2013 Management's Discussion and Analysis and Financial Statements

DUNDEE
ENERGY LIMITED

MANAGEMENT'S DISCUSSION AND ANALYSIS

Dundee Energy Limited ("Dundee Energy" or the "Corporation") is a Canadian-based company focused on creating long-term value through the development and acquisition of high-impact energy projects. The Corporation's common shares trade on the Toronto Stock Exchange ("TSX") under the symbol "DEN". Dundee Energy holds interests, both directly and indirectly, in a large accumulation of producing oil and natural gas assets in southern Ontario (the "Southern Ontario Assets") and in the development of an offshore underground natural gas storage facility in Spain (the "Castor Project"). The Corporation also holds an investment in preferred shares of Eurogas International Inc. ("Eurogas International"), an oil and gas exploration company that is currently active in properties offshore Tunisia.

This Management's Discussion and Analysis ("MD&A") has been prepared with an effective date of March 17, 2014 and provides an update on matters discussed in, and should be read in conjunction with the Corporation's audited consolidated financial statements as at and for the year ended December 31, 2013 (the "2013 Consolidated Financial Statements"), which have been prepared using International Financial Reporting Standards ("IFRS"). All amounts are in Canadian dollars unless otherwise specified. Tabular dollar amounts, unless otherwise specified, are in thousands of dollars, except for per unit or per share amounts.

PERFORMANCE MEASURES AND BASIS OF PRESENTATION

The Corporation's 2013 Consolidated Financial Statements have been prepared in accordance with IFRS and use the Canadian dollar as its presentation currency. However, the Corporation believes that important measures of its economic performance include certain measures that are not defined under IFRS and as such, may not be comparable to similar measures used by other companies. Throughout this MD&A, there will be references to the following performance measures which management believes are valuable in assessing the economic performance of the Corporation. While these measures are not defined by IFRS, they are common benchmarks in the energy industry, and are used by the Corporation in assessing its operating results, including net earnings and cash flow.

- "Barrel of Oil Equivalent" or "boe" is calculated at a barrel of oil conversion ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of oil (6 Mcf to 1 bbl), based on an energy equivalency conversion method which is primarily applicable at the burner tip and does not always represent a value equivalency at the wellhead.

- "Field Level Cash Flows" is calculated as revenues from oil and natural gas sales, less royalties and production expenditures, adjusted for the effect of the Corporation's risk management contracts. Field level cash flows contribute to the funding of the Corporation's working capital and to capital expenditure requirements. Field level cash flows also provide for repayment of amounts owing pursuant to the Corporation's credit facilities (see *"Liquidity and Capital Resources"*).

- "Field Netbacks" refer to field level cash flows expressed on a measurement unit or barrel of oil equivalent basis.

- "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.

- "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.

- "Reserve Life Index" is determined by dividing proved reserves by expected annual production. For greater certainty, the reserve life index includes only proved reserves and does not include probable or possible reserves.

- "Per Day Amount" or "/d" is used throughout this MD&A to reflect production volumes on an average per day basis.

SELECTED CONSOLIDATED FINANCIAL INFORMATION

For the years ended December 31,	2013 Net Earnings (Loss)	2013 Attributable to Owners of the Parent	2013 Non-Controlling Interest	2012 Net Earnings (Loss)	2012 Attributable to Owners of the Parent	2012 Non-Controlling Interest	2011 Net Earnings (Loss)	2011 Attributable to Owners of the Parent	2011 Non-Controlling Interest
Southern Ontario Assets	$ (4,774)	$ (4,774)	$ -	$ (20,170)	$ (20,170)	$ -	$ 1,322	$ 1,322	$ -
Castor Project	(226)	(169)	(57)	(226)	(169)	(57)	(261)	(194)	(67)
Loss from investment in preferred shares of Eurogas International	(1,286)	(1,286)	-	(1,286)	(1,286)	-	(1,286)	(1,286)	-
Corporate activities	45	45	-	5,002	5,002	-	(1,088)	(1,088)	-
Net loss for the year	$ (6,241)	$ (6,184)	$ (57)	$ (16,680)	$ (16,623)	$ (57)	$ (1,313)	$ (1,246)	$ (67)

SIGNIFICANT PROJECTS

The Southern Ontario Assets

Dundee Energy Limited Partnership ("DELP"), a wholly owned limited partnership of the Corporation, holds an approximate 95% working interest in approximately 80,000 gross acres of onshore oil properties and an 85% working interest in approximately 695,000 gross acres of offshore gas properties, all located in and around Lake Erie in Ontario, Canada. The Southern Ontario Assets also include a 100% ownership interest in an onshore drilling rig, and an 85% ownership interest in certain other assets, including an offshore fleet of drilling and completion barges, and five gas plants/compressor stations that are located onshore and process offshore dry gas.

The majority of the Corporation's natural gas flows from offshore wells on Lake Erie that produce from Silurian age sandstone and carbonates at a maximum depth of 550 metres. The main producing horizons are the Grimsby, Whirlpool and Guelph formations. This gas is transported to shore through a pipeline grid on the bottom of Lake Erie, and then processed at one of the Corporation's five onshore processing facilities. The Corporation has entered into transportation agreements with pipeline companies and the majority of its natural gas is transferred to the Dawn Hub, which is conveniently located near the greater Toronto area, at which point it is sold to third parties.

Sweet, light oil production comes from onshore Ordovician and Silurian ages carbonate reservoirs located at geological depths of up to 850 metres. Oil and condensate production is trucked from six oil batteries and several single well locations to Sarnia, Ontario and is subsequently sold to a third party.

On July 5, 2013, the Corporation entered into a transaction pursuant to which it acquired an additional 20% working interest in certain offshore gas properties in southern Ontario, increasing its working interest from 65% to 85%. The acquisition added an average of 2,500 Mcf/d to the Corporation's existing natural gas production and an estimated 24.5 million Mcf in proved and probable natural gas reserves. The increase in working interest was acquired for aggregate cash consideration of $4.9 million, representing an average cost of $0.20/Mcf or $1.22/boe of proved and probable reserves.

In addition, on September 10, 2013, the Corporation entered into an asset exchange agreement pursuant to which it acquired certain oil producing assets and seismic data in exchange for the transfer of its working interests in certain other oil producing assets and certain property, plant and equipment. The Corporation realized a net gain of $0.3 million from the exchange of property, plant and equipment.

Castor UGS Limited Partnership and the Castor Project

The Corporation has an indirect interest in the Castor Project, a Spanish infrastructure undertaking that has converted an abandoned oil field, located off the eastern Mediterranean coast of Spain, to a natural gas storage facility. The Castor Project utilizes the abandoned Cretaceous aged carbonate Amposta reservoir, which lies at a depth of 1,800 metres approximately 22 kilometres off the east coast of Spain in the Mediterranean Sea, for gas storage.

The Castor Project facilities include two offshore platforms including a wellhead platform for 13 wells and a processing platform for processing and other facilities; an onshore gas treatment plant located in the municipality of Vinaroz; and a 30-inch diameter pipeline linking the onshore facilities and offshore processing platform. The Castor Project is expected to contribute approximately 25% to Spain's gas storage capacity, providing a dedicated source of easily deliverable natural gas that will moderate seasonal and daily demand peaks, and ensure supply continuity in the event of disruption to Spain's national gas system.

ACS Servicios Communicacions y Energia S.L. ("ACS"), a large construction group in Spain, is a 67% shareholder of Escal UGS S.L. ("Escal"), the owner of the Castor Project. Castor UGS Limited Partnership ("CLP"), the Corporation's 74% owned subsidiary, holds the remaining 33% interest in Escal, providing the Corporation with an effective 25% interest.

CLP has entered into certain agreements with ACS and with Enagas, S.A. ("Enagas"), Spain's natural gas transportation company, the technical manager of the Spanish gas system and common carrier for the gas network in Spain. These agreements provide that within 15 days of formal inclusion into the Spanish gas system of the Castor Project and subject to certain other conditions, ACS will sell, and Enagas will buy, 50% of ACS' interest in Escal based on a pre-established pricing formula, at which point CLP, ACS and Enagas will each own 33% of the equity of Escal. In addition, and for a period of 180 days after the formal inclusion into the Spanish gas system of the Castor Project, CLP has the right to sell part or all of its shares in Escal to ACS and/or Enagas on substantially the same terms and conditions.

Pending Inclusion of the Castor Project to the Spanish Gas System

Final inclusion of the Castor Project into the Spanish gas system remains contingent on completion of the injection of cushion gas, followed by the subsequent completion of the necessary performance and control testing.

In addition, the remuneration regime associated with the Castor Project is subject to the conclusion of an audit by the Spanish authorities of the expenditures forming the remuneration basis. Subject to the conclusion of the audit, the key aspects of the current remuneration regime are as outlined below:

- The capital cost of the Castor Project, as determined by an independent economic audit, will be returned to Escal in equal payments over a 20-year period, adjusted for annual inflation at a rate of 2.5% on any unamortized amount.

- In addition to the return of its capital cost, the remuneration regime provides for Escal receiving a return on its capital investment at a rate of 8.76% per annum on any unamortized amount, being the average rate of Spanish 10-year bonds calculated based on the 24-month period ended immediately before July 5, 2012, plus 3.5%. For remuneration purposes, the end of the capital investment period and the initiation of remuneration is deemed to be July 5, 2012, the date of receipt by Escal of the Provisional Commissioning Act.

- Escal retains the right to relinquish the Castor Project to the Spanish authorities for any unamortized value until June 2033.

In early 2013, Escal reached an agreement with Enagas to provide the 600 million cubic metres of cushion gas required for the Castor Project. Enagas subsequently completed the acquisition of approximately 125 million cubic metres, and injection of the cushion gas into the reservoir began in June 2013. Approximately 85% of the acquired cushion gas was injected by September 16, 2013.

In mid September 2013, seismic activity was detected in the area surrounding the Castor Project. Importantly, throughout this period, gas to liquid levels in the reservoir remained stable, significantly reducing concerns over the leakage of cushion gas. However, and while the seismic activity did not affect the integrity of the facility and the underground reservoir, nor cause any damage, the Spanish authorities have implemented a suspension to the injection of further volumes of cushion gas until an independent assessment of the source of seismic activity is completed. Independent assessments were subsequently completed and are currently under review and consideration by the Spanish authorities. The assessments put forward that the seismicity observed appears to be related to a secondary fault present in the area.

The technical and economic audits that are required for inclusion of the Castor Project to the Spanish gas system commenced in July 2013, were completed in late December 2013 and were delivered to the Spanish authorities in January 2014. On a preliminary basis, these audits have concluded that the Castor Project is technically fit to store and deliver gas; it has an appropriate process design and configuration and it has sufficient safety engineering for operation. The audits have also concluded that the capital costs employed for the construction of the Castor Project are reasonable. These findings are now subject to the review of, and concurrence by, the Spanish authorities.

Issuance of Euro-Denominated Senior Secured Bonds (the "Euro Bonds")
On July 26, 2013, Escal announced that it had arranged for the issuance of Euro Bonds totalling €1.40 billion. The Euro Bonds are subject to an annual interest rate of 5.756%, payable semi-annually, and are repayable in equal semi-annual installments over a period of 21 and a half years, with the last payment due in December 2034. The Euro Bonds are listed on the Luxembourg stock exchange. A copy of the prospectus document relating to the Euro Bonds may be accessed at *www.bourse.lu/home*, by referencing ISIN code XS0943010503.

The Euro Bonds were issued by a special purpose vehicle, Watercraft Capital S.A. ("Watercraft"), a Luxembourg corporation. The proceeds from the issuance were subsequently on-lent to Escal, pursuant to a credit facility between Watercraft and Escal, and were used by Escal to repay amounts owing pursuant to Escal's previously existing bank-funded project financing arrangements.

Escal provided a general security interest against its assets for the benefit of Watercraft to secure Escal's obligations under these arrangements, and the shareholders of Escal pledged their respective shares in Escal as part of the overall security package. In addition, the European Investment Bank has committed to provide a €200 million standby letter of credit as a form of subordinated credit enhancement instrument in support of the Euro Bonds.

Following the reporting of seismicity in the area as outlined above, on October 1, 2013, Fitch Ratings Inc. placed the Euro Bonds, previously rated at BBB+ on a "Rating Watch Negative". Standard & Poor's subsequently reaffirmed its rating for the Euro Bonds issue at BBB.

Series A Preference Share Investment in Eurogas International Inc.
The Corporation holds a $32,150,000 preferred share investment in Eurogas International, an independent oil and gas company engaged in the exploration and evaluation of landholdings offshore Tunisia, targeting large scale oil and gas reserves. The Series A Preference Shares rank in priority to the common shares of Eurogas International as to the payment of dividends and the distribution of assets on dissolution, liquidation or winding up of Eurogas International and entitle the Corporation to a fixed preferential cumulative dividend at a rate of 4% per annum. The Corporation may reinvest any dividends received into common shares of Eurogas International, subject to obtaining the necessary regulatory approvals. The Series A Preference Shares may be redeemed at the option of the Corporation or may be retracted by Eurogas International at any time at a price equal to their face value of $1.00 per Series A Preference Share. The Series A Preference Shares are non-voting except in the event Eurogas International fails to pay the cumulative 4% dividend for eight quarters. Thereafter, but only so long as any dividends on the Series A Preference Shares remain in arrears, the Corporation shall be entitled, voting exclusively and separately as a series, to elect a majority of the members of the Board of Directors of Eurogas International. Notwithstanding the Corporation not receiving any dividends on its investment at December 31, 2013, the Corporation had not exercised its entitlement to elect the majority of the members of the Board of Directors of Eurogas International.

Farmout Agreement with DNO Tunisia AS ("DNO")
In June 2003, Eurogas International entered into a joint operating agreement with Atlas Petroleum Exploration Worldwide Ltd. ("APEX"), pursuant to which Eurogas International and APEX (jointly, the "Original Contractors") agreed to undertake exploration, appraisal and extraction activities on the Sfax offshore exploration permit (the "Sfax Permit), which currently covers approximately 800,000 acres in the shallow Mediterranean waters in the Gulf of Gabes, offshore Tunisia and southeast of the city of Sfax. Eurogas International held a 45% working interest in the arrangement. APEX held the remaining 55% working interest, and was the operator of the project.

In June 2013, the Original Contractors entered into negotiations to complete a farmout agreement with DNO (the "DNO Agreement") with respect to the Sfax Permit and the associated Ras El Besh development concession. The DNO Agreement provides for DNO acquiring an 87.5% working interest in the Sfax Permit in exchange for a US$6 million cash payment to the Original Contractors, and the carrying of 100% of all future costs associated with the Sfax Permit, including the Original Contractors' drilling commitments pursuant to the Sfax Permit. The DNO Agreement was completed in January 2014.

Under the terms of the DNO Agreement, the Original Contractors are entitled to 12.5% of the profit oil or profit gas component of production from the Sfax Permit, to a maximum of US$125 million (or 12.5% of the profit oil or profit gas from the production of 75 million barrel of oil equivalents, whichever comes first). Thereafter, the Original Contractors are entitled to 6.25% of the profit oil or profit gas component of production from the Sfax Permit to a maximum of an additional US$75 million (or 6.25% of the profit oil or profit gas component from the production of an additional 45 million barrel of oil equivalents, whichever comes first). Eurogas International is entitled to 45% of any payments made to the Original Contractors under these arrangements.

The Original Contractors have conceded a temporary deferral of 50% of their entitlement to a share of the profit oil or profit gas component of production from the Sfax Permit, as outlined above, until such time as DNO recovers $150 million of total incurred costs, including costs to be incurred by DNO subsequent to completion of the DNO Agreement, from the cost oil or cost gas component of production on the Sfax Permit.

In addition to their entitlement to a share of the profit oil or profit gas, the DNO Agreement also provides the Original Contractors with entitlement to receive 20% of the cost oil or cost gas component of production from the Sfax Permit, to a maximum of the lesser of 18% of the costs incurred by the Original Contractors prior to completion of the DNO Agreement, or US$20 million.

Investment in Windiga Energy Inc. ("Windiga")

On May 22, 2013, the Corporation acquired a 31% interest in Windiga (formerly SMF Energy Inc.) for $1.1 million of cash consideration. Windiga is a private, Canadian independent power producer that is focused on developing, owning and operating renewable energy facilities on the African continent.

Windiga's most advanced initiative includes an 85% interest in the Zina Solar Project, which is comprised of a 40-hectare, 20 megawatt (AC) private solar power plant in Burkina Faso. The feasibility study has been completed, and a term sheet for a power purchase agreement with the state-owned power utility was signed in August 2013.

The Corporation has determined that it does not have significant influence over the operating and financial policies of Windiga and accordingly, the Corporation is accounting for its investment in Windiga as a financial instrument at fair value through profit or loss. As Windiga is a private enterprise and its fair value cannot be reliably measured, the Corporation's investment in Windiga is carried at cost.

CONSOLIDATED RESULTS OF OPERATIONS

Year ended December 31, 2013 compared with the year ended December 31, 2012

Consolidated Net Loss

During 2013, the Corporation incurred a net loss attributable to the owners of the parent of $6.2 million or a loss of $0.03 per share. This compares with a net loss attributable to the owners of the parent of $16.6 million or $0.10 per share incurred in 2012. Current year losses include an impairment of $3.5 million against an oil-based property, reflecting a decrease in estimated reserves. In the prior year, the Corporation recognized an impairment provision of $15.5 million against certain natural gas properties, consistent with substantial decreases in forecasted natural gas prices at December 31, 2012.

