EAGLE ENERGY™
TRUST

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2013

(Dated as of March 20, 2014)

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NOTE TO READERS

The following information used in this Annual Information Form is set out in Schedule D at the end of this document:

- Definitions and Abbreviations
- Conversions
- Barrel of Oil Equivalency
- Exchange Rates

All information in this Annual Information Form is reported in Canadian dollars unless otherwise noted.

Forward-looking Statements and Risk Factors

The forward-looking statements in this Annual Information Form are based on Eagle Energy Trust's current expectations, estimates, projections and assumptions. This information is subject to a number of risks and uncertainties, including those discussed in this document in the Risk Factors section, many of which are beyond the control of the Trust. The Trust cautions users of this information that the Trust's actual results may differ materially from those projected in any forward-looking statements included in this Annual Information Form. Refer to the section under the heading "Advisory - Forward-Looking Statements and Risk Factors", below, for information on the risk factors and material assumptions underlying the forward-looking information.

Non-IFRS Financial Measures

This Annual Information Form refers to the terms "field netback" and "funds flow from operations", which are non-IFRS financial measures that do not have any standardized meaning prescribed by IFRS and are therefore unlikely to be comparable to similar measures presented by other issuers. Management believes that "field netback" and "funds flow from operations" provide useful information to investors and management since such measures reflect the quality of production, the level of profitability, the ability to drive growth through the funding of future capital expenditures and the sustainability of distributions to unitholders. Funds flow from operations is calculated before changes in non-cash working capital and abandonment expenditures. See the "Non-IFRS financial measures" section of the Trust's Management Discussion and Analysis for the year ended December 31, 2013 for a reconciliation of funds flow from operations and field netback to income for the period, the most directly comparable measure in the Trust's audited annual consolidated financial statements.

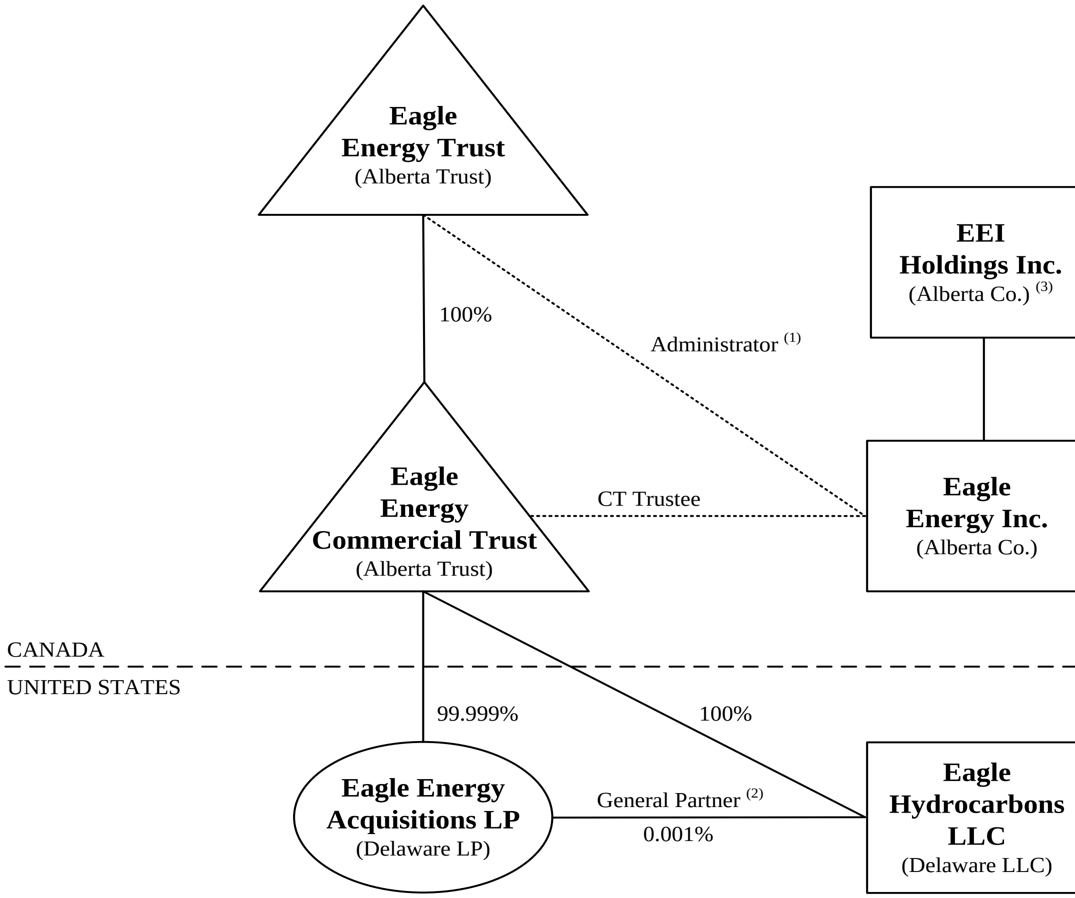
Access to Documents

This Annual Information Form and any document referred to in this Annual Information Form and described as being filed on SEDAR at www.sedar.com (including those documents referred to as being incorporated by reference in this Annual Information Form) may be obtained free of charge from the Trust at Suite 2710, 500 – 4th Avenue S.W., Calgary, Alberta, T2P 2V6.

EAGLE ENERGY TRUST AND ITS SUBSIDIARIES

Eagle Energy Trust

Eagle Energy Trust is an unincorporated open-ended limited purpose trust established under the laws of the Province of Alberta on July 20, 2010 by the Trust Indenture. The following chart illustrates the structure of the Trust and its Subsidiaries and affiliates:



Notes:

(1) Pursuant to the terms of the Administrative Services Agreement, the Administrator performs all general and administrative services that are or may be required or advisable, from time to time, for the Trust. The Administrator performs its services pursuant to the Administrative Services Agreement on a cost recovery basis with no profit to the Administrator.

(2) Pursuant to the terms of the Partnership Agreement, the GP performs all general, administrative and operational services that are or may be required or advisable, from time to time, for the Partnership.

(3) All of the shares of the Administrator are owned by EEI Holdings Inc., which, in turn, is wholly-owned by Richard Clark, the President and Chief Executive Officer and a director of the Administrator and the GP. The voting agreement dated November 12, 2010 among EEI Holdings Inc., the Trustee and the Administrator, provides that Unitholders will be entitled to elect 100% of the directors of the Administrator. The number of the directors of the Administrator is fixed at five until such time as the Unitholders pass a resolution to fix the number of the directors of the Administrator at a new number.

Offices

The head and registered offices of the Trust, the CT and the Administrator are located at Suite 2710, 500 – 4th Avenue S.W., Calgary, Alberta, T2P 2V6. The principal offices of the GP and the Partnership and the U.S. office of the Administrator are located at 333 Clay Street, Suite 3005, Houston, Texas, 77002. The registered office of the Partnership and the GP is located at 1209 Orange Street, Wilmington, Delaware, 19801.

GENERAL DEVELOPMENT OF OUR BUSINESS

Overview

The Trust is an energy trust created to provide investors with a publicly traded, oil and natural gas focused, distribution paying investment, with favourable tax treatment relative to taxable Canadian corporations. The primary strategy of the Trust is to make investments in entities, such as the Partnership, that will enable them to acquire and exploit long-life hydrocarbon reserves in certain established on-shore production basins in the U.S. The Partnership currently owns producing properties with development and exploitation potential predominantly located in Texas in Caldwell, Martin, Palo Pinto and Hardeman counties. The Partnership does not intend to engage substantively in exploration activities. The Trust intends to make monthly distributions of a portion of its available cash to Unitholders and use the remainder of its available cash to reinvest in its Subsidiaries to fund growth through additional acquisitions and capital expenditures.

History

2010 and 2011: Initial Public Offering and Acquisition of Salt Flat Properties

On November 24, 2010, the Trust closed its initial public offering of 15,000,000 Units at a price of $10.00 per Unit for gross proceeds of $150,000,000. In December 2010, the Trust issued an additional 1,950,000 Units at a price of $10.00 per Unit for additional gross proceeds of $19,500,000 pursuant to the terms of an over-allotment option granted to the underwriters in connection with the Trust's initial public offering.

Concurrently with closing the initial public offering, the Partnership completed an acquisition (the "**Salt Flat Acquisition**"), from an arm's length party, of a 73% working interest in the Salt Flat Field, a producing light oil field in Caldwell County in south central Texas, by purchasing 80% of the seller's average 91% working interest in the Salt Flat Field. The purchase price for this acquisition was $US 127.1 million, including closing adjustments, which was funded from a portion of the net proceeds of the initial public offering and by the issuance to the seller of 2,000,000 Units valued at $10.00 per Unit, being the initial public offering price of the Units.

Upon completion of the Salt Flat Acquisition, the seller retained an average 18% working interest, and third parties continue to own the remaining average 9% working interest, in the oil and gas leases that make up the Salt Flat Field. Pursuant to a joint operating agreement, the Partnership manages the drilling, completion and production operations in the Salt Flat Field on behalf of all of the working interest owners in the Salt Flat Field.

Since the closing of the Salt Flat Acquisition in November 2010, the Partnership has achieved the following on its Salt Flat Properties:

- drilled 22 (18.0 net) new horizontal wells, 3 (2.4 net) sidetrack re-entry horizontal wells and 3 (2.6 net) salt water disposal wells,
- constructed 8 batteries,
- completed the extension of the power trunk line to bring electrical power to the balance of the Salt Flat Properties, and
- increased production from 320 boe/d to 1,643 boe/d at the end of December 31, 2013.

2012: Public Offering and Acquisition of Interests in Permian Basin in Martin and Palo Pinto Counties

On May 18, 2012, the Trust closed a public offering of 7,730,000 Units at a price of $11.00 per Unit for gross proceeds of $85,030,000. On May 29, 2012, the Trust issued an additional 950,000 Units at a price of $11.00 per Unit for additional gross proceeds of $10,450,000 pursuant to the terms of an over-allotment option granted to the underwriters in connection with the May 18, 2012 public offering.

Concurrent with the closing of the public offering on May 18, 2012, the Partnership completed an acquisition, from an arm's length party, of 92.5% of the seller's 99% working interest in certain Permian Basin oil and natural gas properties and related assets located near Midland, Texas in Martin and Palo Pinto counties (the "**Permian Acquisition**"). The purchase price of these assets was $US 114.7 million, including closing adjustments. On the same date, the Partnership acquired all of another party's 1% working interest in the same properties. The Permian Acquisition was funded by the net proceeds of the May 18, 2012 public offering, an advance of approximately $US 28.8 million under the Partnership's credit facility and approximately $US 6.6 million of working capital.

On June 22, 2012, the Trust filed on SEDAR a Form 51-102F4 *Business Acquisition Report* in respect of the Midland Acquisition.

On September 1, 2013, the Partnership assumed operatorship of these assets.

The Partnership's drilling program on the Permian Properties targets multiple pay zones from the Clearfork through to the Atoka. Since the closing of the Permian Acquisition, the Partnership has achieved the following on the Permian Properties:

- drilled 14 (13.2 net) wells, and tied in and brought on stream 14 (13.4 net) wells, and
- increased production from these assets from 600 boe/d to 1,130 boe/d at the end of December 31, 2013.

2013: Acquisition of Remaining Working Interest in Permian Properties and Acquisition of Interests in Hardeman County

On April 22, 2013, the Partnership acquired the seller's remaining 7.5% working interest in the Permian Properties for cash consideration of approximately $US 8.6 million, bringing the Partnership's working interest ownership in those properties to 100%.

On November 25, 2013, the Partnership acquired, from an arm's length party, petroleum producing properties in a new core area, the Hardeman Basin, in Hardeman County, Texas for a purchase price of $US 26.3 million, including closing adjustments. Through this acquisition, the Partnership acquired 34 (29.9 net) producing wells.

The acquisition of the remaining 7.5% working interest in the Permian Properties and the acquisition of the Hardeman Properties were funded by the Partnership from the Credit Facility.

Early 2014: Acquisition of Additional Interests in Hardeman County and nearby in Greer, Harmon and Jackson counties, Oklahoma

On February 27, 2014, the Partnership acquired, from an arm's length party, additional undeveloped acreage and an average 66% working interest in producing properties in Hardeman County and nearby in Greer, Harmon and Jackson counties, Oklahoma for a net purchase price, after preliminary adjustments at closing of $US 300,000, of $US 4.7 million. Through this small, tuck-in acquisition, the Partnership acquired interests in 13 (5.4 net) producing wells, production of approximately 130 boe/d and expanded its land position in this area. The Trust used an advance under its Credit Facility to fund this acquisition. As this acquisition was completed after December 31, 2013, and was not a significant or material acquisition within the meaning of securities laws, the interests acquired by the Partnership are not included in the reserves estimates or other oil and gas information set out below under the heading "Statement of Reserves Data and Other Oil and Gas Information".

Business Opportunity and Strategy

To date, the Trust has invested all of its capital, indirectly, in U.S. oil and gas assets that have been identified by Management as being undercapitalized and underexploited. Due to the larger percentage (compared to Canada) of U.S. oil and gas reserves held privately and by non-industry investors, Management believes that the Partnership will continue to find oil and gas assets that meet the Trust's investment criteria. Management believes that it will be able to continue to acquire, operate and exploit U.S. oil and gas production and reserves at competitive costs compared to producers of Canadian oil and gas production and reserves. Management also believes that the following industry conditions currently exist and make investment in the U.S. oil and gas industry attractive: (i) realized commodity pricing can be significantly higher, due to the absence of transportation differentials, for production such as the Partnership's that is located closer to refineries compared to production coming from Canada, (ii) the royalty burden is competitive compared to Canada, and (iii) drilling, abandonment, operating and service costs are often lower than in Canada.

Management believes that the Trust is well positioned to continue to exploit this investment opportunity, through its indirect investment in the Subsidiaries, and execute its primary objectives of maintaining stable cash flows and pursuing accretive growth opportunities. Each of the ten persons who are the Administrator Directors and Management has 15 to 35 years of experience in the petroleum industry. In addition, Management has extensive experience in acquiring and developing oil and gas assets internationally.

The Partnership intends to continue to focus its acquisition efforts on high quality petroleum production with proven reserves and positive development potential.

Target Assets

The Partnership targets assets that have the following general characteristics:

Reserves and Risk Level – Producing reserves with remaining low risk exploitation and development potential.

Location – Located predominantly in core basins like the Permian within Texas and other basins within the general Midcontinent region of the United States. These areas have been identified as having concentrations of assets with long-life production profiles, unexploited low-risk upside remaining, access to good infrastructure and acceptable operating costs. In addition, Management believes there are consolidation opportunities in these basins as a result of unconsolidated surface rights ownership and, in many cases, production leases being held by non-industry owners who have held such assets as sources of cash flow, often for decades. Investment opportunities in other areas may be assessed from time to time if acquisition opportunities that meet the Partnership's investment criteria are identified.

Operations – The Partnership currently operates almost all of its existing Properties and targets assets for acquisition which it can operate after completing the acquisition. Through 2011 to 2013, the Partnership has hired experienced employees and third party contractors.

Commodity Balance – Over the long term, the Partnership intends to hold a balanced portfolio of petroleum producing properties. However, the Partnership intends to be opportunistic in selecting acquisitions and in the use of exploitation capital. In the near to medium term, the Partnership seeks to acquire and operate oil and natural gas assets with the potential to increase current levels of production.

Credit Facility

The Trust expects available credit under the Credit Facility to increase commensurate with the growth of oil and gas reserves. The Credit Facility is intended to be used to finance growth opportunities and for general corporate purposes. In addition, the Trust may seek to issue additional Units, or issue subordinated debt, if available on favourable terms, from time to time, to provide sufficient capital to fund growth acquisition opportunities. See "Debt Financing".

Hedging Strategy

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates and interest rates will affect the Trust's income. The objective of market risk management is to manage and control market risk exposures within acceptable parameters while optimizing the return

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by various factors, including the exchange rates between the Canadian and United States dollar, but also world economic events that dictate the levels of supply and demand. The Trust enters into certain financial derivative instruments periodically to economically hedge some oil and natural gas sales through the use of various financial derivative forward sales contracts and physical sales contracts. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors. It is the policy of the Trust to not hedge more than 50% of its near-term working interest production. This percentage may increase at certain times as a result of acquisitions. As at the date of this Annual Information Form, the Trust has entered into contracts to mitigate the effect of commodity price fluctuations.

Foreign exchange risk is the risk that future cash flows will fluctuate as a result of changes in market foreign exchange rates. The Trust's operating cash flows are generated in US dollars and distributions are declared in Canadian dollars. As a consequence, there is an element of foreign exchange risk to the Trust. The Trust's treasury management function is responsible for managing funding requirements and investments, which include banking and cash flow management. Prices for oil are determined in global markets and denominated in US dollars. Generally, an increase in the value of the $CA as compared to the $US will reduce the prices received by the Trust for its petroleum and natural gas sales, but will also reduce the operating expenses associated with those sales as well as reduce the price paid by the subsidiary of the Trust for future asset acquisitions. As at the date of this Annual Information Form, the Trust has entered into foreign exchange contracts to mitigate its foreign exchange exposure on distributions.

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Trust may be exposed to interest rate risk at both fixed and variable rates as it borrows funds. As at the date of this Annual Information Form, the Trust did not hedge against any interest rate exposure.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information is set forth below (the "**Statement**"). The effective date of the Statement is December 31, 2013 and the preparation date of the Statement is the date of this Annual Information Form. The Report of Management and Directors on Reserves Data and Other Information on Form 51-101F3 and the Report on Reserves Data by the Independent Qualified Reserves Evaluators on Form 51-102F2 are attached as Schedules A and B to this Annual Information Form.

Disclosure of Reserves Data

The reserves data set forth below are based upon an evaluation of the Partnership's reserves by NSAI with an effective date of December 31, 2013 contained in the NSAI Reserve Report dated March 7, 2014. NSAI was engaged by the Administrator and the Partnership to provide an evaluation of proved and probable reserves of the Partnership. As at December 31, 2013, all of the Partnership's reserves were located in the U.S., in the State of Texas. The tables below are a summary of the reserves and the net present value of future net revenue attributable to the reserves as evaluated in the NSAI Reserve Report based on the January 1, 2014 forecast price for crude oil and natural gas published by GLJ Petroleum Consultants Ltd., cost assumptions and supplied lease operating expenses. Due to rounding, certain columns may not add exactly.

Estimates of after tax future net revenue are not presented in the following tables because, as at December 31, 2013, it is expected that the Trust will not be subject to taxes in Canada. Management does not expect taxes to be payable by the Trust in Canada because the Trust should not be subject to the SIFT tax and will distribute its full taxable income each year to Unitholders. The Trust qualifies as a "mutual fund trust" under the Tax Act and will not be a "SIFT trust" (as defined in the Tax Act) provided the Trust complies at all times with its investment restrictions that preclude the Trust from investing in any entity other than a "portfolio investment entity", holding any "non-portfolio property" (each as defined in the Tax Act), or carrying on business in Canada. The investment restrictions in the Trust Indenture cannot be amended without a Special Resolution of the Unitholders.

The net present value of future net revenue attributable to the reserves is stated without provision for interest costs, income taxes and general and administrative costs, but after providing for estimated royalties, production costs, capital, production taxes (which, in the U.S., consist of severance and *ad valorem*), development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by NSAI. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the reserves estimated by NSAI represent the fair market value of the reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized in this Annual Information Form. The recovery and reserve estimates of the reserves provided in this Annual Information Form are estimates only and there is no guarantee that the reserves, as estimated, will be recovered. Actual reserves may be greater than or less than the estimates provided in this Annual Information Form.

Reserves Data – Forecast Prices and Costs

Summary of Oil, Natural Gas Liquids and Natural Gas Reserves

	Light and Medium Oil		Natural Gas Liquids		Natural Gas		Total	
Reserves Category	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
	(Mbbl)	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(MMcf)*	*(MMcf)*	*(Mboe)*	*(Mboe)*
Proved								
Developed Producing	3,997	3,050	686	511	3,035	2,271	5,189	3,939

Reserves Category	Light and Medium Oil		Natural Gas Liquids		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(Mbbl)	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(MMcf)*	*(MMcf)*	*(Mboe)*	*(Mboe)*
Developed Non-Producing	1,012	769	200	149	830	616	1,350	1,020
Undeveloped	3,218	2,418	689	517	2,855	2,141	4,383	3,291
Total Proved	8,226	6,236	1,576	1,176	6,720	5,027	10,922	8,250
Total Probable	2,826	2,109	343	254	1,428	1,058	3,407	2,540
Total Proved Plus Probable	11,052	8,345	1,919	1,431	8,148	6,085	14,329	10,790

Summary of Net Present Value of Future Net Revenue of Oil, Natural Gas Liquids and Natural Gas Reserves

Reserves Category	Net Present Value of Future Net Revenue Before Income Taxes Discounted at (%/year)(1)					Value Per Boe Before Income Tax Discounted at 10%/year
	0%	5%	10%	15%	20%	
	($US 000)	*($US 000)*	*($US 000)*	*($US 000)*	*($US 000)*	*($US/boe)*
Proved						
Developed Producing	207,731	158,064	131,949	115,487	103,925	33.50
Developed Non-Producing	41,547	31,963	25,632	21,175	17,877	25.13
Undeveloped	102,916	62,620	40,879	27,963	19,703	12.42
Total Proved	352,194	252,646	198,459	164,626	141,505	24.06
Total Probable	135,719	94,601	71,212	56,366	46,187	28.04
Total Proved Plus Probable	487,913	347,248	269,672	220,992	187,692	24.99

Notes:

(1) Estimates of after-tax future net revenue are not presented because it is expected that the Trust will not be subject to taxes in Canada.

Additional Information Concerning Future Net Revenue (Undiscounted)

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Tax Expenses(1)
	($US 000)	*($US 000)*	*($US 000)*	*($US 000)*	*($US 000)*	*($US 000)*
Total Proved	972,790	236,143	295,226	84,593	4,633	352,194
Total Proved Plus Probable	1,299,768	319,181	385,456	102,236	4,982	487,913

Notes:

(1) Estimates of after-tax future net revenue are not presented because it is expected that the Trust will not be subject to taxes in Canada.

Future Net Revenue by Production Group

Reserves Category	Future Net Revenue Before Income Taxes (Discounted at 10%/year)	Unit Value (Net Reserves)
	($US 000)	*($US/BOE for oil and natural gas liquids and $US/Mcfe for natural gas)*
Proved Producing		
Light and Medium Oil (1)	131,878	33.48
Natural Gas (2)	70	0.52
Total Proved		
Light and Medium Oil (1)	198,389	24.05
Natural Gas (2)	70	0.52
Total Proved Plus Probable		
Light and Medium Oil (1)	269,602	24.99
Natural Gas (2)	70	0.52

Notes:
(1) Includes natural gas, natural gas liquids and other by-products associated with oil production.
(2) Includes natural gas liquids and other by-products associated with natural gas production.

Definitions

In the tables set forth above and elsewhere in this Annual Information Form, the following notes and other definitions are applicable.

"**gross**" means:

(a) In relation to the Partnership's interest in production or reserves, its working interest (operating and non-operating) share before deduction of royalties and without including any of its royalty interests.

(b) In relation to wells, the total number of wells in which the Partnership has an interest.

(c) In relation to properties, the total area of properties in which the Partnership has an interest.

"**net**" means:

(a) In relation to the Partnership's interest in production or reserves, the Partnership's working interest (operating and non-operating) share after deduction of royalty obligations, plus the Partnership's royalty interests in production or reserves.

(b) In relation to the Partnership's interest in wells, the number of wells obtained by aggregating the Partnership's working interest in each of its gross wells.

(c) In relation to the Partnership's interest in a property, the total area in which the Partnership has an interest multiplied by the working interest owned by the Partnership.

The estimates presented in the NSAI Reserve Report are based on the definitions and guidelines contained in the CSA Notice 51-324 *Glossary to NI 51-101* and the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook"). A summary of those definitions are set forth below:

Reserve Categories

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

"**Reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on:

(a) analysis of drilling, geological, geophysical and engineering data;

(b) the use of established technology; and

(c) specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates.

"**Proved reserves**" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

"**Developed producing reserves**" are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

"**Developed non-producing reserves**" are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

"**Undeveloped reserves**" are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation is based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

"**Probable reserves**" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to "individual reserves entities", which refers to the lowest level at which reserves calculations are performed, and to "reported reserves", which refers to the highest level sum of individual entity estimates for which reserves estimates are presented. Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Pricing Assumptions – Forecast Prices and Costs

"**forecast prices and costs**" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future;

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the reporting issuer is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

NSAI employed the following pricing and inflation rate assumptions as of December 31, 2013 in estimating reserves data using forecast prices and costs.

	GLJ's January 1, 2014 Price Forecast [1]		NGL Price Forecast [2]	
	Crude Oil	**Natural Gas**	**Natural Gas Liquids**	**Inflation Rate [3]**
Year	**NYMEX WTI Crude Oil at Cushing Oklahoma**	**NYMEX Henry Hub Natural Gas**	**See Note 2**	
Forecast	*($US/bbl)*	*($US/MMbtu)*	*($US/bbl)*	*(%/yr)*
2014	97.50	4.25	36.13	0
2015	97.50	4.50	36.12	2
2016	97.50	4.75	36.16	2
2017	97.50	5.00	36.17	2
2018	97.50	5.25	36.17	2
2019	97.50	5.50	36.16	2
2020	98.54	5.63	36.53	2
2021	100.51	5.74	37.24	2
2022	102.52	5.86	37.97	2
2023	104.57	5.97	38.65	2
2024+	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year

Notes:

(1) Published by GLJ Petroleum Consultant's Ltd. at http://www.gljpc.com/commodity-price-forecasts.

(2) The NGL price forecast is based on the Partnership's average historical relationship of realized prices to the New York Mercantile Exchange ("**NYMEX**") WTI crude oil price.

(3) Inflation rate used for forecasting costs.

The Partnership's weighted average historical prices for the year ended December 31, 2013 was $US/bbl 102.93 for oil, $US/Mcf 3.60 for natural gas and $US/bbl 35.44 for natural gas liquids.

Reconciliation of Changes in Reserves

The following table sets forth the reconciliation of the Partnership's gross reserves as at December 31, 2013, using forecast price and cost estimates derived from the NSAI Reserve Report.

Reserves Reconciliation (Company Gross)	Oil	Natural Gas Liquids	Natural Gas	Total
	(Mbbls)	*(Mbbls)*	*(MMcf)*	*(Mboe)*
Total Proved				
Opening Balance (Dec. 31, 2012)	8,271	1,342	5,992	10,612
Discoveries	-	-	-	-
Extensions and Improved Recovery	645	55	226	737
Technical Revisions	(1,477)	178	333	(1,244)
Acquisitions	1,694	108	666	1,913
Dispositions	-	-	-	-
Economic Factors	-	-	-	-
Production	(907)	(107)	(497)	(1,096)
Closing Balance (Dec. 31, 2013)	8,226	1,576	6,720	10,922
Total Probable				
Opening Balance (Dec. 31, 2012)	4,322	402	1,790	5,023
Discoveries	-	-	-	-
Extensions and Improved Recovery	71	20	84	106
Technical Revisions	(1,749)	(111)	(596)	(1,959)
Acquisitions	181	32	150	238
Dispositions	-	-	-	-
Economic Factors	-	-	-	-
Production	-	-	-	-
Closing Balance (Dec. 31, 2013)	2,826	343	1,428	3,407
Total Proved Plus Probable				
Opening Balance (Dec. 31, 2012)	12,593	1,744	7,783	15,635
Discoveries	-	-	-	-
Extensions and Improved Recovery	716	75	311	843
Technical Revisions	(3,225)	67	(265)	(3,202)
Acquisitions	1,875	140	816	2,151
Dispositions	-	-	-	-
Economic Factors	-	-	-	-
Production	(907)	(107)	(497)	(1,096)
Closing Balance (Dec. 31, 2013)	11,052	1,919	8,148	14,329

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following discussion generally describes the basis on which proved and probable undeveloped reserves were attributed. The Partnership's plans for developing the undeveloped reserves are described below in "Other Oil and Gas Information".

Proved Undeveloped Reserves

Proved undeveloped reserves are those reserves that are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. In addition, such reserves may relate to planned infill drilling locations. The majority of these reserves are planned to be on stream within a three year timeframe. The following table provides the timing of the initial reserve assignments for the Partnership's proved undeveloped gross reserves.

Timing of Initial Proved Undeveloped Reserves Assignment

	Light & Medium Oil *(Mbbl)*		**Natural Gas** *(MMcf)*		**Natural Gas Liquids** *(Mbbl)*	
Year	**First Attributed**	**Total at Year-End**	**First Attributed**	**Total at Year-End**	**First Attributed**	**Total at Year-End**
Prior	1,600	1,600	0	0	0	0
2011	0	1,440	0	0	0	0
2012	3,563	3,993	3,415	3,415	768	768
2013	527	2,418	143	2,141	35	517

Probable Undeveloped Reserves

Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. The majority of these reserves are planned to be on stream within a five year timeframe. The following table provides the timing of the initial reserve assignments for the Partnership's probable undeveloped gross reserves.

Timing of Initial Probable Undeveloped Reserves Assignment

	Light and Medium Oil *(Mbbl)*		**Natural Gas** *(MMcf)*		**Natural Gas Liquids** *(Mbbl)*	
Year	**First Attributed**	**Total at Year-End**	**First Attributed**	**Total at Year-End**	**First Attributed**	**Total at Year-End**
Prior	3,600	3,600	0	0	0	0
2011	570	3,290	0	0	0	0
2012	1,696	3,386	1,670	1,670	376	376
2013	60	1,269	70	777	17	187

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available production, geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. NSAI is an independent, qualified reserves evaluator as defined in NI 51-101.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year end crude oil and natural gas prices and reservoir performance. Such revisions can be either positive or negative. See “Risk Factors”.

Future Development and Abandonment Costs

The table below sets out the development costs deducted in the estimation of future net revenue attributable to proved reserves and proved plus probable reserves (using forecast prices and costs).

