energy supply, with amounts due being generally payable in the month following the delivery of the energy. The wholesale energy supply component of the Credit Facility is subject to an overall exposure limit of $140 million, subject to certain standard financial covenants and limited to a calculated credit base based on restricted cash in the Lockbox, billed and unbilled receivables, natural gas inventory, forward value of customers and certain other items. The Company incurs a volumetric fee based on the wholesale energy delivered, which is included in the Company's finance costs in the consolidated statements of comprehensive income.

The Credit Facility also includes a syndicated working capital facility, co-lead by Macquarie Energy and National Bank of Canada, with an initial limit of $110 million for the first twelve months, following which it reduces to $100 million, under which letters of credit and cash advances can be made based on the calculated credit base. Such letters of credit and cash advances are subject to an annual interest rate of between 1.75% and 4.25% (depending on Company leverage ratios) plus the applicable 30-day LIBOR or prime rate, in the case of cash advances. The total interest rates were 5.77% and 7.07% as at December 31, 2018 and December 31, 2017, respectively, per annum.

As at December 31, 2018, the Company had letters of credit issued totaling $11.6 million and cash advances of $77.2 million drawn under the working capital facility, compared to letters of credit issued totaling $17.5 million and cash advances of $55.6 million drawn under the working capital facility as at December 31, 2017. The availability under the Credit Facility and legacy facilities was $21.2 million and $31.2 million, respectively, as at December 31, 2018 and December 31, 2017. As at December 31, 2018, the Company was in compliance with all covenants under the Credit Facility.

Term Loans

The Company has two term loans, which are held by the Connecticut Department of Economic and Community Development ("**CT DECD**") and certain USG&E selling shareholders (together referred to as "**Term Loans**").

In January 2017, the CT DECD advanced a term loan to the Company in the amount of $8.0 million, for a term of up to 10 years, at an annual interest rate of 2.0% (the "**CT DECD Term Loan**"). Repayment of the CT DECD Term Loan principal is deferred for the first four years of the loan term. The Term Loan contains a provision for potential debt forgiveness or early redemption based on the Company achieving certain headcount targets agreed upon with the CT DECD.

In July 2017, as part of the USG&E Acquisition, certain selling shareholders advanced a subordinated promissory note ("**USG&E Sellers Note**") to the Company in the amount of $47.5 million at an annual interest rate of 9.5%. The note has an eight year term that matures in July 2025, is non-amortizing with accrued interest being payable quarterly over the term. The promissory note is secured by the assets of USG&E, but is subordinated to the security interest of Macquarie Energy and National Bank of Canada under the Credit Facility. The USG&E Sellers Note was subject to adjustment for post-closing working capital adjustments as well as a portion of any indemnity claims under the acquisition agreements, with the net amount of $44.0 million reflected in the consolidated statements of financial position

Debt and Leverage

The table below shows the total debt and net debt calculations as well as the calculation of certain leverage metrics based on the Trust's consolidated balance sheet as prepared under IFRS as well as certain non-IFRS measures:

Debt and Leverage
(in millions and times)

	As at December 31, 2018	As at December 31, 2017
Credit facility	$77.2	$55.6
Term loans	50.5	53.8
Total debt	**$127.7**	**$109.4**
Cash and cash equivalents	(16.7)	(18.2)
Net debt	**$111.0**	**$91.2**
Adjusted EBITDA (last twelve months)	**$70.2**	**$64.8**
Net debt / Adjusted EBITDA (last twelve months)	**1.6x**	**1.4x**

As of December 31, 2018, the Trust had a leverage ratio of 1.6x, which was an increase over the ratio as of December 31, 2017, with the increase impacted by increased usage on the credit facility and the impacts of solar and certain non-recurring costs incurred in the period.

Total Cash and Availability

As of December 31, 2018, the Trust had Total Cash and Availability of $37.9 million consisting of cash and cash equivalents of $16.7 million and $21.2 million of availability under the Credit Facility. This compares to the Total Cash and Availability as at December 31, 2017 of $49.4 million, consisting of cash and cash equivalents of $18.2 million and $31.2 million of availability under the legacy credit facilities, with the reduction over 2018 being attributable to the settlement of the legal reserve matters, non-recurring costs incurred in the year, and the negative contribution from the solar business.

Working Capital

The table below shows the calculation of certain working capital metrics based on the Trust's consolidated balance sheet as prepared under IFRS:

Adjusted Working Capital
(in millions)

	As at December 31, 2018	As at December 31, 2017
Current assets	$255.7	$227.7
Current liabilities	274.8	236.5
Working capital	**$(19.1)**	**$(8.8)**
Adjusted to exclude:		
Other current financial assets	(15.8)	(19.4)
Adjusted Working Capital	**$(34.9)**	**$(28.1)**
Adjusted to exclude:		
Credit facility	77.2	55.6
Cash and cash equivalents	(16.7)	(18.2)
Net debt (current portion)	60.5	37.4
Adjusted Working Capital excluding net debt	**$25.6**	**$9.3**

As of December 31, 2018, the Trust had a working capital balance of negative $19.1 million, compared to negative $8.8 million in the prior comparable period, with the change impacted by $21.6 million increase in the Credit Facility usage, offset by a positive impact of $15.8 million related to the implementation of the new IFRS-15 accounting standard in 2018, which resulted in the recognition of net current assets primarily related to deferred contract initiation and fulfillment costs that are capitalized and amortized over the customer relationship period.

Working capital includes the impact of other current financial assets and liabilities, which relate to certain mark-to-market positions on derivative instruments outstanding at the end of the reporting period. These gains and losses represent non-cash gains and losses associated with mark-to-market movements on forward hedge positions that are outstanding at period end. These hedges are put in place to hedge either the fixed price exposure of customers on fixed price contracts, the expected short-term exposure of variable priced customers, or the impacts of currency movements on the Trust's distributions, thereby minimizing the impact of these unrealized mark-to-market gains and losses. By way of further clarification, a mark-to-market asset or liability is realized over time together with an equal and offsetting underlying customer position, with the end result being there is no net impact from a liquidity or cash flow perspective. For this reason, Management calculates Adjusted Working Capital, defined as current assets less current liabilities, excluding unrealized gains and losses on derivatives, and Adjusted Working Capital less net debt, which is Adjusted Working Capital adjusted to exclude debt and cash and equivalents, as alternative non-IFRS measures to assess the working capital position of the Company from a liquidity and cash flow perspective.