Southern Ontario Assets

In accordance with industry practice, production volumes, reserve volumes and oil and gas sales are reported on a working interest or "net" basis.

Operating Performance

The Corporation's operating performance is dependent on both production volumes of oil, natural gas and natural gas liquids, as well as the prices received for these commodities. During 2013, sales of oil and natural gas, net of royalty interests, were $33.2 million, an increase of $2.7 million over the prior year. As illustrated in the following table, the effect of increases in commodity prices for both oil and natural gas resulted in increased revenues of $5.8 million. However, these increases were partially offset by decreases in oil and liquids production volumes, which reduced revenues by $3.1 million.

	Natural Gas	Oil and Liquids	Total
Net Sales			
Year ended December 31, 2013	$ 14,203	$ 19,005	$ 33,208
Year ended December 31, 2012	10,005	20,478	30,483
Net increase (decrease) in net sales	$ 4,198	$ (1,473)	$ 2,725
Effect of changes in production volumes	$ 87	$ (3,145)	$ (3,058)
Effect of changes in commodity prices	4,111	1,672	5,783
	$ 4,198	$ (1,473)	$ 2,725

Production Volumes

In 2013, production volumes decreased to an average of 2,333 boe/d compared with an average of 2,428 boe/d produced in 2012.

Average daily volume during the years ended December 31,	2013	2012
Natural gas (Mcf/d)	10,196	10,081
Oil (bbls/d)	615	721
Liquids (bbls/d)	19	27
Total (boe/d)	2,333	2,428

Average natural gas production during 2013 increased marginally, by approximately 1% over production volumes achieved in the prior year. Increased volumes from the acquisition of additional working interests completed in July 2013 were offset by the natural decline in the Corporation's reserves, which has averaged approximately 5% per annum. Decreased volumes also resulted from scheduled plant shutdowns and the permanent closing of the Corporation's Port Stanley gas plant. These initiatives are expected to improve the efficiency of the gathering system in the central Lake Erie field, and ultimately reduce operating costs.

In 2013, oil production volumes decreased to an average of 615 bbl/d compared with an average of 721 bbl/d produced in 2012. The Corporation's drilling program throughout 2013 (see *"Capital Expenditures"*) did not successfully replace the natural decline rate in the Corporation's oil reserves, which has averaged approximately 14% per annum.

Net Sales of Oil and Gas

For the years ended December 31,		2013		2012
	Sales	Realized Prices ($ / unit)	Sales	Realized Prices ($ / unit)
Natural gas	$ 16,711	4.49	$ 11,746	3.18
Oil	22,153	98.63	23,589	89.44
Liquids	310	44.52	539	54.65
	39,174		35,874	
Less: Royalties at 15% (2012 – 15%)	(5,966)		(5,391)	
Net sales	$ 33,208		$ 30,483	

Revenues from oil and gas sales were $39.2 million in 2013. This compares with revenues of $35.9 million earned in the prior year. The Corporation's revenues are subject to royalty payments to provincial governments, freehold landowners and overriding royalty owners. In 2013, the Corporation recorded royalty obligations of $6.0 million (2012 – $5.4 million) against its oil and gas sales, representing an average royalty rate of approximately 15% (2012 – 15%) of revenues.

Effect of Commodity Prices on Revenues from Oil and Gas Sales
Prices for oil and natural gas vary from period to period due to several factors including supply, demand, weather, general economic conditions and changes in foreign exchange rates. The following table illustrates several benchmark prices for these commodities, compared with the Corporation's realized prices, prior to the effect of its risk management contracts.

For the years ended December 31,			2013			2012
	US$	CAD$	Realized Prices ($)	US$	CAD$	Realized Prices ($)
Natural Gas						
Dawn Hub	4.07	4.19	4.49	3.07	3.07	3.18
NYMEX Henry Hub	3.73	3.83		2.75	2.75	
Oil						
Edmonton Par	n/a	93.41	98.63	n/a	86.57	89.44
West Texas Intermediate	97.98	100.81		94.06	94.17	

The Corporation realized an average price on sales of natural gas of $4.49/Mcf in 2013, an increase of 41% from the average price of $3.18/Mcf realized in the prior year. The increase is reflective of increased prices for natural gas in North America, which have trended higher during 2013 compared with 2012, and is reflected in a 33% increase in the US dollar-denominated average natural gas price at the Dawn Hub and a 36% increase at the Henry Hub. In addition, and due to the proximity of the Corporation's operations to the Dawn Hub, a leading provider of natural gas supply to the greater Toronto market area, the Corporation's realized price from sales of natural gas continues to include a positive basis differential from average industry benchmarks.

In 2013, the Corporation realized an average price of $98.63/bbl on sales of crude oil, an increase of 10% over an average price of $89.44/bbl realized during the prior year. This compares with a year-over-year increase of 8% in the Edmonton Par average price for crude oil, and a 7% increase in the US dollar-denominated average West Texas Intermediate ("WTI") price. The year-over-year increase in the Corporation's realized price for oil exceeds comparative industry benchmark increases, and results from a realignment of the Corporation's crude oil marketing contracts earlier in 2013, whereby the sales price received was based on the higher-priced WTI benchmark, rather than the Edmonton Par price as previously contracted. During 2014, and on the basis of its existing marketing arrangements, the Corporation expects that its realized sales price for crude oil will be correlated to the Edmonton Par pricing model.

Risk Management Contracts – Price Risk Management
In order to mitigate its exposure to price volatility, the Corporation may, from time to time, enter into fixed price contracts. These price risk management strategies assist the Corporation in securing a stable amount of cash flow to protect a desired level of capital spending and for debt management. As well, the Corporation's revenues are primarily received in Canadian dollars, however, pricing for commodities, including oil and natural gas, are closely referenced to the US dollar. The Corporation partially mitigates its exposure to changes in commodity prices resulting from foreign exchange variability by entering into commodity risk management contracts on a Canadian dollar basis.

The following table summarizes the realized and unrealized gains or losses from the Corporation's risk management contracts in 2013, compared with the prior year. For accounting purposes, the Corporation has not designated its risk management contracts as hedges. Accordingly, the gains or losses from these contracts are not reflected in the Corporation's reported amounts of oil and natural gas sales, but rather they are separately reported as gains or losses from risk management contracts in the Corporation's net earnings or loss.

For the years ended December 31,			2013			2012
	Realized loss	Unrealized loss	Total	Realized gain	Unrealized gain (loss)	Total
Oil swaps	$ (262)	$ (307)	$ (569)	$ 965	$ 264	$ 1,229
Gas swaps	(12)	-	(12)	2,963	(1,665)	1,298
	$ (274)	$ (307)	$ (581)	$ 3,928	$ (1,401)	$ 2,527

The aggregate realized loss from natural gas risk management contracts is net of a $0.3 million payment made early in 2013 to cancel natural gas risk management contracts representing 3,750 mbtu/d.

The Corporation's risk management contracts at December 31, 2013 had a negative value of $92,000 and consisted of the following arrangements:

Contract Fixed Price Swap	Volume	Pricing Point	Strike Price (Cdn$/unit)	Maturity Date	Settlement Date
Crude oil	500 bbl/d	NYMEX	$98.22	Dec 31/13	Jan 25/14

Subsequent to December 31, 2013, the Corporation entered into a commodity swap on an additional 300 bbls per day of oil from April 1, 2014 to December 31, 2014, at a fixed price in Canadian dollars of $105.00/bbl.

The fair values of risk management contracts outstanding at the end of a reporting period are determined using market conditions and third-party forecasts prevailing as at the reporting date. Changes in the fair values of risk management contracts are recognized as unrealized risk management contract gains or losses. Unrealized risk management contract gains or losses may or may not be realized in subsequent periods and are dependent on changes in commodity prices and foreign exchange rates.

Production Expenditures

Production expenditures include costs associated with bringing oil and natural gas from the reservoir to the surface sales point, and include separating the oil and gas, treating the oil and gas to remove impurities and disposing of produced water. Also included in production expenditures is an allocation of general and administrative costs, including labour, which is directly attributable to these activities. During 2013, the Corporation incurred production expenditures of $15.0 million, compared with production expenditures of $13.5 million incurred in the prior year. Production costs incurred during 2013 include costs associated with the acquisition of an increased working interest in certain natural gas properties completed in July 2013. Production costs on a per unit basis increased to $17.60/boe in 2013, compared with $15.18/boe incurred during 2012, reflecting lower production volumes.

For the years ended December 31,			2013			2012
	Natural Gas	Oil and Liquids	Total	Natural Gas	Oil and Liquids	Total
Production expenditures	$ 8,007	$ 6,983	$ 14,990	$ 7,041	$ 6,442	$ 13,483
Production expenditures	(per Mcf)	(per bbl)	(per boe)	(per Mcf)	(per bbl)	(per boe)
per unit	$ 2.15	$ 30.16	$ 17.60	$ 1.91	$ 23.55	$ 15.18

Field Level Cash Flows

During 2013, the Corporation earned field level cash flows of $18.2 million, before the effect of risk management contracts. This compares with field level cash flows before risk management contracts of $17.0 million in 2012. Field level cash flows from natural gas production and sales increased by $3.2 million, and included the effect of the acquisition of increased working interests. Field level cash flows from production and sales of oil and liquids decreased by $2.0 million, reflecting lower production volumes.

Risk management contracts reduced field level cash flows in 2013 by $0.3 million. In comparison, the Corporation's risk management strategies in the prior year added $3.9 million to field level cash flows.

For the years ended December 31,			2013			2012
	Natural Gas	Oil and Liquids	Total	Natural Gas	Oil and Liquids	Total
Total sales	$ 16,711	$ 22,463	$ 39,174	$ 11,746	$ 24,128	$ 35,874
Royalties	(2,508)	(3,458)	(5,966)	(1,741)	(3,650)	(5,391)
Production expenditures	(8,007)	(6,983)	(14,990)	(7,041)	(6,442)	(13,483)
	6,196	12,022	18,218	2,964	14,036	17,000
Realized risk management (loss) gain	(12)	(262)	(274)	2,963	965	3,928
Field level cash flows	$ 6,184	$ 11,760	$ 17,944	$ 5,927	$ 15,001	$ 20,928

Field Netbacks

Field netbacks from natural gas, before the effect of risk management contracts, were $1.67/Mcf in 2013, compared with $0.80/Mcf in 2012. The substantial increase reflects both an improvement in the underlying commodity price, as well as improvements realized from the acquisition of increased working interests.

Field netbacks from oil and liquids, before the effect of risk management contracts, increased marginally to $51.90/bbl in 2013, compared with $51.30/bbl in 2012. The increase results from the improved realized price for oil, offset by higher production costs as a result of lower production volumes.

Risk management contracts decreased field netbacks by $0.32/boe in 2013, compared with an increase of $4.42/boe realized in the prior year.

For the years ended December 31,			2013			2012
	Natural Gas	Oil and Liquids	Total	Natural Gas	Oil and Liquids	Total
	$/Mcf	$/bbl	$/boe	$/Mcf	$/bbl	$/boe
Total sales	$ 4.49	$ 97.00	$ 45.99	$ 3.18	$ 88.19	$ 40.37
Royalties	(0.67)	(14.94)	(7.00)	(0.47)	(13.34)	(6.07)
Production expenditures	(2.15)	(30.16)	(17.60)	(1.91)	(23.55)	(15.18)
	1.67	51.90	21.39	0.80	51.30	19.12
Realized risk management (loss) gain	-	(1.13)	(0.32)	0.80	3.53	4.42
Field netbacks	$ 1.67	$ 50.77	$ 21.07	$ 1.60	$ 54.83	$ 23.54

Capital Expenditures

For the years ended December 31,	2013	2012
Offshore		
Pipeline	$ 916	$ 90
Facilities	59	26
Total offshore	975	116
Onshore		
Drilling and completion	4,122	2,168
Pipeline	-	196
Workovers	853	1,462
Facilities	344	66
Land and building	72	-
Other	(360)	539
Total onshore	5,031	4,431
Exploration and Evaluation		
Undeveloped properties	2,679	1,132
Onshore seismic	4,697	3,607
Total exploration and evaluation	7,376	4,739
Drilling rig	-	3,500
Office equipment, computer hardware and software	92	16
	13,474	12,802
Disposition of property, plant and equipment	(1,385)	-
	$ 12,089	$ 12,802

During 2013, the Corporation expended $12.1 million on capital expenditures, net of $1.4 million received on the disposition of certain property, plant and equipment. This compares with capital expenditures of $12.8 million incurred during 2012.

As part of its offshore capital program, the Corporation incurred costs of $1.0 million to complete an extensive pipeline replacement and rerouting project. In addition, this project included dredging the harbour in front of the dock lands at Port Burwell harbour. Both of these projects are expected to result in a reduction of future marine operating costs on Lake Erie. Other than these offshore initiatives, the Corporation's capital expenditure program was focused on onshore projects, as the Corporation expected that success on oil projects would yield greater returns than natural gas projects, due to forecasted low prices for natural gas in North America.

Onshore, the Corporation incurred capital expenditures of $5.0 million, including $4.1 million incurred on drilling and completion costs on four wells, which included a horizontal re-entry of a well initially drilled in 2012. After acid stimulation, the well came on production at 10 bbl/d in December 2013. The Corporation has determined that the other three wells drilled were uneconomic. The Corporation also expended $0.9 million in late 2013 to stimulate a further six wells, increasing production by approximately 20 bbl/d.

Exploration and evaluation expenditures were $7.4 million in 2013, including $4.7 million incurred on the acquisition and processing of 2-D and 3-D seismic data, which will be used to identify future drill locations. Another $2.7 million of costs were incurred on undeveloped properties, including $1.6 million of costs incurred on a horizontal natural gas well from a new geological formation. Further work on this exploration well will be considered if gas production rates remain economic. The remaining $0.9 million of exploration and evaluation costs were incurred on maintenance costs associated with undeveloped land, including leasing costs.

2014 Work Program

The Corporation anticipates spending $7.3 million on its 2014 work program. Approximately $4.8 million will be directed towards development of its oil fields in southern Ontario; a further $1.4 million will be directed towards the Corporation's offshore natural gas assets; and, approximately $1.1 million will be incurred to acquire or maintain mineral rights for both producing and undeveloped properties.

The 2014 onshore capital work program includes a three-well drilling and completion program estimated to cost $2.5 million. Based on previously obtained seismic information, the Corporation has identified five possible drill locations, including four vertical wells and one horizontal well opportunity, and it is currently assessing each position in order to determine the appropriate drilling selection. In addition, the Corporation intends to spend $1.5 million on three workovers during 2014, and it has budgeted approximately $0.8 million for the shooting and processing of both 2-D and 3-D seismic, covering 50 to 60 kilometres.

The Corporation has limited its 2014 offshore capital work program to approximately $1.4 million needed to complete four workovers in order to arrest some of the natural decline of the Corporation's natural gas assets.

Reserves

The Corporation retained Deloitte LLP ("Deloitte"), an independent qualified reserves evaluator to prepare a report on the Corporation's working interest in its oil and natural gas reserves in southern Ontario. The Corporation has a Corporate Governance and Reserves Committee that oversees the selection, qualifications and reporting procedures of the independent engineering consultants. Reserves at December 31, 2013 were determined using the guidelines and definitions set out under National Instrument 51-101. At December 31, 2013, the proved and probable reserves in southern Ontario increased by 18% to 19,364 million boe ("Mboe") from 16,358 Mboe at December 31, 2012. The following table outlines the change in the Corporation's reserves since December 31, 2012.

	Natural Gas (MMcf)	Oil (Mbbl)	Natural Gas Liquids (Mbbl)	Total (Mboe)	NPV @ 10% Before Tax (Mboe)	NPV per boe
Proved Reserves						
Opening balance, January 1, 2013	66,526	1,777	55	12,919	$ 108,600	$ 8.41
Net acquisitions	14,455	(21)	-	2,388		
Revisions	6,712	16	(2)	1,133		
Production	(3,971)	(227)	(8)	(897)		
Closing balance, December 31, 2013	83,722	1,545	45	15,543	$ 131,795	$ 8.48
Probable Reserves						
Opening balance, January 1, 2013	15,541	822	27	3,439	$ 31,500	$ 9.16
Net acquisitions	7,190	(10)	-	1,188		
Revisions	(4,366)	(75)	(3)	(806)		
Closing balance, December 31, 2013	18,365	737	24	3,821	$ 33,001	$ 8.64
Total proved and probable	102,087	2,282	69	19,364	$ 164,796	$ 8.51
Percentage increase (decrease) in reserves	24%	(12%)	(16%)	18%		

At December 31, 2012, the Corporation estimated the reserve life index for natural gas and oil at 23.2 years and 9.4 years, respectively. As at December 31, 2013, the reserve life index for natural gas increased to 25 years, while the reserve life index for oil remained the same at 9.4 years.

The following table outlines Deloitte’s forecasted future prices for each of oil and natural gas. These forecasts form the basis for Deloitte’s evaluation of the Corporation’s reserves at December 31, 2013, as outlined above.

