2012 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".

This Management's Discussion and Analysis ("MD&A") has been prepared with an effective date of February 15, 2013 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, 2012 (the "2012 Consolidated Financial Statements") 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 2012 Consolidated Financial Statements are 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, as well as to capital expenditure requirements for these activities. 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.

SIGNIFICANT PROJECTS AND BUSINESS DEVELOPMENTS

Dundee Energy holds interests, both directly and indirectly, in the largest 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 holds a 45% participating interest in the Sfax permit located offshore Tunisia (the "Sfax Permit").

The Southern Ontario Assets

Dundee Energy Limited Partnership ("DELP"), a wholly owned limited partnership of the Corporation, holds an approximate 90% working interest in 84,293 acres of onshore oil properties and a 65% working interest in 904,036 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 a 65% ownership interest in certain other assets, including an offshore fleet of drilling and completion barges, and six 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 six onshore processing facilities. The Corporation entered into transportation agreements with pipeline companies and the majority of its natural gas is transferred to the Dawn Hub, which is conveniently located proximate to the Greater Toronto Area, at which point it is sold to third parties.

Sweet, light oil production comes from Ordovician and Silurian ages carbonates at a maximum geological depth of 850 metres. Oil and condensate production is trucked from six oil batteries and several single well locations to Sarnia, Ontario and subsequently sold to a third party.

On August 4, 2011, the Corporation expanded its operations in southern Ontario through the acquisition of 100% of the outstanding common shares of Torque Energy Inc., ("Torque") a Canadian based company engaged in the exploration, development and production activities from oil and natural gas properties. At the time of the acquisition, net production volumes from the Torque assets included 85 bbl/d of oil and condensate as well as 300 Mcf/d of natural gas. The fair value of the purchase consideration for Torque was $7.1 million, including cash of $6.0 million and the issuance of 1,346,926 common shares of the Corporation with a value of $1.1 million. On December 1, 2011, the Corporation completed the integration of the assets and business processes acquired pursuant to the Torque transaction with its existing operations in southern Ontario, providing the Corporation with efficiencies of scale.

In 2013, the Corporation will focus its efforts relating to the Southern Ontario Assets on increasing light oil production and reserves from the Ordovician formation, both from existing pool development and exploration. The Corporation's geophysical program will include the reprocessing of legacy data and the acquisition of new seismic data to improve its understanding of the geological environment and add to the inventory of drillable targets. The Corporation's new drill rig, the *"Dundee Discovery"* is fully operational and future drilling will be faster, less expensive and notably safer than third-party equipment otherwise available in the Ontario market place.

Castor UGS Limited Partnership and the Castor Project

The Corporation has an indirect interest in the Castor Project, a Spanish infrastructure project 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. Strategically located in a high demand region, 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. It will also provide Spain with strategic gas storage, ensuring supply continuity in the event of disruption to its national gas system.

The Castor Project is managed by ACS Servicios Communicacions y Energia S.L. ("ACS"), a large construction group in Spain and 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, 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.

In July 2010, Escal entered into a €1.3 billion project financing arrangement with a syndicate of banks to complete the construction of the Castor Project, including the purchase of cushion gas. In accordance with the agreements with ACS, during the construction phase, and until commissioning of the Castor Project and its formal inclusion into the Spanish gas system, ACS assumed responsibility for all funding of the project, other than that provided directly by the project financing, as may be required. Notwithstanding any additional funding provided by ACS, CLP remains entitled to 33% of all distributions from Escal.