Adjusted Working Capital as of December 31, 2018 was negative $25.6 million compared to negative $9.3 million as at December 31, 2017. The negative working capital and Adjusted Working Capital as at December 31, 2018 is impacted by the increased usage on the credit facility of $77.2 million. The credit facility is a revolving facility and although the balance is classified in current liabilities, the outstanding balance is not due for repayment during the term of the facility provided the Company remains in compliance with its terms and covenants. As at December 31, 2018, Adjusted Working Capital excluding net debt is $25.6 million, compared to $9.3 million as of December 31, 2017.

Contractual Obligations

In the normal course of business, the Company is obligated to make future payments under various non-cancellable contracts and other commitments. As at December 31, 2018, the payments due by period are set forth in the following table and the Company expects to be able to fund such amounts from cash flows provided by operations during the corresponding periods, as well as cash and availability under the Company's Credit Facility:

Contractual Obligations (in millions)	**Contractual cash flow**	**Less than 1 year**	**1 to 5 years**	**More than 5 years**
Trade and other payables	$229.4	$199.0	$30.5	$—
Operating leases	16.8	2.5	10.3	4.0
Financing leases	1.4	1.0	0.4	—
Credit facility	77.2	77.2	—	—
Distribution payable	3.0	3.0	—	—
Other non-current liabilities	10.1	—	9.4	0.7
Term loan payable	50.7	0.1	4.3	46.2
	$388.6	**$282.8**	**$54.9**	**$50.9**

Outstanding Unit Data

As at December 31, 2018, the Trust had the following securities outstanding: (i) 56,605,607 Units; (ii) 750,000 Warrants (which were issued to Macquarie Energy in February 2014); and (iii) 126,129 Deferred Trust Units (which were issued under the Deferred Trust Unit Plan of the Trust to non-executive directors of the Administrator as a component of their annual compensation). All of the 750,000 Warrants outstanding are vested and have a strike price of C$6.23 per Unit over a five-year term and expired on February 6, 2019.

During the period commencing March 29, 2018 and ending on March 28, 2019, the Company had approval to make a normal course issuer bid to purchase up to 4,425,557 Units, representing approximately 8% of the then issued and outstanding Units. Purchase of Units may be made through the facilities of the TSX in accordance with its rules or alternative Canadian trading platforms. Daily limits were limited to 45,312 Units, other than block purchase exceptions. The price that the Trust will pay for any Units purchased under the bid will be the prevailing market price at the time of purchase and any Units purchased by the Trust will be cancelled. For the year ended December 31, 2018, the Company purchased 449,445 Units at an average price of C$7.23 per Unit, for total proceeds of approximately $2.5 million.

Financial Instruments and Risk Management

Overview

The Trust's operations are affected by a number of underlying risks, both internal and external to the Trust. The Trust's financial position, results of operations and cash distributions are directly impacted by these factors. A description of the operational and business risks is set out in the annual information form of the Trust for the fiscal year ended December 31, 2018, dated March 14, 2019, which is available on SEDAR under the Trust's issuer profile at www.sedar.com and on the Trust's website at www.criusenergytrust.ca. The Trust's activities expose it to a variety of financial risks that arise as a result of its operating, investing, and financing activities, including:

- market risk, including commodity risk, interest rate risk and foreign currency risk;
- credit risk, including customer credit risk and counterparty credit risk;
- liquidity risk; and
- supplier risk.

This part of the MD&A sets out information about the Trust's exposure to each of the above-noted risks, the Trust's objectives, policies and processes for measuring and managing such risks, and the Trust's management of capital. Further quantitative disclosures are included throughout the Trust's consolidated financial statements.

Market Risk

Market risk is the potential loss that may be incurred as a result of changes in the market or fair value of a particular instrument or commodity. Components of market risk to which the Trust is exposed are discussed below.

Commodity risk

The Company has entered into contracts with customers to provide electricity or natural gas at variable or fixed prices. Fixed-price contracts expose the Company to changes in market prices of electricity and natural gas, as the Company is obligated to purchase electricity and natural gas at floating wholesale market prices for delivery to its customers. The Trust is, therefore, exposed to market risks associated with commodity prices and market volatility where estimated customer requirements do not match actual customer requirements. Management actively monitors these positions on a daily basis in accordance with the Company's risk management policies (the "**Risk Management Policies**"). The Risk Management Policies prohibits speculative positions and set out a variety of hedging limits, most importantly a target of maintaining a 100% hedged position, within certain tolerance bands, at all times for fixed-price contracts exposure in our electricity and natural gas portfolios. The Trust's exposure to commodity risk is affected by a number of factors, including the accuracy of estimation of customer commodity requirements, commodity prices, and market volatility and liquidity.

Electricity and natural gas derivatives

To reduce its exposure to short-term and long-term movements in commodity prices, arising from the procurement of electricity and natural gas at floating prices, the Company uses derivative instruments. These derivative instruments are principally physical forward contracts and fixed-for-floating swaps, whereby the Company agrees with a counterparty, through the Credit Facility, to take physical delivery or cash settle the difference between the floating price and the fixed price on a notional quantity of electricity or natural gas, for a specified timeframe at a specified location. The cash flow from these instruments is expected to be effective in offsetting the Company's price exposure and serves to fix the Company's wholesale cost of electricity or natural gas to be delivered to the customer. The Company remains subject to commodity risk for any volumetric differences between the actual quantities used by customers and the forecasted quantities upon which the commodity hedging instruments are based.

Realized swap settlements under derivative instruments are included in cost of sales in the Trust's consolidated statements of comprehensive income. Unrealized gains or losses resulting from changes in the fair value of the derivative instruments, generally referred to as mark-to-market gains or losses, have been recognized as the change in fair value on derivative instruments in the consolidated statements of comprehensive income.

The fair value of derivative financial instruments is the estimated amount that the Company would pay or receive to dispose of these derivative instruments in the market in the unlikely event that the Company was required to dispose of its derivative instruments. The Company has estimated the value of its derivative instruments using market-based, forward wholesale price curves wherever available.