	Natural Gas	Oil
Reserve Prices	Union Parkway CAD$ / Mcf	Edmonton Par (delivered to Sarnia, ON) CAD$ / bbl
2014	4.50	99.55
2015	4.75	96.10
2016	4.90	99.00
2017	5.10	98.60
2018	5.35	99.40
Average five year forecast	4.92	98.53

Impairment of Natural Gas Assets

During the year ended December 31, 2013, the Corporation recognized an impairment of $3.5 million on an oil property and its related cash generating unit (“CGU”). The impairment charge reflects a reduction in reserves and associated expected future production volumes from the oil property.

The recoverable amount of the impaired CGU was determined by calculating its value-in-use. In determining the CGU’s value-in-use, the Corporation considered expected cash flows based on its most recent externally evaluated reserves reports and long-term views on commodity prices. In computing the recoverable amount, expected future cash flows were discounted using a discount rate of 8%.

In the prior year, the Corporation recognized an impairment of $15.5 million on certain gas properties and their related CGUs, reflecting a reduction in forecasted natural gas prices as at December 31, 2012. The Corporation has determined that the forecasted improvements in the price of natural gas since December 31, 2012 are not of significant magnitude to recognize a reversal of the impairment previously recognized by the Corporation.

Decommissioning Liabilities

The Corporation has recorded a decommissioning liability, representing its best estimate of the costs that it will incur to settle future site restoration, abandonment and reclamation obligations. At December 31, 2013, the Corporation's estimate of these future costs on an undiscounted basis was approximately $91.8 million, including $12.5 million of decommissioning liabilities assumed as part of the acquisition of additional working interests during 2013. These obligations are forecasted to be incurred over a 50-year period. The Corporation incurred $1.3 million in reclamation costs during 2013, including the abandonment of 15 offshore gas wells, and it anticipates that it will incur another $1.3 million in reclamation costs over the next twelve months.

In accordance with accounting requirements, the estimated decommissioning liability is recorded in the Corporation's consolidated financial statements on a discounted basis using discount rates that are specific to the underlying obligations. At December 31, 2013, the discounted amount of the Corporation's decommissioning liabilities was $42.7 million. The discount used in calculating the Corporation's decommissioning liabilities is accreted over time. During 2013, the Corporation incurred accretion expense of $0.9 million (2012 – $0.9 million).

Share of Loss from Equity Accounted Investment in Escal

The Corporation accounts for its investment in Escal using the equity method. Prior to the issuance of the Euro Bonds, Escal had established a hedging strategy to mitigate its exposure to interest rate risk associated with the project financing arrangements for the Castor Project. During the third quarter of 2013, and following completion of the issuance of the Euro Bonds, Escal paid cash to cancel all outstanding hedging strategies. Recognition of these amounts paid to settle the hedging instruments draws the Corporation's carrying value in Escal to zero. At December 31, 2013, the Corporation had not recognized a liability of $34.1 million (2012 – $38.6 million) related to additional losses incurred by Escal, as it does not have the legal or constructive obligation in respect thereof.

In order to comply with minimum equity to debt ratio requirements, ACS has contributed an issuance premium on newly issued shares of Escal totalling €40.9 million and Escal issued €64.2 million in subordinated loans. The Corporation has not recognized the benefit of its 33% interest in the share premium and subordinated loans as the realization and measurement of the benefit is subject to a significant number of risks and uncertainties, including but not limited to the conclusion of the commissioning of the project and the uncertainties and timing of receipts pursuant to the remuneration regime.

Investment in Series A Preference Shares of Eurogas International

Because of the Corporation's entitlement to demand redemption of the Series A Preference Shares at any time from Eurogas International, the Corporation has classified its investment in the Series A Preference Shares as a loan receivable and the associated dividends as interest income. The Corporation has completed an assessment of the fair value of the Series A Preference Shares. In its assessment, the Corporation considered factors such as the delinquency of dividend payments, and the financial resources available to Eurogas International to meet current commitments and pursue growth opportunities. The Corporation concluded that there was significant impairment in the par value of the Series A Preference Shares and the related accrued dividends thereon and accordingly, the Corporation has fully provided against the carrying values of these assets. During 2013, the Corporation provided for an impairment loss relating to its investment in Eurogas International of $1.3 million (2012 – $1.3 million).

Other Items in Consolidated Net Earnings

General and Administrative Expenses

General and administrative expenses incurred during 2013 were $5.9 million, a decrease of $1.1 million from general and administrative expenses of $7.0 million incurred during 2012. In the latter part of 2012, the Corporation implemented certain initiatives aimed at reducing costs associated with professional services paid to third parties, predominantly costs associated with maintaining its database of land rights, leases and other entitlements. In addition, and reflecting current operations, discretionary incentive compensation was also decreased. These initiatives significantly reduced general and administrative expenses in 2013 compared to the prior year.

Interest Expense

The Corporation incurred interest expense of $4.6 million in 2013, consistent with interest expense of $4.6 million incurred during the prior year. Included in interest expense is $0.9 million (2012 – $0.9 million) of accretion expense associated with the Corporation's decommissioning liabilities, with the balance of interest expense incurred in respect of borrowings pursuant to the Corporation's credit facility.

Income Taxes

The Corporation recognized an income tax recovery of $0.8 million in 2013 (2012 – $5.9 million) on pre-tax losses, generating an effective tax rate of 11% (2012 – 26%). The lower than expected 2013 effective income tax rate can be attributed primarily to the renunciation of exploration expenses. As at December 31, 2013, the Corporation's net deferred income tax assets were $9.3 million (2012 – $9.3 million) and included deferred income tax assets of $9.4 million (2012 – $9.5 million) offset by deferred income tax liabilities of $0.1 million (2012 – $0.2 million).

SELECTED QUARTERLY FINANCIAL INFORMATION

	2013				2012			
	31-Dec	30-Sep	30-Jun	31-Mar	31-Dec	30-Sep	30-Jun	31-Mar
Revenues	$ 8,264	$ 9,340	$ 8,245	$ 7,359	$ 7,507	$ 7,359	$ 7,543	$ 8,074
Net loss attributable to owners of the parent	**(3,183)**	**(1,472)**	**(457)**	**(1,072)**	**(13,431)**	**(2,470)**	**(302)**	**(420)**
Basic and fully diluted loss per share	$ (0.01)	$ (0.01)	$ -	$ (0.01)	$ (0.08)	$ (0.02)	$ -	$ -
Capital expenditures	$ 3,300	$ 3,419	$ 3,447	$ 1,923	$ 3,009	$ 3,894	$ 4,532	$ 1,367

- During the fourth quarter of 2013, the Corporation recognized an impairment on an oil property of $3.5 million, reflecting decreased production from certain oil wells.
- During the third quarter of 2013, the Corporation completed the acquisition of additional working interests in certain natural gas properties, resulting in increased revenues.
- In the fourth quarter of 2012, the Corporation recognized an impairment on certain natural gas properties of $15.5 million, reflecting a reduction in forecasted natural gas prices.
- Changes in the fair value of the Corporation's risk management contracts are included in the Corporation's net earnings. The key drivers affecting fair value changes may cause significant volatility in the Corporation's earnings, some of which are beyond the control of the Corporation. The following table illustrates the impact of changes in the fair value of the Corporation's risk management contracts to its net earnings (loss) on a quarterly basis:

	2013				2012			
	31-Dec	30-Sep	30-Jun	31-Mar	31-Dec	30-Sep	30-Jun	31-Mar
Changes in the fair value of risk management contracts	$ 80	$ (509)	$ 214	$ (366)	$ 114	$ (354)	$ 1,507	$ 1,260

QUARTERLY CONSOLIDATED RESULTS OF OPERATIONS

Three months ended December 31, 2013 compared with the three months ended December 31, 2012

During the three months ended December 31, 2013, the Corporation's net loss attributable to the owners of the parent was $3.2 million, compared with a net loss attributable to the owners of the parent of $13.4 million in the fourth quarter of the prior year. Losses in the fourth quarter of 2013 include a $3.5 million impairment against an oil property (2012 – $15.5 million against natural gas properties) as previously discussed.

For the three months ended December 31,		2013			2012	
	Net Earnings (Loss)	Attributable to Owners of the Parent	Non-Controlling Interest	Net Earnings (Loss)	Attributable to Owners of the Parent	Non-Controlling Interest
Southern Ontario Assets	$ (3,617)	$ (3,617)	$ -	$ (17,738)	$ (17,738)	$ -
Castor Project	2	1	1	(15)	(12)	(3)
Loss from investment in preferred shares of Eurogas International	(324)	(324)	-	(323)	(323)	-
Corporate activities	757	757	-	4,642	4,642	-
Net loss for the period	$ (3,182)	$ (3,183)	$ 1	$ (13,434)	$ (13,431)	$ (3)

Southern Ontario Assets

During the fourth quarter of 2013, sales of oil and natural gas, net of royalty interests were $8.3 million, an increase of $0.8 million from the $7.5 million of sales in the same period of the prior year. As illustrated in the table below, both improved commodity prices and production volumes increased revenues from sales of natural gas by $1.0 million on a quarter-over-quarter basis. However, and despite increases in the average realized price for oil, decreases in production volumes in the fourth quarter of 2013, compared with the fourth quarter of 2012, resulted in a decrease of $0.2 million in revenues from sales of oil and liquids.

	Natural Gas	Oil and Liquids	Total
Net Sales			
Three months ended December 31, 2013	$ 3,909	$ 4,355	$ 8,264
Three months ended December 31, 2012	2,984	4,523	7,507
Net increase (decrease) in net sales	$ 925	$ (168)	$ 757
Effect of changes in production volumes	$ 297	$ (685)	$ (388)
Effect of changes in commodity prices	628	517	1,145
	$ 925	$ (168)	$ 757

Average daily volume during the three months ended December 31,	2013	2012
Natural gas (Mcf/d)	10,860	9,878
Oil (bbls/d)	584	684
Liquids (bbls/d)	16	23
Total (boe/d)	2,410	2,353

Production volumes during the fourth quarter of 2013 increased to an average of 2,410 boe/d, compared with an average of 2,353 boe/d produced in the same period of 2012. Consistent with year-over-year results, increased natural gas production volumes stemming from the acquisition of additional working interests completed in July 2013 were partially offset by decreased volumes resulting from the natural decline in the Corporation's reserves. Production volumes of oil and liquids decreased to an average of 600 bbl/d in the fourth quarter of 2013, compared with an average of 700 bbl/d produced in the same period of 2012, reflecting the natural decline rate in the Corporation's oil reserves.

For the three months ended December 31,		2013		2012
	Sales	Realized Prices ($ / unit)	Sales	Realized Prices ($ / unit)
Natural gas	$ 4,597	4.60	$ 3,471	3.82
Oil	5,112	95.22	5,284	83.97
Liquids	56	37.18	94	44.76
	9,765		8,849	
Less: Royalties at 15% (2012 – 15%)	(1,501)		(1,342)	
Net sales	$ 8,264		$ 7,507	

Revenues from natural gas sales, before associated royalties, were $4.6 million in the fourth quarter of 2013, compared with $3.5 million earned in the fourth quarter of the prior year. While the increase is partially attributed to increased production volumes, during the fourth quarter of 2013, the Corporation realized an average sales price of $4.60/Mcf for natural gas, a 20% increase over a realized price of $3.82/Mcf realized in the fourth quarter of the prior year. Consistent with year-to-date results, the increase is reflective of increasing price trends for natural gas in North America.

Sales of crude oil generated revenues, before associated royalties, of $5.1 million during the fourth quarter of 2013, a decrease of 3% over revenues of $5.3 million generated in the fourth quarter of the prior year. The Corporation realized a price of $95.22/bbl on sales of crude oil during the fourth quarter of 2013, compared with a price of $83.97/bbl during the fourth quarter of the prior year. As indicated in the Corporation's year-to-date results, the increase results from a realignment of the Corporation's crude oil marketing contracts to the higher-priced WTI benchmark compared with the Edmonton Par price. However, and also consistent with year-over-year results, decreases in oil production volumes in the fourth quarter of 2013, compared with the same period of 2012, offset the benefit of improved realized prices.

Comparable benchmark prices for oil and natural gas are illustrated in the following table.

For the three months ended December 31,			2013			2012
	US$	CAD$	Realized Prices ($)	US$	CAD$	Realized Prices ($)
Natural Gas						
Dawn Hub	4.11	4.29	4.60	3.79	3.76	3.82
NYMEX Henry Hub	3.86	4.03		3.40	3.37	
Oil						
Edmonton Par	n/a	86.72	95.22	n/a	84.47	83.97
West Texas Intermediate	97.50	101.76		88.01	87.32	

The Corporation incurred aggregate production expenditures of $4.0 million during the three months ended December 31, 2013, an increase of $0.6 million over production expenditures of $3.4 million incurred during the same period of the prior year. Consistent with year-to-date results, production expenditures on a boe/d basis increased to $17.86/boe in the fourth quarter of 2013, compared with $15.84/boe in the fourth quarter of the prior year, reflecting reduced production volumes.

For the three months ended December 31,			2013			2012
	Natural Gas	Oil and Liquids	Total	Natural Gas	Oil and Liquids	Total
Production expenditures	$ 2,001	$ 1,958	$ 3,959	$ 1,716	$ 1,711	$ 3,427
Production expenditures	(per Mcf)	(per bbl)	(per boe)	(per Mcf)	(per bbl)	(per boe)
per unit	$ 2.00	$ 35.49	$ 17.86	$ 1.89	$ 26.31	$ 15.84

Field level cash flows in the fourth quarter of 2013, before realized risk management contract gains or losses, were $4.3 million, a 6% increase over field level cash flows of $4.1 million generated in the fourth quarter of the prior year. The increase results from higher realized prices from sales of both oil and natural gas, partially offset by reduced oil production volumes.

For the three months ended December 31,			2013			2012
	Natural Gas	Oil and Liquids	Total	Natural Gas	Oil and Liquids	Total
Total sales	$ 4,597	$ 5,168	$ 9,765	$ 3,471	$ 5,378	$ 8,849
Royalties	(688)	(813)	(1,501)	(487)	(855)	(1,342)
Production expenditures	(2,001)	(1,958)	(3,959)	(1,716)	(1,711)	(3,427)
	1,908	2,397	4,305	1,268	2,812	4,080
Realized risk management (loss) gain	173	(271)	(98)	301	550	851
Field level cash flows	$ 2,081	$ 2,126	$ 4,207	$ 1,569	$ 3,362	$ 4,931

For the three months ended December 31,				2013				2012
		Natural Gas	Oil and Liquids	Total	Natural Gas	Oil and Liquids		Total
		$/Mcf	$/bbl	$/boe	$/Mcf	$/bbl		$/boe
Total sales	$	4.60	$ 93.64	$ 44.04	$ 3.82	$ 82.70	$	40.87
Royalties		(0.69)	(14.74)	(6.77)	(0.54)	(13.16)		(6.20)
Production expenditures		(2.00)	(35.49)	(17.86)	(1.89)	(26.31)		(15.84)
		1.91	43.41	19.41	1.39	43.23		18.83
Realized risk management (loss) gain		0.17	(4.91)	(0.44)	0.33	8.46		3.93
Field netbacks	$	2.08	$ 38.50	$ 18.97	$ 1.72	$ 51.69	$	22.76

Field netbacks from natural gas, before the effect of risk management contracts, increased to $1.91/Mcf in the fourth quarter of 2013, compared with $1.39/Mcf in the same period of the prior year. Improved prices for the commodity, as well as increased volumes from the acquisition of additional working interests account for this increase.

Field netbacks from oil and liquids, before the effect of risk management contracts, increased marginally to $43.41/bbl in the fourth quarter of 2013, compared with $43.23/bbl in the fourth quarter of 2012. Consistent with year-over-year results, the increase results from the improved realized price for oil, offset by higher production costs as a result of lower production volumes.

Risk management contracts decreased field netbacks by $0.44/boe in the fourth quarter of 2013, compared with an increase of $3.93/boe realized in the prior year.

LIQUIDITY AND CAPITAL RESOURCES

Cash Resources Availability

At December 31, 2013, the Corporation had cash of $0.1 million on deposit with Canadian Schedule I Chartered Bbanks. In addition, the Corporation had access to a further $3.8 million pursuant to its $70.0 million revolving demand credit facility.

Southern Ontario Assets

Completion of Rights Offering to Partially Fund Exploration and Development

During the second quarter of 2013, the Corporation completed a rights offering for aggregate gross proceeds of $8.9 million. Pursuant to the rights offering, the Corporation issued 5,734,067 common shares at a price of $0.34 per common share and it issued 17,787,596 flow-through common shares at a price of $0.39 per flow-through common share. Dundee Corporation subscribed for and received 15,771,991 flow-through common shares pursuant to the rights offering. The net proceeds raised pursuant to the rights offering were used for exploration on the Corporation's assets in southern Ontario, including an enhancement to its previously budgeted 2013 drilling program, and for general corporate purposes. In accordance with the terms of the flow-through shares issued, the Corporation renounced to subscribers of the flow-through shares $6.9 million of Canadian Exploration Expenditures, as defined in the *Income Tax Act*.