	Annual Capital Expenditures	
Year	**Total Proved**	**Total Proved Plus Probable**
	($US 000)	*($US 000)*
2014	19,268	23,068
2015	20,465	23,687
2016	15,107	23,715
2017	16,220	16,220
2018	10,221	12,155
Subtotal(1)	81,281	98,844
Remainder	3,312	3,392
Total(1)	84,593	102,236

Notes:
(1) Numbers may not add due to rounding.

The Trust estimates that internally generated cash flow will be sufficient to fund the future development costs disclosed above. The Trust expects to have available three sources of funding to finance the capital expenditure program of the Partnership: internally generated cash flow from operations, external debt financing when appropriate and new capital through the issuance of additional Units if available on favourable terms. Management anticipates that one source of debt financing will be available pursuant to the Credit Facility at market rates plus margins subject to a pricing grid based upon the percentage of utilization of the borrowing base. The Trust expects to fund the total 2014 capital program of the Partnership with internally generated cash flow and proceeds from the Trust’s distribution reinvestment plan.

Abandonment costs for the Partnership’s wells were estimated using historical Texas Railroad Commission costs for similar fields in their respective areas, without deduction of salvage value. Such costs are assigned to all wells in the NSAI Reserve Report and are included as deductions in arriving at future net revenue. The expected total abandonment costs for an estimated 108.0 net wells is $US 4,981,600 undiscounted ($US 991,995 discounted at 10%), none of which is expected to be incurred in 2014, 2015 or 2016.

Other Oil and Gas Information

Assets in the Salt Flat Field

The Partnership’s oil and natural gas interests in the Salt Flat Field are located in Caldwell County, 75 kilometres south of Austin, Texas. The Partnership is the operator of this property. As at December 31, 2013, the Partnership had a working interest in 55 gross (41.2 net) producing wells and 13 gross (8.2 net) non-producing wells on this property, and its average working interest production from this property for December 2013 was 1,643 boe/d.

The Salt Flat Field was discovered in 1928 with initial production from the Austin Chalk, shortly followed with production from the Edwards, utilizing vertical well technology of the day. The Edwards was believed to have been depleted by the 1960s, but development continued in the up hole Austin Chalk and Buda producing formations. In 2007, a former operator initiated a horizontal drilling program in the Edwards limestone formation as a result of successes experienced by another operator in neighbouring fields.

The oil reservoir contained within the Edwards limestone formation is located approximately 850 metres (2,728 feet) below the surface and is between 15 metres and 45 metres thick. Data collected from the Salt Flat Field indicates the Edwards reservoir consists of a number of stacked dolomite and limestone carbonate beds, referred to as “benches”, with porosity values ranging from 10% to 35%. The horizontal wells that have been drilled to date have been completed mostly in the uppermost dolomite zone of the oil reservoir, located approximately three metres (10 feet) from the top of the Edwards limestone formation, and have lateral reaches of up to 762 metres (2,500 feet). Due to very good reservoir quality, these wells do not require any acid or fracture stimulation. The Edwards formation produces light, low viscosity oil (36 degrees API). Oil produced from the producing wells is trucked to an oil terminal and marketed as West Texas Intermediate at market prices. Produced salt water is disposed of in vertical salt water disposal wells located in the Salt Flat Field. As part of the closing of the Salt Flat Field Acquisition, the Partnership also acquired 80% of the seller’s majority interest in the batteries and salt water disposal facilities located on the Salt Flat Field. The condition of these facilities is good, with all purchased and constructed in the last few years.

Horizontal drilling done to date has revealed some evidence of very small faults in the 15’ to 20’ range. Eagle is currently preparing to shoot proprietary 3D seismic over Salt Flat Field, primarily to better understand the impact of compartmentalization from small faults and fractures, and to identify un-drained reservoir compartments to guide the placement of new well locations. The data is expected to delineate the geologic complexity of the field and optimize future drill locations including the remaining five wells budgeted for 2014. Also, more recent historical vertical wells and a few horizontal wells indicate the lower benches are not drained by production in the uppermost bench. Alternatively, capital may be used to sidetrack three existing wells to lower Edwards bench zones to recover bypassed oil that is not being drained by current wellbores. Confirmation of the Lower Edwards productivity could lead to additional proved and probable reserves.

All of the Partnership’s oil, gas and mineral leases in the Salt Flat Field cover approximately 3,200 (2,600 net) acres. All of the acreage covered by the leases is currently held by production from the Edwards formation.

Assets in Martin and Palo Pinto Counties (the “Permian Properties”)

The Partnership also owns and operates oil and natural gas interests in the Permian Basin in the counties of Martin and Palo Pinto, Texas, which the Partnership refers to as its “Permian Properties”. As at December 31, 2013, the Partnership had a working interest in 45 gross (45.0 net) producing wells and 4 gross (4.0 net) non-producing wells on these properties, and its average working interest production from these properties for December 2013 was approximately 1,130 boe/d.

The Partnership’s oil and natural gas interests in Martin County are located in what is known as the Spraberry (Trend Area) Field (the "Spraberry Field"). The Spraberry Field is a producing oil field that was discovered in 1943 and covers nine counties in the Permian Basin in West Texas. The wells in the Spraberry Field target a stacked reservoir interval currently known as the Wolfberry. The Wolfberry consists of multiple oil bearing reservoirs ranging in depth from 8,000 feet to 11,000 feet and includes the Permian age Spraberry, Dean, Wolfcamp and Cline reservoirs. The Spraberry Field reservoir is considered a "sand" exhibiting a thick sequence of siltstones and sandstones, but interbedded with dolomitic limestone and deposited in a submarine depositional environment. Spraberry Field reservoir rock is generally considered to have high oil in-place, but porosity and permeability vary depending on regional geology. Regional natural fracture systems are observed throughout the Spraberry Field, which trend from northeast to southwest, and enhance porosity and permeability which result in higher recoveries of oil in-place. The Wolfcamp detrital reservoir, which lies beneath the Spraberry formation, exhibits more favorable permeability and porosity than the Spraberry Field, but is more heterogeneous due to detrital material being deposited in more compact and compartmentalized areas.

In addition to producing from the Wolfberry, the Partnership’s assets also produce from the deeper Pennsylvanian age Strawn and Atoka formations. When the entire Spraberry through Atoka are comingled, it is collectively referred to as the "Atokaberry" reservoir. The Atoka formation is at approximately 400 feet below the Strawn formation. Wells are typically completed in all zones in the Atokaberry using multistage hydraulic fracturing methods to stimulate the respective hydrocarbon bearing zones to achieve commercial production levels.

Palo Pinto County production is from the Pennsylvanian age Marble Falls formation. All of the Partnership’s Palo Pinto County oil, gas and mineral leases cover approximately 855 acres (net and gross). The Partnership’s Martin County oil, gas and mineral leases cover approximately 2,160 acres (net and gross). All of the Palo Pinto and Martin County leases are currently held by production.

Assets in Hardeman County (the "Hardeman Properties")

In late 2013, the Partnership acquired oil and natural gas interests in Hardeman County. As at December 31, 2013, the Partnership had a working interest in 34 gross (29.9 net) producing wells, and 16 gross (15.4 net) non-producing wells on these properties and its average working interest production from these properties for December 2013 was 262 boe/d.

The Partnership's oil and natural gas interests in Hardeman County are located in what is known as the Hardeman Basin. Similar to the Permian Basin and Mid-continent regions, the Hardeman Basin contains stacked hydrocarbon bearing reservoirs from as young as the Permian (San Andres and Wolfcamp), to as old as the Cambrian (Hickory), including various reservoirs in the intervening Pennsylvanian (Cisco, Canyon, Strawn, Caddo, Atoka, and Morrow), Mississippian (Chester, Barnett, Holmes, and Chappel), and Ordovician. Based on public data, notable early historical production is from various reservoirs in the Pennsylvanian, having produced approximately 800 MMBO from Hardeman, Wilbarger and Wichita counties in Texas. Current and most recent drilling has been mostly to develop the various zones within the Mississippian, having so far produced approximately 80 MMBO from Hardeman, Wilbarger and Wichita counties in Texas. The Partnership's wells produce from the Mississippian, primarily the Chappel Limestone/Dolomite, with the exception of four Pennsylvanian Atoka Conglomerates. Many of the better vertical Chappel wells were completed by drilling only three to five feet into the good porosity and high permeability that was formed by dissolution and dolomitization of the limestone. Since 2001, horizontal wells, including six of the Partnership's Chappel producing wells, have been drilled along the top of the good porosity using slightly underbalanced brine as a circulating fluid. In the Texas portion of the Hardeman Basin, most of the horizontal wells have been drilled into various Mississippian reservoirs, including the Chester, Chappel, and Barnett. However, production has been found by other operators in horizontal wells drilled in the Permian Wolfcamp, and Pennsylvanian Canyon (Palo Pinto) and Atoka (Bend) formations.

The Partnership has recently licensed 226.78 square miles of 3D seismic data in Hardeman County, covering most of its properties, to aid in additional recovery from the Chappel, Atoka, Cisco and Canyon formations. Reprocessing of the 3D seismic to improve data quality and extract attributes is nearly completed. Management believes that the reprocessing and attribute extraction will build on the experience of previous development in the area and aid in revealing detailed stratigraphic and structural features, which will lead to additional drilling locations in 2014.

On February 24, 2014, the Partnership completed a small acquisition of additional interests in undeveloped acreage and an average 66% working interest in producing properties in Hardeman County and nearby in Oklahoma in Greer, Harmon and Jackson counties. As this acquisition was completed after December 31, 2013, and is not significant or material within the meaning of securities laws, these interests have not been included in the reserves data in the Statement in this Annual Information Form.

Properties With No Attributed Reserves

As at December 31, 2013, with the acquisition of the Hardeman Properties in late November 2013, the Partnership acquired the mineral rights to approximately 7,920 gross (7,395 net) acres that have no petroleum reserves currently attributed to them. None of these rights are set to expire within the next year.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

Management is not currently aware of any significant economic factors or significant uncertainties that affect the anticipated development on its properties with no attributed reserves. As described above, the Partnership is in the process of analyzing the 3D seismic data that was licensed to determine additional drilling locations for these properties.

Wells

The following table summarizes the number of producing and non-producing wells in which the Partnership had a working interest as at December 31, 2013.

Location and State	Producing Oil Wells		Non-Producing Oil Wells		Producing Natural Gas Wells		Non-Producing Natural Gas Wells	
	(Gross)	*(Net)*	*(Gross)*	*(Net)*	*(Gross)*	*(Net)*	*(Gross)*	*(Net)*
Salt Flat Field, Texas	55	41.2	13	8.2	0	0.0	0	0.0
Martin and Palo Pinto Counties, Texas	38	38.0	2	2.0	7	7.0	2	2.0
Hardeman County, Texas	33	28.9	16	15.4	1	1.0	0	0.0
Total	126	108.1	31	25.6	8	8.0	2	2.0

Drilling Activity

The following table summarizes the Partnership's gross and net development wells that were drilled in 2013. No exploration wells were drilled.

	Development Wells	
	(Gross)	*(Net)*
Oil wells	11	10.2
Natural gas wells	0	0.0
Service wells	1	1.0
Stratigraphic test wells	0	0.0
Dry holes	0	0.0
Total	12	11.2

Tax Horizon

The tax horizon, as determined from a full cycle corporate model developed by Management and incorporating all applicable U.S. deductions, indicates that no material U.S. taxes are expected to be payable in respect of income attributable to the Partnership's working interests in its oil and gas properties for several years. Management expects to extend this period through continued capital investments and acquisitions in the U.S. The Trust does not expect to pay any Canadian taxes because the Trust will distribute its full taxable income each year to Unitholders, will not be subject to the SIFT Tax and is not expected to otherwise be subject to Canadian income tax.

Costs Incurred

The following table summarizes property acquisition costs, exploration costs and development costs for 2013. The total capital costs for the period were $US 63,599,741.

Acquisition Costs (net)		Exploration Costs (net)	Development Costs (net)
Proved Properties	**Unproved Properties**		
($US 000)	*($US 000)*	*($US 000)*	*($US 000)*
34,285	0	0	29,314

Production Estimates

The following table discloses the volume of production for 2014 estimated by NSAI for the Partnership's reserves in the estimates of gross proved reserves and gross proved plus probable reserves disclosed above under the heading "Reserves Data – Forecast Prices and Costs".

Location	Light and Medium Crude Oil	Natural Gas	Natural Gas Liquids
	(Mbbl)	*(MMcf)*	*(Mbbl)*
Salt Flat Field			
Total Proved	584	-	-
Total Proved Plus Probable	668	-	-
Martin and Palo Pinto Counties			
Total Proved	239	397	95
Total Proved Plus Probable	256	418	100
Hardeman County			
Total Proved	136	24	-
Total Proved Plus Probable	136	24	-
Total in United States			
Total Proved	959	421	95
Total Proved Plus Probable	1,060	443	100

Notes:
(1) Numbers may not add due to rounding.

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Production History

The following table discloses, on a quarterly basis for the year ended December 31, 2013, the Partnership's share of average gross daily oil, natural gas and natural gas liquids production volume, the average prices received, U.S. state royalties paid, production costs (consisting of transportation and other operating costs) and resulting field netbacks.

	Three Months Ended 2013			
	March 31	June 30	September 30	December 31
Share of Average Gross Daily Production				
Light and Medium Crude Oil *(bbl/d)*	2,553	2,472	2,447	2,452
Gas *(Mcf/d)*	1,019	1,425	1,559	1,413
Natural Gas Liquids *(bbl/d)*	207	312	345	307
Combined *(boe/d)*	2,929	3,022	3,052	2,995
Average Price Received				
Light and Medium Crude Oil *($US /bbl)*	97.55	99.33	112.94	102.01
Gas *($US/Mcf)*	3.49	3.79	3.57	3.53
Natural Gas Liquids *($US/bbl)*	32.63	35.19	36.49	36.36
Combined *($US/Boe)*	88.57	86.68	96.51	88.92
Royalties Paid				
Light and Medium Crude Oil *($US/bbl)*	27.12	27.17	30.88	26.81
Gas *($US/Mcf)*	0.94	1.08	0.94	0.92
Natural Gas Liquids *($US/bbl)*	8.99	9.26	9.66	9.49
Combined *($US/boe)*	24.80	24.26	27.00	24.55
Production Costs				
Light and Medium Crude Oil *($US/bbl)*	11.19	10.22	12.73	16.79
Gas *($US/Mcf)*	1.87	1.70	2.12	2.80
Natural Gas Liquids *($US/bbl)*	11.19	10.22	12.73	16.79
Combined *($US/boe)*	11.19	10.22	12.73	16.79
Resulting Field Netbacks (2)				
Light and Medium Crude Oil *($US/bbl)*	59.24	61.94	69.33	58.41
Gas *($US/Mcf)*	0.68	1.01	0.51	(0.19)
Natural Gas Liquids *($US/bbl)*	12.45	15.71	14.10	10.08
Combined *($US/boe)*	52.58	52.20	56.79	47.58

Notes:

(1) Production costs include direct costs incurred to operate both oil and natural gas wells. A number of assumptions are required to allocate these costs among oil, natural gas and natural gas liquids production.

(2) Field netbacks are calculated by subtracting royalties, production costs (consisting of operating costs and transportation costs) from revenues.

Production Volumes

The following table discloses by field, and in total, the Partnership's production volumes for the year ended December 31, 2013.

	Light and Medium Oil	Natural Gas	Natural Gas Liquids
	(Mbbl)	*(MMcf)*	*(Mbbl)*
Salt Flat Field	658	0	0
Martin and Palo Pinto Counties	238	495	107
Hardeman County	10	0	0
Total	905	495	107

DEBT FINANCING

The Trust and its subsidiaries have entered into the Credit Facility with a syndicate of Canadian chartered banks. The Credit Facility is a $US 350 million senior secured revolving facility, which is secured by a first priority security interest on substantially all of the oil and gas properties of the Partnership. See "Material Contracts". A copy of the credit agreement relating to the Credit Facility is available on SEDAR under the Trust's issuer profile on www.sedar.com.

The Credit Facility is used for general corporate purposes, including working capital, capital expenditures and future acquisitions. As at the date of this Annual Information Form, the borrowing base for the Credit Facility is set at $US 90.0 million, consisting of a $US 80 million revolving facility and a one year non-revolving term facility of $US 10 million. Under the Credit Facility, the Trust, the CT, the GP, the Administrator and the Partnership and their subsidiaries, are required to satisfy certain customary affirmative and negative covenants (including financial covenants calculated both for the Partnership and its subsidiaries, and the Trust and its subsidiaries). Borrowings under the Credit Facility may only be made in U.S. dollars. The Credit Facility is secured by a first priority security interest on substantially all of the oil and gas properties of the Partnership, and substantially all personal property of the Trust, the CT, the GP, the Administrator, the Partnership and their subsidiaries, including the interest in the Partnership held by the CT and the GP, and is guaranteed by the Administrator, the Trust, the Partnership, the GP, and their direct and indirect subsidiaries.

The Credit Facility provides for a semi-annual evaluation of the borrowing base each April 1 and October 1, determined, among other things, based on proved reserves of the Partnership and its subsidiaries. Following the semi-annual review on October 1, 2013, the borrowing base for the revolving facility increased to $US 70 million and the term was extended to May 31, 2015. Concurrent with the closing of the Hardeman Acquisition on November 25, 2013, the borrowing base for the revolving facility was increased from $US 70 million to $US 80 million. As at December 31, 2013, $CA 67.5 million has been drawn under this revolving $US 80 million credit facility by way of LIBOR and base rate loans. The LIBOR and base rate margins are subject to a pricing grid based upon the percentage of credit facility utilization, and range from 2.0% to 3.0% and 1.0% to 2.0%, respectively. For the period which the revolver loan was outstanding during 2013, the actual interest rate ranged from 4.8% to 5.0%.

Concurrent with the closing of the Hardeman Acquisition on November 25, 2013, a subsidiary of the Trust entered into the $US 10 million non-revolving term facility with a maturity date of November 25, 2014, which is fully drawn as at the date of this Annual Information Form. The non-revolving facility allows for borrowing by way of LIBOR and base rate loans. The London Interbank Offered Rate ("**LIBOR**") and base rate margins are subject to a pricing grid based upon the percentage of credit facility utilization, and range from 3.0% to 4.0% and 2.0% to 3.0% respectively. For the period which the non-revolver loan was outstanding during 2013, the actual interest rate was 6%.

The Credit Facility provides for customary negative covenants which, among other things, limit the Trust, the CT, the GP, the Administrator and the Partnership from making distributions of cash flow to their partners, noteholders or unitholders if any default or event of default has occurred and is continuing or would result from such distribution, or if the cash distributions made in any quarter exceed the Trust's Available Distributable Cash Flow (as defined in the Credit Facility agreement) for the most recently completed quarter. The Credit Facility also includes other customary restrictive covenants including limitations on indebtedness, liens, contingent obligations, investments, dispositions, mergers, consolidations, liquidations and dissolutions and a negative pledge.

Under the Credit Facility, both the subsidiary of the Trust and the Trust must maintain a minimum current ratio (the ratio of current assets plus the unused commitment under the Credit Facility to current liabilities excluding any amounts owing under the Credit Facility) of not less than 1.00 to 1.00, a minimum coverage of interest expenses of not less than 3.00 to 1.00, and a maximum level of debt to earnings before interest, taxes and depreciation of 3.00 to 1.00. A failure to comply with any of these financial covenants, as well as any of the other affirmative and negative covenants, would result in an event of default which, if not cured or waived, would permit acceleration of the indebtedness pursuant to the Credit Facility. At December 31, 2013, there were no covenant violations. Compliance with the terms of these financial covenants under the Credit Facility could adversely impact the distributable cash of the Trust. See “Risk Factors”.

DESCRIPTION OF THE TRUST

The following is a summary of certain terms of the Trust Indenture which is qualified in its entirety by reference to the text of the Trust Indenture. Reference is made to the Trust Indenture for a complete description of the Units and the full text of its provisions. See “Material Contracts”. A copy of the Trust Indenture is available under the Trust’s issuer profile on www.sedar.com.

General

The Trust is an unincorporated open-ended limited purpose trust established under the laws of the Province of Alberta on July 20, 2010 by the Trust Indenture. The Trustee of the Trust is Computershare Trust Company of Canada (see “Trustee”, below). The Trust indirectly owns an interest in the Partnership through the Trust’s ownership of the CT Units and the CT Notes. Although it is intended that the Trust qualify as a “mutual fund trust” under the Tax Act, the Trust is not a mutual fund under applicable securities laws.

The Trust is a limited purpose trust and the undertaking of the Trust is restricted to investing its funds in property (other than real property or interests in real property) and “portfolio investment entities” as defined in the Tax Act. The Trust is also restricted from holding any “non-portfolio property” or “taxable Canadian property” as defined in the Tax Act and from taking any action, or acquiring, retaining or holding any investment or other property that would result in the Trust, the CT or the Partnership being a “SIFT trust” or “SIFT partnership”, as applicable, or the Trust not being a “mutual fund trust”, each as defined in the Tax Act. These investment restrictions in the Trust Indenture may only be amended by Special Resolution of the Unitholders.

Subject to the investment restrictions contained in the Trust Indenture, including those just noted, the Trustee has the authority to deal with the Trust’s property on behalf of the Trust as if it were the beneficial owner of such property, and in particular, may:

(a) temporarily hold cash and other short term investments in connection with and for the purposes of the Trust’s activities, including paying management, administration and other expenses of the Trust and paying any amounts required in connection with the redemption of Units and making distributions to Unitholders;

(b) give a guarantee on behalf of the Trust to secure performance of an obligation of another person to the extent that such guarantee would not jeopardize the Trust’s status as a mutual fund trust;

(c) mortgage, hypothecate, pledge or otherwise create a security interest in all or any movable or immovable, personal or real or other property of the Trust, owned or subsequently acquired, to secure any obligation of the Trust;

(d) lend, including without limitation the loans contemplated with regard to the CT Notes and other loans to subsidiaries;

(e) enter into the Administrative Services Agreement;

(f) invest, hold shares, securities, units, beneficial interests, partnership interests, joint venture interests or other interests in any person necessary or useful to carry out the purpose of the Trust;

(g) issue or provide for the issuance of debt or equity securities of the Trust, including Units and Other Trust Securities, on such terms and conditions and at such time or times as the Trustee may determine;

(h) redeem or repurchase Units in accordance with the terms set forth in the Trust Indenture;

(i) make or cause to be made application for the listing or quotation on any stock exchange or market of any Units or Other Trust Securities, and to do all things which in the opinion of the Trustee may be necessary or desirable to effect or maintain such listing or listings or quotation;

(j) possess and exercise all the rights, powers and privileges pertaining to the ownership of CT Units and CT Notes;

(k) to the extent not prohibited by applicable law, delegate any of the powers and duties of the Trustee to any one or more agents, representatives, officers, employees, independent contractors, subcontractors or other persons (including to the Administrator pursuant to the terms of the Administrative Services Agreement) without liability to the Trustee except as provided in the Trust Indenture; and

(l) do all such other acts and things as are necessary, useful, incidental or ancillary to the foregoing and exercise all powers and authorities which are necessary, useful, incidental or ancillary to carry on the affairs of the Trust, to promote any purpose for which the Trust is formed and to carry out the provisions of the Trust Indenture.

Units of the Trust

The beneficial interests in the Trust are represented and constituted by one class of units described and designated as “Units”. An unlimited number of the Units may be issued pursuant to the Trust Indenture. The Trust may also issue an unlimited number of Other Trust Securities. As of the date of this Annual Information Form, the Trust has 32,580,320 Units outstanding.

Each Unit represents an equal, undivided beneficial interest in the net assets of the Trust and all Units shall rank equally and rateably with all of the other Units without discrimination, preference or priority. Each Unit entitles the holder to one vote at all meetings of Unitholders.

Unitholders are entitled to receive non-cumulative distributions from the Trust if, as and when declared by the Trust. Units are redeemable on demand by the holders thereof, and may be purchased for cancellation by the Trust through offers made to, and accepted by, such holders. See “Description of the Trust – Redemption at the Option of Unitholders” and “Description of the Trust – Repurchase of Securities”. There are no other conversion, retraction, redemption or pre-emptive rights for Unitholders.

Issuance of Units

Units are to be issued only when fully paid in money, property or past services, and they are not to be subject to future calls or assessments, provided that: (a) Units may be issued for consideration payable in instalments if the Trust takes security over any such Units for unpaid instalments; and (b) the consideration for any Unit issued by the Trust is paid in money or in property or in past services that are not less in value than the fair equivalent of the money that the Trust would have received if the Unit had been issued for money, provided that property may include a promissory note or promise to pay given by the allottee.

The Trust Indenture provides that the Units or Other Trust Securities may be created, issued, sold and/or delivered at such times, to such persons, for such consideration and on such terms and conditions as the Trustee determines, including pursuant to any Unitholder rights plan, distribution reinvestment plan, or any compensation plan established by the Trust. The authority to determine the timing and terms of future offerings of Units has been delegated by the Trustee to the Administrator. See “Description of the Trust - Delegation to the Administrator”. Units may be issued in satisfaction of any non-cash distribution by the Trust to Unitholders on a *pro rata* basis. The Trust Indenture also provides that immediately after any pro rata distribution of Units to Unitholders in satisfaction of any non-cash distribution, the number of outstanding Units will be automatically consolidated such that each Unitholder will hold, after the consolidation, the same number of Units as the Unitholder held before the distribution of such additional Units, subject to reduction for payment of applicable withholding taxes. In this case, each certificate representing a number of Units prior to the distribution of additional Units is deemed to represent the same number of Units after the distribution of such additional Units and the consolidation.

Limitation on Non-Resident Ownership

Under current law, a trust may lose its status under the Tax Act as a “mutual fund trust” if it can reasonably be considered that the trust was established or is maintained primarily for the benefit of non-residents of Canada, except in limited circumstances. Among those circumstances are that all or substantially all of the mutual fund trust's property is not "taxable Canadian property", as defined by the Tax Act. The Trust is restricted from holding or acquiring taxable Canadian property by its investment restrictions, and therefore is not subject to a limit on non-resident ownership as long as it complies with those restrictions. In the event that such non-resident ownership restrictions become applicable, the Trustee has various powers that can be used for the purpose of monitoring and controlling the extent of non-resident ownership of the Units.

Book Entry System and Physical Unit Certificates

Unless and to the extent otherwise determined by the Trustee or the Administrator, or as otherwise provided below, the Units are issued in "book entry only" form and must be purchased or transferred through participants ("**Participants**") in the depositary service of CDS, which include securities brokers and dealers, banks and trust companies. Except as described below or if the Trustee or Administrator has determined otherwise, no Unitholder will be entitled to a physical certificate or other instrument from the Trust or CDS evidencing that holder's ownership thereof, and no Unitholders will be shown on the records maintained by CDS except through a book entry account of a Participant acting on behalf of such holder. Each purchaser acquiring a beneficial interest in the Units (a "Beneficial Owner") will receive a customer confirmation of purchase from the registered dealer from which the Unit is purchased in accordance with the practices and procedures of that registered dealer. The practices of registered dealers may vary, but generally customer confirmations are issued promptly after execution of a customer order. CDS is responsible for establishing and maintaining book entry accounts for its Participants having interests in the Units.

The Trust will not assume any liability for: (a) any aspect of the records relating to the beneficial ownership of the Units held by CDS or the payments relating thereto; (b) maintaining, supervising or reviewing any records relating to the Units; or (c) any statement made with respect to CDS and contained in this Annual Information Form and relating to the rules governing CDS or any action to be taken by CDS or at the direction of its Participants. The rules governing CDS provide that it acts as the agent and depositary for the Participants. As a result, Participants must look solely to CDS and Beneficial Owners must look solely to Participants for the payment of the distributions on the Units paid by or on behalf of the Trust to CDS.

As indirect holders of Units, investors should be aware that they (subject to the situations described below): (a) may not have Units registered in their name; (b) may not have physical certificates representing their interest in the Units; (c) may not be able to sell the Units to institutions required by law to hold physical certificates for securities they own; and (d) may be unable to pledge Units as security.

If: (i) CDS resigns or is removed from its responsibilities as depositary with respect to the Units and the Trust is unable or does not wish to locate a qualified successor, or (ii) the Administrator or the Trust, at their option (including to ensure compliance with the Trust's limitations on non-resident ownership) elects, or is required by law, to terminate the book entry system, or (iii) Unitholders representing not less than 66⅔% of the aggregate votes entitled to be voted at a meeting of Unitholders determine that the continuation of the book entry system is no longer in the best interests of the Unitholders, then Units will be issued in fully registered form to Unitholders or their nominees.

Transfer of Units

Units are transferable at any time and from time to time. Transfers of ownership in the Units will be effected only through records maintained by CDS or its nominee for such Units with respect to interests of Participants, and on the records of Participants with respect to interests of persons other than Participants. Unitholders who are not Participants, but who desire to purchase, sell or otherwise transfer ownership of or other interests in the Units, may do so only through Participants.

Repurchase of Securities

The Trust is entitled, from time to time, to offer to purchase Units or Other Trust Securities for cancellation at a price per security and on a basis determined by the Trustee in its discretion, but in compliance with applicable securities legislation and the rules prescribed under applicable stock exchange or regulatory policies. The authority to determine the timing and terms of any such repurchase of Units has been delegated by the Trustee to the Administrator. Any such purchase will constitute an "issuer bid" under Canadian provincial securities legislation and, if not exempt, must be conducted in accordance with the applicable requirements thereof.

Take-over Bids

If there is a take-over bid for all of the outstanding Units and within 120 days after the date of a take-over bid for the Units (which, depending on the terms of the take-over bid, may also include Units issuable upon conversion, exercise or exchange of Other Trust Securities), the bid is accepted by the holders of not less than 90% of the Units and, as applicable, the Units issuable upon the conversion, exercise or exchange of any relevant Other Trust Securities, taken together (collectively, the "**Bid Units**"), other than Bid Units held by or on behalf of, or issuable to, the offeror or an affiliate or associate of the offeror, then the offeror is entitled to acquire the Bid Units held by persons who did not accept the takeover bid, with such acquisition to occur on the same terms on which the offeror acquired Bid Units from persons who accepted the take-over bid. The Trust Indenture does not provide a mechanism for Unitholders who do not tender their Units to a take-over bid to apply to a court to fix the fair value of their Units.