During the second quarter of 2012, the Government of Spain announced certain regulatory modifications to the remuneration regime applicable to underground gas storage facilities. As originally proposed, these regulatory changes would have an unfavourable impact to the Castor Project economics and project financing. As a consequence, the lenders to the Castor Project suspended the undrawn portion of the project financing facility. Escal subsequently entered into discussions with the Government of Spain, with the full knowledge and involvement of the lenders to the project, with a view to finding a solution that would reestablish economic viability of the Castor Project. In December 2012, the Spanish authorities finalized amendments to the remuneration of underground natural gas storage projects, which Escal and its lenders view as being an acceptable solution. Escal is currently in the process of negotiating an amendment to the project financing facility so as to enable the drawdown of the balance of the project financing facility. The key concepts relevant to the Castor Project in the amended regulatory framework are outlined below:

- The capital cost of the Castor Project was to be returned to Escal in equal payments over a 10-year period (the "Amortization Period"), except for the cost of cushion gas, which was to be returned to Escal in equal payments over a 20-year period. After the Amortization Period, payments would continue at half the rate that was paid in the last year of the Amortization Period, and would continue for the remaining productive life of the Castor Project. The recently approved amendments to the remuneration regime extend the Amortization Period for the return of capital to 20 years, adjusted for annual inflation at a rate of 2.5% on any unamortized amount;

- Amendments deemed July 5, 2012, the date of receipt by Escal of the Provisional Commissioning Act, as the end of the capital investment period, other than for cushion gas;

- The basis for the calculation of the remuneration rate remained unchanged. Escal will receive 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%;

- The amendments provide for the segregation of the purchase and subsequent injection of cushion gas from the underlying construction of the project itself, allowing for a third party purchase of cushion gas. If the cushion gas is purchased by a third party, the third party will receive the corresponding remuneration in accordance with the new regulations, and such remuneration will be paid directly to the purchaser of the cushion gas by the Spanish gas system. Escal has recently initiated discussions with a third party for the purchase by the third party of the cushion gas; and

- The period during which Escal has the right to relinquish the Castor Project to the Spanish authorities for any unamortized value has been extended from five years to 25 years.

Final inclusion of the Castor Project into the Spanish gas system remains contingent on the injection of cushion gas, which is expected to be completed in the first half of 2013, followed by the subsequent completion of the necessary performance and control testing, and the conclusion of the audit by the Spanish authorities of the expenditures forming the remuneration basis.

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 its substantial 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 the 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, 2012, the Corporation had not exercised its entitlement to elect the majority of the members of the Board of Directors of Eurogas International.

Eurogas International holds a 45% participating interest, and is the non-operating partner in the Sfax Permit, encompassing approximately 800,000 acres located within a prolific hydrocarbon fairway extending from offshore Libya, through the Gulf of Gabes, to onshore Tunisia, southeast of the city of Sfax. In November 2012, the Tunisian authorities approved a renewal of the Sfax Permit to December 8, 2015 (the “First Renewal Period”). Eurogas International is committed to drilling two exploration wells prior to expiry of the First Renewal Period. The first drilling commitment carries an obligation to drill to the Bireno limestones of the Cretaceous age, while the second drilling commitment must be of sufficient depth to enable an appropriate assessment of potential reserves. The actual cost of drilling these wells will depend on the selection of the prospect and location within the Sfax Permit. Based on current information, Eurogas International estimates that its share of the cost to meet the first drilling commitment ranges between US$6 million and US$9 million. Eurogas International has not yet completed its assessment of the costs associated with the second drilling commitment. In the event that these drilling commitments are not completed prior to the expiry of the First Renewal Period, a compensatory payment of up to US$8 million per well will be payable to the Tunisian government by Eurogas International and its joint venture partner, less any amounts incurred in respect of the completion of these commitments. Eurogas International is currently exploring options to raise the necessary funding to complete these commitments.