Credit Facility

The Corporation's southern Ontario operations are conducted through DELP, the Corporation's wholly-owned subsidiary. DELP has established a credit facility with a Canadian chartered bank that is structured as a revolving demand loan, with a tiered interest rate schedule that varies based on DELP's net debt to cash flow ratio, as defined in the credit facility. On July 31, 2013, the interest rate structure of DELP's credit facility was amended, increasing the interest rate on loans or letters of credit to the bank's prime lending rate plus 3.5%; or, for bankers' acceptances, to the bank's then prevailing bankers' acceptance rate plus 4.5%. The amended agreement provides for a standby fee of 0.55% on unused amounts under the credit facility. At December 31, 2013, DELP had drawn $66.2 million against the credit facility.

The Corporation has assigned a limited recourse guarantee of its units in DELP as security pursuant to the credit facility. The credit facility is subject to certain covenants, including maintenance of minimum levels of working capital. At December 31, 2013, the Corporation was in compliance with all such covenants.

Cash flows generated from ongoing operating activities, combined with amounts available pursuant to its credit facility and funds raised as part of the rights offering, provide the Corporation with sufficient cash flow to support its working capital requirements for the foreseeable future.

Spain

Escal's controlling shareholder, ACS, is responsible for providing equity and arranging project financing for the Castor Project, including providing all guarantees that may be required, from the day it became a majority shareholder in Escal, through development and construction and inclusion of the underground storage facility into the Spanish gas system. After the Castor Project is operational, the Corporation will be responsible for its proportionate share of any new capital investments, unless otherwise funded through working capital generated directly by Escal.

At December 31, 2013, approximately €1.4 billion had been borrowed pursuant to the Euro Bonds issued by Watercraft and on-lent to Escal, pursuant to a credit facility between Watercraft and Escal. Escal has used the proceeds from the Euro Bonds issuance to repay the amounts owing pursuant to Escal's previously established project financing arrangement.

Other than the pledging of its shares, the Corporation and its subsidiaries will not be required to provide any additional equity or debt funds or provide any warranties required by the project finance lenders. Notwithstanding any form by which ACS has, or may in the future, fund Escal during the construction phase and through to the inclusion of the Castor Project to the Spanish gas system, the Corporation retains full entitlement to its existing proportionate interest in Escal and in any distribution made by Escal.

Outstanding Share Data and Dilutive Securities

At December 31, 2013 and March 17, 2014, the Corporation had 188,204,184 common shares outstanding. In addition, it had granted 5,605,000 stock options to purchase common shares of the Corporation to directors and key management at a weighted average exercise price of $0.68 per share, and it had issued 1,325,817 deferred share units.

OFF BALANCE SHEET ARRANGEMENTS

In the normal course of business, the Corporation and its subsidiaries have entered into arrangements with several third-party goods and services providers. In certain instances, the Corporation, directly and through its subsidiaries, has provided indemnities and/or guarantees to these third parties for the payment of goods or services provided, or otherwise. Generally, there are no pre-determined amounts or limits included in these arrangements, and the occurrence of an event that would trigger the Corporation's obligations pursuant to these arrangements is difficult to predict. Therefore, the Corporation's potential future liability cannot be reasonably estimated.

COMMITMENTS AND CONTINGENCIES

The Corporation has certain lease arrangements that were entered into in the normal course of operations. All leases are treated as operating leases and accordingly, lease payments are included in net operations as incurred. No asset or liability value has been assigned to these leases on the consolidated statement of financial position at December 31, 2013.

The following table summarizes payments due for the next five years and thereafter in respect of the Corporation's lease arrangements and other contractual obligations.

	Expected Payments Schedule				
	2014	2015 to 2016	2017 to 2018	Thereafter	TOTAL
Bank loan	$ 65,709	$ -	$ -	$ -	$ 65,709
Decommissioning liabilities	1,284	2,495	2,696	85,278	91,753
Office, vehicle and equipment leases	317	399	66	-	782
	$ 67,310	$ 2,894	$ 2,762	$ 85,278	$ 158,244

RELATED PARTY TRANSACTIONS

Other than as described in Note 17 to the 2013 Consolidated Financial Statements, there are no other material related party transactions.

BUSINESS RISKS

There are a number of inherent risks associated with the Corporation's activities. These risks are described in the Corporation's 2013 Annual Information Form dated March 17, 2014, under *"Risk Factors"*, which may be accessed through the System for Electronic Document Analysis and Retrieval ("SEDAR") website *www.sedar.com*. These business risks should be considered by interested parties when evaluating the Corporation's performance and its outlook.

ACCOUNTING POLICIES AND CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's consolidated financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosure of contingent assets and liabilities. Critical accounting estimates represent estimates made by management that are, by their very nature, uncertain. The Corporation evaluates its estimates on an ongoing basis. Such estimates are based on historical experience and on various other assumptions that the Corporation believes are reasonable under the circumstances, and these estimates form the basis for making judgments about the carrying values of assets and liabilities and the reported amount of revenues and expenses that are not readily apparent from other sources. Actual results may differ from these estimates under different assumptions or conditions. Summaries of the significant accounting policies applied in the preparation and significant judgments, estimates and assumptions made by management in the preparation of its financial statements are provided in Notes 3 and 4 to the 2013 Consolidated Financial Statements.

CONTROLS AND PROCEDURES

In accordance with the Canadian Securities Administrators' National Instrument 52-109, the Corporation has filed certificates signed by its Chief Executive Officer and the Chief Financial Officer certifying that, among other things, the design of disclosure controls and procedures and the design of internal control over financial reporting are adequate as at December 31, 2013.

Disclosure controls and procedures are designed to ensure that information required to be disclosed by the Corporation in the reports it files or submits under securities legislation is recorded, processed, summarized and reported on a timely basis and that such information is accumulated and reported to management, including the Corporation's Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow required disclosures to be made in a timely fashion. Based on their evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that as at December 31, 2013, the Corporation's disclosure controls and procedures were effective.

The Chief Executive Officer and the Chief Financial Officer of the Corporation have also evaluated whether there were changes to the Corporation's internal control over financial reporting during 2013 that have materially affected, or are reasonably likely to materially affect the Corporation's internal control over financial reporting. There were no changes identified during their evaluation.

FORWARD-LOOKING STATEMENTS

This MD&A contains forward-looking statements that reflect management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities. Forward-looking statements include future-oriented financial information, within the meaning of the "safe harbor" provisions of the *U.S. Private Securities Litigation Reform Act of 1995* and the securities legislation of certain of the provinces of Canada, including the *Securities Act* (Ontario).

Certain information set forth in this MD&A, including management's assessment of the Corporation's future plans and operations, contains forward-looking statements. Forward-looking statements are statements that are predictive in nature, depend upon or refer to future events or conditions and may include words such as "expects", "anticipates", "intends", "plans", "believes", "estimates" or similar expressions. In particular, forward-looking statements contained in this document include, but are not limited to, statements with respect to: financial and business prospects and financial outlook; performance characteristics of the Corporation's oil and natural gas properties; oil and natural gas production levels and reserve estimates; the quantity of oil and natural gas reserves and recovery rates; the Corporation's capital expenditure programs; supply and demand for oil and natural gas and commodity prices; drilling plans and strategy; availability of rigs, equipment and other goods and services; expectations regarding the Corporation's ability to raise capital and continually add to reserves through acquisitions, exploration and development; treatment under government regulatory regimes and tax laws; anticipated work programs and land tenure; the granting of formal permits, licences or authorities to prospect; the timing of acquisitions; and the realization of the anticipated benefits of the Corporation's acquisitions and dispositions. In addition, statements relating to "reserves" or "resources" are, by their nature, forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future.

By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond the Corporation's control, including risks related to the exploration, development and production of oil and gas, uncertainty of reserve estimates, project development risks, reliance on operators, management and key personnel, the cyclical nature of the oil and gas business, dependence on a small number of customers, the need for additional funding to execute on further exploration and development work, the granting of operating permits and licenses, the mitigation of environmental risks including risks associated with induced or activated seismicity and other risk factors discussed or referred to in the section entitled *"Risk Factors"* in the Corporation's Annual Information Form and other documents filed from time to time with the securities administrators, all of which may be accessed at *www.sedar.com*. These statements are only predictions, not guarantees, and actual events or results may differ materially. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements.

Forward-looking statements and other information contained herein concerning the oil and gas industry and the Corporation's general expectations concerning this industry are based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Corporation believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market share and performance characteristics. While the Corporation is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

In addition, a number of assumptions were made by the Corporation in connection with certain forward-looking information and forward-looking statements for 2014 and beyond. These assumptions include: the impact of increasing competition; the general stability of the economic and political environment in which the Corporation operates; the timely receipt of any required regulatory approvals; the ability of the Corporation to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects in which the Corporation has an interest to operate such projects in a safe, efficient and effective manner; the ability of the Corporation to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and/or exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of the Corporation to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Corporation operates; the ability of the Corporation to successfully market its oil and natural gas products; estimates on global industrial production in key geographic markets; global oil and natural gas demand and supply; that the Corporation will not have any labour, equipment or other disruptions at any of its operations of any significance in 2014 other than any planned maintenance or similar shutdowns and that any third parties on which the Corporation is relying will not experience any unplanned disruptions; that the reports it relies on for certain of its estimates are accurate; and that the above mentioned risks and the risk factors described in the Corporation's Annual Information Form do not materialize.

The Corporation's actual results, performance or achievements could differ materially from those expressed in, or implied by, these forward-looking statements and accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what resulting benefits the Corporation will derive. The forward-looking statements, including future-oriented financial information, contained herein are presented solely for the purpose of conveying management's reasonable belief of the direction of the Corporation and may not be appropriate for other purposes. The Corporation disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law.

INFORMATION CONCERNING DUNDEE ENERGY LIMITED

Additional information relating to Dundee Energy Limited, including a copy of the Corporation's Annual Information Form, may be accessed through the SEDAR website at *www.sedar.com* and the Corporation's website at *www.dundee-energy.com*.

Toronto, Ontario
March 17, 2014

Management's Report on Internal Control over Financial Reporting

The accompanying consolidated financial statements of Dundee Energy Limited ("the Corporation"), the notes thereto and other financial information contained in the Corporation's management's discussion and analysis have been prepared by, and are the responsibility of the management of the Corporation. These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards and, where appropriate, include management's best estimates and judgments.

Management maintains a system of internal control designed to provide reasonable assurance that assets are safeguarded from loss or unauthorized use, and that financial information is timely and reliable. However, any system of internal control over financial reporting, no matter how well designed and implemented, has inherent limitations and may not prevent or detect all misstatements.

The Board of Directors is responsible for ensuring that management fulfills its responsibility for financial reporting and internal control. The Audit Committee, which is comprised entirely of independent directors, meets with management and with the external auditor to satisfy itself that management is properly discharging its financial reporting responsibilities and to review the consolidated financial statements and the report of the auditor. The Board of Directors, based on recommendations from the Audit Committee, reviews and approves the consolidated financial statements and the Corporation's accompanying management's discussion and analysis.

The consolidated financial statements have been audited by PricewaterhouseCoopers LLP, the independent auditor, in accordance with Canadian generally accepted auditing standards. The auditor has full and unrestricted access to the Audit Committee.

(signed) M. Jaffar Khan
President and
Chief Executive Officer

(signed) David Bhumgara
Chief Financial Officer

Toronto, Canada
March 17, 2014

Independent Auditor's Report

To the Shareholders of **Dundee Energy Limited**

We have audited the accompanying consolidated financial statements of Dundee Energy Limited, which comprise the consolidated statements of financial position as at December 31, 2013 and 2012 and the consolidated statements of operations, the consolidated statements of comprehensive loss, the consolidated statements of changes in shareholders' equity, and the consolidated statements of cash flow for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Dundee Energy Limited as at December 31, 2013 and 2012 and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

(signed) PricewaterhouseCoopers LLP
Chartered Professional Accountants, Licensed Public Accountants
Toronto, Canada
March 17, 2014

DUNDEE ENERGY LIMITED
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(expressed in thousands of Canadian dollars)

	Note	As at December 31, 2013	December 31, 2012
ASSETS			
Current			
Cash		$ 111	$ 125
Accounts receivable	5	4,807	3,775
Prepaids and security deposits		1,217	1,198
Inventory		333	350
Investments	6	1,340	241
Derivative financial assets	10	-	215
Taxes recoverable (payable)		72	(25)
		7,880	5,879
Non-current			
Oil and gas properties	7	155,460	154,450
Equity accounted investment in Escal	14	-	-
Deferred income taxes	16	9,255	9,277
		$ 172,595	$ 169,606
LIABILITIES			
Current			
Bank loan	8	$ 65,709	$ 62,633
Accounts payable and accrued liabilities	17	5,230	5,340
Derivative financial liabilities	10	92	-
Decommissioning liabilities	9	1,284	1,796
		72,315	69,769
Non-current			
Decommissioning liabilities	9	41,416	42,909
		113,731	112,678
SHAREHOLDERS' EQUITY			
Equity Attributable to Owners of the Parent			
Share capital	11	112,626	104,838
Contributed surplus	11	7,475	7,086
Deficit		(58,345)	(52,161)
Accumulated other comprehensive loss		(3,082)	(3,082)
		58,674	56,681
Non-controlling interest		190	247
		58,864	56,928
		$ 172,595	$ 169,606

The accompanying notes are an integral part of these consolidated financial statements.

Commitments (Note 18)

On behalf of the Board,

(signed) Harold P. Gordon
Director

(signed) Garth A.C. MacRae
Director

DUNDEE ENERGY LIMITED
CONSOLIDATED STATEMENTS OF OPERATIONS

For the years ended December 31, 2013 and 2012
(expressed in thousands of Canadian dollars, except per share amounts)

	Note		2013		2012
REVENUES					
Oil and gas sales		$	39,174	$	35,874
Royalties			(5,966)		(5,391)
Net sales			33,208		30,483
Production expenditures	13		(14,990)		(13,483)
Depreciation and depletion	7		(12,562)		(15,003)
General and administrative	13		(5,900)		(7,044)
(Loss) gain on fair value changes of risk management contracts	10		(581)		2,527
Gain (loss) on fair value changes in financial instruments	6		24		(38)
Impairment of oil and gas properties	7		(3,500)		(15,500)
Impairment of financial instruments	6		(1,286)		(1,286)
Interest and other income	7		2,885		1,468
Interest expense	8, 9		(4,588)		(4,588)
Foreign exchange gain (loss)			267		(116)
LOSS BEFORE INCOME TAXES			(7,023)		(22,580)
Income tax (expense) recovery	16				
Current			(5)		(163)
Deferred			787		6,063
			782		5,900
NET LOSS FOR THE YEAR		$	(6,241)	$	(16,680)
NET LOSS ATTRIBUTABLE TO:					
Owners of the parent		$	(6,184)	$	(16,623)
Non-controlling interest			(57)		(57)
		$	(6,241)	$	(16,680)
BASIC AND DILUTED NET LOSS PER SHARE	15	$	(0.03)	$	(0.10)

The accompanying notes are an integral part of these consolidated financial statements.

DUNDEE ENERGY LIMITED
CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

For the years ended December 31, 2013 and 2012
(expressed in thousands of Canadian dollars)

	Note		2013		2012
NET LOSS FOR THE YEAR		$	(6,241)	$	(16,680)
Other comprehensive income					
Taxes associated with equity accounted investment			-		32
Other comprehensive income for the year			-		32
COMPREHENSIVE LOSS FOR THE YEAR		$	(6,241)	$	(16,648)
COMPREHENSIVE LOSS ATTRIBUTABLE TO:					
Owners of the parent		$	(6,184)	$	(16,591)
Non-controlling interest			(57)		(57)
		$	(6,241)	$	(16,648)

The accompanying notes are an integral part of these consolidated financial statements.

DUNDEE ENERGY LIMITED
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

For the years ended December 31, 2013 and 2012
(expressed in thousands of Canadian dollars)

	Attributable to Owners of the Parent						
	Share Capital	Contributed Surplus for Option Reserve	Contributed Surplus for Deferred Share Unit Reserve	Deficit	Accumulated Other Comprehensive Loss	Non-controlling Interest	TOTAL
Balance, December 31, 2011	$ 104,854	$ 6,051	$ 580	$ (35,538)	$ (3,114)	$ 304	$ 73,137
For the year ended December 31, 2012							
Acquisition of common shares for cancellation pursuant to normal course issuer bid (Note 11)	(16)	-	-	-	-	-	(16)
Net loss	-	-	-	(16,623)	-	(57)	(16,680)
Stock based compensation (Note 12)	-	316	139	-	-	-	455
Other comprehensive income	-	-	-	-	32	-	32
Balance, December 31, 2012	104,838	6,367	719	(52,161)	(3,082)	247	56,928
For the year ended December 31, 2013							
Net loss	-	-	-	(6,184)	-	(57)	(6,241)
Share issuance pursuant to rights offering, net of issue costs (Note 11)	7,777	-	-	-	-	-	7,777
Stock based compensation (Notes 12)	11	253	136	-	-	-	400
Balance, December 31, 2013	$ 112,626	$ 6,620	$ 855	$ (58,345)	$ (3,082)	$ 190	$ 58,864

The accompanying notes are an integral part of these consolidated financial statements.