As at December 31, 2018, the Company had electricity and natural gas derivative instruments outstanding with the following terms:

	Notional Volume	Total Remaining Volume	Maturity Date (months)	Fixed Price ($)	Fair Value ($ millions)	Notional Value ($ millions)
Fixed-for-floating electricity swaps	(20) – 100 MW	7,066,115 MWh	1 – 48	$23.49 to $68.10	$11.5	$359.0
Fixed-for-floating natural gas swaps	(1,786) – 4,100 MMBtu	7,188,639 MMBtu	1 – 28	$2.57 to $4.52	($0.9)	$27.3
Physical electric forward contracts	1 – 20 MW	2,661,385 MWh	1 – 40	$17.56 to $50.00	$5.4	$94.4
Physical natural gas forward contracts	(2,476) – 8,627 MMBtu	1,791,341 MMBtu	1 – 1	$(0.40) to $8.25	($0.2)	$8.1
Fixed-for-floating natural gas basis swaps	(2,500) – 2,500 MMBtu	– MMBtu	1 – 22	$(0.52) to $3.44	$0.1	$1.1
Electricity capacity contracts	4 – 21 MW	124,000 MWh	1 – 5	$0.67 to $3.17	$—	$0.2
Financial transmission rights	0 – 59 MW	193,827 MWh	1 – 5	$(1.52) to $7.54	($0.1)	$0.4

The fair value of electricity and natural gas financial instruments is significantly influenced by the variability of forward commodity prices. Periodic changes in forward prices could cause significant changes in the mark-to-market valuation of these financial instruments. For example, assuming that all other variables remain constant, a market move of +/-10% would result in an increase / (decrease) in net income and total comprehensive income of $39.5 million but would not impact Adjusted EBITDA or Distributable Cash.

Interest rate risk

The Trust is exposed to interest rate risk on certain advances within the Company's Credit Facility. As at December 31, 2018, the Trust has cash advances outstanding of $77.2 million, under its Credit Facility and, therefore, is exposed to interest rate risk. The Trust's current exposure to interest rate risk does not economically warrant the use of derivative instruments. In the year ended December 31, 2018, the impact of a 1.0% increase (decrease) in the interest rate on these balances would not have had a material impact on finance costs in the statement of comprehensive income.

Foreign currency risk

The Trust is exposed to currency rate risk in that its business operations are conducted in U.S. dollars; however, its distributions and publicly listed Units are denominated in Canadian dollars. The Company's policy is to mitigate its economic exposure to currency rate movements by entering into currency derivative products including options and swaps. Period to period changes in forward currency prices could cause significant changes in the mark to market valuation of these contracts. For example, assuming that all other variables remain constant, a market move of +/-10% would result in increase/(decrease) in net income of $0.9 million and $(0.1) million, respectively, for the year ended December 31, 2018.

Currency derivatives

The Trust's policy is to mitigate its exposure to currency rate movements by entering into currency derivative products, including foreign currency options whereby the Company agrees with a counterparty to have the right to swap the floating price for a fixed price on a notional quantity of currency at or over a specified timeframe. The Trust maintains a rolling hedging program for this foreign currency exposure of at least 12 forward months, which may be extended on a quarterly basis.

As at December 31, 2018, the Trust was hedged for its currency exposure to December 31, 2019 with a foreign exchange option of C$1.25 per US$1.00, based on approximately the current level of future distributions.

As at December 31, 2018, the Company had foreign currency derivatives outstanding with the following terms:

	Notional Value (millions)	Maturity Date (months)	Fixed Price	Fair Value (millions)
Foreign exchange options	US$37.4 C$46.8	1-12	C$1.25 per US$1	US$0.1

Realized settlements under derivative instruments are included in the relevant section of the consolidated statements of comprehensive income or consolidated balance sheet. Unrealized gains or losses resulting from changes in the fair value of the derivatives, generally referred to as mark-to-market gains or losses, have been recognized as the change in fair value on derivative instruments in the consolidated statements of comprehensive income.

The fair value of derivative financial instruments is the estimated amount that the Company would pay or receive to dispose of these derivative instruments in the market in the unlikely event that the Company was required to dispose of its derivative instruments. The Company has estimated the value of derivative instruments using market-based prices and option valuation methods.

Period to period changes in forward currency prices could cause significant changes in the mark-to-market valuation of these hedge contracts. For example, assuming that all other variables remain constant, a market move in C$ to US$ of +/-10% would result in increase (decrease) in net income of $0.9 million and $(0.1) million, respectively, but would not impact Adjusted EBITDA or Distributable Cash.

Credit risk

Credit risk is the risk that one party to a financial instrument fails to discharge an obligation and causes financial loss to another party. The Trust is exposed to credit risk in two specific areas: customer credit risk and counterparty credit risk.

Customer credit risk

In certain markets in which the Company serves electricity and natural gas customers, LDCs provide collection services and assume the risk of any bad debts owing from the Company's customers for a fee, which is referred to as a POR fee. Management believes that the risk of the LDCs failing to deliver payment to the Company is minimal; however, there is no assurance that the LDCs that provide these services will continue to do so in the future.

In certain other markets in which the Company operates, the Company is exposed directly to customer credit risk. As a result, credit review and other processes have been implemented to perform credit evaluations of customers and manage customer defaults. Customer credit risk exposure represents the risk related to the Company's accounts receivable from certain markets. If a significant number of customers in these markets were to default on their payments, it could have an adverse effect on the operations and cash flows of the Company.

As at December 31, 2018, the customer credit risk exposure was in the amount of $12.6 million, and the accounts receivable aging for these markets are as follows:

	Total	Current	30-59 days	Over 60 days
Accounts receivable	$12.6	$10.9	$0.6	$1.1

Counterparty credit risk

Counterparty credit risk represents the loss that the Trust would incur if a counterparty fails to perform its contractual obligations. This risk would manifest itself in the Trust replacing the contracted commodities or currencies at prevailing market rates, thus impacting the related financial results. Counterparty risk relating to the Company's derivative financial assets with its counterparties for commodity, currency and other derivatives amounted to $15.8 million as at December 31, 2018 compared to $19.4 million for the year ended December 31, 2017. The Trust is also exposed to counterparty credit risk on certain loans and other receivables totaling $10.9 million, owed to it by Viridian International, Path One Group, Brighton & Leeds Utility Holdings Limited and Toto Energy Limited. The amounts due from Viridian International and Path One are fully reserved for, based on the Company's current understanding and assessment of Viridian International's and Path One's respective abilities to pay. The failure of a counterparty to meet its contracted obligations could have a material adverse effect on the operations and cash flows of the Trust.

Liquidity risk

Liquidity risk is the potential inability to meet financial obligations as they fall due. The Trust manages this risk by monitoring near-term and long-term cash flow forecasts to ensure adequate and efficient use of cash resources and the Credit Facility.