Investments

Monies or other property received by the Trust or the Trustee on behalf of the Trust, including the net proceeds of any offering, may be used at any time and from time to time, for any purpose not inconsistent with the Trust Indenture. See "Description of the Trust – General" and "Description of the CT – Acquisitions and Investments".

The Trust Indenture contains investment restrictions to ensure that the Trust:

(a) complies at all times with the requirements for a "mutual fund trust", as defined in the Tax Act;

(b) does not take any action, or acquire or retain any investment, that would result in the Trust not being considered a "unit trust" or a "mutual fund trust" for purposes of the Tax Act;

(c) does not take any action, or acquire, retain or hold any investment or other property that would result in the Trust, the CT or the Partnership being a SIFT trust or a "SIFT partnership", as applicable, as defined in the Tax Act;

(d) does not invest in any entity other than a "portfolio investment entity" and, for greater certainty, does not hold any "non-portfolio property", each as defined in the Tax Act; and

(e) does not acquire any "taxable Canadian property" as defined in the Tax Act.

These restrictions in the Trust Indenture may only be amended by Special Resolution of the Unitholders.

Distributions

The Trust intends to make monthly distributions to Unitholders of record as of the close of business on the last business day of each month which are expected to be paid to Unitholders on or about the 23rd[th] day of the following month or if not a business day, the immediately preceding business day. The amount of cash to be distributed on a pro rata basis per month per Unit will be determined in the discretion of the Trust. Since November 24, 2010, the Trust has paid a monthly cash distribution of $0.0875 per Unit. As results of operations may vary, the distribution of cash is not guaranteed.

The Administrator anticipates that approximately 50 to 60% of the distributable cash for 2014 will be included in the income of Unitholders for income tax purposes and the balance will not be taxable and will be deducted from the adjusted cost base of their Units.

Where the Administrator, as administrator of the Trust, determines that the Trust does not have cash in an amount sufficient to make payment of the full amount of any distribution which has been declared to be payable, payment of such distribution may, at the option of the Administrator, include the issuance of additional Units, if necessary, having an aggregate value equal to the difference between the amount of such declared distribution and the amount of cash which has been determined by the Administrator to be available for the payment of such distribution. The value of each Unit which is to be issued in payment of distributions shall be the "market price" (as determined in accordance with the provisions of the Trust Indenture). See "Description of the Trust – Issuance of Units". Such additional Units will be issued pursuant to applicable exemptions under applicable securities laws, discretionary exemptions granted by applicable securities regulatory authorities or a prospectus or similar filing.

Payments of distributions on each Unit issued in "book entry only" form will be made by the Trust to CDS or its nominee, as the case may be, as the registered owner of Units, and the Trust understands that such payments will be forwarded by CDS or its nominee, as the case may be, to Participants. As long as CDS or its nominee is the registered owner of Units, CDS or its nominee, as the case may be, will be considered the sole owner of those Units for the purposes of receiving payments on those Units. The responsibility and liability of the Trust in respect of the payment of distributions in respect of the Units is limited to making payment of any income or capital in respect of those Units to CDS or its nominee.

The Trust's ability to pay distributions to Unitholders is dependent upon the ability of the Partnership and the CT to meet their interest, principal and other distribution obligations. The Partnership's income will be derived from the production of oil and natural gas from its resource properties and is susceptible to the risks and uncertainties associated with the oil and natural gas industry generally, and specifically in the U.S.

The CT and the Partnership are required to comply with covenants under the Credit Facility. In the event that they do not comply with covenants under the Credit Facility, the ability to make distributions to Unitholders may be restricted. See "Risk Factors".

Premium Distribution™ and Distribution Reinvestment Plan

The Trust has adopted a Premium Distribution™ and Distribution Reinvestment Plan (the "**Plan**"). The Plan provides eligible Unitholders with the opportunity to reinvest their monthly cash distributions in new trust units at a 5% discount to the average market price (as defined in the Plan) on the applicable distribution payment date, which new trust units will, at the participant's election, either be credited to the participant's account under the distribution reinvestment component of the Plan, or delivered to the designated Plan Broker in exchange for a premium cash payment to the participant equal to 102% of the reinvested distributions under the Premium Distribution™ component of the Plan. Participation in the Plan by Unitholders is optional. Those Unitholders who do not enroll in the Plan will still receive monthly cash distributions as declared by the Trust.

Unitholders who are resident in Canada may participate in either the distribution reinvestment component or the Premium Distribution™ component of the Plan. Unless otherwise announced by the Trust, a Unitholder who is a resident of the United States or is otherwise a "U.S. person" (as defined in the Plan) may not participate in either the distribution reinvestment component or the Premium Distribution™ component of the Plan. Unitholders who are resident in any jurisdiction outside of Canada (other than the United States) may participate in the distribution reinvestment component of the Plan only if their participation is permitted by the laws of the jurisdiction in which they reside and provided that the Trust is satisfied, in its sole discretion, that such laws do not subject the Plan or any of the Trust, the Plan Agent or the Plan Broker to additional legal or regulatory requirements. Unless otherwise announced by the Trust, Unitholders who are not resident in Canada may not participate in the Premium Distribution™ component of the Plan. The amount of any distributions to be reinvested under the Plan on behalf of Unitholders who are not residents of Canada will be reduced by the amount of any applicable non-resident withholding tax.

The Trust reserves the right to limit the amount of new equity available under the Plan on any particular distribution payment date. No assurances can be made that new trust units will be made available under the Plan on a monthly basis, or at all. Accordingly, participation may be prorated in certain circumstances. If on any distribution payment date the Trust determines not to issue any equity under the Plan, or the availability of new trust units is prorated in accordance with the terms of the Plan, then participants will be entitled to receive from the Trust the full amount of the regular distribution for each trust unit in respect of which the distribution is payable but cannot be reinvested under the Plan in accordance with the applicable election.

Materials relating to the Plan are available on the Trust's website at www.eagleenergytrust.com or by contacting the Trust by phone at (403) 531-1575 or by mail at the Trust's address set out above.

Redemption at the Option of Unitholders

Units are redeemable at any time and from time to time on demand by the Unitholders thereof upon delivery to the Trust at its head office and to CDS (if a global unit certificate has been issued by the Trust) of a duly completed and properly executed notice, in a form reasonably acceptable to the Trustee, requesting redemption, together with written instructions as to the number of Units to be redeemed and together with the certificates, if any, representing Units to be redeemed (if a global unit certificate has not been issued by the Trust). Upon tender of Units by a Unitholder for redemption, all rights to and under the Units tendered for redemption shall immediately cease, provided that the Unitholder thereof shall retain the right to receive distributions thereon which have been declared payable to Unitholders of record prior to the date of tender for redemption (the "**Redemption Date**") and the right to receive a price per Unit (the "**Redemption Price**") in cash equal to the lesser of: (i) 90% of (a) the volume weighted average trading price of a Unit traded on the principal stock exchange on which the Units are listed (or, if the Units are not listed on any such exchange, on the principal market on which the Units are quoted for trading) during the period of the last 10 trading days ending immediately prior to the Redemption Date; (b) if the applicable exchange or market does not provide information necessary to compute a volume weighted average trading price, an amount equal to the volume weighted average of the closing prices of a Unit for each of the last 10 trading days occurring immediately prior to the Redemption Date on which there was a closing price; provided that if the applicable exchange or market does not provide a closing price, but only provides the highest and lowest prices of the Units traded on a particular day, the price shall be an amount equal to the volume weighted average of the average of the highest and lowest prices for each of the trading days on which there was a trade; and (c) if there was trading on the applicable market or exchange for fewer than five of the 10 trading days occurring immediately prior to the Redemption Date, the volume weighted average of the following prices established for each of the 10 trading days: (1) the average of the last bid and last asking prices for each day on which there was no trading; (2) the closing price of the Units for each day that there was trading if the exchange or market provides a closing price; and (3) the average of the highest and lowest prices of the Units for each day that there was trading, if the exchange or market provides only the highest and lowest prices of Units traded on a particular day; and (ii) an amount equal to 100% of the (a) volume weighted average trading price of a Unit on the Redemption Date, on the principal stock exchange on which Units are listed (or, if the Units are not listed on any such exchange, on the principal market on which the Units are quoted for trading) if the applicable exchange or market provides information necessary to compute a volume weighted average trading price on such date; (b) the closing price of a Unit if there was a trade on the Redemption Date, and the exchange or market provides only a closing price; (c) simple average of the highest and lowest prices of Units on the Redemption Date if there was trading on such date and the exchange or market provides only the highest and lowest trading prices of Units traded on a particular day; or (d) simple average of the last bid and the last asking prices of the Units on the Redemption Date if there was no trading on such date.

The aggregate Redemption Price payable by the Trust in respect of any Units tendered for redemption during any month shall be paid by cheque drawn on a Canadian chartered bank or trust company in lawful money of Canada payable to the Unitholder who exercised the right of redemption, on or before the fifth business day after the end of the calendar month following the calendar month in which the Units were tendered for redemption; provided that Unitholders shall not be entitled to receive cash upon the redemption of their Units if: (i) the total amount payable by the Trust in respect of such Units and all other Units tendered for redemption in the same month exceeds $100,000 (provided that such limitation may be waived at the discretion of the Trustee); (ii) at the time such Units are tendered for redemption, the outstanding Units are not listed for trading on the TSX and are not traded or quoted on any other stock exchange or market which the Trustee considers, in its discretion, provides representative fair market value prices for the Units; (iii) the normal trading of Units is suspended or halted on any stock exchange on which the Units are listed (or, if not listed on a stock exchange, on any market on which the Units are quoted for trading) on the Redemption Date or for more than five trading days during the 10 trading-day period immediately prior to the Redemption Date; or (iv) the Trust or any affiliate of the Trust (including the Partnership) is, or after such redemption would be, in default under the Credit Facility or any other credit facilities and agreements entered into by the Trust or any of its affiliates, from time to time, which set forth the terms and conditions of any debt financing obtained by the Trust, or by any one of its affiliates (as the case may be), from any person or persons not affiliated with the Trust (and for further certainty, shall include all agreements pertaining to issuances of debentures or other debt securities to the public).

If a Unitholder is not entitled to receive cash upon the redemption of Units as a result of the limitations set forth in the immediately preceding paragraph, then the redemption price for each Unit tendered for redemption shall be equal to the fair market value of a Unit as determined by the Trustee, in its discretion, and shall, subject to all necessary regulatory approvals, be paid and satisfied by way of a distribution in specie of Trust Property which may include the CT Notes or other Trust Property (other than the CT Units), as determined by the Trustee in its discretion. Any CT Notes so distributed shall be in the principal amount of $100. No fractional CT Notes will be distributed and where the number of CT Notes to be received by a Unitholder includes a fraction, such number shall be rounded to the next lowest whole number.

It is anticipated that the redemption right will not be the primary mechanism for Unitholders to dispose of their Units. The CT Notes and other assets of the Trust which may be distributed *in specie* to Unitholders in connection with a redemption will not be listed on any stock exchange and no market is expected to develop in the CT Notes or in the other assets of the Trust. The CT Notes and other Trust Property so distributed are expected to be subject to resale restrictions under applicable securities laws and are not expected to be qualified investments for Registered Plans.

Trustee

Computershare Trust Company of Canada is the Trustee and the transfer agent and registrar for the Units. Subject to the express limitations contained in the Trust Indenture and any grant of certain powers to the Administrator, as administrator of the Trust, the Trustee has full, absolute and exclusive power, control and authority over the Trust Property and over the affairs of the Trust to the same extent as if the Trustee were the sole and absolute beneficial owner of the Trust Property in its own right, and to do all such acts and things as in its discretion are necessary or incidental to, or desirable for, the carrying out of the duties of the Trust created pursuant to the Trust Indenture. The Trustee has no obligation to Unitholders beyond the obligations set out in the Trust Indenture, except as may be mandated by law.

The Trust Indenture provides that the Trustee must discharge its duties honestly, in good faith and in the best interests of the Trust and the Unitholders and in connection therewith, exercise the degree of care, diligence and skill that a reasonably prudent trustee would exercise in comparable circumstances.

Except as expressly prohibited by law, the Trustee may in its discretion delegate the execution of certain of its authority and powers to the Administrator, as the administrator of the Trust, pursuant to the terms of the Administrative Services Agreement. The Trustee may in its discretion also delegate the execution of certain of its authority and powers to such other persons as is necessary or desirable to carry out and effect the actual management and administration of the duties of the Trustee under the Trust Indenture without regard to whether such authority is normally delegated by trustees. See "Description of the Trust – Delegation to the Administrator".

The Trustee shall be entitled to make any reasonable decisions, designations or determinations not contrary to the Trust Indenture which it may determine are necessary or desirable in interpreting, applying or administering the Trust Indenture, or in administering, managing or operating the Trust. Any Trustee's decisions, designations or determinations made pursuant to the Trust Indenture shall be conclusive and binding upon the Trust and the Unitholders.

The Trustee may resign as Trustee by giving to the Administrator, in its capacity as administrator of the Trust, not less than 90 days' prior written notice, unless the Administrator agrees to a shorter period of notice. The Trustee may be removed at any time with or without cause by Ordinary Resolution. The Trustee may also be removed at any time by the Administrator, in its capacity as administrator of the Trust, by notice in writing to the Trustee upon the occurrence of certain events, including where the Trustee is declared bankrupt or insolvent or enters into liquidation to wind up its affairs, all of its assets (or a substantial part thereof) are subject to seizure or confiscation, it becomes incapable or refuses to perform its responsibilities under the Trust Indenture, or the Trustee at any time ceases (i) to be incorporated under the laws of Canada or a province thereof, (ii) to be resident in Canada for the purposes of the Tax Act, or (iii) to be authorized and registered under the laws of the Province of Alberta to carry on the business of a trust company.

Any resignation or removal of the Trustee will take effect on the date upon which the last of the following occurs (i) a successor Trustee is appointed or elected pursuant to the Trust Indenture, and (ii) the new successor Trustee has accepted such election or appointment and has legally and validly assumed all obligations of the Trustee under the Trust Indenture. If no successor Trustee has been appointed or elected within 60 days of notice being given by the Trustee of its resignation, approval of an Ordinary Resolution to remove the Trustee, or the giving of notice by the Administrator to remove the Trustee, as the case may be, any Unitholder, the Trustee, the Administrator or any other interested person may apply to a court of competent jurisdiction for the appointment of a successor trustee.

Upon the taking effect of any resignation or removal of the Trustee under the terms of the Trust Indenture, the Trustee shall cease to be a party to the Administrative Services Agreement and the Voting Agreement.

The Trust Indenture provides that the Trustee shall be entitled to rely on and shall have no liability to any Unitholder, holder of Other Trust Securities, or any person for acting or failing to act, in good faith, in relation to any matter relating to the Trust where such action or failure is based upon, statements from, the opinion or advice of, or information from auditors, counsel or any valuator, engineer, surveyor or appraiser where it is reasonable to conclude that the matter in respect of which such statements are made, or opinion or advice given, ought to be within the expertise of such advisor or expert, provided that with respect to advisors and experts, the Trustee has satisfied its standard of care in selecting such advisors and experts. The Trustee shall have no liability whatsoever to any Unitholder or holder of Other Trust Securities for any obligation, liability or claim arising in connection with, directly or indirectly, the Trust Property or the conduct and undertaking of the affairs of the Trust, including (i) any action or failure to act by the Trustee in respect to its duties, responsibilities, powers, authorities and discretion under the Trust Indenture (including failure to compel in any way any trustee to redress any breach of trust or any failure of the Administrator to perform its duties under, or delegated to it under, the Trust Indenture, the Administrative Services Agreement or any other contract), (ii) any error in judgment, (iii) any matters pertaining to the administration or termination of the Trust, (iv) any Environmental Liabilities, (v) any action or failure to act by the Administrator or any other person to whom the Trustee has, as permitted by the Trust Indenture, delegated any of its duties, and (vi) any depreciation of, or loss to, the Trust incurred by reason of the retention or sale of any Trust Property; unless such liabilities arise from or out of the wilful misconduct, fraud or gross negligence of the Trustee or the breach by the Trustee of its standard of care under the Trust Indenture. Where the Trustee is held liable to any person in circumstances or its property or assets are subject to levy, execution or other enforcement resulting in personal loss to the Trustee where there is to be no liability on the Trustee on the basis just described, the Trustee shall be indemnified out of the Trust Property to the full extent of such liability and the costs of any action, suit or proceeding or threatened action, suit or proceeding, including without limitation, reasonable legal fees and disbursements. The Trust Indenture also contains other customary provisions limiting the liability of the Trustee.

Certain Restrictions on Trustee's Powers

The Trust Indenture provides that a change to the Administrative Services Agreement or any extension thereof (which includes any increase in fees or other amounts payable by the Trust or its affiliates thereunder) and the terms of any agreement entered into by the Trust or its affiliates with the Administrator or any affiliate of the Administrator, must be approved by a majority of the Administrator Directors.

The Trust Indenture further provides that the Trustee shall not, without approval of Unitholders by Ordinary Resolution, (i) vote the CT Units with respect to any matter which, under the CT Trust Indenture, requires or permits approval of the holders of the CT Units by Ordinary Resolution, (ii) instruct on the voting of any share of the Administrator pursuant to the Voting Agreement for the appointment of Administrator Directors by the Unitholders, or (iii) appoint or change the auditors of the Trust, except in the event of a voluntary resignation of such auditors, acting reasonably.

In addition, the Trust Indenture provides that the Trustee shall not, without approval of Unitholders by Special Resolution, (i) vote the CT Units with respect to any matter which, under the CT Trust Indenture, requires or permits approval by the holders of the CT Units by Special Resolution, (ii) amend the Trust Indenture, except as permitted by the Trust Indenture (as described under "Amendments to the Trust Indenture" below), (iii) sell, lease or exchange all or substantially all of the Trust Property, other than (a) pursuant to in specie redemptions permitted under the Trust Indenture, (b) in order to acquire the CT Units and the CT Notes in connection with pursuing the purpose of the Trust and completing the transactions described herein, or (c) in conjunction with an internal reorganization involving the sale, lease, exchange or other transfer of the Trust Property (whether or not involving all or substantially all of the Trust Property) as a result of which the Trust has substantially the same interest, whether directly or indirectly, in the Trust Property that it had prior to the reorganization and, for greater certainty, such reorganization includes an amalgamation, arrangement or merger of the Trust and its affiliates with any entities.

Amendments to the Trust Indenture

Except where otherwise specifically provided in the Trust Indenture, the indenture may only be amended or altered by Special Resolution. The Trustee will be entitled, at its discretion (which discretion has been delegated to the Administrator) and without the approval of the Unitholders, to make amendments to the Trust Indenture at any time for any of the following purposes: (i) ensuring the Trust continues to comply with applicable laws, regulations, requirements or policies of any governmental or regulatory authority having jurisdiction over the Trustee or the Trust; (ii) providing, in the opinion of the Trustee, additional protection for the Unitholders or to obtain, preserve or clarify the provision of desirable tax treatment to Unitholders; (iii) making amendments which, in the opinion of the Trustee, are necessary or desirable in the interests of the Unitholders as a result of changes in taxation laws or in their interpretation or administration; (iv) making minor corrections, or removing or curing any conflicts or inconsistencies between the provisions of the Trust Indenture or any supplemental indenture, and any other agreement to which the Trust is a party, or any applicable law or regulation of any jurisdiction, or any prospectus filed with any governmental or regulatory authority with respect to the Trust, provided that, in the opinion of the Trustee in each case, the rights of the Unitholders are not materially prejudiced thereby; (v) providing for the electronic delivery by the Trust to Unitholders of documents relating to the Trust (including annual and quarterly reports, including financial statements, notice of Unitholder's meetings and information circulars and proxy related materials) at such time as applicable securities laws have been amended to permit such electronic delivery in place of normal delivery procedures, provided that such amendments are not contrary to or do not conflict with such laws; (vi) curing, correcting or rectifying any ambiguities, defective or inconsistent provisions, errors, mistakes or omissions, provided that, in the opinion of the Trustee, the rights of the Unitholders are not materially prejudiced thereby; and (vii) making amendments as are required to undertake an internal reorganization involving the sale, lease, exchange or other transfer of the Trust Property the result of which the Trust has substantially the same interest, whether direct or indirect, in the Trust Property that it had prior to the reorganization and, for greater certainty, includes an amalgamation, arrangement or merger of the Trust and its affiliates with any entities.

No amendment may be made to the to modify the voting rights attributable to Units or to reduce the fractional undivided beneficial interest in the Trust Property represented by any Unit without the consent of the holder of such Unit.

Rights of Unitholders

The rights of the Unitholders are established by the Trust Indenture. A Unitholder of the Trust has all of the material protections, rights and remedies a shareholder of a corporation would have under the ABCA, except as described below.

Many of the provisions of the ABCA respecting the governance and management of a corporation have been incorporated in the Trust Indenture. For example, Unitholders are entitled to exercise voting rights in respect of their holdings of Units in a manner comparable to shareholders of an ABCA corporation, including to elect Administrator Directors and to appoint auditors. The Trust Indenture also includes provisions modeled after comparable provisions of the ABCA dealing with the calling and holding of meetings of Unitholders, the quorum for and procedures at such meetings and the right of Unitholders to participate in the decision-making process where certain fundamental actions are proposed to be undertaken. Unlike shareholders of an ABCA corporation, Unitholders do not have a comparable right to make a unitholder proposal at a general meeting of the Trust. The matters in respect of which Unitholder approval is required under the Trust Indenture are generally less extensive than the rights conferred on the shareholders of an ABCA corporation, but effectively extend to certain fundamental actions that may be undertaken by the Trust and its subsidiary entities. These Unitholder approval rights are supplemented by provisions of applicable securities laws that are generally applicable to issuers (whether corporations, trusts or other entities) that are "reporting issuers" or the equivalent or listed on the TSX.

Unitholders do not have recourse to a dissent right under which shareholders of an ABCA corporation are entitled to receive the fair value of their shares where certain fundamental changes affecting the corporation are undertaken (such as an amalgamation, a continuance under the laws of another jurisdiction, the sale of all or substantially all of its property, a going private transaction or the addition, change or removal of provisions restricting (i) the business or businesses that the corporation can carry on, or (ii) the issue, transfer or ownership of shares). As an alternative, Unitholders seeking to terminate their investment in the Trust are entitled to redeem their Units, as described under "Description of the Trust – Redemption at the Option of Unitholders". Unitholders similarly do not have recourse to the statutory oppression remedy that is available to shareholders of an ABCA corporation where the corporation undertakes actions that are oppressive, unfairly prejudicial or disregarding the interests of securityholders and certain other parties.

Shareholders of an ABCA corporation may apply to a court to order the liquidation and dissolution of the corporation in those circumstances, whereas Unitholders can rely only on the general provisions of the Trust Indenture which permit the winding up of the Trust with the approval of a Special Resolution of the Unitholders. Shareholders of an ABCA corporation may also apply to a court for the appointment of an inspector, subject to court oversight and other investigative procedures, to investigate the manner in which the business of the corporation and its affiliates is being carried on where there is reason to believe that fraudulent, dishonest or oppressive conduct has occurred. By virtue of the right to requisition a meeting of Unitholders, the Trust Indenture allows Unitholders to call meetings to consider the appointment or removal of the Trustee and the Administrator Directors, but does not specifically contemplate the appointment of an inspector. The ABCA also permits shareholders to bring or intervene in derivative actions in the name of the corporation or any of its subsidiaries, with the leave of a court. The Trust Indenture does not include a comparable right of the Unitholders to commence or participate in legal proceedings with respect to the Trust. The protections, rights and remedies available to a Unitholder are described in the Trust Indenture. See "Risk Factors – Risks Relating to the Trust's Structure and Ownership of Units".

Meetings of Unitholders

The Trust Indenture provides that there shall be an annual meeting of the Unitholders immediately prior to, and at the same place as, each annual meeting of holders of the CT Units and common shares of the Administrator for the purpose of: (i) presentation of the financial statements of the Trust for the immediately preceding fiscal year; (ii) appointing the auditors of the Trust for the ensuing year; (iii) transacting such other business as the Trustee may determine or as may be properly brought before the meeting; and (iv) directing and instructing the Trustee as to the manner in which the Trustee shall vote, at the annual meeting of the holders of CT Units which is to immediately follow the annual meeting of Unitholders, the CT Units held by the Trust; and (v) electing the Administrator Directors.

The Trust Indenture provides that special meetings of Unitholders may be convened at any time and for any purpose by the Trustee or the Administrator (so long as the Trust holds any CT Units) and must be convened, except in certain circumstances, if requisitioned in writing by the Unitholders representing not less than 20% of all votes entitled to be voted at a meeting of Unitholders. A requisition will be required to state in reasonable detail the business proposed to be transacted at the meeting.

Unitholders may attend and vote at all meetings of the Unitholders either in person or by proxy. A proxyholder will not be required to be a Unitholder. One or more persons present in person and being Unitholders or representing, by proxy, Unitholders who hold in the aggregate not less than 10% of all votes entitled to be voted at a meeting of Unitholders shall constitute a quorum for the transaction of business at all such meetings. At any meeting at which a quorum is not present within 30 minutes after the time fixed for the holding of such meeting, the meeting, if convened upon the requisition of the Unitholders, shall be terminated, but in any other case, the meeting will stand adjourned to a day not less than 14 days later and to a place and time as determined by the chairman of the meeting and if at such adjourned meeting a quorum is not present, the Unitholders present either in person or by proxy shall be deemed to constitute a quorum.

Every question submitted to a meeting, other than questions to be decided by Special Resolution, shall, unless a poll vote is demanded, be decided by a show of hands on which every person present and entitled to vote shall be entitled to one vote. On a poll vote at any meeting of Unitholders, each Unit shall entitle the holder thereof to one vote.

The Trust Indenture contains provisions as to the notice required and other procedures with respect to the calling and holding of meetings of Unitholders.

Information and Reports

The Administrator, as administrator of the Trust, will furnish to Unitholders, in accordance with applicable securities laws, all financial statements of the Trust (including quarterly and annual financial statements and certifications) and other reports as are from time to time required by applicable law, including prescribed forms needed for the completion of Unitholder's tax returns under the Tax Act and equivalent provincial legislation.

Each voting Unitholder has the right to obtain, on demand and without fee, from the head office of the Trust a copy of the Trust Indenture and any amendments thereto, and will be entitled to examine a list of Unitholders, subject to providing an affidavit to the Administrator, as administrator of the Trust, similar to the affidavit required under the ABCA for a shareholder to obtain a list of shareholders.

Prior to each meeting of Unitholders, the Administrator, as administrator of the Trust, will provide to the Unitholders (along with notice of the meeting) all information, together with such certifications, as are required by applicable law and by the Trust Indenture to be provided to Unitholders.

Term of the Trust

The Trust has been established for a term ending 21 years after the date of death of the last surviving issue of Her Majesty, Queen Elizabeth II, alive on July 19, 2010. The termination or winding up of the Trust may also be effected by passage of a Special Resolution authorizing the same.

Delegation to the Administrator

Under the terms of the Trust Indenture, the Trustee is authorized to delegate any of the powers and duties granted to it (to the extent not prohibited by law) to any person as the Trustee may deem necessary or desirable. The Trustee has delegated many of its powers and duties to the Administrator, as administrator of the Trust, pursuant to the terms of the Administrative Services Agreement. Among other things, the Administrative Services Agreement sets forth all of the rights, restrictions and limitations (including, without limitation, limitations of liability and indemnification rights) which pertain to the performance by the Administrator of the duties delegated to it by the Trustee. Pursuant to the terms of the Trust Indenture, those rights, restrictions and limitations also apply in all respects to the Administrator, as administrator of the Trust, in the exercise and performance by it of all powers, duties and authorities conferred upon or delegated to the Administrator under the terms of the Trust Indenture. In the event of a termination of the Administrative Services Agreement, the Trustee will, until a successor administrator is appointed, perform the duties otherwise to have been performed by the Administrator under the Administrative Services Agreement and the Trust Indenture on the same terms and conditions as they were performed by the Administrator. See "Administrative Services Agreement". The Trust Indenture provides that the Trustee shall have no liability to any Unitholder as a result of the delegation by the Trustee of its powers and duties to the Administrator.

In performing the duties delegated to it, the Administrator must exercise its power and carry out its function honestly, in good faith and in the best interests of the Trust and is also obligated to exercise that degree of care, diligence and skill as would be exercised, in Canada, by a reasonably prudent person having responsibilities of a similar nature to those under the Administrative Services Agreement in comparable circumstances. The Administrator Directors are indemnified by the Trust in respect of their activities on behalf of the Trust, as referred to above, unless the Administrator Directors act in a manner which is fraudulent, grossly negligent or in wilful default of their duties.

Power of Attorney

Upon becoming a Unitholder, each Unitholder, pursuant to the terms of the Trust Indenture, grants to the Trustee a power of attorney constituting the Trustee, with full power of substitution, as the true and lawful attorney of such Unitholder to act on his behalf, with full power and authority in his name, place and stead, to execute, swear to, acknowledge, deliver, make, file or record (and to take all requisite action in connection with such matters), when, as and where required: (i) the Trust Indenture and any other instrument required or desirable to qualify, continue and keep in good standing the Trust as a "mutual fund trust" under the Tax Act in all jurisdictions that the Trustee deems appropriate; (ii) any instrument, deed, agreement or document in connection with carrying on the affairs of the Trust as authorized in the Trust Indenture, including all conveyances, transfers and other documents required in connection with any disposition of Units; (iii) all conveyances, transfers and other documents required in connection with the dissolution, liquidation or termination of the Trust; (iv) any and all elections, determinations or designations whether jointly with third parties or otherwise, under the Tax Act or any other taxation or other legislation or similar laws of Canada or of any other jurisdiction in respect of the affairs of the Trust or of a Unitholder's interest in the Trust; (v) any instrument, certificate and other documents necessary or appropriate to reflect and give effect to any duly authorized amendment to the Trust Indenture; and (vi) all transfers, conveyances and other documents required to facilitate the acquisition of Units of non-tendering offerees in the event of a takeover bid.