DUNDEE ENERGY LIMITED
CONSOLIDATED STATEMENTS OF CASH FLOW

For the years ended December 31, 2013 and 2012
(expressed in thousands of Canadian dollars)

	Note	2013	2012
OPERATING ACTIVITIES			
Net loss for the year		$ (6,241)	$ (16,680)
Adjustments for:			
Depreciation and depletion	7	12,562	15,003
(Gain) loss on fair value changes in financial instruments	6	(24)	38
Impairment of oil and gas properties	7	3,500	15,500
Impairment of financial instruments	6	1,286	1,286
Loss on fair value changes of risk management contracts	10	307	1,401
Deferred income taxes	16	(787)	(6,063)
Stock based compensation	12	389	455
Reclamation expenditures	9	(1,320)	(993)
Other		(781)	(339)
		8,891	9,608
Changes in:			
Accounts receivable		(1,037)	1,331
Accounts payable and accrued liabilities		(515)	(3,746)
Current income taxes		(97)	55
Prepaids and security deposits		(19)	334
Inventory		17	271
CASH PROVIDED FROM OPERATING ACTIVITIES		7,240	7,853
FINANCING ACTIVITIES			
Advanced from bank loan arrangements	8	3,076	3,442
Proceeds from rights offering, net of issue costs	11	8,586	-
Acquisition of common shares for cancellation	11	-	(16)
CASH PROVIDED FROM FINANCING ACTIVITIES		11,662	3,426
INVESTING ACTIVITIES			
Acquisition of investments	6	(1,075)	-
Acquisition of working interest in oil and gas properties	7	(4,893)	-
Investment in oil and gas properties	7	(12,948)	(13,710)
CASH USED IN INVESTING ACTIVITIES		(18,916)	(13,710)
DECREASE IN CASH		(14)	(2,431)
CASH, BEGINNING OF YEAR		125	2,556
CASH, END OF YEAR		$ 111	$ 125
Interest paid		$ 3,641	$ 3,645
Income taxes paid		$ 102	$ 108

The accompanying notes are an integral part of these consolidated financial statements.

For the years ended December 31, 2013 and December 31, 2012 Tabular dollar amounts in thousands of Canadian dollars, except per share amounts

1. NATURE OF OPERATIONS

Dundee Energy Limited ("Dundee Energy" or the "Corporation") is an oil and natural gas company with a mandate to create long-term value through the exploration, development, production and marketing of oil and natural gas and through other high impact energy projects. Dundee Energy is incorporated under the Canada Business Corporations Act. The Corporation's head office is located at Suite 2100, 1 Adelaide Street East, Toronto, Ontario, Canada, M5C 2V9, and its registered office is located at Suite 250, 435 – 4th Avenue SW, Calgary, Alberta, Canada, T2P 3A8. The Corporation's common shares trade on the Toronto Stock Exchange ("TSX") under the symbol "DEN". At December 31, 2013, Dundee Corporation was the principal shareholder of the Corporation.

Dundee Energy's operating interests include its 100% ownership of Dundee Energy Limited Partnership ("DELP"), a limited partnership involved in the exploration, development and production of oil and gas properties in southern Ontario, Canada, and a 74% interest in Castor UGS Limited Partnership ("CLP"), its principal asset being a 33% interest in Escal UGS S.L. ("Escal"), the owner of the Castor underground gas storage project located in Spain. The Corporation also holds preferred shares of Eurogas International Inc. ("Eurogas International" or "EII"), an oil and gas exploration company that holds a working interest in the Sfax permit offshore Tunisia.

2. BASIS OF PREPARATION

These consolidated financial statements of the Corporation as at and for the year ended December 31, 2013 ("2013 Consolidated Financial Statements") have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"), and with interpretations of the International Financial Reporting Interpretations Committee which the Canadian Accounting Standards Board has approved for incorporation into Part 1 of the CPA Canada Handbook – Accounting. These consolidated financial statements were authorized for issuance by the Board of Directors on March 17, 2014.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies adopted by the Corporation in the preparation of its consolidated financial statements are set out below.

Basis of Measurement
The consolidated financial statements have been prepared under the historical cost convention, except for certain financial instruments, including risk management contracts, which are measured at fair value as determined at each reporting date.

Principles of Consolidation
These consolidated financial statements include the accounts of the Corporation and its subsidiaries. All intercompany transactions have been eliminated in these consolidated financial statements.

Subsidiaries are those entities that Dundee Energy controls by having the power to govern the financial and operating policies of the entity. The existence and effect of potential voting rights that are currently exercisable are considered when assessing whether Dundee Energy controls another entity. Subsidiaries are fully consolidated from the date on which control is obtained by Dundee Energy and are subsequently deconsolidated from the consolidated financial statements on the date that control ceases.

Non-controlling Interest

Non-controlling interest represents equity interests in subsidiaries owned by outside parties. The share of net assets, net earnings and other comprehensive income ("OCI") of subsidiaries attributable to non-controlling interest is presented as a component of equity. Changes in the Corporation's interest in subsidiaries that do not result in a loss of control are accounted for as equity transactions.

Equity Accounted Investments

Equity accounted investments are investments over which the Corporation has significant influence, but not control. The financial results of the Corporation's equity accounted investments are included in the Corporation's consolidated financial statements using the equity method whereby the Corporation recognizes its proportionate share of earnings or losses and of OCI of the equity accounted investment in its own earnings or OCI, as applicable. Dilution gains and losses arising from changes in the Corporation's interest in equity accounted investments are recognized in earnings. If the Corporation's investment is reduced to zero, additional losses are not provided for, and a liability is not recognized, unless the Corporation has incurred legal or constructive obligations, or made payments on behalf of the equity accounted investment.

The Corporation assesses at least annually whether there is objective evidence that its interests in equity accounted investments are impaired. If impaired, the carrying value of the Corporation's share of the underlying assets of equity accounted investments is written down to its estimated recoverable amount, with any difference charged to the consolidated statement of operations.

Foreign Currency

Functional and Presentation Currency

These consolidated financial statements are presented in Canadian dollars, which is the Corporation's functional currency.

Functional Currency of Subsidiaries and Equity Accounted Investments

The financial statements of consolidated subsidiaries and equity accounted investments that have a functional currency that is different from that of the Corporation are translated into Canadian dollars using average rates for the period for items included in the consolidated statement of operations and OCI and the rates in effect at the dates of the consolidated statement of financial position for assets and liabilities. All resulting changes are recognized in OCI as cumulative translation adjustments.

If the Corporation's interest in foreign operations of a subsidiary is diluted, but the foreign operations remain a subsidiary, a pro rata portion of cumulative translation adjustments related to those foreign operations are reallocated between controlling and non-controlling interest. When the Corporation disposes of its entire interest in foreign operations, or when it loses control or significant influence, the cumulative translation adjustment included in OCI related to the foreign operations is recognized in the consolidated statement of operations on a pro rata basis.

Transactions

Foreign currency transactions are translated into the Corporation's functional currency using exchange rates prevailing at the dates of the transactions. Generally, foreign exchange gains and losses resulting from the settlement of foreign currency transactions and from the translation of monetary assets and liabilities denominated in currencies other than the Corporation's functional currency at each period-end date, are recognized in the consolidated statement of operations.

Inventories

The Corporation's oil production is stored in oil batteries until such time as it is delivered for sale. Any remaining oil production in oil batteries at the end of a reporting period is recognized as inventory in the consolidated financial statements and is valued at the lower of cost and net realizable value. Cost of inventory includes production costs, including direct overhead costs, and depreciation and depletion. Net realizable value is determined with reference to the relevant average sales price realized for oil production during the immediately preceding period, less variable selling expenses. The Corporation's natural gas production is immediately interconnected to the gas distribution network and therefore, the Corporation does not hold inventory of natural gas.

Financial Instruments

The Corporation's financial instruments include cash, accounts receivable, risk management contracts, investments, amounts due pursuant to bank loan arrangements and accounts payable and accrued liabilities.

Financial assets and liabilities are recognized when the Corporation becomes a party to the contractual provisions of the instrument. Financial assets are derecognized when the rights to receive cash flows from the assets have expired or are assigned and the Corporation has transferred substantially all risks and rewards of ownership in respect of the asset. Financial liabilities are derecognized when the related obligation is discharged, cancelled or expires.

Classification of financial instruments in the Corporation's consolidated financial statements depends on the purpose for which the financial instruments were acquired or incurred. Management determines the classification of financial instruments at initial recognition.

Financial Assets and Liabilities at Fair Value through Profit or Loss

A financial asset or liability is classified in this category if acquired principally for the purpose of selling or repurchasing in the short term. Derivatives, if any, are also included in this category, unless they are designated as hedges. Transaction costs related to these financial instruments are expensed in the consolidated statements of operations.

Certain of the Corporation's investments and its risk management contracts have been classified in this category. These financial instruments are measured at fair value, with the exception of equity investments that do not have quoted market values in active markets. Non-quoted equity investments are carried at cost unless there is indication of impairment.

Risk Management Contracts

The Corporation manages its exposure to changes in commodity prices and associated earnings volatility by periodically entering into derivative risk management contracts in accordance with its risk management policy. Risk management contracts are carried at fair value and are generally reported as assets in circumstances when they have a positive fair value and as liabilities when they have a negative fair value. Both realized and unrealized gains and losses from changes in fair value of risk management contracts are recorded in the consolidated statement of operations.

Loans and Receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. The Corporation's loans and receivables are comprised of cash, accounts receivable, and the Corporation's preferred share investment in Eurogas International (which has been included with other investments in the consolidated statement of financial position). Loans and receivables are initially recognized at the amount expected to be received less, when material, a discount to reduce the loans and receivables to fair value. Subsequently, loans and receivables are measured at amortized cost using the effective interest method, less a provision for impairment.

Financial Liabilities at Amortized Cost

Financial liabilities at amortized cost include amounts due pursuant to bank loan arrangements and accounts payable and accrued liabilities. These amounts are initially measured at the amount required to be paid less, when material, a discount to reduce the liabilities to fair value. Subsequently, these financial liabilities are measured at amortized cost using the effective interest method. Financial liabilities are classified as current liabilities if payment is due within twelve months. Otherwise, they are presented as non-current liabilities.

Impairment of Financial Assets at Amortized Cost

At each reporting date, the Corporation assesses whether there is objective evidence that a financial asset is impaired. A financial asset is impaired and impairment losses are incurred only if there is objective evidence of impairment as a result of one or more events that occurred after the initial recognition of the asset and that loss event has an impact on the estimated future cash flows of the financial asset that can be reliably estimated. Objective evidence may include significant financial difficulty of the obligor or delinquencies in interest and principal payments. If such evidence exists, the Corporation recognizes an impairment loss equal to the difference between the carrying value of the financial asset and the present value of the estimated future cash flows, discounted using the instrument's original effective interest rate for the financial asset. An impairment of a financial asset carried at amortized cost is reversed in subsequent periods if the amount of the loss decreased and the decrease can be related objectively to an event occurring after the impairment was recognized.

Oil and Gas Properties

A portion of the Corporation's exploration, evaluation, development and production activities is conducted pursuant to working interest arrangements with third parties. Accordingly, these consolidated financial statements reflect only the Corporation's share of capital expenditures associated with these activities.

Oil and Gas Development Costs

The Corporation capitalizes all costs associated with its development and production expenditures in southern Ontario, including accrued costs for decommissioning liabilities. Capitalized costs include the acquisition of leases and oil and gas rights, geological and geophysical expenditures, equipment costs and that portion of general and administrative expenses directly attributable to these activities. Expenditures that improve the productive capacity or extend the life of a property are capitalized. Maintenance and repairs are generally expensed as incurred.

Capitalized costs associated with properties with proved reserves, adjusted for estimated future costs to be incurred in developing such proved reserves, are depleted over estimated proved reserves using the unit of production method. For purposes of these calculations, production and reserves of natural gas are converted to barrels on an energy equivalent basis at a ratio of 6,000 cubic feet ("6 Mcf") of natural gas to one barrel ("1 bbl") of oil. Depletion rates are updated annually unless there is a material change in circumstances, in which case they are updated more frequently. Acquisition costs of probable reserves are not depleted or depreciated while under active evaluation for commercial reserves. Costs are transferred to depletable costs as proved reserves are recognized.

Assets used in the development and production of oil and gas properties are depreciated over the estimated economic life of the asset.

Asset Category	Depreciation Method	Depreciation Rate
Pipeline infrastructure	Unit of production	n/a
Machinery and equipment	Straight line	3% to 12%
Land and buildings	Straight line	2% to 5%
Office equipment, computer hardware and software	Declining balance	10% to 35%

Undeveloped Properties

Included in oil and gas properties are undeveloped properties on which the Corporation is conducting exploration and evaluation activities. The Corporation capitalizes all costs associated with undeveloped properties, except for costs incurred before the Corporation has obtained the legal right to explore an area, in which case costs are expensed as incurred. Expenditures on undeveloped properties include costs for an area or project for which technical feasibility and commercial viability have not yet been determined and may include lease acquisitions, geological and geophysical expenditures, carrying costs of non-productive properties, equipment costs, that portion of general and administrative expenses directly attributable to these activities and costs associated with decommissioning liabilities. Technical feasibility and commercial viability of a project is considered to be determined when proved or probable reserves are determined to exist, at which time the costs are reclassified as development costs, with assigned reserves..

Impairment of Oil and Gas Properties

The Corporation evaluates the carrying value of oil and gas properties when events or changes in circumstances indicate that the carrying amounts may not be recoverable. An impairment loss is recognized for the amount by which the asset's carrying value exceeds its recoverable amount. The recoverable amount of an asset is the greater of an asset's fair value less costs to sell and its value in use. For the purpose of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash inflows ("cash generating units" or "CGUs"). If their carrying value is assessed not to be recoverable, an impairment loss is recognized. The Corporation evaluates impairment losses for potential reversals when events or circumstances warrant such consideration.

Decommissioning Liabilities

A decommissioning liability is recognized when the Corporation has a legal or constructive obligation to plug a well, dismantle and remove property, plant and equipment, or complete site restoration work, and when a reliable estimate of the liability can be made. The Corporation has estimated its decommissioning liabilities in consultation with third parties and such estimates are based on current costs and technology. When a decommissioning liability is recognized, a corresponding amount, equivalent to the amount of the obligation, is recognized as part of the cost of related oil and gas properties.

Decommissioning liabilities are measured at the present value of the expected expenditures required to settle the obligation using a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the obligation. The effect of any changes to decommissioning liabilities, including changes to the underlying estimates and changes in market interest rates used to discount the obligation, is added to or deducted from the cost of the related assets. Accretion, representing the increase in decommissioning liabilities due to the passage of time, is recognized as interest expense.

Flow-Through Common Shares

Canadian tax legislation permits a company to issue flow-through common shares, whereby the deduction for tax purposes relating to qualified resource expenditures is claimed by the investor rather than the Corporation. Recording these expenditures for accounting purposes gives rise to taxable temporary differences. Upon issuance of flow-through common shares, the quoted value of the common share, or the non-flow-through common share price, as appropriate, is used to record the increase to share capital.

The difference between the amount recognized in share capital and the amount paid by the investor is recognized as a flow-through share premium liability, which is reversed into operations when eligible expenditures are made, extinguishing the obligation. A deferred tax liability, and the associated income tax expense, are recorded when eligible expenditures are made.

Revenue Recognition

Revenue associated with the Corporation's production and sale of crude oil, natural gas, and natural gas liquids is recognized when title is transferred to the customer and delivery has taken place. A portion of the Corporation's production and sales activities is conducted pursuant to working interest arrangements with third parties. Accordingly, these consolidated financial statements reflect only the proportionate interest of the Corporation in such activities.

Revenue from oil and gas sales is presented before royalty payments to third parties, including the government and other mineral interest owners. Royalties on production are recorded using rates in effect under the terms of contracts with such third parties at the time of production.

Stock Based Compensation

The Corporation issues stock based compensation awards to directors, employees and consultants. These arrangements include stock options and other stock based awards such as deferred share units. The Corporation expects that these stock based awards will be settled in equity of the Corporation.

The Corporation uses a fair value method to account for stock based compensation. The fair value of stock based compensation, as at the date of grant, is measured using an option-pricing model and is recognized over the applicable vesting period as compensation expense, based on the number of stock based awards expected to vest, with a corresponding increase in contributed surplus. When stock options or other stock based compensation arrangements are exercised, the proceeds received, together with any amount in contributed surplus, are included in share capital. The expected number of stock based awards expected to vest is reviewed at least annually, with any impact being recognized immediately.

Income Taxes

The Corporation follows the balance sheet liability method to provide for income taxes on all transactions recorded in its consolidated financial statements. The balance sheet liability method requires that income taxes reflect the expected future tax consequences of temporary differences between the carrying amounts of assets and liabilities and their tax bases. Deferred income tax assets and liabilities are determined for each temporary difference and for unused tax losses and unused tax credits, as applicable, at rates expected to be in effect when the asset is realized or the liability is settled. The effect on deferred income tax assets and liabilities of a change in tax rates is recognized in earnings in the period that includes the substantive enactment date. Deferred tax assets are recognized to the extent that it is probable that the assets can be recovered.

Current tax expense is the expected tax payable on the taxable income for the period, using tax rates enacted or substantively enacted at period end, adjusted for amendments to tax payable with regard to previous years.