The table in the section entitled *"Contractual Obligations"* of this MD&A outlines the contractual maturities of the Trust's financial liabilities as at December 31, 2018.

Supplier risk

The Company purchases the energy it delivers to its customers through contracts primarily entered into with Macquarie Energy. This exposes the Company to supplier risk, as its ability to continue to deliver energy to its customers depends upon the ongoing operations of this supplier and its fulfillment of its contractual obligations.

Off-Balance Sheet Arrangements

Pursuant to its Credit Facility and legacy facilities, the Company has issued letters of credit as at December 31, 2018 and December 31, 2017 totaling $11.6 million and $17.5 million respectively, to various counterparties, principally LDCs.

Pursuant to separate arrangements with various insurance companies, the Company has issued surety bonds to various counterparties, including U.S. states, regulatory bodies and LDCs in return for a fee and/or meeting certain collateral posting requirements. Such surety bond postings are required in order to operate in certain U.S. states or markets. Surety bonds issued as at December 31, 2018 and December 31, 2017 totaled $30.3 million and $40.7 million, respectively.

We are not aware of any event, commitment, trend or uncertainty that would impact our ability to continue using these arrangements.

Transactions Between Related Parties

Certain transactions between the Trust and its subsidiaries meet the definition of related party transactions, including intercompany notes and administrative service fees between the Trust and its subsidiaries. These transactions are eliminated on consolidation and are not disclosed in the Trust's consolidated financial statements.

All related party transactions are in the normal course of operations and have been measured at the agreed to exchange amounts, which are the amounts of consideration established and agreed to by the related parties.

Discussion of Fourth Quarter 2018 Operations
For the three month period ended December 31, 2018 and December 31, 2017

Revenue

For the three month period ended December 31, 2018, revenue was $284.8 million, representing an increase of 14.6% from $248.5 million for the three month period ended December 31, 2017, driven by increased customer usage and higher average customer retail rates.

Electricity

Electricity revenue for the three month period ended December 31, 2018 was $246.6 million, representing an increase of 15.9% from $212.8 million for the three month period ended December 31, 2017, primarily as a result of a 10.5% increase in volume and a 4.9% higher average retail rate per unit. Electricity volumes for the three month period ended December 31, 2018 were 2,419,000 MWh, representing an increase of 10.5% from 2,189,000 MWh for the three month period ended December 31, 2017.

Natural Gas

Natural gas revenue for the three month period ended December 31, 2018 was $35.3 million, representing an increase of 5.9% from $33.3 million for the three month period ended December 31, 2017, primarily as a result of a 4.0% higher average retail rate per unit and a 1.8% increase in volume. Natural gas volumes for the three month period ended December 31, 2018 were 5,212,000 MMBtu, representing an increase of 1.8% from 5,120,000 MMBtu for the three month period ended December 31, 2017.

Solar Revenue

Solar revenue for the three month period ended December 31, 2018 was $2.9 million, representing an increase from revenues of $2.4 million for the three month period ended December 31, 2017.

Gross Margin

For the three month period ended December 31, 2018, gross margin was $54.0 million, representing a decrease of 1.5% from $54.8 million for the three month period ended December 31, 2017. Gross margin for the three month period ended December 31, 2018 was 19.0% of total revenue, a decrease from 22.1% of total revenue for the three month period ended December 31, 2017.

The period-over-period decrease in gross margin and gross margin as a percentage of revenue was driven by the negative impact on our municipal aggregation portfolio of certain regulatory changes which resulted in significant incremental wholesale cost factors in New Jersey and Massachusetts, namely RTEP and RPS costs, which the Company was not able to fully pass through to customers as a result of how the customer contracts are structured.

Electricity

Electricity gross margin for the three month period ended December 31, 2018 was $38.7 million, representing a decrease of 5.7% from $41.1 million for the three month period ended December 31, 2017. For the three month period ended December 31, 2018, electricity gross margin per unit was $16.00/MWh, and electricity gross margin was 15.7% of electricity revenues, representing a decrease from $18.76/MWh and 19.3%, respectively, for the three month period ended December 31, 2017. Gross margins and gross margins per unit variances compared to the prior comparable quarter, were impacted by the increased mix of commercial and municipal aggregation customers in the portfolio, including the commencement of service of a large municipal aggregation in Massachusetts in January 2018. Specifically, gross margins in the fourth quarter were negatively impacted by our municipal aggregation portfolio, which Crius intends to run-off, as regulatory changes resulted in significant incremental wholesale cost factors in New Jersey and Massachusetts, namely RTEP and RPS costs, which the Company was not able to fully pass through to customers as a result of how the customer contracts are structured.

Natural Gas

Natural gas gross margin for the three month period ended December 31, 2018 was $14.5 million, representing a 0.8% increase from $14.4 million for the three month period ended December 31, 2017. For the three month period ended December 31, 2018, natural gas gross margin per unit was $2.79/MMBtu, and natural gas gross margin accounted for 41.2% of natural gas revenues, representing decreases from $2.82/MMBtu and 43.3%, respectively, for the three month period ended December 31, 2017.

Solar

Solar gross margin for the three month period ended December 31, 2018 was $0.8 million compared to negative $0.7 million for the three month period ended December 31, 2017.

Selling Expenses

For the three month period ended December 31, 2018, selling expenses were $13.0 million, representing an increase from $11.2 million for the three month period ended December 31, 2017, with the increase attributable to the channel mix of new sales in the fourth quarter, offset by the accounting benefit of the new IFRS-15 accounting standard. Selling expenses for the three month period ended December 31, 2018 amounted to 4.6% of revenue compared to 4.5% for the three month period ended December 31, 2017. These expenses consist of:

(i) Deregulated energy selling costs for the three month period ended December 31, 2018 of $12.8 million (amounting to 4.5% of deregulated energy revenues), representing an increase from $10.4 million for the three month period ended December 31, 2017 (amounting to 4.2% of deregulated energy revenues). Deregulated energy selling costs were higher in the third quarter of 2018 primarily due to the channel mix of sales being impacted by the residential focused direct-to-consumer channels, which are associated with higher selling costs. Additionally, accounting changes resulted in a net $2.2 million reduction to selling costs in the fourth quarter as compared to the prior comparable quarter, due to the deferral of certain upfront selling costs pursuant to the implementation of the new IFRS-15 accounting standard in 2018.