Each Unitholder is agreeing that the power of attorney is, to the extent permitted by applicable law, irrevocable, is a power coupled with an interest, and shall survive the death, mental incompetence, disability and any subsequent legal incapacity of the Unitholder and shall survive the assignment by the Unitholder of all or part of the Unitholder's interest in the Trust and will extend to and bind the heirs, executors, administrators and other legal representatives and successors and assigns of the Unitholder. Each Unitholder agrees to be bound by any representations or actions made or taken by the Trustee pursuant to the power of attorney and waive any and all defences which may be available to contest, negate or disaffirm any actions taken by the Trustee in good faith under the power of attorney.

DESCRIPTION OF THE COMMERCIAL TRUST

The CT Trust Indenture contains provisions substantially similar to those of the Trust Indenture. The principal differences between the CT Trust Indenture and the Trust Indenture are described below. The description below is a summary only and is qualified in its entirety by reference to the full text of the CT Trust Indenture and the Trust Indenture. See "Material Contracts".

General

The CT is an unincorporated trust established under the laws of the Province of Alberta on September 27, 2010 by the CT Trust Indenture. The CT has been created to acquire and hold a 99.999% interest in the Partnership, with the remaining 0.001% held by the GP, a wholly-owned subsidiary of the CT. The CT's activities are restricted to the direct or indirect operation of energy related businesses, including through the ownership of an interest in the Partnership, provided that the CT does not: (i) take any action, or acquire or retain any investment, that would result in the Trust, the CT or any entity in which the Trust or the CT has invested being considered a "SIFT trust" or a "SIFT partnership" as defined in the Tax Act.

Units of the CT

The beneficial interest in the CT is represented and constituted by one class of units, the CT Units. An unlimited number of the CT Units are authorized for issuance pursuant to the CT Trust Indenture. All of the issued and outstanding CT Units are owned by the Trust. The CT Units are to be issued only when fully paid in money, property or past services and are not to be subject to future calls or assessments. It is anticipated that the Trust will always be the sole holder of the CT Units.

The CT Unitholders are entitled to participate equally with respect to any and all distributions if, as and when declared in accordance with the provisions of the CT Trust Indenture. See "Description of the CT — Distributions".

On the liquidation or termination of the CT or other distribution of assets of the CT among the CT Unitholders for the purpose of winding up the affairs of the CT, each CT Unit will entitle the holder to participate equally with respect to the distribution of the remaining assets of the CT after payment of its debts, liabilities and liquidation or termination expenses. Except as set out immediately above, and as set forth below under "Redemption of the CT Units", there are no conversion, retraction, redemption, repurchase, or pre-emptive rights attaching to the CT Units.

Governance

The trustee of the CT is the Administrator. The Administrator Directors are appointed from time to time by the Unitholders of the Trust pursuant to the terms of the Voting Agreement.

The CT Trust Indenture provides that the Administrator must exercise its power and carry out its function as CT Trustee honestly, in good faith and in the best interest of the CT and CT Unitholders. Additionally, the CT Trustee must exercise the degree of care, diligence and skill that a reasonably prudent trustee would exercise in the circumstances.

Acquisitions and Investments

Monies or other property received by the CT or the Administrator on behalf of the CT may be used for any purpose, activity or undertaking not inconsistent with the CT Trust Indenture.

Distributions

The distributable cash of the CT is an amount determined in the discretion of the CT Trustee and will be derived exclusively from distributions on the interest in the Partnership owned by the CT. The CT intends to make monthly cash distributions to the Trust in conjunction with the monthly distributions made by the Trust to the Unitholders after satisfaction of its interest obligations and other obligations. The description of the distributable cash of the CT is substantially similar to that of the Trust.

Redemption of the CT Units

The CT Units are redeemable at any time on demand by any CT Unitholder upon delivery to the CT of a duly completed and properly executed notice requiring the CT to redeem the CT Units, in a form reasonably acceptable to the Administrator Directors, together with the certificates representing the CT Units to be redeemed and written instructions as to the number of the CT Units to be redeemed. Upon tender of the CT Units by any CT Unitholder for redemption, the tendering CT Unitholder will no longer have any rights with respect to such CT Units other than the right to receive the redemption price for such CT Units and the right to receive distributions in respect of such CT Units which have been declared payable to holders of record on a date prior to the date of tender for redemption. The redemption price for each CT Unit tendered for redemption will be equal to:

$$\frac{(A \times B) - C}{D}$$

where:

A = the cash redemption price per Unit calculated as of the close of business on the date the CT Units were so tendered for redemption by the CT Unitholder;

B = the aggregate number of Units outstanding as of the close of business on the date the CT Units were so tendered for redemption by the CT Unitholder;

C = the aggregate unpaid principal amount of the CT Notes owned by the Trust, taking into account all accrued but unpaid interest thereon, any other indebtedness of, or liabilities owed by, the CT to the Trust, and the fair market value of all other assets or investments owned by the Trust (other than the CT Units and the CT Notes), as of the close of business on the date the CT Units were so tendered for redemption by the CT Unitholder; and

D = the aggregate number of the CT Units outstanding as of the close of business on the date the CT Units were so tendered for redemption by the CT Unitholder.

The CT may also call for redemption, at any time, all or any part of the outstanding CT Units registered in the name of holders thereof (other than those registered in the name of the Trust) at the same redemption price as described above for each CT Unit called for redemption, calculated with reference to the date the Administrator Directors approved the redemption of the CT Units as opposed to the close of business on the date the CT Units are tendered for redemption.

The aggregate redemption price payable by the CT in respect of any CT Units tendered for redemption by the holders thereof during any month shall be satisfied, at the option of the Administrator Directors (i) by cheque in immediately available funds, (ii) by the issuance, to or to the order of the holder whose CT Units are to be redeemed, of such aggregate principal amount of the CT Notes as is equal to the aggregate redemption price payable to such CT Unitholder rounded down to the nearest $100, with the balance of any such aggregate redemption price not paid in the CT Notes to be paid by cheque in immediately available funds; or (iii) by any combination of cash and the CT Notes as the Administrator Directors shall determine in their discretion, in each such case payable or issuable on or before the fifth business day of the calendar month following the calendar month in which the CT Units were so tendered for redemption. A CT Unitholder whose CT Units are so tendered for redemption may elect, at any time prior to the payment of the redemption price, to receive the CT Notes pursuant to subparagraph (ii) above in the place of all or part of the cash otherwise payable, with the principal amount of such CT Notes to be equal to the amount of cash otherwise payable rounded down to the nearest $100. In the case of the CT Units called for redemption by the CT, the aggregate redemption price payable by the CT to the CT Unitholders whose CT Units have been so called for redemption shall be satisfied by payment by cheque, in immediately available funds.

The CT Notes

Following is a summary of the material attributes and characteristics of the CT Notes which have been issued by the CT under the CT Note Indenture. This summary is qualified in its entirety by reference to the provisions of the CT Note Indenture. See “Material Contracts”.

As at December 31, 2013, the CT had issued to the Trust 14,580,693 CT Units at $10.00 per CT Unit, CT Note Series 1 with an aggregate principal amount of $92,644,000 and CT Note Series 3 with an aggregate principal amount of $51,452,875. The Trust owns all of the CT Units, CT Notes Series 1 and CT Notes Series 3 issued by the CT. The CT has not issued any CT Notes Series 2 or CT Notes Series 4.

Interest and Maturity

The CT Note Series 1 bears interest at the rate of 11.5% per annum, payable monthly, in arrears, with such payment to be made on the last business day of each calendar month or such earlier date as the principal balance outstanding and all accrued and unpaid interest is payable by the CT to the holder of the CT Note Series 1. The CT may repay all or any portion of the principal amount of any CT Note at any time without interest or penalty. The CT Note Series 1 will mature on December 31, 2020.

The CT Note Series 3 bears interest at the rate of 10.0% per annum, payable monthly, in arrears, with such payment to be made on the last business day of each calendar month or such earlier date as the principal balance outstanding and all accrued and unpaid interest is payable by the CT to the holder of the CT Note Series 3. The CT may repay all or any portion of the principal amount of any CT Note at any time without interest or penalty. The CT Note Series 3 will mature on May 31, 2022.

Each CT Note Series 2 and CT Note Series 4, if, as and when issued, will mature on a date determined at the issue of the issuance of such CT Note Series 2 or CT Note Series 4 by the CT Trustee.

Payment Upon Maturity

Except as otherwise provided under the CT Note Indenture, on maturity the CT will repay the CT Notes by paying to the CT Trustee the principal amount of the outstanding CT Notes which have then matured, together with accrued and unpaid interest thereon.

Subordination/Security

Payment of the principal amount and interest on the CT Notes will be subordinated in right of payment to the prior payment in full of the principal of and accrued and unpaid interest on, and all other amounts owing in respect of, all senior indebtedness, which will be defined as all indebtedness, liabilities and obligations of the CT that, by the terms of the instrument creating or evidencing the same, is not expressed to rank in right of payment in subordination to or *pari passu* with the indebtedness evidenced by the CT Notes. The CT Note Indentures provide that upon any distribution of the assets of the CT in the event of any dissolution, liquidation, reorganization or other similar proceedings relative to the CT, the holders of all such senior indebtedness will be entitled to receive payment in full before the holders of the CT Notes are entitled to receive any payment.

The CT Series 2 Notes rank prior to the CT Series 1 Note. The CT Series 2 Notes issued under the Note Indenture rank *pari passu* with one another; provided, however, that the principal and interest, if any, may be payable at different times for the CT Series 2 Notes where the CT Notes within such series are issued at different times in accordance with the tenor of such CT Series 2 Notes.

The CT Series 4 Notes rank prior to the CT Series 3 Note. The CT Series 4 Notes issued under the Note Indenture rank *pari passu* with one another; provided, however, that the principal and interest, if any, may be payable at different times for the CT Series 4 Notes where the CT Notes within such series are issued at different times in accordance with the tenor of such CT Series 4 Notes.

Default

The CT Note Indenture provides that any of the following shall constitute an event of default: (i) default in payment of the principal of the CT Notes when the same becomes due and the continuation of such default for a period of 10 business days; (ii) default in payment of any interest due on any CT Notes and continuation of such default for a period of 15 business days; (iii) default in the observance or performance of any other covenant or condition of the CT Note Indenture and continuance of such default for a period of 30 days after notice in writing has been given by the holder(s) of the CT Notes specifying such default and requiring the CT to rectify the same; (iv) if there occurs, with respect to any issue of indebtedness of the CT having an outstanding principal amount of $10 million or more, an event of default that has caused the holder thereof to declare such indebtedness to be due and payable prior to its maturity and such indebtedness has not been discharged in full or such acceleration has not been rescinded or annulled within 30 days of such acceleration; and (v) certain events of dissolution, liquidation, reorganization or other similar proceedings relative to the CT. The provisions governing an event of default under the CT Note Indenture and remedies available thereunder do not provide protection to the holders of the CT Notes which would be comparable to the provisions generally found in debt securities issued to the public.

DESCRIPTION OF THE PARTNERSHIP

General

Eagle Energy Acquisitions LP is a limited partnership formed under the laws of the State of Delaware on September 28, 2010 and governed by the LP Agreement. The purposes of the Partnership are (a) to acquire, own, develop and operate long-life petroleum properties in the United States and (b) to engage in any business activity that is approved by the directors of the GP, as general partner. The following is a summary of the material attributes and characteristics of the Partnership and certain provisions of the LP Agreement, which summary is not intended to be complete. Reference is made to the LP Agreement for a complete description. See “Material Contracts”.

General Partner

The general partner of the Partnership is the GP, a limited liability company formed under the laws of the State of Delaware initially on September 28, 2010. The sole member of the GP is the CT and the directors of the GP are appointed from time to time by the CT.

As general partner of the Partnership, the GP will be allocated 0.001% of the income or loss of the Partnership for each fiscal year and, upon dissolution of the Partnership, will be entitled to receive 0.001% of the remaining property of the Partnership. As general partner, the GP has the authority to manage, operate, control and administer the business and affairs of the Partnership and has unlimited liability for the obligations of the Partnership.

Under the LP Agreement, the GP will receive no fees in consideration of the services it provides to the Partnership as GP. However, the GP will retain a 0.001% interest in the Partnership, which will not be required to be offset against expenses incurred by the GP pursuant to the LP Agreement. The GP is not required to contribute capital to the Partnership in order to earn its 0.001%.

The GP will be entitled to the reimbursement of all costs and expenses reasonably incurred by the GP in carrying out its obligations and duties under the LP Agreement, including but not limited to payroll and payroll related costs, overhead, accounting and other general and administrative costs, and out-of-pocket and third party fees and expenses.

The GP may be replaced as the GP of the Partnership in accordance with the terms of the LP Agreement, upon a determination by the CT as sole member of the GP.

Partnership Interests and Distributions

The CT has a 99.999% interest in the Partnership and the GP holds the remaining 0.001% interest.

The Partnership has a policy to distribute its distributable funds to the extent determined prudent by the directors of the GP, which is expected to coincide with distributions made by the CT to the Trust. Distributions will be made as to 99.999% to the CT and as to 0.001% to the GP within 15 days of the end of each month and the distributions are intended to be received by the CT prior to its related monthly distributions to the Trust. The Partnership may, in addition, make a distribution at any other time. Distributable funds will represent, in general, all of the Partnership's cash flow, after:

1. satisfaction of its debt service obligations (principal and interest) under credit facilities or other agreements with third parties, including amounts payable under the Credit Facility;
2. payment of all general and administrative expenses incurred by the Partnership;
3. retaining reasonable working capital reserves, maintenance and other capital expenditure reserves, or other reserves, including reserves to stabilize distributions to the partners, as may be considered appropriate by the GP; and
4. payment of expenditures other than as provided for in 1 to 3 above, provided such payment has been approved by the GP.

Capital and other expenses, including amounts required to enable the Partnership to stabilize monthly distributions based on anticipated future distributable funds, may be financed with drawings under one or more credit facilities that may be established by the Partnership, other borrowings or additional capital contributions to the Partnership.

Allocation of Income and Losses

The income or loss of the Partnership for each fiscal year will be allocated to the partners in accordance with their respective interests in the Partnership. The amount of income allocated to a partner may exceed or be less than the amount of cash distributed by the Partnership to that partner. For U.S. federal income tax purposes, the Partnership will be treated as a disregarded entity and all items of income or loss will ultimately be allocated to the CT for U.S. federal income tax purposes. The fiscal year end of the Partnership is December 31.

Limited Liability

The GP operates the Partnership in a manner so as to ensure, to the greatest extent possible, the limited liability of the CT as limited partner. Limited liability may be lost in certain circumstances. The GP, as general partner, will indemnify the CT as limited partner against all claims arising from assertions that the CT's liability is not limited as intended by the LP Agreement, unless the liability is not so limited as a result of or arising out of any act of the CT. The GP has no significant assets or financial resources, however, and therefore the indemnity from GP will have nominal value.

Transfer of Partnership Interests

Partnership interests may not be transferred without the prior written consent of the GP, such consent not to be unreasonably withheld. No transfer of a Partnership interest will be accepted by the GP, as general partner, unless a transfer form, duly completed and signed by the holder of the Partnership interest, has been remitted to the GP. In addition, a transferee of a Partnership interest must provide to the GP such other instruments and documents as the GP may reasonably require in appropriate form completed and executed in a manner acceptable to the general partner. A transferee of a Partnership interest will not become a partner or be admitted to the Partnership and will not be subject to the obligations and entitled to the rights of a partner under the LP Agreement until the foregoing conditions are satisfied and such transferee is recorded on the Partnership's register of partners.

Amendments to the LP Agreement

The LP Agreement may only be amended by agreement of the partners. In particular, no amendment will be permitted to be made to the LP Agreement changing the liability of any limited partner, allowing any limited partner to exercise control over the business of the Partnership, adversely affecting the rights, privileges or conditions attaching to any Partnership interest, reducing the percentage of income allocable to the CT as a limited partner to below 99.999% or changing the Partnership from a limited partnership to a general partnership, in each case, without the unanimous approval of the partners. No amendment that would terminate the Partnership other than as provided in the LP Agreement or that would change the priority of distributions or the priority to return of the assets on a liquidation will be permitted to be made without unanimous approval of the partners.

PRICE RANGE AND TRADING VOLUME OF UNITS

The Units are listed and posted for trading on the TSX, the Canadian marketplace on which the greatest volume of trading or quotation of the Units generally occurs. The trading symbol for the Units on the TSX is "EGL.UN". The following table sets forth the high and low closing prices and the aggregate volume of trading of the Units on the TSX for each month in 2013 (as quoted by the TSX):

	Toronto Stock Exchange		
	High $	Low $	Volume
2013			
January	8.60	7.47	1,384,179
February	8.14	7.43	1,299,714
March	7.48	6.4	2,961,867
April	7.73	6.28	2,090,772
May	7.79	6.71	1,794,058
June	8.11	7.40	1,359,345
July	8.45	7.54	1,453,105
August	8.47	7.91	921,557
September	8.68	7.90	1,196,134
October	9.05	8.30	1,185,139
November	8.68	7.26	2,207,862
December	8.17	7.22	1,140,766

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTIONS ON TRANSFER

As at the end of the most recently completed financial year, no securities were held in escrow or were subject to a contractual restriction on transfer.

TRUSTEES, DIRECTORS AND MANAGEMENT

The Trust

Computershare Trust Company of Canada is the Trustee of the Trust, and has been appointed and will continue in office until replaced by Unitholders. Pursuant to the terms of the Administrative Services Agreement, the Trustee has delegated a number of the administrative and governance functions relating to the Trust to the Administrator. The Administrator Directors therefore fulfill the majority of the oversight and governance role for the Trust, with the balance of those duties remaining with the Trustee. See "Administrative Services Agreement".

The Commercial Trust

The Administrator is also the CT Trustee, and has been appointed and will continue in office until dismissed by the Trust as unitholder of the CT. Pursuant to the terms of the CT Trust Indenture, the Administrator is responsible as CT Trustee to provide all of the management, administration, oversight and governance of the CT. See “Description of the Commercial Trust – Governance”.

The General Partner

Pursuant to the terms of the LP Agreement, the GP is the general partner of the Partnership and is responsible for the administrative and governance functions of the Partnership. As the sole member of the GP, the CT is empowered to elect all of the directors of the GP, from time to time.

The Administrator

The Administrator is wholly-owned by EEI Holdings, which is, in turn, wholly-owned by Richard Clark, the President, Chief Executive Officer and a director of the Administrator. Under the terms of the Administrative Services Agreement and the CT Trust Indenture, the Administrator has certain management, administrative, governance and fiduciary duties with respect to the Trust and the CT. The Administrator performs its services pursuant to the Administrative Services Agreement on a cost recovery basis.

The number of the Administrator Directors is fixed at five until such time as the Unitholders of the Trust pass a resolution to fix the number of the Administrator Directors at a new number. The Voting Agreement provides that Unitholders are entitled to elect 100% of the Administrator Directors.

Directors and Executive Officers

The following table provides the names and municipalities of residence of the directors and executive officers as at the date of this Annual Information Form, their offices held, the date they were first appointed as Administrator Directors or executive officers and their principal occupation for the previous five years.

Name and Municipality of Residence	Current Positions	Principal Occupation	Director or Executive Officer Since
David M. Fitzpatrick[(1)(2)(3)] Calgary, Alberta	Director and Chairman of the Board	Retired businessman. From 1996 to 2007, Mr. Fitzpatrick was the President and CEO of Shiningbank Energy Income Fund (an oil and gas income trust).	March 28, 2008
Bruce K. Gibson[(1)(2)(3)] Calgary, Alberta	Director and Audit Committee Chair	Retired businessman. From 1997 to 2007, Mr. Gibson was the CFO of Shiningbank Energy Income Fund.	March 28, 2008
Joseph W. Blandford[(1)(2)(3)] Houston, Texas	Director and Compensation Committee Chair	Retired businessman since 2003. Prior thereto Mr. Blandford was the Chairman and Chief Executive Officer of Atlantia Offshore Limited (an oil and gas services company).	April 1, 2010
Warren D. Steckley[(1)(2)(3)] Calgary, Alberta	Director and Reserves & Governance Committee Chair	Businessman. From 1998 to 2013, Mr. Steckley was the President and Chief Operating Officer of Barnwell of Canada, Limited (an oil and gas company).	April 1, 2010
Richard W. Clark Calgary, Alberta	Director, President and Chief Executive Officer	President and Chief Executive Officer of the Administrator and GP. Prior to April 2010, partner at a national law firm since April 2000 and at a boutique oil and gas law firm since 1991.	March 28, 2008
Kelly A. Tomyn Calgary, Alberta	Chief Financial Officer	Chief Financial Officer of the Administrator and GP. In the five years prior thereto, Ms. Tomyn has been the CFO of two private and public oil and gas companies.	September 30, 2010
J. Wayne Wisniewski Houston, Texas	Chief Operating Officer	Chief Operating Officer of the GP. In the five years prior thereto, Mr. Wisniewski held various senior management positions with BP.	September 17, 2012
Robert J. Cunningham Houston, Texas	Vice President, Business Development	Vice President, Business Development of the GP. Prior thereto, Mr. Cunningham was Vice President, Finance and Business Development with a privately held, Houston based oil and gas company from 2009 to 2010, and Senior Vice President with Marsh and McLennan from 2000 to 2008.	March 1, 2011

Name and Municipality of Residence	Current Positions	Principal Occupation	Director or Executive Officer Since
James D. Elliott Calgary, Alberta	Vice President, Finance	Vice President, Finance of the Administrator. In the two years prior thereto, Mr. Elliott was the controller for a public junior oil sands exploration company and prior thereto, he was the controller for a public oil and gas company.	August 7, 2012
Jo-Anne M. Bund Calgary, Alberta	General Counsel and Corporate Secretary	General Counsel and Corporate Secretary of the Administrator. Prior thereto, Ms. Bund was in-house counsel for a private company for two years, a corporate securities lawyer with a national law firm for three years and senior legal counsel for the Alberta Securities Commission for three years.	November 28, 2012

Notes:
(1) Member of Audit Committee. Mr. Gibson is the Chairman of the Audit Committee.
(2) Member of the Compensation Committee. Mr. Blandford is the Chairman of the Compensation Committee.
(3) Member of the Reserves & Governance Committee. Mr. Steckley is the Chairman of the Reserves & Governance Committee.

The term of office of all Administrator Directors will expire at each annual meeting of Unitholders of the Trust or at the time at which his/her or its successor is elected or appointed, or earlier if any Administrator Director otherwise dies, resigns, is removed or is disqualified. Each director will devote the amount of time as is required to fulfill their obligations to the Administrator. The Administrator's officers are appointed by and serve at the discretion of the Administrator Directors. The GP's officers are appointed by and serve at the discretion of the directors of the GP.

Biographical Information

David M. Fitzpatrick, Chairman of the Board and Director

Mr. Fitzpatrick was a founder, President and Chief Executive Officer of Shiningbank Energy Income Fund, a TSX listed Canadian energy trust. Prior to Shiningbank, Mr. Fitzpatrick was the Chief Operating Officer with Serenpet Energy Inc. (an oil and gas company), a Senior Exploitation Engineer with Canadian Hunter Exploration Ltd. (an oil and gas company) and a Senior Development Engineer with Amoco Canada Petroleum Co. Ltd. (an oil and gas company). Mr. Fitzpatrick obtained a Bachelor of Engineering (Geo.) degree from Queens University in 1981 and is a graduate of the McMaster University Director's College.

Bruce K. Gibson, Director, Audit Committee Chair

Mr. Gibson was Vice President and Chief Financial Officer of Shiningbank Energy Income Fund. Prior to Shiningbank, Mr. Gibson was the Chief Financial Officer of Magrath Energy Corp. (an oil and gas company) and Northridge Exploration Ltd. (an oil and gas company). Mr. Gibson obtained a Bachelor of Commerce degree from the University of Calgary in 1978 and is a member of the Canadian and Alberta Institutes of Chartered Accountants.

Joseph W. Blandford, Director, Compensation Committee Chair

Mr. Blandford was the Chairman and Chief Executive Officer of Atlantia Offshore Limited, a company that was based in Houston and under Mr. Blandford's leadership installed more than 200 offshore drilling and production platforms in the Gulf of Mexico and elsewhere in the world. Mr. Blandford led the company for over 25 years and holds over 50 U.S. and foreign patents related to proprietary technology for deep and shallow water offshore platforms. Mr. Blandford holds a Bachelors degree in Civil Engineering from the University of Texas and a Masters degree in Civil Engineering from the University of Houston, and is a graduate of Harvard Business School's Owner/President Management Program. Although retired since 2003, Mr. Blandford has actively supported higher education by serving on the University of Texas Chancellor's Council and the University of Texas Development Board. He is also the immediate past president of the board of directors of the Petroleum Club of Houston, and is a member of the foundation's board of directors, the Independent Petroleum Association of America, the American Petroleum Institute and the American Society of Civil Engineers. Mr. Blandford was elected in 2004 to serve on the University of Texas Civil, Architectural and Environmental Engineering Academy of Distinguished Alumni and was recognised in 2006 as a Distinguished Graduate of the University of Texas College of Engineering.

Warren D. Steckley, Director, Reserves & Governance Committee Chair

Mr. Steckley combines more than 35 years of oil and gas industry experience with financial and investment expertise. From 1998 to 2013, Mr. Steckley was the President, Chief Operating Officer and a Director of Barnwell of Canada, Limited, an oil and gas company and wholly-owned subsidiary of Barnwell Industries Inc., a public company listed on the American Stock Exchange. Mr. Steckley has been a director of a number of private companies and TSX listed companies. Mr. Steckley is a Professional Engineer with a Bachelors degree in Mechanical Engineering from the University of Alberta and a Masters of Business Administration degree from the University of Alberta.

Richard W. Clark, Director, President and Chief Executive Officer, Administrator and GP

Mr. Clark's career includes over 19 years in the legal profession, first as a founding partner at a boutique oil and gas firm and then for 10 years at a national law firm in Canada, where he specialized in the areas of corporate finance, securities, mergers and acquisitions and venture capital. Mr. Clark has had extensive experience in the royalty trust sector including developing innovative financing structures, leading initial public offerings and other debt and equity financings, multiple corporate and asset mergers and acquisitions, acting as a director, and advising various energy based trusts on international expansion initiatives. Mr. Clark has served on numerous boards in the oil and gas sector. Mr. Clark holds a Bachelor of Arts degree in Economics and Bachelor of Laws degree, both from the University of Calgary.

Kelly A. Tomyn, CA, Chief Financial Officer, Administrator and GP

Ms. Tomyn has over 25 years of experience in the oil and gas industry developing and executing financial strategies primarily for publicly traded companies. From December 2007 to September 2010, Ms. Tomyn was Vice President, Finance and Chief Financial Officer with Aduro Resources Ltd. From October 2004 to October 2007, Ms. Tomyn was Vice President, Finance and Chief Financial Officer with Diamond Tree Energy Ltd., including its predecessor company. Ms. Tomyn has also served as Vice President, Finance and Chief Financial Officer of Ranchgate Energy Inc. (an oil and gas company), Saddle Resources Inc. (an oil and gas company) and WestPoint Energy Inc. (an oil and gas company). Ms. Tomyn graduated from the University of Saskatchewan with a Bachelor of Commerce degree in 1987 and since 1990 has been a member of the Institute of Chartered Accountants of Alberta.

J. Wayne Wisniewski, Chief Operating Officer, GP

Mr. Wisniewski has 30 years of experience in the oil and gas industry, starting as a drilling and completion engineer, and holding various engineering and senior management positions in multiple companies. Prior to joining the GP, Mr. Wisniewski spent the preceding 13 years with a major international E&P company, where he was responsible for operations exceeding 100,000 boe/d. Mr. Wisniewski holds a Bachelor of Petroleum Engineering from Texas A&M University, where he earned the Harold J Vance Award for academic achievement, and a Master of Business Administration from Southern Methodist University in Dallas, Texas.

Robert Cunningham, Vice President, Business Development, GP

Mr. Cunningham has over 25 years of experience in the oil and gas industry including business development, finance, energy banking and risk management. Mr. Cunningham is a member of the Independent Petroleum Association of America, the IPAA Southeast Region Board of Directors, the Acquisition, Divestiture & Merger-Houston Energy Network, the Houston Energy Finance Group (former President and Board member) and the Houston Acquisition & Divestiture Forum (former President). He holds a Bachelor of Business Administration degree in Finance from The University of Houston.

James Elliott, C.A., Vice President, Finance, Administrator

Mr. Elliott has over 17 years of corporate finance and financial accounting experience, including 14 years in the oil and gas industry. Mr. Elliott has held positions in management, corporate finance and planning for various publicly traded companies. He is a Chartered Accountant, has a Bachelor of Commerce degree from the University of Alberta and has completed the Controller Leadership Program of the Alberta Institute of Chartered Accountants.

Jo-Anne Bund, B.A., LLB, General Counsel and Corporate Secretary, Administrator

Ms. Bund has over 18 years of experience as a corporate securities lawyer. During her career, Ms. Bund practiced primarily in the areas of corporate finance, securities, mergers and acquisitions and venture capital, first with a boutique oil and gas securities firm and, later, with a national law firm. Ms. Bund was also senior legal counsel with the Alberta Securities Commission for three years and has been in-house legal counsel with other companies, both private and public. Ms. Bund holds a Bachelor of Arts degree from the University of Toronto and a Bachelor of Laws degree from the University of Calgary.

Security Ownership by Directors and Executive Officers

As a group, the above directors and executive officers beneficially own or exercise control or direction over, directly or indirectly, 715,795 Units, representing 2.2% of the 32,580,320 issued and outstanding Units as of March 20, 2014.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders

To the knowledge of the Administrator, no director or executive officer of the Administrator (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including the Administrator), that: (a) was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**"), that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Bankruptcies

To the knowledge of the Administrator, no director or executive officer of the Administrator (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of the Administrator to affect materially the control of the Administrator: (a) is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including the Administrator) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the ten years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

Penalties or Sanctions

To the knowledge of the Administrator, no director or executive officer of the Administrator (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of the Administrator to affect materially the control of the Administrator, has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Certain officers and directors of the Administrator are also officers and/or directors of other companies engaged in the oil and gas business generally. As a result, situations may arise where the duties of such directors and officers of the Administrator conflict with their interests as directors and officers of other companies. The resolution of such conflicts is governed by applicable corporate laws, which require that directors act honestly, in good faith and with a view to the best interests of the Administrator. Conflicts, if any, will be handled in a manner consistent with the procedures and remedies set forth in the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA. Management is not aware of any existing or potential material conflicts of interest between the Administrator, the Trust or a subsidiary of the Trust and a director or officer of the Administrator or the GP.