CONSOLIDATED RESULTS OF OPERATIONS

Year ended December 31, 2012 compared with the year ended December 31, 2011

Consolidated Net Loss

During 2012, the Corporation incurred a net loss attributable to the owners of the parent of $16.6 million or $0.10 per share. This compares with a net loss attributable to the owners of the parent of $1.2 million, or $0.1 per share incurred in 2011. During 2012, the Corporation completed an impairment analysis based on a reserves report issued by a qualified reserve evaluator as at December 31, 2012. Based on this report, and as a result of decreases in the forecasted natural gas prices as provided for in the reserves report, the Corporation determined that the carrying value of certain of its natural gas assets exceeded their net recoverable amount by $15.5 million. The recoverable amount was determined using cash flow models, discounted at a rate of 8%. Accordingly, during the year ended December 31, 2012, the Corporation recognized an impairment loss of $15.5 million in respect of these natural gas assets. In accordance with IFRS, the impairment loss may be reserved in subsequent periods if there is a positive change in the forecast of future gas prices.

For the year ended December 31,			2012			2011
	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	$ (20,170)	$ (20,170)	$ -	$ 1,322	$ 1,322	$ -
Castor Project	(226)	(169)	(57)	(261)	(194)	(67)
Loss from investment in preferred shares of Eurogas International	(1,286)	(1,286)	-	(1,286)	(1,286)	-
Corporate activities	5,002	5,002	-	(1,088)	(1,088)	-
Net loss for the year	$ (16,680)	$ (16,623)	$ (57)	$ (1,313)	$ (1,246)	$ (67)

Southern Ontario Assets

Operating Performance

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

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 2012, sales of oil and natural gas, net of royalty interests, were $30.5 million, a decrease of $5.3 million from $35.8 million earned in the prior year. As illustrated in the table below, decreases in commodity prices, including a significant decrease in the price of natural gas, accounted for a $5.6 million decrease in year-over-year net sales, partially mitigated by a marginal $0.3 million increase in revenues from increased production volumes.

	Natural Gas	Oil and Liquids	Total
Net Sales			
Year ended December 31, 2012	$ 10,005	$ 20,478	$ 30,483
Year ended December 31, 2011	14,724	21,094	35,818
Net decrease in net sales	$ (4,719)	$ (616)	$ (5,335)
Effect of changes in production volumes	$ (600)	$ 921	$ 321
Effect of changes in commodity prices	(4,119)	(1,537)	(5,656)
	$ (4,719)	$ (616)	$ (5,335)

Production Volumes

Average daily volume during the year ended December 31,	2012	2011
Natural gas (Mcf/d)	10,081	10,538
Oil (bbls/d)	721	692
Liquids (bbls/d)	27	26
Total (boe/d)	2,428	2,474

In 2012, oil production volumes increased to an average of 721 bbl/d compared with an average of 692 bbl/d produced in 2011. The natural decline rate in the Corporation's oil production, which has averaged approximately 14% per annum, was offset primarily by workover programs and by the acquisition of Torque which was completed in the third quarter of 2011.

Offshore, the decline in average production volumes for natural gas during 2012 was consistent with the natural decline rate of approximately 6% per annum. In response to declining natural gas prices, the Corporation has reduced its offshore capital expenditures and workover programs, which impacted average production volumes for natural gas in 2012. The Corporation expects that these strategies will continue to impact production of natural gas in the short term.

In 2013, and in the absence of a marked improvement in the price for natural gas, the Corporation intends to focus its capital program on onshore oil projects, which are expected to include a number of workover initiatives to further optimize oil production from existing fields. In addition, the Corporation continues to assess potential drill opportunities in an ongoing effort to replenish reserves.

Net Sales of Oil and Gas

For the year ended December 31,			2012			2011
		Sales	Realized Prices ($ / unit)		Sales	Realized Prices ($ / unit)
Natural gas	$	11,746	3.18	$	17,316	4.50
Oil		23,589	89.44		24,302	96.15
Liquids		539	54.65		558	59.32
		35,874			42,176	
Less: Royalties at 15% (2011 – 15%)		(5,391)			(6,358)	
Net sales	$	30,483		$	35,818	

Revenues from oil and gas sales were $35.9 million in 2012. This compares with revenues of $42.2 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 2012, the Corporation recorded royalty obligations of $5.4 million (2011 – $6.4 million) against its oil and gas sales, representing an average royalty rate of approximately 15% (2011 – 15%) of revenues.