(ii) Solar selling expenses for the three month period ended December 31, 2018 of $0.2 million, representing a decrease from $0.8 million for the three month period ended December 31, 2017.

General and Administrative Expenses

General and administrative expenses for the three month period ended December 31, 2018 were $21.9 million, compared to $26.0 million for the three month period ended December 31, 2017. The period-over-period reduction in G&A expenses consisted of a $7.2 million decrease in fixed costs due to the cost-synergies achieved and realized, partially offset by a $0.5 million increase in variable costs as a result of higher revenues in the fourth quarter and a $2.2 million increase in solar and non-operating costs impacted by one-time restructuring charges incurred in the fourth quarter related to the achievement of cost-synergies and the exit from the solar business.

General and Administrative Expenses
(in $ millions and % of revenue)

	Quarter ended December 31, 2018		Quarter ended December 31, 2017	
	$	%	$	%
Variable Costs				
POR fees / bad debt	$4.5	1.6%	$3.1	1.2%
Gross receipts taxes and other taxes	2.8	1.0%	3.6	1.5%
Total Variable Costs	**7.3**	**2.6%**	**6.7**	**2.7%**
Fixed Costs				
Processing costs	0.3	0.1%	1.7	0.7%
Human resources	6.7	2.4%	9.0	5.0%
Professional and consultant fees	0.2	0.1%	1.1	0.4%
Legal and regulatory	0.8	0.3%	0.6	0.2%
Other fixed costs	2.6	0.9%	5.2	2.1%
Total Fixed Costs	**10.6**	**3.8%**	**17.6**	**8.4%**
Solar & Non-operating Costs				
Solar operating expenses	2.0	0.7%	1.3	0.5%
Legal reserve and associated legal fees	—	—%	0.4	0.1%
Other costs	1.9	0.7%	—	—%
Total Other Costs	**3.9**	**1.4%**	**1.7**	**0.6%**
Grand Total	**$21.8**	**7.7%**	**$26.0**	**10.5%**

General and administrative expenses incurred during the three month ended December 31, 2018 were made up of the following categories:

Variable Costs

Variable costs, consisting of expenses directly driven by revenues, were $7.3 million for the three month period ended December 31, 2018, representing 2.6% of revenues. Variable costs were $6.7 million for the three month period ended December 31, 2017, representing 2.7% of revenues.

(a) The POR fees/bad debt costs for the three month period ended December 31, 2018 were $4.5 million, representing 1.6% of revenue, compared to $3.1 million for the three month period ended December 31, 2017, representing 1.2% of revenue for that period.

(b) Gross receipts taxes and other taxes for the three month period ended December 31, 2018 amounted to $2.8 million, representing 1.0% of revenue, compared to $3.7 million, incurred in the prior comparable period in 2017, representing 1.5% of revenue.

Fixed Costs

Fixed costs, consisting of operating expenses not directly driven by revenues, were $10.6 million for the three month period ended December 31, 2018, representing 3.8% of revenues. Fixed costs were $17.6 million for the three month period ended December 31, 2017, representing 8.4% of revenues. Decreased fixed costs were attributable to the cost-synergies achieved and realized during the period associated with the integration of the USG&E acquisition and cost-reduction initiatives.

(c) Processing costs for the three month period ended December 31, 2018 of $0.3 million include various data processing and information technology costs incurred to service our customers and sales force. This compares to $1.7 million for the three month period ended December 31, 2017.

(d) Human resource costs for the three month period ended December 31, 2018 of $6.7 million, consist of costs incurred in relation to the Company's employee base, temporary staff and independent contractors compared to costs in the prior comparable period in 2017 of $9.0 million, with the decrease attributable to the headcount reductions associated with the integration of the acquisition of USG&E and cost-reduction initiatives.

(e) Professional and consultant fees for the three month period ended December 31, 2018 amounted to $0.2 million, compared to $1.1 million incurred in the prior comparable period in 2017.

(f) Legal and regulatory costs for the three month period ended December 31, 2018 amounted to $0.8 million compared with $0.6 million in costs incurred in the prior comparable period in 2017.

(g) Other costs for the three month period ended December 31, 2018 amounted to $2.6 million compared with $5.3 million in the prior comparable period in 2017, with the decrease attributable to cost-synergies achieved with respect to the integration of the acquisition of USG&E and cost-reduction initiatives.

Solar and Non-Operating Costs

(h) Solar operating expenses for three month period ended December 31, 2018 amounted to $2.0 million compared with $1.3 million in the prior comparable period in 2017, and were impacted by one-time costs of $0.8 million associated with the wind-down of the solar business.

(i) No legal reserve and associated legal fees were incurred by the Company for the three month period ended December 31, 2018, compared to $0.4 million, in the prior comparable period in 2017. The charges incurred in the prior comparable quarter were excluded from Adjusted EBITDA and Distributable Cash.

(j) Other costs for the three month period ended December 31, 2018 of $1.9 million represent certain non-recurring costs primarily related to restructuring charges, such as employee severance, associated with workforce rationalizations. There were no other costs in the prior comparable period.

Unit-Based Compensation

For the three month period ended December 31, 2018, unit-based compensation expense amounted to $0.0 million representing a decrease from $0.1 million for the three month period ended December 31, 2017. The expense reflects the fair value of the unit-based compensation based on the vesting schedule, applicable performance expectations and the market price of the Units at the end of the period and the applicable vesting period.

Depreciation and Amortization

Depreciation and amortization for the three month period ended December 31, 2018 was $12.8 million, representing an increase from $12.0 million for the three month period ended December 31, 2017.

Finance Costs

Finance costs for the three month period ended December 31, 2018 were $5.4 million, representing an increase from $5.2 million for the three month period ended December 31, 2017.

Change in Fair Value of Derivative Instruments

For the three month period ended December 31, 2018, the changes in unrealized gains or losses associated with derivative contracts were net gains of $0.1 million compared to net gains of $32.2 million for the three month period ended December 31, 2017.

Change in Fair Value of Derivative Instruments
(in millions)

	Quarter Ended December 31, 2018	Quarter Ended December 31, 2017
Forward electricity positions	$1.7	$35.0
Forward natural gas positions	(1.0)	(2.1)
Weather derivative positions	0.0	0.1
Forward currency positions	(0.5)	(0.7)
Change in fair value of derivative instruments	**$0.1**	**$32.3**

Change in Fair Value of Warrants

The change in fair value of warrant liability for the three month period ended December 31, 2018 was a gain of $0.2 million compared to a gain of $0.3 million for the three month period ended December 31, 2017. These gains and losses represent the mark-to-market valuation of the 750,000 Warrants issued to Macquarie Energy in connection with the legacy supplier agreement. The valuation of these Warrants is based on an option valuation model, and accordingly the non-cash gains and losses are the result of changes in the Unit price, volatility, yield, time to maturity and the risk-free rate over the period.