AUDIT COMMITTEE DISCLOSURES

Audit Committee

The written charter for the Audit Committee is attached as Schedule C.

The Audit Committee consists of Messrs. Gibson, Fitzpatrick, Steckley and Blandford, the four non-management members of the Board, with Mr. Gibson as chairman. Each of the members of the Audit Committee is considered "independent" and "financially literate" within the meaning of National Instrument 52-110 *Audit Committees* of the Canadian Securities Administrators.

The Trust believes that each of the members of the Audit Committee possesses: (i) an understanding of the accounting principles used by the Trust to prepare its financial statements; (ii) the ability to assess the general application of such accounting principles in connection with the accounting for estimates, accruals and reserves; (iii) experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Trust's financial statements, or experience actively supervising one or more individuals engaged in such activities; and (iv) an understanding of internal controls and procedures for financial reporting. For a summary of the education and experience of each member of the Audit Committee see "Trustees, Directors and Management – Directors and Executive Officers - Biographical Information".

Principal Accountant Fees and Services

The Audit Committee has not adopted specific policies and procedures for the engagement of non-audit services and pre-approves each such engagement or type of engagement for every fiscal year.

The auditor of the Trust is PricewaterhouseCoopers LLP. The following table is a summary of the services fees billed by the auditor in the years ended December 31, 2012 and December 31, 2013:

	Audit Fees	Audit Related Fees(3)	Tax Fees(4)	All Other Fees
2012	$75,000(1)	$239,046	$229,205	$ Nil
2013	95,300(2)	$105,790	$70,292	$ Nil

Notes:

(1) These fees are for the final billing for the 2011 annual financial statement audit of $45,000 and progress billing for the 2012 annual financial statement audit of $30,000.

(2) These fees are for the final billing for the 2012 annual financial statement audit of $55,300 and progress billing for the 2013 annual financial statement audit of $40,000.

(3) These fees are for quarterly reviews of financial statements, translation, disbursements and audit-related work in connection with financings.

(4) These fees are for tax compliance, planning, advice and filing.

ADMINISTRATIVE SERVICES AGREEMENT

The following is a summary of the principal terms of the Administrative Services Agreement pursuant to which the Trustee has delegated to the Administrator responsibility for the general administration of the affairs of the Trust. The description below is qualified by reference to the text thereof. See "Material Contracts".

The Administrator provides administrative services to the Trust. These arrangements are set forth in the Administrative Services Agreement. In exercising its powers and discharging its duties under the Administrative Services Agreement, the Administrator is required to act honestly, in good faith and in the best interests of the Trust and the Unitholders, exercising the same degree of diligence, care and skill that a reasonably prudent administrator or manager, having responsibilities of a similar nature to those set forth in the Administrative Services Agreement, would exercise in comparable circumstances.

The Administrator, on an exclusive basis, performs or procures all general administrative and operational services as may be required to administer the operations of the Trust, other than the excluded services described below (the "**Excluded Services**").

The services the Administrator provides to the Trust (the "**Administrative Services**") include the following: (i) preparing all returns, filings and other documents necessary to discharge Trustee's obligations pursuant to the Trust Indenture and applicable law, including taxation and securities laws, and otherwise ensuring compliance by the Trust with applicable law; (ii) voting securities owned by the Trust; (iii) assisting with the calculation of distributions to Unitholders, withholding all amounts required by applicable tax law, and making the remittances and filings in connection with such withholdings; (iv) providing investor relations services; (v) performing all services in connection with acquiring or disposing of property; (vi) performing all services required for the purpose of completing any sale of Units from time to time; (vii) establishing and implementing distribution reinvestment plans, unit purchase plans and incentive option or other compensation plans; (viii) calling and holding all annual and/or special meetings of Unitholders pursuant to the Trust Indenture and preparing, approving and arranging for the distribution of all materials including notices of meetings and information circulars in respect thereof; (ix) preparing and causing to be provided to Unitholders on a timely basis all information to which Unitholders are entitled under the Trust Indenture and under applicable laws; (x) engaging and overseeing third party providers of services to the Trust in connection with provision of the Administrative Services; (xi) hire and oversee employees of the Trust in connection with the provision of the Administrative Services and (xii) providing all other services as may be necessary, or requested by the Trustee, for the administration of the Trust, other than the Excluded Services.

The Excluded Services include the following: (i) the issue, certification, exchange or cancellation of Units; (ii) the maintenance of registers of Unitholders; (iii) making the distribution of payments or property to Unitholders and statements in respect thereof; (iv) any mailings to Unitholders; and (v) any matters ancillary or incidental to any of those set forth in (i) through (iv) immediately above.

In addition to those duties in respect of the Trust which are delegated to the Administrator by the Trustee under the Administrative Services Agreement, the Administrator has been conferred and granted certain powers, duties and authorities directly in its capacity as the CT Trustee. In exercising its powers and discharging its duties as the CT Trustee under the CT Trust Indenture, the Administrator is required to satisfy the same standard of care as required of the Trustee pursuant to the Trust Indenture.

Fees and Expenses

Under the Administrative Services Agreement, the Administrator receives no fees in consideration of the services it provides as Administrator of the Trust or as the CT Trustee. The Administrator is entitled to the reimbursement of all costs and expenses reasonably incurred by the Administrator in carrying out its obligations and duties under the Administrative Services Agreement and the CT Trust Indenture, including but not limited to payroll and payroll related costs, overhead, accounting and other general and administrative costs, and out of pocket and third party fees and expenses.

Reliance, Limitation of Liability and Indemnification

The Administrative Services Agreement provides that, in carrying out the Administrative Services, the Administrator is entitled to rely on: (a) statements of fact of other persons (any of which may be persons with whom the Administrator is affiliated or associated) who are considered by the Administrator to be knowledgeable of such facts, provided that the Administrator has satisfied its standard of care under the Administrative Services Agreement in making the assessment as to whether such persons are knowledgeable of such facts (each, a "**Knowledgeable Person**"); and (b) statements from, the opinion or advice of, or information from any solicitor, auditor, valuator, engineer, surveyor, appraiser or other expert selected by the Administrator ("**Experts**"), provided that the Administrator has satisfied its standard of care under the Administrative Services Agreement in selecting such Expert to provide such statements, opinion, advice or information.

The Administrative Services Agreement provides that the Administrator, its affiliates and associates and each of their respective directors, officers and employees (including Trust employees supervised by the Administrator) (collectively, the "**Service Providers**"), will not be liable to the Trust, the Trustee or any Unitholders for: (i) any loss or damage resulting from the performance or non-performance of the Administrative Services by any of the Service Providers, or any act or omission believed by a Service Provider to be within the scope of authority conferred thereon by the Administrative Services Agreement or the Trust Indenture, unless such loss or damage resulted from the fraud, wilful default or gross negligence of a Service Provider; (ii) any loss or damage resulting from the performance or non-performance of the Administrative Services by any of the Service Providers, where such loss or damage is attributable to acting in accordance with the instructions of the Trustee, provided that the Service Providers will bear, on a several basis, their proportionate share of liability in the event of joint or contributory liability with the Trustee; (iii) any loss or damage resulting from any act or omission by any of the Service Providers, provided that such act or omission is based upon the Service Provider's reliance on (A) statements of fact of Knowledgeable Persons (excluding persons with whom the Administrator is affiliated); or (B) the opinion or advice of or information obtained from any Expert; and (iv) any damage, injury or loss of an indirect or consequential nature, including loss of profits, suffered by the Trust, the Trustee or any Unitholder, or any of their respective affiliates, which is in any way connected with the activities, investments or affairs of the Trust or the performance or non-performance of the Administrative Services or any other aspect of the Administrative Services Agreement or the Trust Indenture.

The Administrative Services Agreement provides that the Administrator, its affiliates, associates and any person who is serving or shall have served as a director, officer, employee or agent of the Administrator (collectively the "**Administrator Indemnitees**") will be indemnified out of the Trust's property from and against all losses, claims, damages, liabilities, obligations, costs and expenses (including judgments, fines, penalties, amounts paid in settlement (with the approval of the Trustee, acting reasonably), and legal fees and disbursements) ("**Claims**") incurred by, borne by or asserted against any of the Administrator Indemnitees and which in any way arise from or relate in any manner to the Administrative Services Agreement, the Trust Indenture, or the performance or non-performance of the Administrative Services, and acting as CT Trustee, unless such Claims arise from the fraud, wilful default or gross negligence of any of the Administrator Indemnitees.

The Administrative Services Agreement further provides that, subject to limitations on liability of the Administrator described above, the Trust, the Trustee and any person who is serving or shall have served as a director, officer or employee of the Trustee (the "**Trust Indemnitees**") will be indemnified by the Administrator from and against all losses, claims, damages, liabilities, obligations, costs and expenses (including judgments, fines, penalties, amounts paid in settlement (with the approval of the Administrator, acting reasonably), and legal fees and disbursements) ("**Trust Claims**") incurred by, borne by or asserted against any of the Trust Indemnitees and which arise from the fraud, wilful default or gross negligence of the Administrator or Trust employees supervised by the Administrator in the performance of the Administrative Services, unless such Trust Claims arise from the fraud, wilful default or gross negligence on the part of a Trust Indemnitee, or are attributable to actions undertaken on the specific instructions of the Trustee.

Term and Termination

The Administrative Services Agreement had an initial term to June 30, 2011 and is automatically renewable for additional successive terms of six months unless terminated by the Administrator on prior written notice which is provided at least 30 days before the expiry of the initial term or any renewal term. The Administrative Services Agreement also provides that it may, by written notice given by one party to the other, be immediately terminated in the event of (i) certain events of bankruptcy, insolvency, receivership or liquidation of the other party or (ii) a breach by the other party in the performance of a material obligation, covenant or responsibility under the agreement (other than as a result of the occurrence of a force majeure event) which is not remedied, or when not reasonably capable of being remedied within 60 days, such party nonetheless fails to commence and diligently pursue steps to remedy such default, within 60 days after notice of such breach has been delivered; provided that, prior to the Trust or any of its affiliates (as applicable) being entitled to terminate the Administrative Services Agreement for breach by the Administrator of performance of a material obligation, receipt of approval of the Unitholders by Ordinary Resolution must be obtained authorizing such termination.

A direct or indirect change of control of the Administrator will require the prior written consent of the Trustee. The Administrative Services Agreement permits the Administrator to delegate its responsibilities, but no such delegation will relieve the Administrator of its responsibility for ensuring the performance of its duties and obligations under each such agreement. If, however, the Administrator delegates its responsibilities to a third party and in so doing does not breach its standard of care, the Administrator will not be liable for the acts or omissions of such delegate (except where such delegate is an affiliate of the Administrator). It is anticipated that the Administrator may, from time to time, delegate certain responsibilities to the GP, which shall not constitute a breach of its standard of care.

VOTING AGREEMENT

EEI Holdings, the sole shareholder of the Administrator, has entered into the Voting Agreement with the Trustee as agent for the Unitholders and the Administrator pursuant to which EEI Holdings agrees to vote its shares in the Administrator at the direction of the Unitholders, as communicated by the Trustee as agent for the Unitholders, with regard to the election or removal of the Administrator Directors and setting the number of Administrator Directors from time to time. The Voting Agreement is a unanimous shareholders agreement pursuant to the ABCA and restricts the business of the Administrator to (i) acting as administrator of the Trust pursuant to the terms of the Trust Indenture and the Administrative Services Agreement; (ii) acting as CT Trustee; and (iii) such other activities ancillary to the activities in subsections (i) and (ii) and necessary to perform the obligations of the Administrator and the CT Trustee.

EEI Holdings has waived certain shareholder rights afforded to it under the ABCA, including the right to appoint an auditor, dissent rights, and oppression rights. The Voting Agreement also provides the Administrator with the right to compel EEI Holdings to transfer its shares in the Administrator to the Administrator or its nominee at a nominal price in certain circumstances, including the death, disability, resignation, termination or removal of Richard Clark as a director or officer of the Administrator for any reason and other circumstances. The Administrator's articles require that all transfers of its shares require the approval of the Board.

FIDUCIARY RESPONSIBILITY OF THE ADMINISTRATOR

The Administrator, as administrator of the Trust and trustee of the CT, has a duty to administer the Trust and the CT in a manner beneficial to the respective unitholders thereof. The GP has a duty to manage the Partnership in a manner beneficial to all partners of the Partnership, including the CT. As well, the directors and officers of the Administrator and the GP have fiduciary obligations in that capacity to the unitholders of the Trust and the CT and the Partnership, respectively. Situations may arise in which the interests of the Trust and the CT and their affiliates and associates may conflict with the interests of the GP and the Partnership and their affiliates and associates and the Administrator Directors and the directors of the GP will be obligated to resolve such conflicts. Unless otherwise agreed, neither the GP nor the Administrator are obligated to offer any business opportunities to the Trust, the CT or the Partnership.

PROMOTER

Within the two most recently completed financial years or during the current financial year, no person or company has been a promoter (as defined by the *Securities Act* of Alberta) of the Trust.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Pursuant to the terms of the Voting Agreement, EEI Holdings has granted all of the voting rights to elect the Administrator Directors to the Unitholders of the Trust.

Except as described above or elsewhere in this Annual Information Form, there is no material interest, direct or indirect, of: (i) any director or executive officer of the Administrator or the GP; (ii) any person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of the Units; or (iii) any affiliate of the persons or companies referred to above in (i) or (ii), in any transaction within the three years before the date of this Annual Information Form that has materially affected or is reasonably expected to materially affect the Trust or a subsidiary of the Trust.

THE INDUSTRY

United States Oil and Natural Gas Industry

Overview

The oil and gas industry in the United States is very well-established. Since the 1860's, oil has been produced in economic quantities in a number of discrete sedimentary basins in the lower 48 states and Alaska. Accompanying this production has been the development of supportive infrastructure including pipelines, gas processing facilities and a drilling and service sector as well as a wide range of professional services.

The demand for low cost, domestic sources of hydrocarbons remains strong. U.S. domestic policy has historically supported the development and exploitation of oil and gas reserves to assure access to domestic supplies of hydrocarbons. Many state and municipal governments are also supportive and recognize the monetary contribution that the industry makes to their state and municipal budgets. In Texas, where the Partnership's oil and gas interests are located, oil has been produced since 1866.

Background

This section provides a brief overview of the legal structure of the parts of the U.S. oil and natural gas exploration and production industry in which the Partnership operates.

In the United States, ownership of land carries with it ownership of or the exclusive right to materially benefit from the extraction of substances from under the surface, including oil, natural gas and other minerals. A landowner may convey an estate in the oil and natural gas rights separate and apart from the ownership of the surface rights. When the oil and natural gas interest is severed from the surface interest, two distinct estates or interests are created – the mineral estate and the surface estate.

The owner of the mineral estate has many interests which are capable of being conveyed alone or in various combinations, including the right to convey a working interest to an oil and natural gas exploration and production company to explore for and produce oil and natural gas from the mineral estate. Such a working interest is typically conveyed by the owner or owners of the mineral estate to the working interest owner pursuant to a lease agreement. The owner of the mineral estate typically retains a royalty interest, which is the right to receive a specified percentage of the production of any oil and natural gas recovered from the mineral estate prior to deduction of any costs or expenses.

The rights of exploration, drilling and production conveyed by a typical lease agreement customarily require that production of oil and natural gas in paying quantities be established within a specified period of time, typically two to five years. Absent an ability to extend the primary term of the lease, the lease terminates if such production is not established within the specified time period. Once such production is established during the primary term, the lease agreement would generally continue in effect (either in whole or in part as to the proration units located around producing wells) so long as production in paying quantities continues. However, the interest of the lessee under an oil and gas lease is capable of being abandoned by the lessee and may also be subject to forfeiture for failure on the part of the lessee to comply with express covenants and implied obligations, including, for example, the duty to reasonably develop the premises, the duty to protect the leasehold against drainage and the duty to manage and administer the lease.

Operations

Acquisitions

For the petroleum properties where the Partnership does not own a 100% working interest, the Partnership has been appointed as the operator in the petroleum properties pursuant to the terms of joint operating agreements. This is the case for the Partnership's properties in the Salt Flat Field and for some of its properties in Hardeman County, Texas and in Greer, Harmon and Jackson counties, Oklahoma. The joint operating agreements govern the operation of the petroleum properties as between the Partnership and other working interest owners in those properties. Pursuant to the joint operating agreements, the Partnership, in its capacity as operator, conducts the day-to-day operations for these properties. As the operator and the majority interest owner, the Partnership has the ability to manage the capital spending as contemplated by the applicable joint operating agreements, in accordance with the rights and powers typically afforded (in both Canada and the U.S.) to majority interest owners as a standard term of such agreements.

Marketing

The Partnership sells 99% of its crude oil production to Sunoco Partners Marketing & Terminals L.P. ("Sunoco") pursuant to respective contracts based on location. Sunoco purchases the Partnership's production in Caldwell, Martin and Palo Pinto counties based on an index, and adjusted for transportation and marketing. The price for oil production from the Salt Flat Field in Caldwell County is based on the Light Louisiana Sweet crude pricing index and the price for production from Martin County and Palo Pinto County is based on the West Texas Intermediate pricing index. The Partnership's contracts with Sunoco on its Salt Flat Properties and Martin County interests are binding until February 28, 2014, after which the contracts will continue month to month unless terminated by either party. The Partnership's crude oil production in Palo Pinto County is sold pursuant to a month to month agreement until terminated by either party. The Partnership's production in Hardeman County, Texas is sold to an independent marketing company under a month to month contract based on a West Texas Intermediate pricing index.

The Partnership sells its natural gas and natural gas liquids in the Permian Basin region to four different purchasers pursuant to various contracts based on location. The Partnership sells its natural gas and natural gas liquids in Hardeman County to a single buyer pursuant to a percent of proceeds contract that is month to month. Approximately 85% of 2013 gas volumes were sold to a single buyer, DCP Midstream, LP ("DCP"). No other purchaser of gas volumes in 2013 accounted for more than 7% of the Partnership's total gas volumes. The contracts with DCP were terminated during the first quarter of 2014 and replaced with a long term agreement with WTG Processing, LP which expires December 31, 2019. The respective natural gas and gas liquids contracts in the Permian Basin and Hardeman County are index based, are "percent of proceeds" and are adjusted for volumes delivered and other charges.

Title to Properties

It is customary in the U.S. oil and natural gas industry to conduct a preliminary review of title to both producing and non-producing properties. Prior to the commencement of drilling operations on those properties, a title examination typically is performed and curative work is undertaken with respect to significant defects. Management follows customary U.S. industry due diligence practices in connection with its acquisitions, including performing title reviews on producing properties, undeveloped properties that are assigned significant value and the more significant leases prior to completing an acquisition and, depending on the materiality of the properties, Management may obtain title opinions or reports or review previously obtained title opinions or reports. Depending on the nature of each acquisition, to the extent title opinions or other investigations reflect material title defects, one of either the purchaser or the seller would be responsible for the costs and for curing any title defects. As discussed above, a title examination on other properties and leaseholds would typically be performed prior to the commencement of drilling operations thereon and any curative work would be performed. The Partnership's oil and natural gas properties will be subject to customary royalty and other interests, liens for current taxes and other customary burdens. See "Risk Factors".

Competition

The U.S. petroleum industry is highly competitive in all phases. The Partnership will encounter competition from other petroleum companies in all areas of operations, including the acquisition of leasing options on petroleum properties and the exploration and development of those properties. The Partnership's competitors will include numerous independent petroleum companies, individuals, and drilling and income programs. Many of the Partnership's competitors are large, well established companies that have substantially larger operating staffs and greater capital resources than the Partnership. Such competitors may be able to pay more for lease options on petroleum properties and to define, evaluate, bid for and purchase a greater number of properties and locations than the financial or human resources of the Partnership will permit. The Partnership's ability to acquire additional properties and to discover reserves in the future will depend upon its ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Moreover, these competitors may attract and hire away the Trust's or the Partnership's key employees. To protect its interests, the Trust and the Partnership must pay competitive market-value compensation to its employees at all times. See "Risk Factors".

Regulation of the Petroleum Industry

Operations will be substantially affected by U.S. federal, state and local laws and regulations. In particular, petroleum production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which the Partnership owns or operates properties for petroleum production have statutory provisions regulating the exploration for and production of petroleum, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Operations are also subject to various conservation laws and regulations. These include regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of petroleum wells, and regulations that generally prohibit the venting or flaring of natural gas and that impose certain requirements regarding the rateability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties, and the regulatory burden on the industry in the U.S. increases the cost of doing business and affects profitability. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission, ("**FERC**"), and the courts. The Partnership cannot predict when or whether any such proposals may become effective, nor can they estimate the costs of complying therewith.

Regulation of Transportation of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could re-enact price controls in the future.

Sales of crude oil will be affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate and access regulation. The FERC regulates interstate oil pipeline transportation rates under the *Interstate Commerce Act*. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil that allowed for an increase or decrease in the cost of transporting oil to the purchaser. A review of these regulations by the FERC in 2000 was successfully challenged on appeal by an association of oil pipelines. On remand, the FERC in February 2003 increased the index ceiling slightly, effective July 2001. Following the FERC's five-year review of the indexing methodology, the FERC issued an order in 2006 increasing the index ceiling. In 2010, FERC issued a final order concluding its third five-year review of the oil-pricing index. In this 2010 order, FERC again raised the index ceiling, establishing an index level of Producer Price Index for Finished Goods, plus 2.65% adjustment for the five-year period commencing July 1, 2011.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, Management believes that the regulation of oil transportation rates will not affect operations in any way that is of material difference from those of competitors who are similarly situated.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this common carrier standard, pipelines must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by pro-rationing provisions set forth in the pipelines' published tariffs. Accordingly, Management believes that access to oil pipeline transportation services generally will be available to the Trust to the same extent as to similarly situated competitors.

Regulation of Transportation and Sales of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by the FERC under the *Natural Gas Act of 1938* ("**NGA**"), the *Natural Gas Policy Act of 1978* (the "**NGPA**"), and regulations issued under those statutes. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could re-enact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA and culminated in adoption of the *Natural Gas Wellhead Decontrol Act* which removed all price controls affecting wellhead sales of natural gas effective January 1, 1993.

Regulation of Production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. The jurisdictions in which the Partnership's production is located and in which Management anticipates operating have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas wells that the Trust can produce from and to limit the number of wells or the locations at which the Trust can drill, although the Trust can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each jurisdiction generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids.

The failure to comply with these rules and regulations can result in substantial penalties. Competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect the Partnership's operations.

Other Federal Laws and Regulations Affecting the Industry

The *Energy Policy Act of 2005* (the "**EPAct 2005**") is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the U.S. energy industry. Among other matters, EPAct 2005 amends the NGA to add an anti-manipulation provision which makes it unlawful for any entity to engage in prohibited behaviour to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. EPAct 2005 provides the FERC with the power to assess civil penalties of up to $US 1,000,000 per day for violations of the NGA and increases the FERC's civil penalty authority under the NGPA from $US 5,000 per violation per day to $US 1,000,000 per violation per day. The civil penalty provisions are applicable to entities that engage in the sale and/or transportation of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-manipulation provision of EPAct 2005, and subsequently denied rehearing. The rule makes it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, (1) to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act, practice, or course of business that operates as a fraud or deceit upon any person. The new anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but do apply to activities of gas pipelines and storage companies that provide interstate services, such as NGPA Section 311 service, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704. The anti-manipulation rules and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority. Should Management fail to comply with all applicable FERC administered statutes, rules, regulations, and orders, the Trust could be subject to substantial penalties and fines.

FERC Market Transparency Rules

On December 26, 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing, or Order No. 704. Under Order No. 704, wholesale buyers and sellers of more than 2.5 million MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors, natural gas marketers and natural gas producers, are required to report, on May 1 of each year beginning in 2009, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. In order to provide respondents time to implement new regulations related to Order No. 704, the FERC has extended the deadline for calendar year 2009 until October 1, 2010. The report for calendar year 2010 and subsequent years remains May 1 of the following calendar year. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC's policy statement on price reporting.

FERC has also issued Order Nos. 720 and 720-A. Order No. 720 required major non-interstate pipelines to post scheduled flow information, as well as information for receipt and delivery points with design capacity greater than 15,000MMBtu/day. Order No. 720 also required interstate pipelines to post information regarding no-notice service (that is, firm transportation service by which firm shippers may receive delivery up to their firm entitlements on a daily basis without penalty). Order No. 720-A broadly affirmed Order No. 720. However, in 2011, the U.S. Circuit Court of Appeals for the 5th Circuit vacated Order Nos. 720 and 720-A insofar as the orders imposed reporting requirements on non-interstate pipelines.

In November 2012, FERC issued a Notice of Inquiry seeking comments on what changes, if any, should be made to its natural gas market transparency rules. FERC is still collecting data from commenters pursuant to that Notice of Inquiry.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. Management cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. Management do not believe that the Trust would be affected by any such action materially differently than similarly situated competitors.

Environmental, Health and Safety Regulation

Exploration, development and production operations are subject to various federal, state and local laws and regulations governing health and safety, the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may, among other things, require the acquisition of permits to conduct exploration, drilling and production operations; govern the amounts and types of substances that may be released into the environment in connection with oil and gas drilling and production; restrict the way the Partnership handles or disposes of wastes; limit or prohibit construction or drilling activities in sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered or threatened species; require investigatory and remedial actions to mitigate pollution conditions caused by operations or attributable to former operations; and impose obligations to reclaim and abandon well sites and pits. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of orders enjoining some or all operations in affected areas.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, the Congress and federal and state agencies frequently revise environmental, health and safety laws and regulations, and any changes that result in more stringent and costly waste handling, disposal, cleanup and remediation requirements for the oil and gas industry could have a significant impact on operating costs.

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly waste handling, storage, transport, disposal, or remediation requirements could have a material adverse effect on operations and financial position. Of particular note, the U.S. Environmental Protection Agency ("**EPA**") has recently made the enforcement of environmental laws in the oil and gas exploration and production sector a formal enforcement priority. Increased compliance costs may not be able to be passed on to purchasers or customers. Moreover, accidental releases or spills may occur in the course of operations, and the Trust cannot assure Unitholders that it will not incur significant costs and liabilities as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons.

The following is a summary of the more significant existing environmental, health and safety laws and regulations to which the Partnership's business operations are subject and for which compliance may have a material adverse impact on capital expenditures, results of operations or financial position.

Hazardous Substances and Waste

The *Comprehensive Environmental Response, Compensation, and Liability Act*, as amended, (the "**CERCLA**"), also known as the Superfund law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include current and prior owners or operators of the site where a release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these "responsible persons" may be subject to joint and several, strict liability for the costs of cleaning up hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighbouring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants into the environment. Operations will generate materials that may be regulated as hazardous substances.

Management anticipates operations will also generate solid and hazardous wastes that are subject to the requirements of the *Resource Conservation and Recovery Act*, as amended, (the "**RCRA**"), and comparable state statutes. RCRA imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Management anticipates that operations will generate petroleum hydrocarbon wastes and ordinary industrial wastes that may be regulated as hazardous wastes.

The Partnership owns and leases and, in connection with future acquisitions, will acquire, properties that have been used for numerous years to explore and produce oil and natural gas. Hydrocarbons and wastes may have been disposed of or released on or under the properties owned or leased by the Partnership or on or under other locations where these hydrocarbons and wastes have been taken for treatment or disposal. In addition, certain of these properties may have been operated by third parties whose treatment and disposal or release of hydrocarbons and wastes was not under the Partnership's control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, the Partnership could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) and to perform remedial operations to prevent future contamination.

Air Emissions

The *Clean Air Act*, as amended, and comparable state laws and regulations restrict the emission of air pollutants from many sources and also impose various monitoring and reporting requirements. These laws and regulations may require the Partnership to obtain pre approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. Obtaining permits, including air emission allowances and credits, has the potential to delay and increase the cost of the development of oil and natural gas projects. In addition, the EPA and state regulators have underway a number of regulatory changes (including the EPA's new compressor engine emissions standards and the potential aggregation of exploration and production-related emissions sources to make what have historically been multiple "minor" sources into larger "major" sources) that may significantly increase the regulatory burdens and costs of U.S. oil and gas exploration.

Climate Change

In response to certain scientific studies suggesting that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide and methane, are contributing to the warming of the Earth's atmosphere and other climatic changes, the U.S. Congress has been actively considering legislation to reduce such emissions. On June 26, 2009, the U.S. House of Representatives passed the *American Clean Energy and Security Act* of 2009 (the "**ACESA**"), which would have established an economy-wide cap-and-trade program to reduce U.S. emissions of "greenhouse gases" including carbon dioxide and methane that may contribute to warming of the Earth's atmosphere and other climatic changes. ACESA would have required a 17% reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80% reduction of such emissions by 2050. Under this legislation, the EPA would have issued a capped and steadily declining number of tradable emissions allowances to major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere. These allowances would be expected to escalate significantly in cost over time. The U.S. Senate considered pursuing its own legislation for restricting domestic greenhouse gas emissions and President Obama indicated his support of legislation to reduce greenhouse gas emissions through an emission allowance system. However, in July 2010, Senate Majority Leader Harry Reid said the Senate would not take up the ACESA, and the 111th Congress ended in December 2010 without passing the ACESA. The ACESA would now need to be passed by the Senate and re-passed by the House to become law, and the current prospects of that are extremely unlikely given Republican control of the House. Any future federal laws or implementing regulations that may be adopted to address greenhouse gas emissions could require the Partnership to incur increased operating costs and could adversely affect demand for the oil and natural gas produced.