Effect of Commodity Prices on Revenues from Oil and Gas Sales

Prices for oil and natural gas may vary significantly from quarter to quarter 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 year ended December 31,			2012			2011
	US$	CAD$	Realized Prices ($)	US$	CAD$	Realized Prices ($)
Natural Gas						
Dawn Hub	3.07	3.07	3.18	4.37	4.30	4.50
NYMEX Henry Hub	2.75	2.75		4.00	3.93	
Oil						
Edmonton Par	n/a	86.57	89.44	n/a	95.57	96.15
West Texas Intermediate	94.06	94.17		94.91	93.40	

Realized Price for Natural Gas Sales

Natural gas prices in North America were subjected to considerable downward pressure in 2012, as vast amounts of shale gas supply, combined with diminished demand resulting from relatively warmer winter weather in early 2012 continued to depress prices to levels below historical norms. Prices for natural gas rebounded marginally during the summer months reflecting increased consumption of electrical energy powered by natural gas in response to unusually high summer temperatures and more recently as weather-sensitive demands respond to more normal winter weather. The Corporation remains cautious, however, a considerable amount of supply remains tied in by natural gas producers. Natural gas sales in 2012 represented 69% (2011 – 71%) of total production volume on a boe basis, and 33% (2011 – 41%) of total revenues from oil and gas sales. The Corporation realized an average price on sales of natural gas of $3.18/Mcf during 2012, a decrease of 29% from the average price of $4.50/Mcf realized in the prior year. The Corporation's realized price for natural gas sales, while consistent with the decrease in the natural gas price as reported by NYMEX and the Dawn Hub, is partially mitigated by the Corporation's proximity to the Dawn Hub, a leading provider of natural gas supply to the greater Toronto market area, which provides the Corporation with a positive basis differential from average industry benchmarks.

Realized Price for Sales of Oil

Internationally, oil prices remained stable in 2012, with the West Texas Intermediate ("WTI") price averaging US$94.06, just marginally below an average price of US$94.91 in 2011. Supply concerns stemming from international sanctions cutting Iranian exports following concerns over their nuclear development program, compounded by field maintenance issues and labour disputes in the North Sea, bolstered prices. The Corporation's realized oil price per barrel is more closely correlated to the Edmonton Par price, reflecting that the Corporation enters the western Canadian crude stream at Sarnia. During 2012, a notable discount between the WTI and Edmonton Par price emerged, as technological advancements in horizontal drilling and fracking provided considerable increased volumes of oil from oil shales and tight reservoirs, with the result that supply out of western Canada exceeded the takeaway capacity of pipeline. The Edmonton Par price, responding to excess supply, fell to an average of $86.57/bbl in 2012 compared with $95.57/bbl in 2011.

Sales of crude oil in 2012 represented 31% (2011 – 29%) of total production volume on a boe basis, and 67% (2011 – 59%) of total revenues from oil and gas sales. During 2012, the Corporation realized an average price on sales of crude oil of $89.44/bbl (2011 – $96.15/bbl), representing a premium of approximately 3% (2011 – 1%) over the average price of the Edmonton Par. The Corporation is exploring alternative marketing options to realign the price received for its Ontario oil production to the WTI benchmark for crude oil.

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 during 2012 and 2011. 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 loss and comprehensive loss.

For the year ended December 31,			2012			2011
	Realized gain	Unrealized gain (loss)	Total	Realized (loss) gain	Unrealized gain	Total
Oil swaps	$ 965	$ 264	$ 1,229	$ (62)	$ 403	$ 341
Gas swaps	2,963	(1,665)	1,298	1,065	1,666	2,731
	$ 3,928	$ (1,401)	$ 2,527	$ 1,003	$ 2,069	$ 3,072

The Corporation's risk management contracts at December 31, 2012 had a positive value of $215,000 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	$101.20	Dec 31/12	Jan 25/13

Subsequent to December 31, 2012, the Corporation entered into a commodity swap on an additional 500 bbls per day of oil from February 1, 2013 to December 31, 2013, at a fixed price in Canadian dollars of $98.22/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 an unrealized risk management gain or loss. Unrealized risk management 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. Included in production expenditures is an allocation of general and administrative costs, including labour, which is directly attributable to these activities. During 2012, the Corporation incurred production expenditures of $13.5 million or $15.18/boe, compared with production expenditures of $13.0 million or $14.35/boe incurred in the prior year.