(Benefit from) Provision for Income Taxes

For the three month period ended December 31, 2018, the Trust recorded a benefit from income taxes of $0.4 million (consisting of $0.5 million in current tax expense and $0.9 million in deferred tax benefit) and for the three month period ended December 31, 2017, the Trust recorded a benefit from income taxes of $3.2 million (consisting of $0.3 million in current tax benefit and $2.9 million in deferred tax benefit). The Trust's (benefit from) provision for income taxes relates to the Trust's U.S. subsidiaries. Deferred tax assets are recognized to the extent that the Trust believes that the likelihood of recognition is probable.

Net Income

For the three month period ended December 31, 2018, net income was $1.7 million, compared to net income of $36.0 million for the three month period ended December 31, 2017, with the changes being attributable to the factors noted above. Net income is impacted by numerous non-cash items, some being a result of the industry in which they operate. Accordingly, Management believes the additional non-IFRS financial measures of Adjusted EBITDA and Distributable Cash are useful metrics to be considered together with net income for evaluating the Trust's financial and operating performance, as they are measures that Management uses internally to assess performance.

Critical Accounting Estimates

The preparation of these consolidated financial statements requires the use of judgments, estimates and assumptions to be made in applying accounting policies that affect the reported amounts of assets and liabilities and disclosure of contingent liabilities, at the date of the consolidated financial statements, and the reported income and expenses during the reporting period.

Judgment is commonly used in determining whether a balance or transaction should be recognized in the consolidated financial statements and estimates and assumptions are more commonly used in determining the measurement of recognized transactions and balances. However, judgment and estimates are often interrelated. As the basis for its judgments, Management uses estimates and related assumptions which are based on previous experience and various commercial, economic and other factors that are considered reasonable under the circumstances. These estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimate is revised. Actual outcomes may differ from these estimates under different assumptions and conditions.

Judgments, made by Management in the application of IFRS that have a significant impact on the consolidated financial statements relate to the following:

Revenue recognition

Accounts receivable includes an unbilled receivables component, representing the amount of energy consumed by customers as at the end of the period but not yet billed. Unbilled receivables are estimated by the Company using usage data available, multiplied by the current customer average sales price per unit.

Allowance for expected credit losses

The Company reviews its financial assets not recorded at fair value through the P&L at each reporting date to assess an appropriate allowance for expected credit losses to reflect management's best estimate of losses. In particular, judgment by management is required in the estimation of the amount and timing of collectability of payments, based on financial conditions, the aging of the receivables, customer and industry concentrations, the current business environment, historical loss experience and forward looking factors, if applicable.

Fair value of financial instruments

Determining the fair value of financial instruments requires judgment and is based on market prices or Management's best estimates if there is no market and/or if the market is illiquid. Where the fair value of financial instruments recorded cannot be derived from active markets, they are determined using valuation techniques including making internally generated adjustments to quoted prices in observable markets. The inputs to these models are taken from observable markets where possible, but where this is not feasible, a degree of judgment is required in establishing fair values. The judgment includes consideration of inputs such as liquidity risk, credit risk and volatility of the underlying commodity price. Changes in assumptions about these factors could affect the reported fair value of financial instruments.

Impairment of intangible or non-financial assets

In assessing the recoverable amount of intangible assets or non-financial assets for potential impairment, the Company evaluates value in use and fair value less costs of disposal. In doing so, the Company's market capitalization is considered, as well as recent market transactions or other market indicators, future cash flows, including the discount rate to be used to calculate the present value of those cash flows. These calculations require the use of estimates. If these estimates change in the future, the Company may be required to record impairment charges related to intangible or other non-financial assets.

Deferred taxes

Significant Management judgment is required to determine the amount of deferred tax assets that can be recognized, based upon the likely timing and the level of future taxable income realized, including the usage of tax-planning strategies.

Useful life of property and equipment and intangible assets

The amortization method and useful lives reflect the pattern in which Management expects the asset's future economic benefits to be consumed by the Company, including customer attrition rates.

Acquisition accounting

Management uses judgment to determine whether an acquisition meets the criteria of an asset acquisition or a business combination by reviewing inputs, processes, and outputs within a transaction. All identifiable assets, liabilities and contingent liabilities acquired in an asset acquisition or business combination are recognized at fair value on the date of acquisition. Estimates are used to calculate the fair value of these assets and liabilities as at the date of acquisition.

Classification of Trust Units as equity

Units issued by the Trust give the holder the right to put the Units back to the Trust in exchange for cash. IAS 32 *Financial Instruments: Presentation* establishes the general principle that an instrument which gives the holder the right to put the instrument back to the issuer for cash should be classified as a financial liability, unless such instrument has all of the features and meets the conditions of the IAS 32 "puttable instrument exemption". If these "puttable instrument exemption" criteria are met, the instrument is classified as equity. The Trust has examined the terms and conditions of its Trust Indenture and classifies its outstanding Units as equity because the Units meet the "puttable instrument exemption" criteria as there is no contractual obligation to distribute cash.

Legal Contingencies

Reserves are established for such legal and regulatory claims based upon the probability and estimability of losses and to fairly present, in conjunction with the disclosures of these matters in the Company's financial statements and Management's view of the Company's exposure. The Company continuously reviews outstanding claims with internal as well as external counsel to assess probability and estimates of loss. The risk of loss is reassessed as new information becomes available and any such reserves are adjusted, as appropriate. The actual cost of resolving a claim may be substantially higher, or lower, than the amount of the recorded reserve.