In addition, on December 15, 2009, the EPA published its finding that emissions of greenhouse gases presented an endangerment to human health and the environment. The Endangerment Finding allowed the EPA to proceed with the adoption and implementation of regulations to restrict emissions of greenhouse gases under existing provisions of the federal *Clean Air Act*. Consequently, the EPA proposed two sets of regulations that would require a reduction in emissions of greenhouse gases from motor vehicles and could trigger permit review for greenhouse gas emissions from certain stationary sources. EPA also published a final rule on October 30, 2009, requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the U.S. beginning in 2011 for emissions occurring in 2010. EPA subsequently expanded the reporting rule to include greenhouse gas emissions from owners and operators of onshore oil and natural gas production. Several of EPA's recently finalized rules regulating emissions of greenhouse gases have been challenged in a case currently pending before the U.S. Supreme Court, *Utility Air Regulatory Group v. EPA*, a decision in which is expected in the second half of 2014. The decision in *Utility Air Regulatory Group* could impact the costs incurred by the Trust and the demand for the oil and natural gas produced.

In addition to federal activity, more than one-third of the states have begun taking actions to control and/or reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Although most of the state-level initiatives have to date focused on large sources of greenhouse gas emissions, such as coal-fired electric plants, it is possible that smaller sources of emissions could become subject to greenhouse gas emission limitations or allowance purchase requirements in the future. Any one of these climate change regulatory and legislative initiatives could have a material adverse effect on the Partnership's business, financial condition and results of operations. In Texas, the state agency responsible for regulating air emissions is the Texas Commission on Environmental Quality.

Water Discharges

The *Federal Water Pollution Control Act*, as amended, or the *Clean Water Act*, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters. Pursuant to the *Clean Water Act* and analogous state laws, permits must be obtained to discharge pollutants into, and in certain instances withdraw water from, state waters or waters of the U.S. Any such discharge of pollutants into regulated waters or withdrawal of water must be performed in accordance with the terms of the permit issued by the EPA or the analogous state agency. Spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the *Clean Water Act* and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. In Texas, the Texas Commission on Environmental Quality is the state environmental agency responsible for regulating water quality and discharges of pollutants into water.

The *Oil Pollution Act of 1990*, as amended, (the "**OPA**"), which amends the *Clean Water Act*, establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the U.S. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A "responsible party" under the OPA includes owners and operators of certain onshore facilities from which a release may affect waters of the U.S.

Insurance

The Partnership maintains insurance coverage in the amounts and against the risks typical of entities carrying on businesses similar to that carried on by the Partnership. Where the Partnership is the operator, insurance for the drilling, completion and production operations is maintained by the Partnership, as operator, pursuant to the applicable joint operating agreement.

Employees

As of the date of this Annual Information Form, the Administrator and the GP have, collectively, 37 employees, including the executive officers, who are involved in the operations, commercial, accounting and administrative functions of the Trust and the Subsidiaries.

RISK FACTORS

The risks set out below are not an exhaustive description of all the risks associated with the Trust, the Subsidiaries' business, and the oil and natural gas business generally. A prospective investor should consider carefully the risk factors set out below. In addition, prospective investors should carefully review and consider all other information contained in this Annual Information Form before making an investment decision. An investment in securities of the Trust should only be made by persons who can afford a significant or total loss of their investment.

There can be no assurance that an active trading market in the Units will be sustained. The market price for the Trust's securities could be subject to wide fluctuations. Factors such as commodity prices, government regulation, interest rates, share price movements of the Trust's peer companies and competitors, as well as overall market movements, may have a significant impact on the market price of the securities of the Trust. The stock market has from time to time experienced extreme price and volume fluctuations, particularly in the oil and gas sector, which have often been unrelated to the operating performance of particular companies.

The following is a summary of certain risk factors relating to the activities of the Trust and the Subsidiaries, which prospective investors should carefully consider before deciding whether to purchase Units. Residents of the

United States and other non-residents of Canada should have additional regard to the risk factors under the heading "Risk Factors Applicable to Residents of the United States and Other Non-Residents of Canada".

The Trust is a limited purpose trust and is entirely dependent upon the operations and assets of the Subsidiaries through the Trust's ownership of the CT Notes and the CT Units, and the CT's ownership of a 99.999% interest in the Partnership and future ownership in other Subsidiaries. Accordingly, the Trust's ability to pay distributions to Unitholders is dependent upon the ability of the Subsidiaries and the CT to meet their interest, principal and other distribution obligations. The Subsidiaries' income will be derived from the production of oil and natural gas from U.S. resource properties and is susceptible to the risks and uncertainties associated with the oil and natural gas industry generally, and specifically in the U.S.

If the Partnership's oil and natural gas reserves associated with its interests in the Salt Flat Field and in the Midland area are not supplemented through additional development or the acquisition of additional oil and natural gas properties, the ability of the Subsidiaries to meet their obligations to the Trust and the ability of the Trust to pay distributions to Unitholders may be adversely affected.

Risks Relating to the Business and Operations of the Subsidiaries

The level of distributions paid by the Trust may be decreased in the event that the production from the Partnership's petroleum assets significantly decreases from current production levels.

As of the date of this Annual Information Form, the ability of the Trust to make regular cash distributions to Unitholders is entirely dependent on the Partnership's production from its petroleum assets. The level of distributions paid by the Trust may be decreased in the event that the production from its petroleum assets significantly decreases from current production levels.

The Subsidiaries may not be able to achieve the anticipated benefits of its current and future acquisitions of petroleum assets. The integration of acquisitions may result in the loss of key employees and the disruption of ongoing business relationships.

The Subsidiaries intend to make acquisitions and dispositions of assets in accordance with their investment strategy. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as the ability to realize the anticipated growth opportunities and synergies from combining newly acquired assets with those of the Subsidiaries. The integration of newly acquired assets may require substantial Management effort, time and resources and may divert Management's focus from other strategic opportunities and operational matters, and may also result in the loss of key employees and the disruption of ongoing business, supplier, customer and employee relationships. The Subsidiaries will continually assess the value and contribution of assets that they hold. In this regard, assets may be disposed of from time to time, so that Management can focus efforts and resources more efficiently. Depending on the state of the market for these types of assets, if disposed of, the Subsidiaries may realize less than their carrying value in the Trust's consolidated financial statements.

Declines in oil, natural gas liquids and natural gas prices will negatively affect the Trust's financial results and distributions.

The financial results and condition of the Trust and the Partnership, and therefore the amounts the Trust can pay to Unitholders as distributions, will be dependent on the prices received by the Partnership for crude oil, natural gas and natural gas liquids production. Prices for crude oil, natural gas and natural gas liquids have exhibited extreme volatility over the past few years and monthly distributions may be similarly affected. Declines in prices for crude oil, natural gas and natural gas liquids could result in reductions to, or elimination of, distributions. Prices for crude oil, natural gas and natural gas liquids are determined by economic factors, political factors and a variety of additional factors beyond the Partnership's control. These factors include economic conditions, in the United States, Canada and worldwide, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability in the Middle East and elsewhere, internal capacity to produce and transport oil and natural gas in the United States from shale deposits, the foreign supply of crude oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of crude oil, natural gas or natural gas liquids would have an adverse effect on the carrying value of the Partnership's proved and probable reserves, net asset value, borrowing capacity, revenues, profitability and cash flows from operating activities and ultimately on the overall financial condition of the Trust and its Subsidiaries, and therefore on the amounts to be distributed to Unitholders.

Estimated reserves of the Partnership are based on many assumptions that may turn out to be inaccurate. There are numerous uncertainties inherent in estimating quantities of recoverable oil and natural gas reserves, including many factors beyond Management's control. The incorrect assessment of value of the Partnership's reserves could adversely affect the value of the Units and distributions to Unitholders.

In general, estimates of economically recoverable oil and natural gas reserves and resources, the future net revenues and finding and development costs therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. The reserves and recovery information contained in the NSAI Reserve Report is only an estimate and the actual production and ultimate reserves from the properties may be greater or less than the estimates prepared by NSAI. The NSAI Reserve Report has been prepared using certain commodity price assumptions which are described in the notes to the reserves tables under the heading "Reserves and Other Oil and Gas Information." If the Trust realizes lower prices for crude oil, natural gas and natural gas liquids and they are substituted for the price assumptions utilized in that reserves report, the present value of estimated future net revenues for reserves and net asset value would be reduced and the reduction could be significant. The estimates in the NSAI Reserve Report are based in part on the timing and success of activities Management intends to undertake in 2014 and future years. The reserves and estimated future net revenues to be derived therefrom contained in the NSAI Reserve Report will be reduced in future years to the extent that such activities do not achieve the production performance set forth in the NSAI Reserve Report. Estimates of proved undeveloped reserves are sometimes based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. For these estimates, recovery factors and drainage areas are estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

Additionally, due to the lack of production history using horizontal drilling techniques on certain parts of the Partnership's acreage, any estimates of future production associated with the planned use of such horizontal drilling techniques may be subject to greater variance to actual production than would be the case with properties having a longer production history using such techniques.

If actual production or reserves are less than expected, funds flow from operations and cash available for distribution to Unitholders could be negatively affected.

The net present value of future net revenues attributable to the Partnership's reserves will not necessarily be the same as the current market value of its estimated petroleum reserves.

Potential investors and Unitholders should not assume that the net present value of future net revenues attributable to the Partnership's reserves is the current market value of its estimated petroleum reserves. NSAI based the estimated discounted future net revenues from proved reserves on certain commodity price assumptions, which assumptions are described in the notes to the reserves tables. Actual future net revenues from the Partnership's properties will be affected by factors such as:

- actual prices received for oil, natural gas and natural gas liquids;
- actual cost of development and production expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both production and incurrence of expenses in connection with the development and production of oil, natural gas and natural gas liquids from the properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor used when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Partnership or the oil and natural gas industry in general. Additionally, such calculation excludes a number of important costs that the Partnership will actually incur, such as interest expense, income taxes and general and administrative expenses. Actual future prices and costs may differ materially from those used in the present value estimates included in this Annual Information Form.

Increases in interest rates could increase the Trust's costs and reduce the Trust's income and ability to pay distributions.

There is a risk that interest rates will increase given the current historical low level of interest rates. An increase in interest rates could result in a significant increase in the amount paid by the subsidiary of the Trust to service debt, resulting in a decrease in distributions to Unitholders, and could impact the market price of the Units. In addition, increasing interest rates may put competitive pressure on the levels of distributable income paid by the Trust to Unitholders, increasing the level of competition for capital faced by the Trust, which could have a material impact on the trading price of the Units.

The value of the Canadian dollar against the U.S. dollar will affect the Trust's results and distributions.

World oil prices are quoted in U.S. dollars and, as all of the assets of the Partnership are located in the U.S., the Partnership's oil and natural gas revenue is received in U.S. dollars. Generally, an increase in the value of the Canadian dollar will reduce the prices received by the Trust for its petroleum and natural gas sales, but will also reduce the operating expenses associated with these sales.

The Trust indirectly receives distributions of income from the Partnership in U.S. dollars and pays distributions to Unitholders in Canadian dollars. The Trust also raises funds primarily in Canada from the sale of Units in Canadian dollars and invests indirectly through the Partnership in U.S. oil and gas assets, using U.S. dollars. Thus, when the Canadian dollar increases in value against the U.S. dollar, the Trust's indirect investments in U.S. oil and gas assets will be less expensive; however, distributions received by the Trust indirectly from the Partnership will also be reduced. When the Canadian dollar decreases in value against the U.S. dollar, the Trust's indirect investments in U.S. oil and gas assets will be more expensive; however, distributions received by the Trust indirectly from the Partnership will increase.

The global economy has not fully recovered, and unforeseen events may negatively impact the financial condition of the Trust.

Market events and conditions including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions have historically caused significant volatility to commodity prices. These conditions worsened in 2008 and early 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions may cause the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company and trust valuations and may continue to impact the performance of the global economy going forward.

If the economic climate in the U.S. or the world generally deteriorates, demand for petroleum products could diminish further and prices for oil and natural gas could decrease further, which could adversely impact the Trust's results of operations, liquidity and financial condition.

Non-compliance with the covenants under the Credit Facility could adversely affect the financial condition of the Trust.

The subsidiary of the Trust and the Trust are required to comply with covenants under the Credit Facility. In the event that they do not comply with covenants under the Credit Facility, access to capital could be restricted or repayment could be required on an accelerated basis by the lenders, and the ability to make distributions to Unitholders may be restricted. The lenders have security over substantially all of the assets of the Partnership. If the subsidiary of the Trust becomes unable to pay its debt service charges or otherwise commits an event of default such as breach of its financial covenants, the lender may foreclose on or sell the Partnership's working interests in its properties. Amounts paid in respect of interest and principal on debt may reduce distributions. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service before payment by the CT of distributions on the CT Units and interest on the CT Notes and distributions by the Partnership to the CT. Certain covenants in the Credit Facility may also limit distributions. Although Management believes the Credit Facility will be sufficient for the near term, there can be no assurance that the amount will be adequate for the Partnership's future financial obligations including the Partnership's future capital expenditure programs, or that additional funds will be able to be obtained. For more information, see "Debt Financing".

The Trust's level of indebtedness may reduce financial flexibility.

Concurrent with the closing of the Hardeman Acquisition on November 25, 2013, the subsidiary of the Trust entered into the $US 10 million non-revolving term facility with a maturity date of November 25, 2014, which is fully drawn by way of LIBOR loans as at December 31, 2013. In addition, $CAN 67.5 million has been drawn under the revolving $US 80 million facility by way of LIBOR and base rate loans. The Trust may incur significant indebtedness in the future, including under the Credit Facility, in order to make additional investments in its Subsidiaries for the purpose of enabling them to acquire new properties or develop existing properties. Management intends to manage in a financially conservative manner. The Trust's objective is to maintain an external debt to estimated future annual cash flow ratio not to exceed 1.5 to 1.0. This ratio may increase at certain times as a result of acquisitions. In order to facilitate the management of this ratio, the Trust prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors including current and forecast prices, successful capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors. In the event that debt levels exceed the limits stated above, operations could be affected in several ways, including the following:

- a significant portion of cash flows could be used to service indebtedness;
- a high level of debt would increase vulnerability to general adverse economic and industry conditions;
- the covenants contained in the Credit Facility will limit the Trust's ability to borrow additional funds, dispose of assets, pay distributions and make certain investments;
- a high level of debt may place the Trust at a competitive disadvantage compared to competitors that are less leveraged and therefore, may be able to take advantage of opportunities that the Trust's indebtedness would prevent it from pursuing;
- the Trust's debt covenants may also affect flexibility in planning for, and reacting to, changes in the economy and in the industry;
- a high level of debt may make it more likely that a reduction in the Trust's borrowing base following a periodic redetermination could require the Trust to repay a portion of then-outstanding bank borrowings; and
- a high level of debt may impair the ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes.

A high level of indebtedness increases the risk that the Trust may default on its debt obligations. The Trust's ability to meet its debt obligations and to reduce its level of indebtedness depends on future performance. General economic conditions, oil, natural gas liquids and natural gas prices, and financial, business and other factors affect operations and future performance. Many of these factors are beyond the Trust's control. The Trust may not be able to generate sufficient cash flows to pay the interest on debt and future working capital, borrowings or equity financing may not be available to pay or refinance such debt. Factors that will affect the ability to raise cash through an offering of capital stock or a refinancing of debt include financial market conditions, the value of assets and performance at the time the Trust needs capital.

Many of the risk factors outlined above are likely to occur only in the event that the Trust incurs high levels of debt or if the producing properties of the Partnership suffer a substantial impairment that has a material impact on cash flow from operations or if a substantial decline in the price of oil or natural gas were to occur.

Future acquisition and development projects will require substantial capital expenditures. Trusts have historically relied on external sources of capital, borrowings and equity sales, and the Trust may be unable to obtain needed capital or financing on satisfactory terms, which could lead to expiration of leases or a decline in oil and natural gas reserves.

The Partnership's planned acquisition and development activities will be capital intensive. The Partnership expects to continue to make substantial capital expenditures for the acquisition, development and production of oil and natural gas reserves. If adequate sources of capital are not available on attractive terms, or at all, to fund planned capital expenditures, the Partnership may not be able to fully implement its drilling strategy. The actual amount and timing of future capital expenditures may differ materially from estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

Changes in the Trust's financing needs may require it to alter capitalization substantially through the issuance of debt or additional Units. The issuance of additional debt may require that a portion of cash flows provided by operating activities be used for the payment of principal and interest on existing debt, thereby reducing the ability to use cash flows to fund working capital, capital expenditures, acquisitions and distributions. The issuance of additional Units could have a dilutive effect on the value of previously issued Units.

Future cash flows provided by operating activities and access to capital are subject to a number of variables, including:

- proved reserves;
- the level of oil, natural gas and natural gas liquids the Partnership is able to produce from existing wells;
- the prices at which oil, natural gas and natural gas liquids are sold;
- the costs of developing and producing oil, natural gas and natural gas liquids;
- the ability to acquire, locate and produce new reserves;
- the ability and willingness of the Trust's banks to lend; and
- the ability to access the equity and debt capital markets.

If the borrowing base under the Credit Facility or revenues decreases as a result of commodity prices, operating difficulties, declines in reserves or for any other reason, the Trust, Partnership (or other Subsidiaries formed for future acquisitions) may have limited ability to obtain the capital necessary to sustain operations at current levels. If additional capital is needed, the Trust may not be able to obtain debt or equity financing on favourable terms, or at all. To the extent that external sources of capital become limited or unavailable or available on onerous terms, the Subsidiaries' ability to make capital investments and maintain or expand existing assets and reserves may be impaired, which in turn could lead to a possible expiration of its leases and a decline in petroleum reserves, and the Subsidiaries' assets, liabilities, business, financial condition, results of operations and distributions may be materially and adversely affected as a result. Alternatively, the Trust may issue additional Units from treasury at prices which may result in a decline in production per Unit and reserves per Unit or the Subsidiaries may wish to borrow to finance significant acquisitions or development projects to accomplish their long term objectives on less than optimal terms.

The Partnership, and in the future other Subsidiaries, may participate in hedging activities that reduce the realized prices received for oil and natural gas sales. This may require the Subsidiaries to provide collateral for hedging liabilities and involve risk that counterparties may be unable to satisfy their obligations to the Subsidiaries.

In order to manage exposure to price volatility in marketing oil, natural gas liquids and natural gas, the Partnership has entered into commodity price risk management arrangements for a portion of expected production. Commodity price hedging may limit the prices actually realized and therefore, if future oil, natural gas liquids or natural prices are higher than the hedged price, commodity price hedging could reduce future oil, natural gas liquids or natural gas revenues from what such revenues would otherwise have been. Commodity price hedging activities could impact earnings in various ways, including recognition of certain mark-to-market gains and losses on derivative instruments. The fair value of oil, natural gas liquids and natural gas derivative instruments can fluctuate significantly between periods. In addition, commodity price risk management transactions may expose the Subsidiaries to the risk of financial loss in certain circumstances, including instances in which:

- production is less than expected;
- there is a widening of price differentials between delivery points for production and the delivery point assumed in the hedge arrangement; or
- the counterparties to these contracts fail to perform their obligations.

Hedging transactions involve the risk that counterparties, which are generally financial institutions, may be unable to satisfy their obligations. If any counterparties were to default on obligations under the hedging contracts or seek bankruptcy protection, it could have an adverse effect on the ability to fund planned activities and could result in a larger percentage of future production being subject to commodity price changes. The risk of counterparty default is heightened in a poor economic environment.

The Subsidiaries' obligations under future hedging arrangements may be secured by all or a portion of its proved reserves, the value of which must cover the fair value of the transactions outstanding under the facility by some multiple. If the collateral value falls below the coverage designated, the Subsidiaries would be required to post cash or letters of credit with the counterparties if the Subsidiaries did not have sufficient unencumbered oil and natural gas properties available to cover the shortfall. Future collateral requirements would be dependent to a great extent on oil and natural gas prices.

Units may from time to time trade at a price that is less than the net asset value per Unit.

Net asset value from time to time will vary depending upon a number of factors beyond the Trust's control, including oil and gas prices. The trading price of the Units from time to time is determined by a number of factors, some of which are beyond the Trust's control and such trading price may be greater or less than the net asset value.

Failure of third parties to meet their contractual obligations may have a material adverse effect on the Trust's financial condition.

The Trust and its Subsidiaries are exposed to third party credit risk through contractual arrangements with current or future joint venture partners, third party operators, marketers of its petroleum and natural gas production and other parties. Poor credit conditions in the industry and of joint venture partners or other working interest owners may impact a joint venture partner's or working interest owner's willingness to participate in ongoing capital programs, potentially delaying such programs and the results thereof until the Trust or its Subsidiaries finds a suitable alternative partner.

The Subsidiaries' business is heavily regulated, and such regulation increases its costs and may adversely affect its financial condition.

Oil and natural gas operations (including drilling, land tenure, exploration, development, production, refining, water and waste disposal, emissions controls, transportation and marketing) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. Governments may regulate or intervene with respect to price, taxes, royalties, emissions, water use and disposal, and the exportation of oil and natural gas. Increasing regulation increases costs. In order to conduct oil and gas operations, licenses and permits from various governmental authorities are required. There can be no assurance that the Subsidiaries will be able to obtain all of the licenses and permits that may be required to conduct operations that they may wish to undertake. See "The Industry".

Income tax laws or other laws may in the future be changed or interpreted in a manner that adversely affects the Trust and its Unitholders.

The Trust intends to continue at all times to qualify as a "unit trust" and a "mutual fund trust" for purposes of the Tax Act.

The SIFT Rules apply to a trust that is a SIFT trust, and in some cases cause significant amounts of SIFT tax to be paid. The Trust will not be a SIFT trust as long as it complies with its investment restrictions set out in the Trust Indenture. The Trust's investment restrictions may only be amended by Special Resolution of the Unitholders.

The Trust and Partnership tax horizons, as determined from a full cycle corporate model developed by Management and incorporating all applicable U.S. and Canadian deductions, indicates that no material Canadian or U.S. taxes are expected to be payable for several years. Management expects to extend this period through continued capital investments and acquisitions in the U.S.

However, there can be no assurance that Canadian federal income tax laws, the judicial interpretation thereof or the administrative and assessing practices and policies of the CRA and the Department of Finance (Canada) will not be changed in a manner that adversely affects the Trust or Unitholders. Any such change could increase the amount of tax payable by the Trust or the CT or could otherwise adversely affect Unitholders by reducing the amount available to pay distributions or changing the tax treatment available to Unitholders in respect of such distributions.

Specifically, should the Trust cease at any time to qualify as a mutual fund trust under the Tax Act, some of the significant consequences of losing this status are that the Units would not be qualified investments for Registered Plans, and the Trust would cease to be eligible for the capital gains refund mechanism available under the Tax Act. Similarly, should the SIFT Rules apply to the Trust so as to cause the payment of a significant amount of SIFT tax, that could have a materially adverse impact on the Trust and on the distributions received by the Unitholders.

In addition, the U.S. Internal Revenue Service ("**IRS**") may adopt tax positions that differ from the positions taken by the Trust or the Subsidiaries, including the CT's position that the interest on the CT Notes is deductible. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions taken by the Trust. The Trust or the Subsidiaries could lose a contest with the IRS if a United States court does not agree with some or all of the positions taken by them. Any contest with the IRS may materially and adversely impact the market for the Units and the price at which they trade, cash flow of the Trust and distributions. The costs of any contest with the IRS will be borne indirectly by Unitholders because the costs will reduce cash available for distribution.

Potential legislative and regulatory actions could increase costs, reduce revenue and cash flow from oil and natural gas sales, reduce liquidity or otherwise alter the way the Subsidiaries conduct their business.

The activities of exploration and production companies operating in the United States are subject to extensive regulation at the federal, state and local levels. Changes to existing laws and regulations or new laws and regulations such as those described below could, if adopted, have an adverse effect on the Trust.

Recent proposals to increase U.S. Federal income taxation of independent producers may negatively affect the Trust's results.

Recently, U.S. federal budget proposals would potentially increase and accelerate the payment of federal income taxes of independent producers of oil and natural gas. Proposals that would significantly affect the Subsidiaries would repeal the expensing of intangible drilling costs, repeal the percentage depletion allowance and increase the amortization period of geological and geophysical expenses. These changes, if enacted, will make it more costly to explore for and develop oil and natural gas resources. The Trust is unable to predict whether any changes, or other proposals to such laws, ultimately will be enacted. Any such changes could negatively impact cash flows, the cash available for distribution to Unitholders, and the value of the Units.

New U.S. regulation of derivatives trading could reduce hedging opportunities and negatively affect the Trust's results.

New U.S. regulation of derivatives trading could reduce hedging opportunities and negatively affect the Trust's results. In 2010, the U.S. Congress enacted the Dodd Frank Wall Street Reform and Consumer Protection Act (the "Dodd Frank Act"), which contains measures aimed at increasing the transparency and stability of the over the counter (OTC) derivative markets and preventing excessive speculation. Pursuant to the Dodd Frank Act, the U.S. Commodity Futures Trading Commission (the "CFTC") enacted regulations that impose, *inter alia*, reporting requirements and leverage limitations on certain types of financial transactions. Most energy transactions are exempt from these regulations and requirements. However, the CFTC continues to issue new and revised regulations and the precise application of either the Dodd Frank Act or the CFTC's regulations is yet to be determined. In the future, the Subsidiaries may use the OTC market for its oil and natural gas derivative contracts. However, the Dodd Frank Act or the CFTC's regulations could reduce liquidity in the energy futures markets. Such changes could materially reduce hedging opportunities and negatively affect revenues and cash flow during periods of low commodity prices.

Regulation of environmental matters related to climate change could have a negative impact on the Trust.

Federal and state governments are considering enacting new legislation and promulgating new regulations governing or restricting the emission of greenhouse gases from certain stationary sources common in the Trust's industry. The EPA has already made findings and issued proposed regulations that could lead to the imposition of restrictions on greenhouse gas emissions from certain stationary sources and that could require the Subsidiaries to establish and report an inventory of greenhouse gas emissions. In addition, the U.S. Congress has been considering various bills that would establish an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. Such a program, if enacted, could require phased reductions in greenhouse gas emissions over several or many years as could the issuance of a declining number of tradable allowances to sources that emit greenhouse gases into the atmosphere. Legislative and regulatory proposals for restricting greenhouse gas emissions or otherwise addressing climate change could require the Partnership to incur additional operating costs and could adversely affect demand for the oil and natural gas that the Partnership sold. At the state level, the Partnership is aware of changes in air quality standards that are regulated in Texas by the Texas Railroad Commission and the Texas Commission on Environmental Quality and is implementing changes at the Partnership's facilities to meet or exceed these new standards. The potential increase in operating costs could include new or increased costs to obtain permits, operate and maintain equipment and facilities, install new emission controls on equipment and facilities, acquire allowances to authorize greenhouse gas emissions, pay taxes related to greenhouse gas emissions and administer and manage a greenhouse gas emissions program. Moreover, incentives to conserve energy or use alternative energy sources could reduce demand for oil and natural gas.

Acquiring, developing and exploring for oil and natural gas involves many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome.

The business plan of the Partnership (and other Subsidiaries formed for future acquisitions) contemplates acquisitions of additional producing properties and developmental drilling, and its future financial condition and results of operations will depend on the success of these activities. Oil and natural gas acquisition, development and production activities are subject to numerous risks beyond the control of Subsidiaries' and Trust's control.

These risks include, but are not limited to, encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, equipment failures and other accidents, sour gas releases, uncontrollable flows of oil, natural gas or well fluids, adverse weather conditions, pollution, other environmental risks, fires, spills and delays in payments between parties caused by operation or economic matters. These risks will increase as the Subsidiaries undertake more developmental drilling. Although the Subsidiaries will maintain insurance in accordance with customary industry practice, they are not fully insured against all of these risks. Continuing production from a property, and to some extent the marketing of production therefrom, are largely dependent upon the ability of the operator of the property. Although the Partnership operates all of its properties, other companies may operate other properties the Subsidiaries acquire in the future and, as a result, returns on assets operated by others depends upon a number of factors outside the Subsidiaries' control. To the extent the operator fails to perform these functions properly, income may be reduced. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Trust's financial condition, prospects and its ability to maintain distributions.

Distributions on Units are variable and may be reduced or suspended entirely.

The actual cash flow available for distribution to Unitholders is dependent on the amount of cash flow paid to the Trust by its Subsidiaries and can vary significantly from period to period for a number of reasons, including among other things: (i) the operating entities' operational and financial performance (including fluctuations in the quantity of their oil, natural gas liquids and natural gas production and the sales price that they realize for such production (after hedging contract receipts and payments)); (ii) fluctuations in the costs to produce oil, natural gas liquids and natural gas, including royalty burdens, and to administer and manage the Trust and its Subsidiaries; (iii) the amount of cash required or retained for debt service or repayment; (iv) amounts required to fund capital expenditures and working capital requirements; and (v) foreign currency exchange rates and interest rates. These amounts are subject to the discretion of the Board, which will regularly evaluate the Trust's distribution payout with respect to anticipated cash flows, debt levels, capital expenditure plans and amounts to be retained to fund acquisitions and expenditures. In addition, the Trust's level of distributions per Unit will be affected by the number of outstanding Units and other securities that may be entitled to receive cash distributions. Distributions may be increased, reduced or suspended entirely depending on the Trust's revenue streams and the performance of its assets. The market value of the Units may deteriorate if the Trust is unable to meet distribution expectations in the future and such deterioration may be material.

The Trust Indenture also provides for the consolidation of the Units to the pre-distribution number of Units after any pro-rata distribution of additional Units to all Unitholders. Accordingly, the Trust Indenture allows for the payment of distributions in a form other than cash and Unitholders may have taxable income and cash taxes payable in excess of the amount of cash distributions they receive from the Trust.

The Subsidiaries are participating in larger projects and have concentrated risk in certain areas of operations.

The Partnership's petroleum assets are currently located in Texas and Oklahoma. The Partnership plans to undertake a variety of small and large projects in respect of its petroleum assets. However, project delays may impact expected revenues from operations and significant project cost over-runs could make a project uneconomic. The Subsidiaries' ability to execute projects and market oil and natural gas depends upon numerous factors beyond Management's control, including:

- obtaining the necessary permits and licenses;
- the availability of processing capacity;
- the availability and proximity of pipeline capacity or other means of transporting oil and natural gas;
- the availability of storage capacity;
- changes in oil and natural gas prices;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected changes in costs;
- availability of capital;
- accidental events;
- the availability and productivity of skilled labour; and

- changes in regulation, including regulations of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Subsidiaries could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil, natural gas liquids and natural gas that are produced.