Per Share Information

The basic loss per common share is computed by dividing the net loss attributable to common shareholders by the weighted average number of common shares outstanding during the year. Diluted per common share amounts, if applicable, are calculated to reflect the dilutive effect of exercising outstanding share based awards by applying the treasury stock method.

Reclassified 2012 Comparative Amounts

Certain items on the consolidated statement of financial position as at December 31, 2012 have been reclassified to conform to the December 31, 2013 presentation. The Corporation does not believe that these reclassifications had a material effect on the 2013 Consolidated Financial Statements, from either a quantitative or a qualitative perspective.

Changes in Accounting Policies Implemented During the Year Ended December 31, 2013

The Corporation has adopted the following new and revised accounting standards, including any consequential amendments thereto, effective January 1, 2013. Changes in accounting policies adopted by the Corporation were made in accordance with the applicable transitional provisions as provided in those standards and amendments.

IFRS 7, "Financial Instruments: Disclosure" ("IFRS 7")
Amendments to IFRS 7 require the disclosure of information that enables users of an entity's financial statements to evaluate the effect, or potential effect, of offsetting financial assets and financial liabilities, to the entity's financial position. The Corporation adopted IFRS 7 on January 1, 2013 and accordingly, the Corporation has included disclosures relating to the offsetting of derivative financial assets against derivative financial liabilities, if any, in Note 10 to the 2013 Consolidated Financial Statements.

IFRS 12, "Disclosure of Interests in Other Entities" ("IFRS 12")
IFRS 12 establishes disclosure requirements for interests in other entities, such as joint arrangements, equity accounted investments, special purpose vehicles and off balance sheet vehicles. The standard carries forward existing disclosure and also introduces significant additional disclosure requirements that address the nature of, and risks associated with an entity's interests in other entities. The Corporation adopted IFRS 12 on January 1, 2013. These disclosures have been included in Note 14 to the 2013 Consolidated Financial Statements.

IFRS 13, "Fair Value Measurement" ("IFRS 13")
IFRS 13 provides a single framework for measuring fair value within IFRS. The new standard requires that the measurement of the fair value of an asset or liability, as measured for accounting purposes, be based on assumptions that market participants would use when pricing the asset or liability under market conditions existing as of the date of the statement of financial position, including assumptions relating to risk. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange. The Corporation adopted IFRS 13 on January 1, 2013, on a prospective basis. The adoption of IFRS 13 did not require any adjustments to the valuation techniques used by the Corporation to measure fair value and did not result in any measurement adjustments as at January 1, 2013.

Accounting Standards, Interpretations and Amendments to Existing Standards not yet Effective

IAS 36, "Impairment of Assets" ("IAS 36")
On May 29, 2013, the IASB made amendments to the disclosure requirements of IAS 36, requiring disclosure, in certain instances, of the recoverable amount of an asset or cash generating unit, and the basis for the determination of fair value less costs of disposal, when an impairment loss is recognized or when an impairment loss is subsequently reversed. The amendments to IAS 36 are effective for annual periods beginning on or after January 1, 2014 and will be applied prospectively. In previous years, the Corporation impaired the carrying value of certain of its oil and gas properties (Note 7). If further impairment is required, or if the conditions that gave rise to the impairment are subsequently reversed, the Corporation will be subject to the disclosures required by IAS 36.

IFRS 9, "Financial Instruments" ("IFRS 9")
In November 2009, the IASB issued IFRS 9, "*Financial Instruments*", replacing IAS 39, "*Financial Instruments: Recognition and Measurement*" ("IAS 39"). IFRS 9 will be issued in three phases. The first phase, which has already been issued, addresses the accounting for financial assets and financial liabilities. The second phase will address impairment of financial instruments, while the third phase will address hedge accounting. IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, and replaces the multiple category and measurement models in IAS 39. The approach in IFRS 9 focuses on how an entity manages its financial instruments in the context of its business model, as well as the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods currently provided in IAS 39.

Requirements for financial liabilities were added to IFRS 9 in October 2010. Although the classification criteria for financial liabilities will not change under IFRS 9, the fair value option may require different accounting for changes to the fair value of a financial liability resulting from changes to an entity's own credit risk.

In December 2013, new hedge accounting requirements were incorporated into IFRS 9 that increase the scope of items that can qualify as a hedged item and change the requirements of hedge effectiveness testing that must be met to use hedge accounting. The effective date for IFRS 9 has been deferred by the IASB. The Corporation is currently evaluating the impact of adopting this standard on its consolidated financial statements.

4. CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND ASSUMPTIONS

The preparation of these consolidated financial statements in accordance with IFRS requires the Corporation to make judgments in applying its accounting policies and estimates and assumptions about the future. These judgments, estimates and assumptions affect the reported amounts of assets, liabilities, revenues and expenses, and the related disclosure of contingent assets and liabilities included in the Corporation's consolidated financial statements. The Corporation evaluates its estimates on an ongoing basis. Such estimates are based on historical experience and on various other assumptions that the Corporation believes are reasonable under the circumstances, and these estimates form the basis for making judgments about the carrying value of assets and liabilities and the reported amount of revenues and expenses that are not readily apparent from other sources. Actual results may differ from these estimates under different assumptions or conditions. The following discusses the most significant accounting judgments, estimates and assumptions that the Corporation has made in the preparation of its consolidated financial statements.

Oil and Natural Gas Reserves

The Corporation's proved and probable reserves of oil, natural gas and natural gas liquids are estimated by management and are evaluated and reported on by independent petroleum engineering consultants in accordance with Canadian Securities Administrators' National Instrument 51-101. The process of estimating proved and probable reserves requires significant judgment in evaluating and assessing available geological, geophysical, engineering and economic data, projected rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are, by their very nature, subject to interpretation and uncertainty. The evaluation of reserves is an ongoing process impacted by current production, continuing development activities and changing economic conditions. The aggregate of capitalized costs, net of certain costs related to unproved properties, and estimated future development costs are depleted using the unit of production method based on estimated proved reserves. Changes in estimates of proved and probable reserves may materially impact the determination of recoverability of the carrying value of the Corporation's oil and gas properties, the recorded amount of depletion and depreciation, the determination of the Corporation's obligations pursuant to decommissioning liabilities and the assessment of impairment provisions.

Recoverability of the Carrying Value of Exploration and Evaluation Costs on Undeveloped Properties

The Corporation is required to review the carrying value of its undeveloped properties for potential impairment. Impairment is indicated if the carrying value of the Corporation's undeveloped properties is not recoverable. If impairment is indicated, the amount by which the carrying value of undeveloped properties exceeds their estimated fair value is charged to the consolidated statement of operations.

Evaluating for recoverability during the exploration and evaluation phase requires judgment in determining whether it is likely that future economic benefit from future exploitation, sale or otherwise, is likely. Evaluations may be more complex where activities have not reached a stage which permits a reasonable assessment of the existence of reserves. Management must make certain estimates and assumptions about future events or circumstances including, but not limited to, the interpretation of geological, geophysical and seismic data, the Corporation's financial ability to continue exploration and evaluation activities, contractual issues with working interest partners and the impact of current and expected future oil and natural gas prices to potential reserves.

Activities in Spain through the Corporation's equity accounted investment in Escal are in the pre-development stage, pending commissioning of the underlying project to the Spanish gas distribution system. All pre-development costs have been capitalized by Escal. The recovery of these costs is dependent upon the economic viability of the underground natural gas storage project and the remuneration program in place by the Spanish authorities.

Decommissioning Liabilities

The Corporation is required to provide for decommissioning liabilities. The Corporation must estimate these costs in accordance with existing laws, contracts and other policies. The estimate of future costs involves a number of estimates relating to timing, type of costs and associated contract negotiations, and review of potential methods and other technical advancements. Furthermore, due to uncertainties concerning environmental remediation, the ultimate cost of the Corporation's decommissioning liabilities could differ from amounts provided. The estimate of the Corporation's obligations are subject to change due to amendments to applicable laws and regulations and as new information concerning the Corporation's operations becomes available. The Corporation is not able to determine the impact on its financial position, if any, of environmental laws and regulations that may be enacted in the future.

Business Combinations and Asset Acquisitions

Management uses judgment in applying the acquisition method of accounting for business combinations and in determining fair values in asset acquisitions, and specifically, in identifying and valuing intangible assets and liabilities acquired in acquisitions, if any. The value placed on the acquired assets and liabilities, including identifiable intangible assets, will have an effect on the amount of goodwill that the Corporation may record on an acquisition.

Income Tax

The determination of the Corporation's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. Judgment is required in determining whether deferred tax assets should be recognized on the consolidated statements of financial position. Deferred tax assets, including those arising from unutilized tax losses, requires management to assess the likelihood that the Corporation will generate taxable income in future periods in order to utilize recognized deferred tax assets. Estimates of future taxable income are based on forecasted cash flows from operations and the application of existing tax laws in each applicable jurisdiction. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Corporation to realize a deferred tax asset could be materially impacted.

Fair Value of Financial Instruments

Certain financial instruments are recorded in the Corporation's statements of financial position at values that are representative of, or approximate fair value. The fair value of a financial instrument that is traded in active markets at each reporting date is determined by reference to quoted market prices or dealer price quotations. For all other financial instruments carried at fair value, the fair value is determined using valuation techniques. By their nature, these valuation models require the use of assumptions. Changes in the underlying assumptions of these models could materially impact the determination of the fair value of a financial instrument. Imprecision in determining fair value using these valuation techniques may affect the amount of net earnings or loss recorded for a particular investment in a particular period. The Corporation believes that its estimates of fair value are reasonable and appropriate. The Corporation reviews assumptions relating to financial instruments on an ongoing basis to ensure that the basis for determination of fair value is appropriate.

5. ACCOUNTS RECEIVABLE

As at December 31,		2013		2012
Customers for oil and natural gas production	$	3,070	$	2,635
Third-party drilling receivable		542		-
Working interest partners		71		174
Amounts receivable from Escal		1,124		966
	$	4,807	$	3,775

6. INVESTMENTS

As at December 31,	2013	2012
Investment in publicly listed equity securities	$ 265	$ 241
Investment in private enterprises	1,075	-
Preferred shares of Eurogas International	32,150	32,150
Less: Impairment	(32,150)	(32,150)
	-	-
Accrued dividends on preferred share investment in Eurogas International	6,953	5,667
Less: Impairment	(6,953)	(5,667)
	-	-
	$ 1,340	$ 241

At each of December 31, 2013 and December 31, 2012, the Corporation held 32,150,000 Series A Preference Shares of Eurogas International ("Series A Preference Shares") with an aggregate par value of $32,150,000. The Series A Preference Shares rank in priority to the common shares of Eurogas International as to the payment of dividends and the distribution of assets on dissolution, liquidation or winding up of Eurogas International and entitle the Corporation to a fixed preferential cumulative dividend at the rate of 4% per annum. The Corporation may reinvest any dividends received into common shares of Eurogas International, subject to obtaining the necessary approvals. The Series A Preference Shares may be redeemed at the option of the Corporation or may be retracted by Eurogas International at any time at a price equal to their face value of $1.00 per Series A Preference Share.

The Series A Preference Shares are non-voting except in the event Eurogas International fails to pay the cumulative 4% dividend for eight quarters. Thereafter, but only so long as any dividends on the Series A Preference Shares remain in arrears, the Corporation shall be entitled, voting exclusively and separately as a series, to elect a majority of the members of the Board of Directors of Eurogas International. Notwithstanding the Corporation not receiving any dividends on its investment at December 31, 2013, the Corporation had not exercised its entitlement to elect the majority of the members of the Board of Directors of Eurogas International.

Because of the Corporation's entitlement to demand redemption of the Series A Preference Shares at any time from Eurogas International, the Corporation has classified its investment in Series A Preference Shares as a loan receivable and the associated dividends as interest income. The Corporation has completed an assessment of the fair value of the Series A Preference Shares and has determined that the par value of the Series A Preference Shares and the related accrued income thereon are impaired and accordingly, the Corporation has fully provided against the carrying value of these assets. During the year ended December 31, 2013, the Corporation recognized an impairment loss of $1,286,000 (2012 – $1,286,000) relating to dividends receivable on the Series A Preference Shares.

The Corporation's investments in publicly listed securities have been designated as financial assets at fair value through profit or loss and as such, changes in their fair values are recorded in net earnings. During the year ended December 31, 2013, the Corporation recognized an unrealized gain from changes in fair value relating to publicly listed equity securities of $24,000 (2012 – loss of $38,000).

During the year ended December 31, 2013, the Corporation acquired a 31% interest in Windiga Energy Inc. (formerly SMF Energy Inc.) ("Windiga") for $1,075,000. The Corporation has determined that it does not have significant influence over the operating and financial policies of Windiga and accordingly, the Corporation is accounting for its investment in Windiga as a financial instrument at fair value through profit or loss. As Windiga is a private enterprise and its fair value cannot be reliably measured, the Corporation's investment in Windiga is carried at cost.

7. OIL AND GAS PROPERTIES

Transactions During the Year Ended December 31, 2013

On July 5, 2013, the Corporation entered into a transaction pursuant to which it acquired an additional 20% working interest in certain offshore gas properties in southern Ontario, increasing its working interest to approximately 85%. The increase in working interest was acquired for aggregate cash consideration of $4,893,000.

On September 10, 2013, the Corporation entered into an asset exchange agreement pursuant to which it acquired certain seismic data and certain other oil producing assets in exchange for the transfer of its working interests in certain other oil producing assets and certain property, plant and equipment. The Corporation realized a net gain of $337,000 from the exchange of property, plant and equipment which has been included in *"interest and other income"* on the Corporation's consolidated statements of operations.

A summary of the allocation of the aggregate consideration transferred to the fair value of the net assets acquired in the above transactions is summarized below.

	Transaction on July 5, 2013	Transaction on September 10, 2013	TOTAL
Net assets acquired			
Oil and gas development costs	$ 10,035	$ 344	$ 10,379
Pipeline infrastructure	734	-	734
Machinery and equipment	535	-	535
Land and buildings	103	-	103
Undeveloped properties	12	642	654
	11,419	986	12,405
Decommissioning liability	(6,526)	(68)	(6,594)
	$ 4,893	$ 918	$ 5,811
Aggregate consideration transferred:			
Cash	$ 4,893	$ -	$ 4,893
Transfer of interests in property, plant and equipment	-	918	918
	$ 4,893	$ 918	$ 5,811

Impairment of Oil and Gas Properties

During the year ended December 31, 2013, the Corporation recognized an impairment of $3,500,000 on an oil property and its related CGU. The impairment charge reflects a reduction in reserves and associated expected future production volumes from the oil property.

The recoverable amount of the impaired CGU was determined by calculating its value-in-use. In determining the CGU's value-in-use, the Corporation considered expected cash flows based on its most recent externally evaluated reserves reports and long-term views on commodity prices. In computing the recoverable amount, expected future cash flows were discounted using a discount rate of 8%.

Selected key price forecasts used to determine the recoverable amount of the Corporation's oil and gas properties were as follows:

	Natural Gas	Oil
		Edmonton Par
	Union Parkway	(delivered to Sarnia, ON)
Reserve Prices	CDN$ / Mcf	CDN$ / bbl
2014	4.50	99.55
2015	4.75	96.10
2016	4.90	99.00
2017	5.10	98.60
2018	5.35	99.40
Average five year forecast	4.92	98.53

In the prior year, the Corporation recognized an impairment of $15,500,000 on certain gas properties and their related CGUs, reflecting a reduction in forecasted natural gas prices as at December 31, 2012. The Corporation has determined that the forecasted improvements in the price of natural gas since December 31, 2012 are not of significant magnitude to recognize a reversal of the impairment previously recognized by the Corporation.