New Standards and Accounting Policies Adopted

The consolidated financial statements have been prepared following the same accounting policies as those that were followed in the preparation of the Trust's prior year consolidated financial statements, with the exception of the following new standards:

IFRS 15, *Revenue from Contracts with Customers,* was released in May 2014 which focuses on a principles based five-step model which is required to be applied to all contracts with customers. The guidance amongst other things provides for (i) whether revenue should be recognized at a point in time or over time, which replaces the previous distinction between goods and services, (ii) identifies distinct performance obligations, accounting for contract modifications and accounting for the time value of money and (iii) new, increased requirements for disclosure of revenue in the financial statements. Furthermore, the standard specifies how to account for incremental costs of obtaining a contract and the costs directly associated with fulfilling a contract. Provided these costs are expected to be recovered, such costs will be capitalized, subsequently amortized over the useful life of customers and tested for impairment. IFRS 15 is effective for financial statements for periods beginning on or after January 1, 2018. The Company transitioned to IFRS 15 using the modified retrospective approach. The impact of the new revenue standard, as amended, on its financial statements and related disclosures, is as follows. The new standard did not impact revenue recognition for the electricity and gas business. Revenue recognized for the solar installation business under Verengo continues to be an over-time revenue recognition model, as the installation work is completed, but changed from the milestone method previously used to a cost-based input method upon the adoption of IFRS 15. Revenue recognized for Crius Energy's solar business continues to be the point in time revenue recognition model, as the installation work is completed, but accelerates the amounts recognized as revenue and expenses upon completion from 80% to 100%, based upon fulfilling the performance obligation at this point. This change did not have a material impact to the Company's financial statements. Upon the adoption of IFRS 15, the Company's accounting for direct incremental costs of obtaining customer contracts (for example, upfront selling expenses and fees paid for new customer origination) and direct fulfillment costs changed. Under the new standard, such direct incremental costs, which were previously being expensed as incurred, are required to be deferred and amortized. The overall impact of the adoption of IFRS 15 was an increase to Unitholders' equity of $9.2 million.

In July 2014, the IASB issued the final version of IFRS 9, *Financial Instruments,* bringing together the classification and measurement, impairment, and hedge accounting phases of the IASB's project to replace IAS 39, Financial Instruments: Recognition and Measurement. This version adds a new expected loss impairment model and limited amendments to classification and measurement for financial assets. The standard supersedes all previous versions of IFRS 9 and is effective for annual periods beginning on or after January1, 2018, however, it did not have a material impact on the Company's consolidated financial statements.

The IASB issued amendments to IFRS 2, *Share-based Payment,* that address three main areas: the effects of vesting conditions on the measurement of a cash-settled share-based payment transaction; the classification of a share-based payment transaction with net settlement features for withholding tax obligations; and accounting where a modification to the terms and conditions of a share-based payment transaction changes its classification from cash settled to equity settled. On adoption, entities are required to apply the amendments without restating prior periods, but retrospective application is permitted if elected for all three amendments and other criteria are met. These amendments are effective for annual periods beginning on or after January 1, 2018, however, they did not have a material impact on the Company's consolidated financial statements.

IFRIC 22, *Foreign Currency Transactions and Advance Consideration,* was issued by the IASB in December 2016. This interpretation provides guidance where (i) there is consideration that is denominated or priced in a foreign currency; (ii) an entity recognizes a prepayment or a deferred liability in respect of that consideration in advance of recognition of the related asset; and (iii) where the prepayment asset or deferred income liability is non-monetary. The interpretation is effective for annual periods beginning on or after January 1, 2018, however, it did not have a material impact on the Company's consolidated financial statements.

Future Accounting Pronouncements

Recent accounting pronouncements that are issued but not yet effective up to the date of issuance of the Company's consolidated financial statements are listed below.

IFRS 16 *Leases* was issued by the IASB in January 2016. This guidance brings most leases onto the balance sheet for lessees under a single model, eliminating the distinction between operating and finance leases. Lessor accounting remains largely unchanged and the distinction between operating and finance leases is retained. Furthermore, per the standard, a lessee recognizes a right-of-use asset and a lease liability. The right-of-use asset is treated similarly to other non-financial assets and depreciated accordingly, and the liability accrues interest. The lease liability is initially measured at the present value of the lease payments payable over the lease term, discounted at the rate implicit in the lease. Lessees are permitted to make an accounting policy election, by class of underlying asset, to apply a method like IAS 17's operating lease accounting and not recognize lease assets and lease liabilities for leases with a lease term of 12 months or less, and on a lease-by-lease basis, to apply a method similar to current operating lease accounting to leases for which the underlying asset is of low value. IFRS 16 supersedes IAS 17 *Leases* and related interpretations, and is effective for periods beginning on or after January 1, 2019. The Company will transition using the modified retrospective approach and will not restate comparative amounts for the year prior to first adoption. Right-of-use assets for all leases will be measured on transition as if the new rules had always been applied. The Company has evaluated the impact of the new leasing standard on its financial statements and related disclosures, and believes the adoption of the new standard will primarily affect the accounting for the Company's operating leases. For leases other than those classified as short-term or low-value the Company expects to recognize right-of-use assets in the range of $9.0 million to $11.0 million on January 1, 2019, lease liabilities in the range of $13.0 million to $15.0 million (after adjustments for prepayments and accrued lease payments recognized as at December 31, 2018) and deferred rent liability of approximately $3.0 million. Overall net assets will be approximately $1.0 million lower. Additionally, the Company will incur decreased rent expense, increased depreciation charges and increased interest expense as a result of the implementation of IFRS 16.

IFRIC 23 *Uncertainty over Income Tax Treatments* was issued by the IASB in June 2017. This interpretation provides guidance to be applied in the determination of taxable profit or loss, tax bases, unused tax losses, unused tax credits and tax rates, when there is uncertainty over income tax treatments under IAS 12. The interpretation is effective for annual periods beginning on or after January 1, 2019. The interpretation is not expected to have a material impact on the consolidated financial statements of the Company.

Amendments to IFRS 9 *Financial Instruments*, were issued by the IASB in October 2017. The amendments clarify that a financial asset passes the solely payments of principal and interest criterion regardless of the event or circumstance that causes the early termination of the contract and irrespective of which party pays or receives reasonable compensation for the early termination of the contract. The amendments should be applied retrospectively and are effective from January 1, 2019. The amendments are not expected to have a material impact on the consolidated financial statements of the Company.

Amendments to IAS 12 *Income Taxes*, were issued by the IASB in December 2017. The amendments clarify that the income tax consequences of dividends are linked more directly to past transactions or events that generated distributable profits than to distributions to owners. Therefore, an entity recognizes the income tax consequences of dividends in profit or loss, other comprehensive income or equity according to where the entity originally recognized those past transactions or events. The amendments are effective for annual periods beginning on or after January 1, 2019. The Company will continue to assess the impact of this standard on the consolidated financial statements.