Predominantly all of the Partnership's producing properties and operations are located in Texas, making the Trust vulnerable to risks associated with the Partnership operating in one major geographic area.

As of December 31, 2013, predominantly all of the proved reserves and production of the Partnership are located in the counties of Caldwell, Martin, Palo Pinto and Hardeman, Texas. The Partnership has only recently acquired a small interest in petroleum properties in Greer, Harmon and Jackson counties, Oklahoma. As a result, the Partnership, and by extension the Trust, may be disproportionately exposed to the impact of delays or interruptions of production from these wells caused by transportation capacity constraints, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation and permit or license approvals, natural disasters, adverse weather conditions, plant closures for scheduled maintenance or interruption of transportation of oil or natural gas produced from the wells in this area. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and gas producing areas containing the Partnership's properties, which may cause these conditions to occur with greater frequency or magnify the effect of these conditions on the Partnership. Due to the concentrated nature of the Partnership's portfolio of properties, a number of these properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on the Partnership's results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on the results of operations of the Partnership, the Subsidiaries and the financial condition of the Trust.

The Trust has just over three years of operations.

The Trust is still a relatively new company as it had no assets or operating history prior to the completion of its initial public offering and the Salt Flat Acquisition in November 2010. Management may not be successful in implementing the Partnership's business strategies or development plan. In the event that the Partnership's development plan is not completed or is delayed, operating results will be adversely affected and operations will differ materially from the activities described in this Annual Information Form. As a result of industry factors or factors relating specifically to the Partnership, Management may have to change methods of conducting business, which may cause a material adverse effect on results of operations and financial condition.

The Partnership only operates in one region of the United States and expansion outside of this area or into new business activities may increase its risk exposure.

All proved reserves and production of the Partnership are predominantly located in the counties of Caldwell, Martin, Palo Pinto and Hardeman, Texas. The Partnership business plan contemplates acquisitions of additional production and the development thereof in the mid-continental U.S. (Williston to south Texas) as well as other select basins. In the future, the Partnership or other Subsidiaries may acquire oil and gas properties outside these geographic areas. In addition, the Subsidiaries are not limited to investment in oil and gas production and development, and may acquire and own assets or property in connection with gathering, processing, transporting, extracting, buying, storing or selling petroleum, natural gas, natural gas liquids or other related products, or in connection with other forms of energy and related businesses. Expansion of activities into new areas may present new additional risks or alternatively, significantly increase the exposure to one or more of the present risk factors which may adversely affect the Trust's future financial condition.

The Trust's growth strategy depends on the Subsidiaries' successful acquisition of additional proved reserves. The Subsidiaries may be subject to risks in connection with acquisitions and the integration of significant acquisitions may be difficult.

The overall business strategy contemplates future acquisitions targeting undercapitalized, conventional oil and natural gas producing properties and developmental drilling thereon. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;
- development and operating costs;
- availability of capital; and

- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, Management anticipates undertaking a review of the subject properties that is generally consistent with industry practices. Management's review may not reveal all existing or potential problems, nor will it permit Management to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. The Trust may not be entitled to contractual indemnification for environmental liabilities and may acquire properties on an "as is" basis.

Significant acquisitions and other strategic transactions may involve other risks, including:

- diversion of Management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of the Subsidiaries while carrying on its ongoing business;
- difficulty associated with coordinating geographically separate organizations; and
- challenge of attracting and retaining personnel associated with acquired operations.

The process of integrating operations could cause an interruption of, or loss of momentum in, the Subsidiaries' business. Management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage the business. If Management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, the Subsidiaries' business could suffer.

The Subsidiaries may not be able to realize the anticipated benefits of acquisitions and dispositions.

The Subsidiaries plan to make acquisitions of producing properties in the ordinary course of business. The price the Subsidiaries pay for the purchase of properties is based on engineering and economic estimates of the reserves made by Management and independent engineers modified to reflect technical and economic views. These assessments include a number of material factors and assumptions. Consequently, the reserves acquired may be less than expected, which could adversely impact cash flow from operating activities and distributions to Unitholders. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the ability to realize the anticipated developmental drilling opportunities. There is no assurance that the Subsidiaries will be able to continue to complete acquisitions or dispositions of oil and natural gas properties which realize all the synergistic benefits anticipated by the Subsidiaries.

Increased regulation of hydraulic fracturing and oil and gas development could result in reductions or delays in production, which could adversely impact the Trust's revenues.

A number of federal agencies, including the U.S. Environmental Protection Agency (the "EPA") and the U.S. Department of Energy, are analyzing, or have been requested to review, a variety of environmental issues associated with oil and gas development, including hydraulic fracturing. In addition, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act's Underground Injection Control Program and has begun the process of drafting guidance documents related to this assertion of regulatory authority. While the EPA has yet to take any action to enforce or implement this newly asserted regulatory authority, industry groups have filed suit challenging the EPA's recent decision. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with the initial progress report released December 2012 and final draft report expected to be released for public comment and peer review in 2014. In the interim, however, the EPA has utilized its existing Safe Drinking Water Act's enforcement authorities to order actions and potentially to pursue penalties against some oil and natural gas producers where EPA believes their activities may have impacted groundwater. Also, for the second consecutive session, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Moreover, the EPA has announced that it will develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have or are evaluating various other aspects of hydraulic fracturing, with the Department of Interior currently developing a rule to require oil and natural gas producers to publicly disclose their hydraulic fracturing chemicals in connection with their drilling of wells on federal lands. These studies or reviews, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms. In addition, some states have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations. In addition, some states and municipalities have adopted, and other states and municipalities are considering adopting, moratoriums and/or regulations that could impose more stringent disclosure and/or well construction requirements on hydraulic fracturing operations or ban such operations altogether. For instance, in June 2011, Texas' Governor Perry signed a law requiring disclosure of chemicals used in hydraulic fracturing for which implementing regulations were adopted in December 2012. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for the operators to perform fracturing to stimulate production from tight formations. Restrictions on hydraulic fracturing also could reduce the amount of oil, natural gas and natural gas liquids that are ultimately produced in commercial quantities from the Partnership's properties. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, the Partnership's business and operations and the properties in which the Partnership have an interest could be subject to additional permitting requirements, and also to attendant permitting delays, increased operating and compliance costs and process prohibitions.

On April 17, 2012, the EPA approved final regulations under the Clean Air Act that, among other things, require additional emissions controls for natural gas and natural gas liquids production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require the reduction of VOC emissions from natural gas wells through the use of reduced emission completions or "green completions" on all hydraulically fractured wells constructed or refractured after January 1, 2015. For well completion operations occurring at such well sites before January 1, 2015, the final regulations allow operators to capture and direct flowback emissions to completion combustion devices, such as flares, in lieu of performing green completions. These regulations also establish specific new requirements regarding emissions from dehydrators, storage tanks and other production equipment. Compliance with these requirements could require a number of modifications to operations, including the installation of new equipment, and could significantly increase the Partnership's costs of development and production, although the Trust does not expect these requirements to be any more burdensome to the Partnership than to other similarly situated companies involved in oil and natural gas exploration and production operations.

At the same time, certain environmental groups have suggested that additional laws may be needed to more closely and uniformly regulate the hydraulic fracturing process and legislation has been proposed by some members of United States Congress to provide for such regulation. The Trust cannot predict whether any such legislation will ever be enacted and if so, what its provisions would be. If additional levels of regulation and permits were required through the adoption of new laws and regulations at the federal or state level, that could lead to delays, increased operating costs and process prohibitions that could reduce the volumes of natural gas that move through the Partnership's gathering systems which would materially adversely affect the Partnership's revenues and results of operations.

Operations are subject to hazards and unforeseen interruptions for which the Trust may not be adequately insured.

There are a variety of operating risks inherent in the Partnership's wells, gathering systems and associated facilities, such as leaks, explosions, mechanical problems and natural disasters, all of which could cause substantial financial losses. Any of these or other similar occurrences could result in the disruption of operations, substantial repair costs, personal injury or loss of human life, significant damage to property, environmental pollution, impairment of operations and substantial revenue losses. The location of the Partnership's wells, gathering systems and associated facilities near populated areas, including residential areas, commercial business centers and industrial sites, could significantly increase the level of damages resulting from these risks.

The Partnership and the other Subsidiaries are not fully insured against all risks. In addition, pollution and environmental risks generally are not fully insurable. Additionally, Management may elect not to obtain insurance if they believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could, therefore, occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Moreover, insurance may not be available in the future at commercially reasonable costs and on commercially reasonable terms. Losses and liabilities from uninsured and underinsured events and a delay in the payment of insurance proceeds could adversely affect the Trust's financial condition and ability to make distributions to Unitholders.

The nature of the Partnership's assets exposes it to significant costs and liabilities with respect to environmental, operational and safety matters.

The Partnership and other Subsidiaries formed for future acquisitions may incur significant costs and liabilities as a result of environmental and safety requirements applicable to oil and gas production activities. These costs and liabilities could arise under a wide range of U.S. federal, state and local environmental and safety laws and regulations, including agency interpretations of the foregoing and governmental enforcement policies, which have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and to a lesser extent, issuance of injunctions to limit or cease operations. In addition, claims for damages to persons or property may result from environmental and other impacts of operations.

Strict joint and several liabilities may be imposed under certain environmental laws, which could cause the Subsidiaries to become liable for the conduct of others or for consequences of its actions that were in compliance with all applicable laws at the time those actions were taken. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require the Subsidiaries to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on its results of operations, competitive position or financial condition. If the Subsidiaries are not able to recover the resulting costs through insurance or increased revenues, the ability to make distributions to Unitholders could be adversely affected. See "The Industry – Environmental, Health and Safety Regulation" for more information.

Competition in the oil and natural gas industry is intense, making it more difficult to acquire properties, market oil and natural gas and secure trained personnel.

The ability of the Subsidiaries to acquire and develop additional reserves in the future will depend on the ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing equipment and trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many competitors possess and employ financial, technical and personnel resources substantially greater than the Subsidiaries'. Those companies may be able to pay more for productive oil and natural gas properties or to identify, evaluate, bid for and purchase a greater number of properties than the Subsidiaries' financial or personnel resources permit. Furthermore, these companies may also be better able to withstand the financial pressures of unsuccessful drilling attempts, sustained periods of volatility in financial markets and generally adverse global and industry-wide economic conditions, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, which would adversely affect competitive position. In addition, companies may be able to offer better compensation packages to attract and retain qualified personnel. The cost to attract and retain qualified personnel has increased over the past few years due to competition and may increase substantially in the future. The Subsidiaries may not be able to compete successfully in the future in acquiring and developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on the Trust.

Application of International Financial Reporting Standards ("IFRS") to the Trust's financial results may result in non-cash losses which may adversely affect the market price of Units.

IFRS requires that management apply certain accounting policies and make certain estimates and assumptions which affect reported amounts in the financial statements. The accounting policies may result in non-cash charges to net income and write downs of net assets in the financial statements. Such non-cash charges and write-downs may be viewed unfavourably by the market and may result in an inability to borrow funds and/or may result in a decline in the Unit price. Under IFRS, the net amounts at which petroleum and natural gas costs on a cash generating unit ("**CGU**") basis are subject to an assessment at the end of each reporting period whether there is any indication that an asset may be impaired. If any such indication exists, an estimate of the recoverable amount will be made. The recoverable amount is the greater of its value in use and its fair value less costs to sell. In determining fair value less costs to sell, the Trust will consider recent transactions within the industry, long-term views of commodity prices, externally evaluated reserves volumes and discount rates specific to the CGU. If net capitalized costs for a CGU exceed the estimated recoverable amounts, the Trust will have to charge the amount of the excess to earnings. A decline in the net value of oil and natural gas properties could cause capitalized costs to exceed the recoverable amounts, resulting in a charge against earnings. The net value of oil and gas properties is highly dependent upon the prices of oil and natural gas. Under IFRS, the accounting for financial instruments may result in non-cash charges against net income as a result of changes in the fair market value of financial instruments. A decrease in the fair market value of the financial instruments as the result of fluctuations in commodity prices and foreign exchange rates may result in a write-down of net assets and a non-cash charge against net income. Such write-downs and non-cash charges may be temporary in nature if the fair market value subsequently increases. Where there is objective evidence of a subsequent increase in fair value, these non-cash impairment charges may be reversed.

Success depends in large measure on certain key personnel and the Trust's ability to retain its key personnel.

The loss of key personnel could delay the completion of certain projects or otherwise have a material adverse effect on the Trust. Unitholders will be dependent on Management in respect of the administration and management of all matters relating to the Trust, its subsidiaries and affiliates, their respective properties, assets, operations, and the safekeeping of their primary workspace and computer systems.

The Subsidiaries will be reliant on operators of any property they acquire an interest in but do not operate.

To the extent that the Subsidiaries will not be the operator of certain of their properties, they will be dependent upon other operators or third parties for the timing of such activities and will be largely unable to control the activities of such operators. The failure of such operators and their contractors to properly perform their obligations may have a material adverse effect on the Trust's financial condition and the value of its Units.

Oil and natural gas reserves are a depleting resource and decline as such reserves are produced.

Distributions by the Trust, absent commodity price increases or cost effective acquisition and development activities, will decline over time in a manner consistent with declining production from typical oil, natural gas and natural gas liquid reserves. Future oil, natural gas and natural gas liquids reserves and production, and therefore the Trust's cash flows from operating activities, will be highly dependent on the Subsidiaries' success in exploiting reserves base and acquiring additional reserves. Without reserves additions through acquisition or development activities, reserves and production may decline over time as reserves are produced. There can be no assurance that the Subsidiaries will be successful in developing or acquiring additional reserves on terms that meet the Trust's investment objectives.

Acreage must be drilled before lease expiration, generally within two to five years, in order to hold the acreage by production. In the highly competitive market for acreage, failure to drill sufficient wells in order to hold acreage will result in a substantial lease renewal cost, or if renewal is not feasible, loss of the Partnership's lease and prospective drilling opportunities.

If the Partnership acquires leasehold that is not held by production, it must establish production prior to the expiration of the applicable lease or else the lease for such acreage will expire. The cost to renew leases may increase significantly, and the Partnership may not be able to renew such leases on commercially reasonable terms or at all. As such, the Partnership's actual drilling activities may materially differ from current expectations, which could adversely affect the ability to pay distributions.

The Subsidiaries may incur losses as a result of title defects in the properties in which the Subsidiaries' invest.

Industry practice in the U.S. for acquiring oil and gas leases or interests does not typically involve retaining lawyers to examine the title to the mineral interest and instead relies upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest. Prior to the drilling of an oil or gas well, however, it is the normal practice in the industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Failure to cure any title defects may adversely impact the ability in the future to increase production and reserves. There is no assurance that the Partnership and other Subsidiaries formed for future acquisitions will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which the Partnership (and other Subsidiaries formed for future acquisitions) holds an interest, it may suffer a financial loss.

Risks Relating to the Trust's Structure and Ownership of Units

Distributions do not represent a "yield" and are not comparable to debt instruments and rights of redemption have limited liquidity.

Units will have no value when reserves from the properties owned by the Subsidiaries can no longer be economically produced and, as a result, distributions do not represent a "yield" in the traditional sense and are not comparable to bonds or other fixed yield securities where investors are entitled to a full return of the principal amount of debt on maturity in addition to a return on investment through interest payments. Distributions represent a blend of return of Unitholders' initial investment and a return on Unitholders' initial investment. Unitholders have a limited right to require a repurchase of their Units, which is referred to as a redemption right. It is anticipated that the redemption right will not be the primary mechanism for Unitholders to liquidate their investment. The right to receive cash in connection with a redemption is subject to material limitations. Any securities which may be distributed in specie to Unitholders in connection with a redemption may not be listed on any stock exchange and a market may not develop for such securities and such securities may be illiquid. The CT Notes are not expected to be qualified investments within the meaning of the Tax Act for Registered Plans. In addition, there may be resale restrictions imposed by law upon the recipients of the securities pursuant to the redemption right. See "Description of the Trust – Redemption at the Option of Unitholders".

The Units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in a corporation.

The Units represent a fractional interest in the Trust. Corporate law does not govern the Trust and the rights of Unitholders. As Unitholders, Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring oppression or derivative actions. The rights of Unitholders are specifically set forth in the Trust Indenture. In addition, trusts are not defined as recognized entities within the definitions of legislation such as the *Bankruptcy and Insolvency Act* (Canada), the *Companies' Creditors Arrangement Act* (Canada) and in some cases the *Winding Up and Restructuring Act* (Canada). As a result, in the event of an insolvency or restructuring, a Unitholder's position as such may be quite different than that of a shareholder of a corporation. The Trust's sole asset is its investment in the CT through its ownership of the CT Units and the CT Notes. The price per Unit is a function of anticipated distributable income, the properties acquired by the Subsidiaries and the ability to effect long-term growth in value. The market price of the Units will be sensitive to a variety of market conditions including, but not limited to, interest rates and the ability to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of the Units.

The Units are not "deposits" within the meaning of the *Canada Deposit Insurance Corporation Act* (Canada) and are not insured under the provisions of that Act or any other legislation. Furthermore, the Trust is not a trust company and, accordingly, is not registered under any trust and loan company legislation and does not carry on or intend to carry on the business of a trust company.

Unitholder limited liability is subject to contractual and statutory assurances which may have some enforcement risks.

The Trust Indenture provides that no Unitholder will be subject to any liability in connection with the Trust or its obligations and affairs and, in the event that a court determines Unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of the Trust's assets. Pursuant to the Trust Indenture, the Trust will indemnify and hold harmless each Unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by a Unitholder resulting from or arising out of such Unitholder not having such limited liability. The Trust Indenture provides that all written instruments signed by or on behalf of the Trust must contain a provision to the effect that such obligation will not be binding upon Unitholders personally. Personal liability may also arise in respect of claims against the Trust that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The possibility of any personal liability of this nature arising is considered unlikely. *The Income Trusts Liability Act* (Alberta) came into force on July 1, 2004. The legislation provides that a Unitholder will not be, as a beneficiary, liable for any act, default, obligation or liability of the trustee that arises after the legislation came into force. The Trust's operations will be conducted, upon the advice of counsel, in such a way and in such jurisdictions as to avoid as far as possible any material risk of liability on Unitholders for claims against the Trust.

Payment of distributions.

The Trust Indenture and the CT Trust Indenture provide that all of the distributable income of the Trust or the CT, as the case may be at the end of any calendar month, including December 31 shall be declared payable and distributed to the Unitholders (or the CT Unitholder) of record on the last day of each such calendar month. These distributions are enforceable by the Unitholders or the CT Unitholder of record. However, if this amount is not determined and declared payable in accordance with the rules of the TSX, the right to receive this income will trade with the Units. The Trust Indenture provides that this distributable income is allocated to Unitholders for tax purposes and to the extent a Unitholder trades Units in this period, they will be allocated such income but will have disposed of their right to receive such distribution. The Trust Indenture also provides for the consolidation of the Units to the pre-distribution number of Units after any pro-rata distribution of additional Units to all Unitholders. Accordingly, the Trust Indenture allows for the payment of distributions in a form other than cash and Unitholders may have taxable income and cash taxes payable in excess of the amount of cash distributions they receive from the Trust.

Risk Factors Applicable to Residents of the United States and Other Non-Residents of Canada

There is limited liability of residents in the United States to enforce civil remedies.

The Trust and the CT are organized under the laws of Alberta, Canada and have their principal place of business in Canada. The Partnership is organized under the laws of the State of Delaware and has its principal place of business in Houston, Texas. Most of the Administrator's directors and officers and the representatives of the experts who provide services to the Trust (such as its auditors), and all of the Trust's assets and all or a substantial portion of the assets of such persons are located in Canada. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon such directors, officers and representatives of experts who are not residents of the United States or to enforce against them judgments of the United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States. There is doubt as to the enforceability in Canada against the Trust and the CT or against any of the Administrator's directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgments of United States courts of liabilities based solely upon the United States federal securities laws or securities laws of any state within the United States.

There are differences in reporting practices in Canada and the United States.

The Trust reports its production and reserve quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the Securities Exchange Commission by companies in the United States. The Trust incorporates additional information with respect to production and reserves which is either not generally included or prohibited under rules of the Securities Exchange Commission and practices in the United States. The Trust follows the Canadian practice of reporting gross production and reserve volumes (before deduction of Crown and other royalties); however, it also follows the United States practice of separately reporting reserve volumes on a net basis (after the deduction of royalties and similar payments). The Trust also follows the Canadian practice of using forecast prices and costs when estimating reserves; whereas the Securities Exchange Commission requires that prices and costs be averaged for the 12 months as of the date of the reserves report. Included in this Annual Information Form are estimates of proved, and proved plus probable reserves. Probable reserves are higher risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves. The Securities Exchange Commission generally prohibits the inclusion of estimates of probable reserves in filings made with it. This prohibition does not apply to the Trust as a Canadian foreign private issuer.

As a consequence of the foregoing, the reserve estimates and production volumes in this Annual Information Form may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

There is additional taxation applicable to non-residents.

Net income of the Trust, other than certain net realized capital gains, distributed to non-residents will be subject to withholding tax under the Tax Act at a 25% rate, subject to reduction under an applicable income tax treaty.

An additional 15% Canadian withholding tax also applies to the return of capital portion of distributions made to non-resident unitholders for publicly traded trusts whose trust units derive more than 50% of their value from any combination of real property situated in Canada, "Canadian resource property" (as defined in the Tax Act), or "timber resource property" (as defined in the Tax Act). The Trust and its affiliates do not expect that this additional withholding tax will apply to the Trust and its Unitholders. There can be no assurance that Canadian tax laws or international tax treaties will not be changed in a manner which adversely affects the rate of withholding on distributions of the Trust's capital and/or income.

If the Trust ceases to qualify as a "mutual fund trust" for purposes of the Tax Act, non-resident Unitholders may be subject to Canadian tax (subject to any treaty relief) on gains realized on a disposition of Units if such Units constitute "taxable Canadian property" as defined in the Tax Act. However, Units will generally not constitute "taxable Canadian property" unless in the 60 month period preceding the disposition date more than 50% of the value of the Units was derived, directly or indirectly, from "real or immovable property situated in Canada", "Canadian resource property" (as defined in the Tax Act), "timber resource property" (as defined in the Tax Act) and/or options and interests in any of the foregoing. Given the anticipated holdings of the Trust and its affiliates, it is not expected that the Units will constitute "taxable Canadian property"; however, no assurances can be given in this regard.

There is a foreign exchange risk of non-resident Unitholders.

The Trust's distributions are declared in Canadian dollars and converted to foreign denominated currencies at the spot exchange rate at the time of payment. As a consequence, investors are subject to foreign exchange risk. To the extent that the Canadian dollar strengthens with respect to their currency, the amount of the distribution will be reduced when converted to their home currency.

ADVISORY - FORWARD-LOOKING STATEMENTS AND RISK FACTORS

Certain statements contained in this Annual Information Form constitute forward-looking statements and forward-looking information (collectively, "forward-looking statements"). The Trust cautions investors in the Units about important factors that could cause the Trust's actual results to differ materially from those projected in any forward-looking statements included in this Annual Information Form.

Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result", "are expected to", "will continue", "is anticipated", "believes", "estimated", "intends", "plans", "projection" and "outlook") are not historical facts and may be forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in such forward-looking statements. No assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form. In addition, this Annual Information Form may contain forward-looking statements attributed to third party industry sources. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, the information and factors discussed throughout this Annual Information Form.

In particular and without limitation, this Annual Information Form contains forward-looking statements pertaining to the following:

- the performance characteristics of the Partnership's existing crude oil and natural gas properties;
- anticipated crude oil, natural gas and natural gas liquids production levels;
- the quantity of the Partnership's existing crude oil, natural gas and natural gas liquids reserves;
- net present values of future net revenues from the Partnership's reserves;
- projections of market prices for crude oil, natural gas and natural gas liquids and the impact of changes in crude oil, natural gas and natural gas liquids prices on the Partnership's cash flows;
- projections of anticipated costs for exploration, development, operations, production, abandonment and reclamation for the Partnership;
- Management's expectation that internally generated cash flow will be sufficient to fund the Partnership's future development costs;
- anticipated capital expenditure program for the Partnership and sources of funding of the capital expenditure program;
- the ability of the Partnership to achieve drilling success consistent with Management's expectations
- supply and demand fundamentals for crude oil, natural gas and natural gas liquids;
- realization of anticipated benefits of acquisitions or dispositions;
- plans for, and results of, exploration and development activities;
- business plans, growth strategy and opportunities;

- the source of funding for the Partnership's activities;
- treatment under governmental regulatory regimes and tax laws;
- the timing for and cost of additional development drilling, and the timing for, and levels of, increases to production and reserves;
- the development risk and exploitation potential of assets and properties owned by the Partnership;
- status of the Trust as a "mutual fund trust" and not as a "SIFT trust", and the taxability of the Trust;
- the ability to maintain payment of distributions to holders of the Units, as well as the composition and stability of such distributions;
- the taxability of cash distributions received by Canadian resident Unitholders;
- expectations regarding the ability to raise capital and to continually acquire reserves through acquisitions and development;
- access to, and sufficiency of, credit facilities and related borrowing base capacity;
- the Trust's objective to maintain an external debt to cash flow ratio not to exceed 1.5 times estimated future cash flow;
- hedging activities of the Trust and its Subsidiaries;
- access to capital markets and availability of funding for growth and acquisition opportunities; and
- control of capital spending pursuant to joint operating agreements.

With respect to forward-looking statements contained in this Annual Information Form, assumptions have been made regarding, among other things:

- future commodity prices;
- future currency exchange rates;
- the ability of the Partnership to obtain qualified staff and equipment in a timely and cost-efficient manner;
- the regulatory framework governing taxes and environmental matters in the U.S.;
- the Partnership's ability to successfully market future crude oil, natural gas and natural gas liquids production;
- the Partnership's future production levels;
- conditions in general economic and financial markets;
- marketability of oil, natural gas and natural gas liquids;
- anticipated cash flow;
- the regulatory framework governing taxes and environmental matters in the U.S.;
- the applicability of technologies for recovery and production of the Subsidiaries' crude oil, natural gas and natural gas liquids resources;
- the recoverability of the Partnership's reserves;
- future capital expenditures to be made by the Partnership and the Trust's ability to obtain financing on acceptable terms for these capital projects and future acquisitions;
- future sources of funding for the Partnership's capital program;
- geological and engineering estimates in respect of the Partnership's resources;
- the impact of increasing competition on the Trust;
- the Partnership's ability to obtain financing on acceptable terms for future capital projects and acquisitions;
- the deductibility of interest on the CT Notes; and
- the Trust's status as a "mutual fund trust" and not as a "SIFT trust".

The success of the Partnership's drilling program is a key assumption in the production estimates for 2014. The primary risk factors which could lead to the Partnership not meeting its production targets are: (i) production additions from drilling activity are less than expected; (ii) a lack of access to drilling rigs and related equipment on a timely basis and at reasonable prices; and (iii) unexpected operational delays and challenges. Increases in capital costs from forecast amounts can result from the foregoing reasons as well as general cost inflation in the industry. Additionally, the Partnership may choose to decrease capital expenditures from those anticipated in its budget projections, therefore affecting production estimates for 2014.

There are many risk factors inherent in the oil and gas industry in general that could result in production levels being less than anticipated from petroleum reserves, including such risk factors as greater than anticipated declines in existing production, the unanticipated encroachment of water or other fluids into the producing formation, mechanical failures or human error or inability to access production facilities, among other factors.

The Trust's actual results, including with respect to meeting its production targets, could differ materially from those anticipated in forward-looking statements as a result of the risk factors set forth below and included elsewhere in this Annual Information Form:

- failure to achieve success in the planned drilling program and, in particular, to achieve the Partnership's expected working interest production;
- failure to realize the anticipated benefits of the assets and properties owned by the Partnership and future acquisitions;
- unforeseen difficulties in integrating future acquisitions into the Partnership's operations;
- risks associated with reservoir performance;
- volatility of costs of development, operations and maintenance of properties;
- general economic, market and business conditions;
- volatility of market prices for crude oil, natural gas and natural gas liquids and marketability and hedging activities related thereto;
- risks related to the exploration, development and production of crude oil, natural gas and natural gas liquids reserves and resources;
- risks which may create liabilities to the Trust or the Partnership in excess of the Trust and the Partnership's insurance coverage;
- current global financial conditions, including fluctuations in interest rates, foreign exchange rates, inflation, commodity prices, and stock market volatility;
- uncertainties associated with estimating crude oil, natural gas and natural gas liquids reserves and cash flows to be derived therefrom;
- competition for, among other things, capital, acquisitions of resources and reserves, undeveloped or underdeveloped lands and skilled personnel;
- political or economic developments;
- liabilities inherent in oil and natural gas operations;
- the results of litigation or regulatory proceedings that may be brought against the Trust or the Subsidiaries;
- fluctuations in the cost of borrowing;
- incorrect assessments of the value of acquisitions and the likelihood of success of exploration and development programs;
- geological, technical, drilling and processing problems, including the availability of equipment and access to properties;
- environmental risks and hazards;
- changes in tax laws and incentive programs relating to the oil and natural gas industry;
- changes in government regulations;
- the use of derivative financial instruments;
- failure to obtain regulatory, industry partner and third party consents and approvals where required;
- failure to engage or retain key personnel;
- claims made in respect of the Partnership's properties or assets;
- potential losses which would stem from any disruptions in production, including work stoppages or other labour difficulties, or disruptions in the transportation network on which the Partnership will be reliant;
- potential delays or changes in plans with respect to exploration or development projects or capital expenditures;
- the failure of the Trust or any of its Subsidiaries to meet specific requirements of its leases or agreements;

- failure to accurately estimate abandonment and reclamation costs;
- the ability to obtain financing on acceptable terms;
- failure of third parties' reviews, reports and projections to be accurate;
- the occurrence of unexpected events; and
- the other factors discussed under "Risk Factors".

Since actual results or outcomes could differ materially from those expressed in any forward-looking statements of the Trust made by or on behalf of the Trust, investors should not place undue reliance on any such forward-looking statements. Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, and that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive.