Property, Plant and Equipment as at December 31, 2013

	Property, Plant and Equipment					*Exploration and Evaluation*	
	Oil and Gas Development Costs	Pipeline Infrastructure	Machinery and Equipment	Land and Buildings	Other	Undeveloped Properties	TOTAL
At December 31, 2011							
Cost	$ 130,470	$ 25,317	$ 23,429	$ 4,580	$ 2,754	$ 7,928	$ 194,478
Accumulated depreciation and depletion	(17,139)	(2,959)	(1,842)	(37)	(817)	-	(22,794)
Net carrying value, December 31, 2011	113,331	22,358	21,587	4,543	1,937	7,928	171,684
Year ended December 31, 2012							
Carrying value December 31, 2011	113,331	22,358	21,587	4,543	1,937	7,928	171,684
Net additions	3,630	286	3,592	-	555	4,739	12,802
Remeasure decommissioning liability (Note 9)	467	-	-	-	-	-	467
Depreciation and depletion	(11,775)	(1,737)	(1,344)	(26)	(121)	-	(15,003)
Impairment	(15,500)	-	-	-	-	-	(15,500)
Net carrying value, December 31, 2012	90,153	20,907	23,835	4,517	2,371	12,667	154,450
At December 31, 2012							
Cost	134,567	25,603	27,021	4,580	3,309	12,667	207,747
Accumulated depreciation, depletion and impairment	(44,414)	(4,696)	(3,186)	(63)	(938)	-	(53,297)
Net carrying value, December 31, 2012	90,153	20,907	23,835	4,517	2,371	12,667	154,450
Year ended December 31, 2013							
Carrying value December 31, 2012	90,153	20,907	23,835	4,517	2,371	12,667	154,450
Acquisitions	10,379	734	535	103	-	654	12,405
Net additions	4,236	916	(214)	40	(265)	7,376	12,089
Remeasure decommissioning liability (Note 9)	(7,422)	-	-	-	-	-	(7,422)
Depreciation and depletion	(9,422)	(1,421)	(1,535)	(29)	(155)	-	(12,562)
Impairment	(3,500)	-	-	-	-	-	(3,500)
Net carrying value, December 31, 2013	84,424	21,136	22,621	4,631	1,951	20,697	155,460
At December 31, 2013							
Cost	140,767	27,253	27,236	4,721	3,041	20,697	223,715
Accumulated depreciation, depletion and impairment	(56,343)	(6,117)	(4,615)	(90)	(1,090)	-	(68,255)
Net carrying value, December 31, 2013	$ 84,424	$ 21,136	$ 22,621	$ 4,631	$ 1,951	$ 20,697	$ 155,460

8. BANK LOAN

DELP has established a credit facility for $70,000,000 (2012 – $70,000,000) with a Canadian Schedule I Chartered Bank. The credit facility provides DELP with a revolving demand loan, subject to a tiered interest rate structure based on DELP's net debt to cash flow ratio, as defined in the credit facility. On July 31, 2013, the interest rate structure of DELP's credit facility was amended, increasing the interest rate on loans or letters of credit to the bank's prime lending rate plus 3.5% from the bank's prime lending rate plus 3.0%; or, for bankers' acceptances, to the bank's then prevailing bankers' acceptance rate plus 4.5% from the bank's then prevailing bankers' acceptance rate plus 4.0%. The amended agreement provides for a standby fee of 0.55% on unused amounts under the credit facility, an increase from a standby fee of 0.50% prior to the amendment.

The credit facility is secured against all of the oil and natural gas properties owned by DELP. In addition, the Corporation has assigned a limited recourse guarantee of its units in DELP as further security pursuant to the credit facility. The credit facility is subject to certain covenants, including maintenance of minimum levels of working capital. At December 31, 2013, the Corporation was in compliance with all such covenants.

As at December 31,		2013		2012
Prime rate loans	$	1,200	$	3,100
Bankers' acceptances		65,000		60,000
Less: Unamortized discount		(491)		(467)
	$	65,709	$	62,633
Letter of credit	$	-	$	3,270

At December 31, 2013, DELP had drawn $66,200,000 (2012 – $66,370,000) pursuant to the credit facility. Available credit under the credit facility at December 31, 2013 was $3,800,000. During the year ended December 31, 2013, the Corporation incurred interest expense relating to the credit facility, including bank charges, arrangement fees and standby fees, of $3,637,000 (2012 – $3,642,000).

9. DECOMMISSIONING LIABILITIES

The carrying amount of the Corporation's decommissioning liabilities is comprised of the expected future abandonment and site restoration costs associated with its oil and gas properties. Abandonment and site restoration costs are based on the Corporation's net ownership in the underlying wells and facilities, the estimated cost to abandon these wells and facilities and the estimated timing of the costs to be incurred in future periods.

As at December 31,		2013		2012
Undiscounted future obligations, beginning of year	$	81,278	$	83,739
Effect of acquisitions (Note 7)		12,544		-
Effect of changes in estimates		(749)		(1,468)
Liabilities settled (reclamation expenditures)		(1,320)		(993)
Undiscounted future obligations, end of year	$	91,753	$	81,278

Changes in the Corporation's estimate of its decommissioning liabilities on an undiscounted basis reflect the impact of inflation to the timing of abandonment and site restoration costs.

The following reconciles the Corporation's decommissioning liabilities on a discounted basis:

As at December 31,		2013		2012
Discount rates applied to future obligations		*1.10% - 3.09%*		*1.13% - 2.27%*
Inflation rate		*2.00%*		*2.00%*
Discounted future obligations, beginning of year	$	44,705	$	44,288
Effect of acquisitions (Note 7)		5,790		-
Effect of changes in estimates and				
remeasurement of discount rates		(7,422)		467
Liabilities settled (reclamation expenditures)		(1,320)		(993)
Accretion (interest expense)		947		943
Discounted future obligations, end of year	$	42,700	$	44,705
Current	$	1,284	$	1,796
Non-current		41,416		42,909
	$	42,700	$	44,705

As required by statute, the Corporation has provided a security deposit to the Ontario Ministry of Natural Resources in the amount of $270,000 in respect of future abandonment costs.

10. RISK MANAGEMENT CONTRACTS

During the year ended December 31, 2013, the Corporation had entered into risk management contracts. These derivative instruments were not designated in a qualifying hedge relationship and accordingly, they were classified as financial instruments *"at fair value through profit or loss"* and were measured at fair value with changes in fair value recorded in net earnings in the period in which they occurred.

The Corporation has determined that the fair value of risk management contracts at December 31, 2013 resulted in a liability balance of $92,000 (2012 – asset balance of $215,000). All outstanding risk management contracts entered into by the Corporation expired on December 31, 2013 and were settled at their fair value in January 2014.

During the year ended December 31, 2013, the Corporation recognized a loss of $581,000 (2012 – gain of $2,527,000) from changes in the fair value of risk management contracts. The loss recognized during the current year includes a loss of $313,000 following the cancellation of natural gas fixed price contracts representing 3,750 mbtu/day.

11. SHARE CAPITAL

Issued and Outstanding

					Contributed Surplus		
	Number of Common Shares Outstanding		Share Capital		Option Reserve		DSUP Reserve
Outstanding, December 31, 2011	164,675,147	$	104,854	$	6,051	$	580
Transactions during the year ended December 31, 2012							
Stock based compensation	-		-		316		139
Redeemed pursuant to issuer bid	(23,500)		(16)		-		-
Outstanding, December 31, 2012	164,651,647		104,838		6,367		719
Transactions during the year ended December 31, 2013							
Stock based compensation	30,874		11		253		136
Shares issued pursuant to rights offering	5,734,067		1,950		-		-
Flow-through shares issued pursuant to rights offering	17,787,596		6,937		-		-
Deferred tax recognized on flow-through shares (Note 16)	-		(889)		-		-
Issue costs associated with rights offering	-		(301)		-		-
Deferred tax recognized on issue costs (Note 16)	-		80		-		-
Outstanding, December 31, 2013	188,204,184	$	112,626	$	6,620	$	855

Authorized
The authorized capital of the Corporation consists of an unlimited number of common shares without nominal or par value and an unlimited number of preferred shares without nominal or par value, issuable in series.

Rights Offering
On April 5, 2013, the Corporation completed a rights offering for aggregate gross proceeds of $8,887,000. Pursuant to the rights offering, the Corporation issued 5,734,067 common shares at a price of $0.34 per common share and it issued 17,787,596 flow-through common shares at a price of $0.39 per flow-through common share. The Corporation incurred costs of $301,000 to complete the rights offering. As at December 31, 2013, the Corporation had incurred $6,937,000 of expenses available for renunciation to flow-through common shareholders.

The Corporation initially included a share premium liability of $889,000 in "*Accounts payable and accrued liabilities*", representing the premium paid for the flow-through benefit associated with the issuance of flow-through common shares pursuant to the rights offering. The share premium liability was amortized to income and was recognized as "*current income tax expense*" in the statement of operations, as the associated expenditures were incurred and renounced by the Corporation (Note 16).

Normal Course Issuer Bid
On May 3, 2013, the Corporation announced that it had received regulatory approval for the renewal of its normal course issuer bid from May 6, 2013 to May 5, 2014. Subject to certain conditions, the Corporation may purchase up to a maximum of 9,408,665 common shares pursuant to these arrangements, representing approximately 5% of its common shares outstanding immediately prior to approval of the normal course issuer bid.

The Corporation did not purchase any common shares for cancellation during the year ended December 31, 2013. During the prior year ended December 31, 2012, the Corporation purchased 23,500 common shares, having an aggregate stated capital value of $16,000 for cancellation pursuant to these arrangements. The Corporation paid $16,000 or $0.61 per share to retire these shares.

Issuance of Shares Pursuant to Share Incentive Arrangements
On June 28, 2013, the Corporation issued 30,874 common shares pursuant to the share bonus component of its share incentive plan (Note 12). The Corporation incurred compensation expense of $20,000 in respect of the issuance of shares pursuant to these arrangements, including $9,000 in associated income taxes.

12. STOCK BASED COMPENSATION

Stock Option Plan
The shareholders of the Corporation have approved a share incentive plan (the "SIP") pursuant to which the Corporation may issue up to 15,611,845 common shares of the Corporation to employees, directors and officers. Included in the SIP is a stock option plan component. The exercise price of each option issued pursuant to the terms of the SIP shall be established at the grant date by the directors of the Corporation and in all cases shall not be less than the closing price of the common shares of the Corporation on the trading day immediately preceding the grant date. Options are generally issued with a five-year term from the date of grant and are subject to vesting conditions whereby one third of the options granted vest immediately, with the remaining two thirds vesting over a two year period.

During the year ended December 31, 2013, the Corporation granted 2,090,000 (2012 – 400,000) stock options at an exercise price of $0.50 (2012 – $0.60) per option. The fair value of the options granted was $0.20 (2012 – $0.31) per option and was estimated at the grant date using an option pricing model with the following assumptions:

	2013	2012
Risk free interest rate	1.03%	1.30%
Expected dividend yield	0.00%	0.00%
Expected volatility	62.00%	71.00%
Expected life of the options	3 to 5 years	3 to 5 years

A summary of the status of the stock option component of the Corporation's SIP as at December 31, 2013 and 2012 and the changes during the years then ended is as follows:

For the years ended December 31,		2013		2012
	Stock Options	Weighted Average Exercise Price	Stock Options	Weighted Average Exercise Price
Options outstanding, beginning of year	3,815,000	$ 0.77	5,665,000	$ 0.92
Granted	2,090,000	0.50	400,000	0.60
Forfeited	(300,000)	0.63	(2,250,000)	1.12
Options outstanding, end of year	5,605,000	$ 0.68	3,815,000	$ 0.77
Exercisable options	4,078,326	$ 0.74	3,548,332	$ 0.79

Option Price	Options Outstanding	Options Exercisable	Contractual Life Remaining (Years)
At $0.50	2,090,000	696,660	4.70
At $0.60	400,000	266,666	3.34
At $0.81	3,115,000	3,115,000	1.83

During the year ended December 31, 2013, the Corporation recognized stock based compensation expense of $253,000 (2012 – $316,000) in respect of outstanding stock options.

Deferred Share Unit Plan

The Corporation has established a deferred share unit plan ("DSUP") pursuant to which directors, officers, employees and consultants of the Corporation or any affiliate of the Corporation may be granted deferred share units. The Compensation Committee of the Board of Directors administers the DSUP, which is intended to provide participants with a long-term incentive tied to the long-term performance of the Corporation's common shares. Discretionary awards will be based on certain criteria, including services performed or to be performed.

The total number of deferred share units cannot exceed 4,000,000. During the year ended December 31, 2013, the Corporation issued 380,507 (2012 – 341,480) deferred share units with a fair value on the date of issuance of $136,000 (2012 – $139,000). The deferred share units were issued in settlement of outstanding directors' fees payable. At December 31, 2013, the Corporation had 1,325,817 (2012 – 945,310) deferred share units outstanding.

The Corporation's deferred share units have no vesting period and may only be redeemed by the recipient upon retirement from the Corporation. The terms of the deferred share units provide for the issuance of shares to the recipient in settlement of these awards, subject to the necessary regulatory approvals.

For the years ended December 31,	2013	2012
Number of deferred share units outstanding, beginning of year	945,310	603,830
Granted	380,507	341,480
Number of deferred share units outstanding, end of year	1,325,817	945,310

13. GENERAL AND ADMINISTRATIVE EXPENSES AND PRODUCTION EXPENDITURES BY NATURE

General and Administrative Expenses

For the years ended December 31,		2013		2012
Salary and salary-related	$	4,017	$	4,287
Stock based compensation		389		455
Corporate and professional fees		2,095		2,712
General office		1,692		1,542
Exploration and development costs		1,299		1,022
Capitalization of general and administrative costs		(3,592)		(2,974)
	$	5,900	$	7,044

The Corporation's working interest arrangements provide for an overhead allocation of general and administrative charges, based on a pre-determined formula as outlined in a working interest agreement. These formulas are generally determined as a percentage of production expenditures.

Production Expenditures

For the years ended December 31,		2013		2012
Labour	$	3,742	$	4,116
Materials, equipment and supplies used		6,540		4,414
Transportation		1,340		1,317
Utilities		1,851		1,795
Rental and lease payments		710		933
Other		807		908
	$	14,990	$	13,483

14. EQUITY ACCOUNTED INVESTMENT IN ESCAL

The Corporation's 74% owned subsidiary, CLP, holds a 33% interest in Escal, the owner of the Castor underground gas storage project located in Spain. The remaining interest in Escal is held by ACS Servicios Comunicaciones y Energia, S.L. ("ACS"). The Corporation accounts for its investment in Escal using the equity method.

The following table summarizes financial information about Escal's assets and liabilities as at and for the years ended December 31, 2013 and 2012. As the Corporation only has significant influence, it is unable to obtain reliable information at year-end on a timely basis. The Corporation has included in its consolidated financial statements, equity accounted information based on the most recent audited annual financial statements or unaudited interim financial statements prepared by Escal, all within three months of the year-end of the Corporation. Adjustments are made to reflect material transactions and events in the intervening period. For purposes of the following disclosure, the assets and liabilities of Escal have been translated using prevailing foreign exchange rates at the dates of the consolidated statements of financial position.

As at and for the years ended December 31,		2013		2012
Assets	$	2,496,348	$	1,983,912
Liabilities		(2,540,542)		(2,047,754)
Net liabilities	$	(44,194)	$	(63,842)

As Escal is in the pre-commissioning phase, amounts in net earnings and other comprehensive income are not meaningful and have therefore not been included in the above table.

In accordance with the memorandum of understanding between the shareholders of Escal, ACS is obligated to provide all equity or quasi-equity funding, as may be required pursuant to the project financing agreement. Notwithstanding ACS's obligation to provide such equity financing, CLP retains a 33% interest in all distributions out of Escal, including distributions that may be made through repayment by Escal of amounts owing pursuant to subordinated and/or participating loan arrangements.

In order to comply with minimum equity to debt ratio requirements, ACS has contributed an issuance premium on newly issued shares of €40,861,000 and Escal issued €64,200,000 in subordinated loans. CLP has not recognized the benefit of its 33% interest in the issuance premium and subordinated loans as the ultimate realization and measurement of the benefit is subject to a significant number of risks and uncertainties, including but not limited to the conclusion of the commissioning of the project and receipt of remuneration.

Refinancing of the Castor Project
On July 26, 2013, Escal announced that it had arranged for the issuance of euro-denominated senior secured bonds (the "Euro Bonds") totalling €1.40 billion. The Euro Bonds are subject to an annual interest rate of 5.756%, payable semi-annually, and are repayable in equal semi-annual installments over a period of 21 and a half years, with the last payment due in December 2034. The Euro Bonds are listed on the Luxembourg stock exchange.

The Euro Bonds were issued by a special purpose vehicle, Watercraft Capital S.A. ("Watercraft"), a Luxembourg corporation. The proceeds from the issuance were subsequently on-lent to Escal, pursuant to a credit facility between Watercraft and Escal, and have been used by Escal to repay amounts owing pursuant to Escal's previously existing bank-funded project financing arrangements. In order to facilitate the issuance of the Euro Bonds, CLP initially advanced €31,000 to Watercraft, which amount was subsequently returned to CLP upon completion of the Euro Bond issuance. CLP does not retain any equity interest in Watercraft, nor does it have any ongoing obligations or commitments in respect of Watercraft.

Escal has provided a general security interest against its assets for the benefit of Watercraft to secure Escal's obligations under these arrangements, and the shareholders of Escal have pledged their respective shares in Escal as part of the overall security package. In addition, the European Investment Bank has provided a standby letter of credit as a form of subordinated credit enhancement instrument in support of the Euro Bonds.

Prior to the issuance of the Euro Bonds, Escal had established a hedging strategy to mitigate its exposure to interest rate risk associated with its project financing arrangements. Following completion of the issuance of the Euro Bonds, Escal paid cash to cancel all outstanding hedging strategies. Recognition of these amounts paid to settle the hedging instruments draws the Corporation's carrying value in Escal to zero. At December 31, 2013, the Corporation had not recorded a liability of $34,096,000 (2012 – $38,552,000) related to additional losses incurred by Escal, as it does not have the legal or constructive obligation in respect thereof.