Amendments to IFRS 3 *Business Combinations*, were issued by the IASB in December 2017. The amendments clarify that: i) to be considered a business, an acquired set of activities and assets must include, at a minimum, an input and a substantive process that together significantly contribute to the ability to create outputs; ii) narrow the definitions of a business and of outputs by focusing on goods and services provided to customers and by removing the reference to an ability to reduce costs; iii) remove the assessment of whether market participants are capable of replacing any missing inputs or processes and continuing to produce outputs; and iv) add an optional concentration test that permits a simplified assessment of whether an acquired set of activities and assets is not a business. The amendments are effective for annual periods beginning on or after January 1, 2020, to asset acquisitions that occur on or after that date. The amendments are not expected to have a material impact on the consolidated financial statements of the Company.

Disclosure Controls and Procedures & Internal Controls over Financial Reporting

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the Trust is accumulated and communicated to Management of the Trust as appropriate to allow timely decisions regarding required disclosure.

The Chief Executive Officer and Chief Financial Officer of the Trust are responsible for establishing and maintaining disclosure controls and procedures ("**DC&P**") and internal control over financial reporting ("**ICFR**"), as those terms are defined in National Instrument 52-109 — *Certification of Disclosure in Issuers' Annual and Interim Filings* ("**NI 52-109**").

The Chief Executive Officer and Chief Financial Officer of the Trust have concluded that, as at December 31, 2018, the Trust's DC&P have been designed and operate effectively to provide reasonable assurance that (i) material information relating to the Trust is made known to them by others, particularly during the period in which the annual filings are being prepared, and (ii) information required to be disclosed by the Trust in its annual filings, interim filings or other reports filed or submitted by the Trust under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation. They have also concluded that the Trust's ICFR has been designed effectively to provide reasonable assurance regarding the reliability of the preparation and presentation of the financial statements for external purposes in accordance with IFRS, and were effective as at December 31, 2018.

It should be noted that, while the Chief Executive Officer and Chief Financial Officer of the Trust believe that the Trust's DC&P provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls will prevent all errors and fraud. A control system, no matter how well conceived or operated, can only provide reasonable, not absolute, assurance that the objectives of the control system are met.

ICFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements for external reporting purposes in line with IFRS. Management is responsible for establishing and maintaining appropriate ICFR in relation to the nature and size of the Trust. However, any system of ICFR has inherent limitations and can only provide reasonable assurance with respect to financial statement preparation and presentation.

The Trust's ICFR has been designed based on the control framework established in *Internal Control - Integrated Framework* published in 2013 by The Committee of Sponsoring Organizations of the Treadway Commission. There were no changes to the Trust's ICFR that occurred during the year ended December 31, 2018 that materially affected, or are reasonably likely to affect, the Trust's ICFR.

Non-IFRS Financial Measures

Statements throughout this MD&A make reference to EBITDA, Adjusted EBITDA, Distributable Cash, Embedded Margin, Total Distributions, Payout Ratio, Adjusted Working Capital, Total Cash and Availability and Maintenance Capital Expenditures which are non-IFRS financial measures commonly used by financial analysts in evaluating the financial performance of companies, including companies in the energy industry. Accordingly, Management believes these non-IFRS financial measures may be useful metrics for evaluating the Trust's financial performance as they are measures that Management uses internally to assess performance, in addition to IFRS measures. As there is no generally accepted method of calculating these non-IFRS financial measures, these terms as used herein are not necessarily comparable to similarly titled measures of other companies. These non-IFRS financial measures have limitations as analytical tools and should not be considered in isolation from, or as an alternative to, net income (loss), cash flow provided from (used in) operating activities or other data prepared in accordance with IFRS. Additionally, there may be certain items included or excluded from these non-IFRS financial measures that are significant in assessing the Trust's operating results and liquidity.

Forward-Looking Statements

This MD&A contains forward-looking statements and forward-looking information (collectively, "**forward-looking statements**") including, without limitation, statements relating to non-IFRS financial measures; the Trust's outlook, strategy, and ability to execute its business objectives; future payments owed to the Company; the electricity, natural gas and solar industries; governmental regulatory regimes; acquisitions and strategic partnerships; marketing channels; customer mix and customer growth; hedging strategies; risk management; market risk; credit risk; off-balance sheet arrangements; related party-transactions; liquidity and capital resources; critical accounting estimates; ICFR; potential transactions; results of operations; cost-synergies; the Trust's exit from the solar business; portfolio optimization; focus on higher-margin sales; the continued strength of the Company's deregulated energy business; repurchases under the Trust's normal course issuer bid program; financial position or cash flows; expenses and distributions to Unitholders. Often, but not always, forward-looking statements can be identified by the use of words such as "plans", "expects" or "does not expect", "is expected", "budget", "scheduled", "estimates", "forecasts", "intends", "anticipates" or "does not anticipate", or "believes", or describes a "goal", or variation of such words and phrases or state that certain actions, events or results "may", "could", "would", "might" or "will" be taken, occur or be achieved. All forward-looking statements reflect the Trust's beliefs and assumptions based on information available at the time the statements were made. Actual results or events may differ from those predicted, assumed or inferred in forward-looking statements. All of the Trust's forward-looking statements are qualified by: (i) the assumptions that are stated or inherent in such forward-looking statements; (ii) the risks described in the section entitled *"Financial Instruments and Risk Management"* in this MD&A; and (iii) the risks described in the sections entitled *"Risk Factors"* and *"Forward-Looking Statements"* in the annual information form of the Trust for the fiscal year ended December 31, 2018, dated March 14, 2019, which is available on SEDAR under the Trust's issuer profile at www.sedar.com and on the Trust's website at www.criusenergytrust.ca. Forward-looking statements involve known and unknown risks, future events, conditions, uncertainties and other factors which may cause the actual results, performance or achievements to be materially different from any future results, prediction, projection, forecast, performance or achievements expressed or implied by the forward-looking statements. Although the Trust has attempted to identify important factors that could cause actual actions, events or results to differ materially from those described in forward-looking statements, there may be other factors that cause actions, events or results not to be as anticipated, estimated or intended. There can be no assurance that forward-looking statements will prove to be accurate, as actual results and future events could differ materially from those anticipated in such statements. Accordingly, readers should not place undue reliance on forward-looking statements. The Trust disclaims any intention or obligation to update or revise any forward-looking statements whether as a result of new information, future events, or otherwise, except in accordance with applicable securities laws.