Further, any forward-looking statement is made only as of the date of this Annual Information Form, and the Trust undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as required by applicable securities laws. New factors emerge from time to time, and it is not possible for Management to predict all of these factors or to assess in advance the impact of each such factor on the Trust or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. There can be no assurance that the plans, intentions or expectations upon which forward-looking statements are based will in fact be realized. Actual results may differ, and the difference may be material and adverse to the Trust and its Unitholders.

LEGAL PROCEEDINGS AND REGULATORY ACTION

During 2013, the Trust, its Subsidiaries or their property was not subject to any material legal proceedings where the amount involved, exclusive of interest and costs, exceeds ten percent of the current assets of the Trust, nor is Management aware of any such material legal proceedings being contemplated.

During 2013, there have not been any penalties or sanctions imposed against the Trust by a court relating to provincial and territorial securities legislation or by a securities regulatory authority, nor have there been any other penalties or sanctions imposed by a court or regulatory body against the Trust, and the Trust has not entered into any settlement agreements before a court relating to provincial and territorial securities legislation or with a securities regulatory authority.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Units is Computershare Trust Company of Canada, at its principal offices in Calgary, Alberta and Toronto, Ontario where transfers of securities may be recorded.

MATERIAL CONTRACTS

Copies of the following documents are available for inspection during normal business hours at the Administrator's office at Suite 2710, 500 - 4th Avenue S.W., Calgary, Alberta, T2P 2V6, or at the website maintained by the Canadian Securities Administrators at: www.sedar.com.

1. Trust Indenture. See "Description of the Trust".
2. CT Trust Indenture. See "Description of the Commercial Trust".
3. LP Agreement. See "Description of the Partnership".
4. Administrative Services Agreement. See "Administrative Services Agreement".
5. CT Note Indenture. See "Description of the Commercial Trust – the CT Notes".
6. The credit agreement relating to the Credit Facility. See "Debt Financing".
7. The Voting Agreement. See "Voting Agreement".

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a report, valuation, statement or opinion made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Trust during, or related to, the Trust's most recently completed financial year other than NSAI, the Trust's independent reserves evaluator, and PriceWaterhouseCoopers LLP, the Trust's auditor. As at the date hereof, the principals of NSAI, as a group, beneficially owned, directly or indirectly, less than one per cent of outstanding securities of the Trust, including the securities of associates and affiliates of the Trust. The Trust's auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have prepared an independent auditors' report dated March 20, 2014 in respect of the Trust's consolidated financial statements as at December 31, 2013 and for the year ended December 31, 2013. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Trust within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Trust or of any of the associates or affiliate entities of the Trust.

ADDITIONAL INFORMATION

Additional information about the Trust may be found on SEDAR at www.sedar.com.

Additional information including remuneration and indebtedness of directors and officers of the Administrator, principal holders of the Units, and securities authorized for issuance under equity compensation plans, is contained in the Management Information Circular of the Trust for its most recent annual meeting of Unitholders, which is available on SEDAR at www.sedar.com and on the Trust's website at www.eagleenergytrust.com.

Additional financial information is provided in the Trust's consolidated financial statements and accompanying management's discussion and analysis for the year ended December 31, 2013, which may be found on SEDAR at www.sedar.com and on the Trust's website at www.eagleenergytrust.com.

SCHEDULE A
FORM 51-101F3-
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Eagle Energy Inc. as administrator (the "**Administrator**") of Eagle Energy Trust (the "**Trust**") are responsible for the preparation and disclosure of information with respect to the Trust's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenues as at December 31, 2013 estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the reserves data in respect to the Trust's reserves data. The report of the independent qualified reserves evaluators is presented below.

The Reserves & Governance Committee of the board of directors (the "**Board**") of the Administrator has:

(a) reviewed the Administrator's procedures for providing information to the independent qualified reserves evaluators;

(b) met with each of the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservations; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Reserves & Governance Committee of the Board, has reviewed the Administrator's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board has, on the recommendation of the Reserves & Governance Committee, approved:

(a) the content and filing with the securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that the reserves are categorized according to the probability of their recovery.

DATED March 20, 2014.

(signed) *Richard W. Clark*
Richard W. Clark
President, Chief Executive Officer and Director

(signed) *Kelly A. Tomyn*
Kelly A. Tomyn
Chief Financial Officer

(signed) *David M. Fitzpatrick*
David M. Fitzpatrick
Director

(signed) *Warren. D. Steckley*
Warren D. Steckley
Director

SCHEDULE B
FORM 51-101F2 –
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS

To the Board of Directors of Eagle Energy Trust (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2013, and identifies the respective portions thereof that we have evaluated and reported on to the Administrator's board of directors:

Independent Qualified Reserves Evaluator or Auditor	**Description and Preparation Date of Evaluation Report**	**Location of Reserves (Country or Foreign Geographic Area)**	**Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – $US 000)**			
			Audited	**Evaluated**	**Reviewed**	**Total**
Netherland Sewell & Associations, Inc.	February 21, 2014	United States	Nil	269,671.7	Nil	**269,671.7**

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgments regarding future events, actual events will vary and the variations may be material.

EXECUTED as to our report referred to above:

NETHERLAND, SEWELL & ASSOCIATES INC.
Texas Registered Engineering Firm F-2699
Dallas, Texas, United States of America, March 7, 2014

By: *_/s/ C.H. (Scott) Rees III_*

C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

SCHEDULE C
ADMINISTRATOR'S AUDIT COMMITTEE MANDATE

PART I – ESTABLISHMENT OF COMMITTEE

1. Audit Committee

The Board of Directors (the "Board") of Eagle Energy Inc. (the "Corporation") has established an audit committee (the "Audit Committee" or the "Committee") of directors for the purpose of overseeing the accounting and financial reporting processes of both: (i) the Corporation and audits of its financial statements; and (ii) in its capacity as administrator of Eagle Energy Trust (the "Trust"), the Trust and audits of the Trust's financial statements.

2. Composition of Committee

(a) The Audit Committee will consist of at least three directors. All members of the Committee must be independent as defined in applicable securities laws (subject to permitted exemptions under those laws) and the rules of any stock exchange on which the Corporation's or the Trust's securities are listed for trading.

(b) Each member of the Audit Committee must be financially literate, or become financially literate within a reasonable period of time following his or her appointment to the Committee (provided that the Board has determined that this will not materially adversely affect the ability of the Committee to satisfy its responsibilities). A member is financially literate under applicable securities laws if he or she has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements.

(c) At least one-quarter of the members of the Audit Committee must be resident Canadians.

3. Appointment of Committee Members

Members of the Audit Committee will be appointed by the Board and re-appointed at the meeting of the Board immediately following each annual meeting of shareholders. Committee members will hold office until the next annual meeting or earlier if their successors are appointed, they are removed by the Board or they cease to be directors of the Corporation.

4. Compensation of Committee Members

The Board will fix the remuneration of the members of the Audit Committee and may provide additional remuneration to the Chair of the Committee. Other than as remuneration for acting in his or her capacity as a member of the Board or any Board committee, or as a part-time chair or vice-chair of the Board or any Board committee, or as otherwise permitted by applicable securities laws, no consulting, advisory or other compensatory fee will be paid to a member of the Audit Committee by the Corporation, the Trust or any subsidiary of the Corporation or the Trust.

5. Vacancies

When a vacancy occurs in the membership of the Audit Committee, it may be filled by the Board and must be filled by the Board if the membership of the Committee as a result of the vacancy is less than three directors. Any member may be removed or replaced at any time by the Board. Any member will cease to be a member upon ceasing to be a director.

PART II – COMMITTEE PROCEDURES

6. Committee Chair

The Committee Members will appoint a Chair for the Audit Committee. The Chair may be removed and replaced by the Committee.

7. Absence of Committee Chair

If the Chair is not present at any meeting of the Audit Committee, one of the other members of the Committee present at the meeting will be chosen by the Committee to preside at the meeting.

8. Secretary of Committee

The Audit Committee will appoint a Secretary who need not be a director of the Corporation.

9. Meetings

The Audit Committee will meet at least four times per year. All Committee members are expected to attend each meeting, in person or by tele or video conference. A resolution in writing, signed by all the Audit Committee members entitled to vote on that resolution at a meeting of the Committee, is as valid as if it had been passed at a meeting of the Committee.

10. Notice of Meetings

(a) A meeting of the Audit Committee may be called by any member of the Committee, by the chief executive officer or the chief financial officer of the Corporation (or persons holding equivalent offices) or by the external auditor. Notice of the time and place of a meeting will be given in writing or by electronic communication to each member of the Committee and to the external auditor at least 48 hours prior to the time fixed for the meeting.

(b) A member of the Audit Committee may in any manner waive notice of a Committee meeting. Attendance of a member at a Committee meeting is a waiver of notice of the meeting, except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting is not lawfully called.

11. Quorum and Participation

(a) A majority of the number of members of the Audit Committee appointed by the Board constitutes a quorum at any meeting of the Committee.

(b) A member of the Audit Committee may, if all the members of the Committee consent, participate in a meeting of the Committee by means of a telephonic, electronic or other communication facility that permits all participants to communicate adequately with each other during the meeting. A member participating in a Committee meeting by those means is deemed to be present at that meeting.

12. Attendance by External Auditor and Others

(a) The external auditor is entitled, at the expense of the Corporation, to attend and be heard at every meeting of the Audit Committee, and, if so requested by a member of the Committee, shall attend every meeting of the Committee held during the term of office of the external auditor.

(b) At the invitation of the Chair of the Audit Committee, one or more officers or employees of the Corporation or directors who are not members of the Committee may attend a meeting of the Committee.

13. Procedure, Records and Reporting

The Audit Committee will fix its own procedure at meetings, keep minutes of its meetings and report to the Board when the Committee deems appropriate (but not later than the next meeting of the Board). An agenda will be prepared and provided to members sufficiently in advance of an Audit Committee meeting, along with draft minutes of the previous meeting and appropriate briefing materials.

14. Independent Advisors

The Audit Committee may engage independent counsel and other advisors as it determines necessary to carry out its duties. Furthermore, the Committee has the authority to set and pay the compensation for any such advisors which are employed by the Committee.

15. Review of Charter

The Audit Committee will review this charter annually or otherwise as it deems appropriate and recommend to the Board any necessary changes.

16. Duties and Reliance

(a) In exercising their powers and discharging their duties under this charter and applicable law, each member of the Audit Committee must (i) act honestly and in good faith with a view to the best interests of the Corporation and, for so long as the Corporation remains the administrator of the Trust, the Trust and (ii) exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

(b) Each member of the Audit Committee will be entitled to reasonable reliance, or reliance in good faith, on:

(i) financial statements of the Corporation and the Trust, as applicable, represented to the member of the Committee by an officer of the Corporation or in a written report of the external auditor of the Corporation to reflect fairly the financial condition of the Corporation and the Trust, as applicable;

(ii) the Corporation's disclosure compliance system and on the Corporation's officers, employees and others whose duties would in the ordinary course have given them knowledge of the relevant facts; and

(iii) a report, statement or opinion of an expert, being a person or company whose profession gives authority to a statement made in a professional capacity by the person or company including, without limitation, an accountant, actuary, appraiser, auditor, engineer, financial analyst, geologist or lawyer.

PART III – MANDATE OF COMMITTEE

17. External Auditor

(a) The external auditor will report directly to the Audit Committee, be responsible for planning with the Corporation and carrying out the audit of the annual financial statements (and any requested review of quarterly financial statements) of the Corporation and the Trust and ultimately be accountable to the Audit Committee and the Board as the representatives of the shareholders and, so long as the Corporation remains the administrator of the Trust, as the representatives of the unitholders of the Trust.

(b) The Audit Committee will recommend to the Board:

(i) the external auditor to be nominated for the purpose of preparing or issuing an auditor's reports or performing other audit, review or attest services for the Corporation and, so long as the Corporation remains the administrator of the Trust, the Trust; and

(ii) the compensation of the external auditor.

(c) The Audit Committee will be directly responsible for overseeing the work of the external auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation and the Trust, including the following:

(i) review of the mandate of the external auditor, including the annual engagement letter, audit plan and audit scope;

(ii) review of the independence of the external auditor, any rotation of the partners assigned to the audit in accordance with applicable laws and professional standards, the internal quality control findings of the external auditor's firm and peer reviews;

(iii) review of the performance of the external auditor, including the relationship between the external auditor and management and the evaluation of the lead partner of the external auditor;

(iv) termination or resignation of the external auditor if circumstances warrant, after due inquiry and discussion with management and the external auditor;

(v) resolution of disagreements between management and the external auditor regarding financial reporting;

(vi) review of material written communications between the external auditor and management;

(vii) review of the annual management letter from the external auditor regarding internal controls and opportunities for improvement or efficiency, plus management's response and follow-up in respect of any identified weakness; and

(viii) communication with the external auditor regarding such other matters as are required by the Canadian Institute of Chartered Accountants Handbook and other professional standards.

(d) The Audit Committee will meet or communicate directly with the external auditor, without management being present, as required or appropriate to discharge the responsibilities of the Committee.

18. <u>Non-Audit Services</u>

(a) The Audit Committee will pre-approve all non-audit services to be provided to the Corporation or the Trust or their respective subsidiaries by the external auditor.

(b) The Audit Committee may delegate to one or more of its members the authority to pre-approve non-audit services. The pre-approval of non-audit services by any member to whom authority has been delegated must be presented to the Committee at its first scheduled meeting following such pre-approval.

(c) Pre-approval of *de minimus* non-audit services will be satisfied if:

(i) the aggregate amount of all the non-audit services that were not pre-approved is reasonably expected to constitute no more than five per cent of the total amount of fees paid by the Corporation or, for so long as the Corporation remains the administrator of the Trust, the Trust, and their respective subsidiaries to the Corporation's external auditor during the fiscal year in which the services are provided;

(ii) the Corporation or, for so long as the Corporation remains the administrator of the Trust, the Trust, or the applicable subsidiary, as the case may be, did not recognize the services as non-audit services at the time of the engagement; and

(iii) the services are promptly brought to the attention of the Audit Committee and approved, prior to the completion of the audit, by the Committee or by one or more of its members to whom authority to grant such approvals has been delegated by the Committee.

(d) Pre-approval of non-audit services will also be satisfied if the Audit Committee adopts specific policies and procedures for the engagement of non-audit services and:

(i) the pre-approval policies and procedures are detailed as to the particular service;

(ii) the Audit Committee is informed of each non-audit service; and

(iii) the procedures do not include delegation of the Audit Committee's responsibilities to management.

19. <u>Financial and Other Disclosure</u>

(a) The Audit Committee will review, discuss with management (and the external auditor where required or appropriate) and, if required or appropriate, approve or recommend that the Board approve the following Corporation and Trust documents prior to public disclosure:

(i) annual audited financial statements and related management's discussion and analysis;

(ii) quarterly unaudited financial statements and related management's discussion and analysis;

(iii) certifications by the chief executive officer and chief financial officer of annual and quarterly filings, disclosure controls and procedures and internal controls over financial reporting;

(iv) news releases announcing financial results, containing financial information based on unreleased financial results or non-GAAP financial measures or providing earnings guidance or forward-looking financial information; and

(v) financial information contained in any annual information form, information circular, prospectus, take-over bid circular, issuer bid circular or rights offering circular.

(b) The Audit Committee will be satisfied that adequate procedures are in place for the review of the Corporation's and the Trust's public disclosure of financial information extracted or derived from the Corporation's or the Trust's financial statements and will periodically assess the adequacy of those procedures.

(c) The Audit Committee will review the disclosure required by applicable securities laws to be included in its annual information form and cross-referenced in a management information circular to solicit proxies from the shareholders of the Corporation or from unitholders of the Trust for the purpose of electing directors to the Board. That disclosure will consist of the text of this charter, the composition of the Audit Committee, the relevant education and experience of Committee members, reliance on certain exemptions from securities laws relating to audit committees, oversight of the nomination and compensation of the external auditor, policies and procedures for non-audit services and external auditor service fees.

20. <u>Financial Reporting Processes</u>

(a) The Audit Committee will review with management and the external auditor:

(i) the appropriateness of the Corporation's and the Trust's accounting principles and policies and financial reporting;

(ii) any changes to the Corporation's or the Trust's accounting principles and policies and financial reporting as such changes are recommended by management or the external auditor;

(iii) the accounting treatment of significant risks and uncertainties;

(iv) key estimates and judgments of management that may be material to the Corporation's or the Trust's financial reporting; and

(v) significant auditing and financial reporting issues discussed during the financial period and the method of resolution.

(b) The Audit Committee will in particular review the following specific matters, where material:

(i) the effect of regulatory and accounting initiatives;

(ii) extraordinary transactions;

(iii) the use of special purpose entities;

(iv) off-balance sheet transactions;

(v) financial risk management, including the use of derivatives;

(vi) asset retirement or reclamation obligations;

(vii) pension obligations;

(viii) commitments, contingencies and guarantees;

(ix) related party transactions;

(x) actual or pending legal claims, tax or regulatory matters; and

(xi) any other matters of accounting or auditing risk.

21. Internal Audit

(a) The Audit Committee will review:

(i) the audit plans of the internal auditor of the Corporation and the Trust and coordination with the external auditor;

(ii) the adequacy of the resources of the internal auditor to ensure the objectivity and independence of the internal audit function; and

(iii) the significant findings of the internal auditor and recommendations relating to internal audit issues, together with management's response thereto.

(b) The Audit Committee will meet or communicate directly with the internal auditor, without management being present, as required or appropriate to discharge the responsibilities of the Committee.

22. Other Responsibilities

(a) The Audit Committee will establish procedures for:

(i) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters; and

(ii) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

(b) The Audit Committee will review on a timely basis all discovered incidents of fraud within the Corporation, regardless of monetary value.

(c) The Audit Committee will oversee any auditing or accounting reviews or similar procedures or investigations and may conduct its own investigations with full access to books, records, facilities and personnel of the Corporation and the Trust.

(d) The Audit Committee will at least annually provide oversight of the Corporation's financial risk management policies.

(e) The Audit Committee will review and approve the Corporation's policies regarding officer expenses and may review expenses actually incurred by the chief executive officer and other senior officers.

(f) The Audit Committee will review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and any former external auditor of the Corporation or the Trust.

(g) The Audit Committee will review and/or approve any other matter specifically delegated to the Committee by the Board and undertake on behalf of the Board such other activities as may be necessary or desirable to assist the Board in fulfilling its responsibilities.

SCHEDULE D
DEFINITIONS, ABBREVIATIONS, CONVERSIONS AND EXCHANGE RATES

Definitions

In this Annual Information Form, the initially capitalized terms set forth below have the following meanings:

"**ABCA**" means the *Business Corporations Act* (Alberta), and the regulations thereunder, as amended from time to time.

"**Administrative Services Agreement**" means the administrative services agreement dated September 14, 2010 among the Trustee and the Administrator, as amended and restated on April 2, 2012 and as amended, supplemented or restated from time to time, pursuant to which the Administrator provides administrative services to the Trust and pursuant to which the Administrator is delegated certain duties in connection with the governance of the Trust.

"**Administrator**" means Eagle Energy Inc., or such other party as may be appointed as administrator from time to time pursuant to the Administrative Services Agreement.

"**Administrator Directors**" means the directors of the Administrator from time to time.

"**affiliate**" or "**associate**" has the meaning ascribed thereto in the *Securities Act* (Alberta), as amended from time to time.

"**Board**" means all of the Administrator Directors.

"**business day**" means a day other than a Saturday, Sunday or a day on which the principal chartered banks located at Calgary, Alberta are not open for business.

"**CDS**" means CDS Clearing and Depository Services Inc.

"**Credit Facility**" means the U.S. dollar credit facility established in favour of the subsidiary of the Trust as described under "Debt Financing".

"**CT**" means Eagle Energy Commercial Trust, an unincorporated open-ended trust established under the laws of the Province of Alberta.

"**CT Note Indenture**" means the note indenture dated November 24, 2010 between the CT and Computershare Trust Company of Canada, as trustee thereunder, as supplemented by the note indenture dated May 18, 2012 between the CT and Computershare Trust Company of Canada, as trustee thereunder, pursuant to which the CT will issue CT Notes from time to time.

"**CT Notes**" means the unsecured promissory notes issued, and to be issued from time to time, by the CT pursuant to the CT Note Indenture.

"**CT Note Series 1**" means the Note, Series 1 of the CT issued under the CT Note Indenture dated November 24, 2010.

"**CT Note Series 2**" means the Notes, Series 2 of the CT issued under the CT Note Indenture dated November 24, 2010.

"**CT Note Series 3**" means the Note, Series 3 of the CT issued under the CT Note Indenture dated May 18, 2012.

"**CT Note Series 4**" means the Notes, Series 4 of the CT issued under the CT Note Indenture dated May 18, 2012.

"**CT Trust Indenture**" means the trust indenture establishing the CT dated September 27, 2010 as amended and restated on November 12, 2010, as amended, supplemented or restated from time to time.

"**CT Trustee**" means the Administrator or such other trustee as may be appointed pursuant to the CT Trust Indenture.

"**CT Unitholder**" means a holder of CT Units.

"**CT Units**" means the trust units of the CT, each CT Unit representing an equal undivided beneficial interest in the CT.

"**EEI Holdings**" means EEI Holdings Inc., the sole shareholder of the Administrator.

"**Environmental Liabilities**" means all liabilities, losses, costs, charges, damages, expenses, and penalties (including costs and expenses of abatement and remediation of spills or releases of contaminants and all liabilities to third parties (including governmental agencies) in respect of bodily injuries, property damage, damage to or impairment of the environment or any other injury or damage, including foreseeable and unforeseeable consequential damages) sustained, suffered or incurred in connection with or as a result of (a) the administration of the Trust, or (b) the exercise or performance by the Trustee or the Administrator of any rights or obligations under the Trust Indenture or under any other contracts, and which, in either case, result from or relate, directly or indirectly, to:

(a) the presence or release or threatened presence or release of any contaminants, by any means or for any reason, on or in respect of any properties of the Trust, whether or not such presence or release or threatened presence or release of the contaminants was under the control, care or management of the Trust or the Administrator or of a previous owner or operator of such property;

(b) any contaminant present on or released from any property adjacent to or in the proximate area of any properties of the Trust;

(c) the breach or alleged breach of any federal, provincial, state or municipal environmental law, regulation, by law, order, rule or permit by the Trust or the Administrator, or an owner or operator of a property; or

(d) any misrepresentation or omission of a known fact or condition made by the Administrator relating to any property.

"**Escrow Agent**" means Computershare Trust Company of Canada.

"**GP**" means Eagle Hydrocarbons LLC, a limited liability company formed pursuant to the laws of Delaware and the general partner of the Partnership.

"**Hardeman Properties**" means the working interest owned by the Partnership in the oil and gas properties in Hardeman County, Texas.

"**Initial Public Offering**" means the initial public offering of the Trust pursuant to which it distributed 15,000,000 Units pursuant to the prospectus of the Trust dated November 16, 2010.

"**LP Agreement**" means the amended and restated limited partnership agreement dated October 5, 2010 between the GP, as the general partner, and the CT as the limited partner, establishing and governing the business and affairs of the Partnership, as amended on May 1, 2013 and as amended, supplemented or restated from time to time.

"**Management**" means the executive officers of the Administrator and the GP from time to time.

"**NSAI**" means Netherland, Sewell & Associates, Inc., an independent firm of petroleum engineers based in Dallas, Texas.

"**NSAI Reserve Report**" means the independent engineering evaluation of the oil and natural gas reserves relating to the Partnership's oil and gas interests titled "Estimates of Reserves and Future Revenue to the Eagle Energy Acquisitions LP Interest in Certain Oil and Gas Properties located in Caldwell, Martin, Palo Pinto and Hardeman Counties, Texas", prepared by NSAI as of December 31, 2013.

"**NI 51-101**" means National Instrument 51-101 – "*Standards of Disclosure for Oil and Gas Activities*" of the Canadian Securities Administrators.

"**Option Plan**" means the Unit option plan of the Trust.

"**Options**" means options to acquire Units, granted under the Option Plan.

"**Ordinary Resolution**" means a resolution passed by more than 50% of the votes cast, either in person or by proxy, at a meeting of Unitholders or CT Unitholders, as applicable, at which a quorum was present, called (at least in part) for the purpose of approving such resolution, or a resolution approved in writing by holders of more than 50% of the votes entitled to be voted on such resolution.

"**Other Trust Securities**" means any type of securities of the Trust, other than Units, including notes, options, rights, warrants or other securities convertible into or exercisable for Units or other securities of the Trust (including convertible debt securities, subscription receipts and instalment receipts).

"**Partnership**" means Eagle Energy Acquisitions LP, a limited partnership established under the laws of the State of Delaware and governed by the LP Agreement, the partners of which are the GP, as general partner, and the CT as limited partner.

"**Permian Acquisition**" means the acquisition on May 18, 2012 by the Partnership of the Permian Properties.

"Permian Properties" means the working interest owned by the Partnership in the oil and gas properties in Martin and Palo Pinto counties, Texas.

"**person**" means and includes individuals, companies, corporations, limited partnerships, general partnerships, joint stock companies, limited liability companies, joint ventures, associations, trusts, banks, trust companies, pension funds, and other organizations, whether or not legal entities and governments and agencies and political subdivisions thereof.

"**Redemption Price**" means the redemption price applicable to any redemption of Units by Unitholders as further described under "Description of the Trust – Redemption at the Option of Unitholders".

"**Registered Plans**" means, collectively, registered retirement savings plans, registered education savings plans, registered retirement income funds, deferred profit sharing plans, registered disability savings plans and tax-free savings accounts.

"**Salt Flat Acquisition**" means the acquisition on November 24, 2010 by the Partnership of the Salt Flat Properties.

"**Salt Flat Properties**" means the working interest owned by the Partnership in the oil and gas properties known as the Salt Flat Field located in Caldwell County, Texas.

"**SIFT Rules**" means the provisions of the Tax Act that apply to a SIFT trust.

"**SIFT tax**" means the tax to which SIFT trusts are subjected by the SIFT Rules.

"**SIFT trust**" means a trust as defined in section 122.1 of the Tax Act.

"**Special Resolution**" means a resolution passed by more than 66⅔% of the votes cast, either in person or by proxy, at a meeting of Unitholders or CT Unitholders, as applicable, at which a quorum was present, called (at least in part) for the purpose of approving such resolution, or a resolution approved in writing by holders of more than 66⅔% of the votes entitled to be voted on such resolution.

"**Subsidiaries**" means the subsidiaries of the Trust.

"**subsidiary**" has the meaning ascribed thereto in the ABCA.

"**Tax Act**" means the *Income Tax Act* (Canada) and the regulations thereunder, as amended from time to time.

"**Trust**" means Eagle Energy Trust, an unincorporated open ended limited purpose trust established under the laws of the Province of Alberta.

"**Trust Indenture**" means the trust indenture establishing the Trust dated July 20, 2010, as amended and restated on June 5, 2013 and as may be further amended, supplemented or restated from time to time.

"**Trust Property**" means, at any time, all of the money, properties and other assets of any nature of kind whatsoever as are, at such time, held by the Trust or by the Trustee or its delegate on behalf of the Trust.

"**Trustee**" means the trustee of Eagle Energy Trust, which, as at the date of this Annual Information Form, is Computershare Trust Company of Canada.

"**TSX**" means the Toronto Stock Exchange.

"**Unitholder**" means a registered holder of Units.

"**Units**" means the trust units of the Trust, each Unit representing an equal undivided beneficial interest in the Trust.

"**United States**" or "**U.S.**" means the United States of America, its territories and possessions, any state of the United States and the District of Columbia.

"**Voting Agreement**" means the voting agreement dated November 12, 2010 among EEI Holdings, the Trustee and the Administrator, with regard to, among other matters, the election of the Administrator Directors (as directed by the Trustee as agent for the Unitholders).

"**West Texas Intermediate**" or "**WTI**" means West Texas Intermediate grade crude oil at a reference sales point in Cushing, Oklahoma, a common benchmark for crude oil.

Certain other terms used in this Annual Information Form but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

Words importing the singular include the plural and vice versa and words importing any gender include all genders.

Abbreviations and Conversions

In this Annual Information Form, the following abbreviations have the meanings set forth below:

bbl	barrel and barrels, each barrel representing 34.972 Imperial gallons or 42 U.S. gallons	MMboe	one million barrels of oil equivalent
bbl/d	barrels per day	Mcf	one thousand cubic feet
boe	barrels of oil equivalent converting 6 Mcf of natural gas or one barrel of natural gas liquids to one barrel of oil equivalent	Mcf/d	one thousand cubic feet per day
boe/d	barrels of oil equivalent per day	MMBTU	one million British Thermal Units
Mbbl	one thousand barrels	MMcf	one million cubic feet
Mboe	one thousand barrels of oil equivalent	Bcf	one billion cubic feet
MMboe	one million barrels of oil equivalent	Mcf	one thousand cubic feet
MMBO	one million barrels of oil		

Barrel of Oil Equivalency Measures

The Trust has adopted the standard of 6 Mcf: 1 bbl when converting natural gas to boes. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalent of six to one, utilizing a boe conversion ratio of 6 Mcf: 1 bbl would be misleading as an indication of value.

Conversions

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.293
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

Currency and Exchange Rate Information

In this Annual Information Form, unless otherwise specified or the context otherwise requires, all dollar amounts are expressed in Canadian dollars. References to "$" are to Canadian dollars unless otherwise specified.

The following table sets forth, for the periods indicated, the high, low, average and period-end noon spot rates of exchange for one U.S. dollar, expressed in Canadian dollars, as published by the Bank of Canada. Such rates are shown as, or are derived from, the reciprocals of the noon buying rates in New York City for cable transfers payable in Canadian dollars, as available on the Bank of Canada website.

	Year Ended December 31		
	2013	**2012**	**2011**
	($CA)	($CA)	($CA)
Highest Rate During the Period	1.0697	1.0418	1.0604
Lowest Rate During the Period	0.9839	0.9710	0.9449
Average Noon Spot Rate for the Period	1.0299	0.9996	0.9891
Rate at the End of the Period	1.0636	0.9949	1.0170

On March 19, 2014, the noon rate of exchange posted by the Bank of Canada for conversion of U.S. dollars into Canadian dollars was $US 1.00 equals $CA 1.1179.