15. NET LOSS PER SHARE

For the years ended December 31,		2013		2012
Net loss for the year attributable to owners of the parent	$	(6,184)	$	(16,623)
Weighted average number of common shares outstanding		182,131,494		164,653,361
Basic and diluted net loss per common share	$	(0.03)	$	(0.10)

16. INCOME TAXES

During the year ended December 31, 2013, the Corporation recognized an income tax recovery of $782,000 (2012 – $5,900,000), the major components of which include the following items:

For the years ended December 31,	2013	2012
Current income tax expense		
Current year resource tax	$ -	$ 70
Adjustments in respect of prior years	5	93
	5	163
Deferred income tax recovery		
Origination and reversal of timing differences	102	(6,118)
Flow-through share premuim	(889)	-
Adjustments in respect of prior years	-	55
	(787)	(6,063)
Income tax recovery	$ (782)	$ (5,900)

The income tax amounts on the Corporation's loss before income taxes differs from the income tax amount that would arise using the combined Canadian federal and provincial statutory tax rate of 26% (2012 – 26%) as a result of the following items:

For the years ended December 31,	2013	2012
Loss before tax at statutory rate of 26% (2012 – 26%)	$ (1,860)	$ (5,985)
Effect on taxes of:		
Non-deductible expenses	122	43
Renounced exploration expenses	1,838	-
Flow-through share premium amortization	(889)	-
Net income tax not previously recognized	5	148
Changes in substantively enacted income tax rates	-	(177)
Other differences	2	71
Income tax recovery	$ (782)	$ (5,900)

Deferred tax assets arise from available income tax loss carry forwards and future income tax deductions. A deferred tax asset is recognized when management believes it is more likely than not that the benefit will be recognized.

The movement in the deferred income tax assets and liabilities during the year, and the net components of the Corporation's net deferred income tax assets are as follows:

Deferred Tax Assets	Loss Carry Forwards	Oil and Gas Properties	Decomm-issioning Liability	Cumulative Eligible Capital	Share Issue Costs	Other	TOTAL
Balance, December 31, 2011	$ 12	$ 2,004	$ 978	$ 178	$ 46	$ 481	$ 3,699
(Charged) credited to the statement of operations	26	4,878	838	(3)	(35)	(2)	5,702
(Charged) credited to the statement of comprehensive loss	-	-	-	-	-	32	32
Balance, December 31, 2012	$ 38	$ 6,882	$ 1,816	$ 175	$ 11	$ 511	$ 9,433
(Charged) credited to the statement of operations	(38)	(474)	373	(12)	(28)	25	(154)
(Charged) credited to shareholders' equity	-	-	-	-	80	-	80
Balance, December 31, 2013	$ -	$ 6,408	$ 2,189	$ 163	$ 63	$ 536	$ 9,359

Deferred Tax Liabilities	Flow-Through Shares	Equity Accounted Investment	Other	TOTAL
Balance, December 31, 2011	$ -	$ (84)	$ (433)	$ (517)
(Charged) credited to the statement of operations	-	(5)	366	361
Balance, December 31, 2012	$ -	$ (89)	$ (67)	$ (156)
(Charged) credited to the statement of operations	889	-	52	941
(Charged) credited to accounts payable	(889)	-	-	(889)
Balance, December 31, 2013	$ -	$ (89)	$ (15)	$ (104)

As at December 31, 2013, the Corporation had no operating loss carry forwards (2012 – $143,000).

17. RELATED PARTY TRANSACTIONS

Other than as disclosed elsewhere in these 2013 Consolidated Financial Statements, related party transactions and balances as at and for the years ended December 31, 2013 and 2012 are as described below.

Services Arrangement with Dundee Resources Limited

Dundee Resources Limited, a wholly owned subsidiary of Dundee Corporation, provides the Corporation with administrative support services as well as geophysical, geological and engineering consultation with regard to the Corporation's activities. During the year ended December 31, 2013, the Corporation incurred costs of $1,393,000 (2012 – $2,109,000) in respect of these arrangements.

Accounts Payable and Accrued Liabilities

Included in accounts payable and accrued liabilities at December 31, 2013 are amounts owing to the Corporation's parent, Dundee Corporation, and to Dundee Corporation's subsidiaries of $973,000 (2012 – $762,000).

Financial Services

Officers, directors and employees of the Corporation and other related parties may make use of the facilities of Dundee Securities Limited ("DSL"), a full-service investment dealer, and a subsidiary of Dundee Corporation. In addition, certain of the Corporation's incentive compensation arrangements and the purchase of its common shares for cancellation pursuant to its normal course issuer bid may be administered by DSL. Transactions with DSL are conducted on normal market terms and are recorded at their exchange value.

Key Management Compensation

Compensation and other fees paid to directors of the Corporation and to the President and Chief Executive Officer of the Corporation during the years ended December 31, 2013 and 2012 are shown below:

For the years ended December 31,		2013		2012
Directors' fees and executive consulting	$	562	$	548
Stock based compensation		153		193
Benefits		25		26
	$	740	$	767

During the prior year ended December 31, 2012, the Corporation paid $500,000 to a director of Dundee Corporation in respect of the director's involvement in the Castor underground gas storage project (Note 14).

18. COMMITMENTS

The Corporation and its subsidiaries have lease agreements for premises and equipment pursuant to which future minimum annual lease payments, exclusive of operating costs and realty taxes, are as follows:

As at December 31,		2013		2012
Less than 1 year	$	317	$	334
Between 1 and 5 years		465		392
Thereafter		-		-

19. FINANCIAL INSTRUMENTS

Measurement Categories

The Corporation's financial instruments have been classified into categories that determine their basis of measurement and, for items at fair value, whether changes in fair value are recognized in the consolidated statement of operations or in OCI.

The following table illustrates the carrying values of financial instruments and their classification. At December 31, 2013 and 2012, the carrying value of the Corporation's financial instruments approximated their fair value.

As at December 31,	2013	2012
Financial Assets		
Fair value through profit or loss		
Investments	$ 1,340	$ 241
Risk management contracts	-	215
Loans and receivables		
Cash	111	125
Accounts receivable	4,807	3,775
Financial Liabilities		
Fair value through profit or loss		
Risk management contracts	(92)	-
Amortized cost		
Bank loan	(65,709)	(62,633)
Accounts payable and accrued liabilities	(5,230)	(5,340)

Fair Value of Financial Instruments

The Corporation classifies the fair value of its financial instruments according to the following hierarchy, which is based on the amount of observable inputs used to value the instrument:

- Level 1 – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 – inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 – inputs to the valuation methodology are unobservable and significant to the fair value measurement.

The following table classifies financial instruments that are recognized in the Corporation's consolidated statement of financial position at fair value in accordance with the fair value hierarchy described above.

As at December 31,	2013	2012
Level 1		
Fair value through profit or loss		
Investment in publicly listed securities	$ 265	$ 241
Level 2		
Fair value through profit or loss		
Investment in private enterprises	1,075	-
Risk management contracts	(92)	215

Risk Management

The Corporation is exposed to financial risks due to the nature of its business and the financial assets and liabilities that it holds. The Corporation's overall risk management strategy seeks to minimize potential adverse effects on the Corporation's financial performance.

Credit Risk

Credit risk is the risk that one party to a financial instrument will cause a financial loss for the other party by failing to discharge an obligation.

The Corporation's accounts receivable are with customers for its oil and gas production, with its working interest partners in oil and natural gas development and production activities and with third parties. In addition, included in accounts receivable is a loan receivable from Escal, the Corporation's equity accounted investment. These amounts expose the Corporation to risk for non-payment. The Corporation's maximum exposure to credit risk relating to these items approximates the carrying amount of these assets on the Corporation's consolidated statement of financial position.

The Corporation currently markets its production to customers with investment grade credit ratings. Otherwise, the Corporation may seek parental guarantees and/or letters of credit prior to transacting with such customers.

The majority of the Corporation's revenue is from four core customers, who individually accounted for 57%, 20%, 12% and 9% (2012 – 66%, 14%, 10% and 8%) of total revenue. Of the Corporation's individual accounts receivable due from customers, approximately 49% (2012 – 58%) was due from one marketer.

Amounts receivable from working interest partners and from other third parties represent receivables from other participants in the oil and natural gas sector, and collection of the outstanding balances may be dependent on industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling. The Corporation attempts to mitigate the credit risk on receivables from working interest partners by obtaining pre-approval of significant capital expenditures. Where the Corporation is the operator of properties, it has the ability to withhold production from working interest partners in the event of non-payment.

Market Risk

Market risk is the risk that the fair value of a financial instrument will fluctuate because of changes in market prices. For purposes of this disclosure, the Corporation segregates market risk into three categories: currency risk, fair value risk and interest rate risk.

Currency Risk

Currency risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in foreign exchange rates. The Corporation is exposed to the risk of changes in the Canadian to U.S. dollar exchange rate on sales of natural gas. A 3% change in the foreign exchange translation rate of Canadian to U.S. dollars would result in a change to net earnings of approximately $532,000 (2012 – $341,000), before associated income taxes.

The Corporation also has foreign exchange exposure to the Euro through amounts advanced to Escal. A 3% change in the foreign exchange translation rate of Euros to Canadian dollars would result in a change to net earnings of approximately $34,000 (2012 – $29,000), before associated income taxes.

The Corporation's investment in Escal had been reduced to zero during the year ended December 31, 2011 and therefore, at December 31, 2013 and 2012, the Corporation was no longer exposed to currency risk in respect of its investment.

Fair Value Risk

Fair value risk is the potential for loss from an adverse movement in market prices of financial instruments, excluding movements relating to changes in interest rates and foreign exchange currency rates. Fair value risk includes commodity price risk, which is the risk that future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices are influenced by global levels of supply and demand and when realized, may be further impacted by changes in the Canadian and U.S. dollar exchange rate. Significant commodity price fluctuations may materially impact the Corporation's borrowing base under its bank loan, or its ability to raise additional capital, if required.

In order to mitigate its exposure to adverse changes in commodity prices, the Corporation has entered into risk management contracts (Note 10). These risk management contracts are recognized in the consolidated financial statements at fair value. The fair value of these risk management contracts is primarily driven by prices of the underlying commodities. Accordingly, the Corporation is exposed to fair value risk in respect of these contracts that is partially correlated to changes in commodity prices. A $1.00 change in the price of crude oil on a per barrel basis would result in a change to net earnings of $16,000 (2012 – $16,000) before associated taxes. There are no outstanding natural gas risk management contracts at December 31, 2013 (2012 – $nil).

Interest Rate Risk
Interest rate risk relates to the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market interest rates. The Corporation's primary exposure to interest rate risk is through amounts borrowed under its bank loan arrangements. In general, for every 50 basis point change in market interest rates, net earnings before income taxes would change by approximately $316,000 (2012 – $363,000).

The Corporation also incurs interest rate risk through its holdings of certain investments. The Corporation did not hold any investments in 2013 and 2012 that exposed it to interest rate risk.

Liquidity Risk
Liquidity risk is the risk that the Corporation will encounter difficulty in meeting obligations associated with financial liabilities as they become due. The Corporation's financial liabilities are comprised of amounts due pursuant to its bank loan arrangements, as well as accounts payable and accrued liabilities. The following table summarizes the maturity profile of the Corporation's financial liabilities as at December 31, 2013.

	Carrying Amount	Contractual Term to Maturity
Bank loan	$ 65,709	Demand facility
Accounts payable and accrued liabilities	5,230	Typically due within 20 to 90 days
Derivative financial liabilities	92	Expected settlement in January 2014
Current portion of decommissioning liabilities	1,284	Expected settlement in 2014
	$ 72,315	

Draws against the Corporation's bank loan arrangements are due on demand. The Corporation anticipates that amounts pursuant to the facility will be available on a revolving basis until July 31, 2014, after which the Corporation may request annual renewal periods, subject to approval by the lender. At December 31, 2013, the Corporation was in compliance with all required financial covenants pursuant to its bank loan arrangements.

The Corporation mitigates liquidity risk by monitoring operational cash flows, planning its project expenditures and securing financing facilities in advance of undertaking significant commitments. The Corporation anticipates that it will continue to have adequate liquidity to fund its financial liabilities through its future cash flows.

Capital Management
The Corporation defines the capital that it manages as its working capital. The Corporation's objectives when managing capital are to manage its business in an effective manner with the goal of increasing the value of its assets. The Corporation regularly monitors its available capital and as necessary, adjusts to changing economic circumstances and the risk characteristics of the underlying assets. In order to maintain or adjust capital requirements, the Corporation may consider the issuance of new shares, the entry into joint venture arrangements or farmout agreements, or engage in debt financing.

20. GEOGRAPHIC SEGMENTED INFORMATION

Segmented information is provided based on geographic segments, consistent with how the Corporation manages its business and how it reviews business performance. Items that are not directly attributable to specific geographic locations have been allocated to the corporate segment.

Segmented Statements of Operations for the years ended December 31, 2013 and December 31, 2012

	Southern Ontario		Spain		Corporate		TOTAL	
	2013	2012	2013	2012	2013	2012	2013	2012
REVENUES								
Oil and gas sales	$ 39,174	$ 35,874	$ -	$ -	$ -	$ -	$ 39,174	$ 35,874
Royalties	(5,966)	(5,391)	-	-	-	-	(5,966)	(5,391)
Net sales	33,208	30,483	-	-	-	-	33,208	30,483
Production expenditures	(14,990)	(13,483)	-	-	-	-	(14,990)	(13,483)
Depreciation and depletion	(12,555)	(14,993)	-	-	(7)	(10)	(12,562)	(15,003)
General and administrative	(3,516)	(4,683)	(339)	(219)	(2,045)	(2,142)	(5,900)	(7,044)
(Loss) gain on fair value changes of risk management contracts	(581)	2,527	-	-	-	-	(581)	2,527
Gain (loss) on fair value changes in financial instruments	-	-	-	-	24	(38)	24	(38)
Impairment of oil and gas properties	(3,500)	(15,500)	-	-	-	-	(3,500)	(15,500)
Impairment of financial instruments	-	-	-	-	(1,286)	(1,286)	(1,286)	(1,286)
Interest and other income	1,590	174	-	-	1,295	1,294	2,885	1,468
Interest expense	(4,584)	(4,585)	-	(1)	(4)	(2)	(4,588)	(4,588)
Foreign exchange gain (loss)	154	(110)	113	(6)	-	-	267	(116)
LOSS BEFORE INCOME TAXES	(4,774)	(20,170)	(226)	(226)	(2,023)	(2,184)	(7,023)	(22,580)
Income tax (expense) recovery								
Current	-	-	-	-	(5)	(163)	(5)	(163)
Deferred	-	-	-	-	787	6,063	787	6,063
	-	-	-	-	782	5,900	782	5,900
NET (LOSS) EARNINGS FOR THE YEAR	$ (4,774)	$ (20,170)	$ (226)	$ (226)	$ (1,241)	$ 3,716	$ (6,241)	$ (16,680)
NET (LOSS) EARNINGS ATTRIBUTABLE TO:								
Owners of the parent	$ (4,774)	$ (20,170)	$ (169)	$ (169)	$ (1,241)	$ 3,716	$ (6,184)	$ (16,623)
Non-controlling interest	-	-	(57)	(57)	-	-	(57)	(57)
	$ (4,774)	$ (20,170)	$ (226)	$ (226)	$ (1,241)	$ 3,716	$ (6,241)	$ (16,680)

Segmented Net Assets as at December 31, 2013 and December 31, 2012

	Southern Ontario		Spain		Corporate		TOTAL	
	2013	2012	2013	2012	2013	2012	2013	2012
ASSETS								
Current								
Cash	$ 25	$ 76	$ 15	$ 7	$ 71	$ 42	$ 111	$ 125
Accounts receivable	3,683	2,809	1,124	966	-	-	4,807	3,775
Prepaids and security deposits	1,214	1,195	3	3	-	-	1,217	1,198
Inventory	333	350	-	-	-	-	333	350
Investments	-	-	-	-	1,340	241	1,340	241
Derivative financial assets	-	215	-	-	-	-	-	215
Taxes recoverable (payable)	-	-	-	-	72	(25)	72	(25)
	5,255	4,645	1,142	976	1,483	258	7,880	5,879
Non-current								
Oil and gas properties	155,414	154,397	-	-	46	53	155,460	154,450
Equity accounted investment in Escal	-	-	-	-	-	-	-	-
Deferred income taxes	-	-	-	-	9,255	9,277	9,255	9,277
	$ 160,669	$ 159,042	$ 1,142	$ 976	$ 10,784	$ 9,588	$ 172,595	$ 169,606
LIABILITIES								
Current								
Bank loan	$ 65,709	$ 62,633	$ -	$ -	$ -	$ -	$ 65,709	$ 62,633
Accounts payable and accrued liabilities	3,777	4,029	22	29	1,431	1,282	5,230	5,340
Derivative financial liabilities	92	-	-	-	-	-	92	-
Decommissioning liabilities	1,284	1,796	-	-	-	-	1,284	1,796
	70,862	68,458	22	29	1,431	1,282	72,315	69,769
Non-current								
Decommissioning liabilities	41,416	42,909	-	-	-	-	41,416	42,909
	$ 112,278	$ 111,367	$ 22	$ 29	$ 1,431	$ 1,282	$ 113,731	$ 112,678
SEGMENTED NET ASSETS	$ 48,391	$ 47,675	$ 1,120	$ 947	$ 9,353	$ 8,306	$ 58,864	$ 56,928

Dundee Energy Limited
250-435-4th Avenue SW
Calgary, Alberta
T2P 3A8
Canada

www.dundee-energy.com

Registrar and Transfer Agent
Computershare Investor Services Inc.
100 University Avenue, 8th Floor
Toronto, Ontario M5J 2Y1
Toll Free: 1.800.564.6253
Email: service@computershare.com

Stock Exchange
Toronto Stock Exchange

Stock Symbol
DEN