For the year ended December 31,			2012			2011
	Natural Gas	Oil and Liquids	Total	Natural Gas	Oil and Liquids	Total
Production expenditures	$ 7,041	$ 6,442	$ 13,483	$ 7,254	$ 5,703	$ 12,957
Production expenditures	(per Mcf)	(per bbl)	(per boe)	(per Mcf)	(per bbl)	(per boe)
per unit	$ 1.91	$ 23.55	$ 15.18	$ 1.89	$ 21.75	$ 14.35

Field Level Cash Flows and Field Netbacks

For the year ended December 31,			2012			2011
	Natural Gas	Oil and Liquids	Total	Natural Gas	Oil and Liquids	Total
Total sales	$ 11,746	$ 24,128	$ 35,874	$ 17,316	$ 24,860	$ 42,176
Realized risk management gain (loss)	2,963	965	3,928	1,065	(62)	1,003
Royalties	(1,741)	(3,650)	(5,391)	(2,592)	(3,766)	(6,358)
Production expenditures	(7,041)	(6,442)	(13,483)	(7,254)	(5,703)	(12,957)
Field level cash flows	$ 5,927	$ 15,001	$ 20,928	$ 8,535	$ 15,329	$ 23,864

During 2012, the Corporation earned field level cash flows of $20.9 million compared with $23.9 million earned in 2011. Included in field level cash flows is $3.9 million (2011 – $1.0 million) from realized gains on risk management contracts. Field level cash flows should not be considered more meaningful than, or an alternative to net earnings or loss in accordance with IFRS.

For the year ended December 31,				2012			2011
	Natural Gas	Oil and Liquids	Total		Natural Gas	Oil and Liquids	Total
	$/Mcf	$/bbl	$/boe		$/Mcf	$/bbl	$/boe
Total sales	$ 3.18	$ 88.19	$ 40.37		$ 4.50	$ 94.83	$ 46.70
Realized risk management gain (loss)	0.80	3.53	4.42		0.28	(0.24)	1.11
Royalties	(0.47)	(13.34)	(6.07)		(0.67)	(14.37)	(7.04)
Production expenditures	(1.91)	(23.55)	(15.18)		(1.89)	(21.75)	(14.35)
Field netbacks	$ 1.60	$ 54.83	$ 23.54		$ 2.22	$ 58.47	$ 26.42

Field netbacks from natural gas were $1.60/Mcf in 2012 compared with $2.22/Mcf in 2011. The decrease reflects the impact of declining market prices for natural gas, partially offset by realized gains from the Corporation's price risk management strategies, which added $0.80/Mcf (2011 – $0.28/Mcf) to field netbacks from natural gas.

Field netbacks from oil and liquids were $54.83/bbl in 2012 compared with $58.47/bbl in 2011. Despite successful price risk management strategies that added $3.53/bbl in 2012 (2011 – loss of $0.24/bbl), the discount to the Edmonton Par price relative to the WTI adversely affected the Corporation's field level cash flows and resulting field netbacks from oil and liquids.

Capital Expenditures

During 2012, the Corporation incurred capital expenditures of $12.8 million (2011 – $11.1 million) on its assets in southern Ontario.

For the year ended December 31,	2012	2011
Offshore		
Drilling and completion	$ -	$ 2,963
Pipeline	90	369
Workovers	-	203
Facilities	26	164
Offshore fleet	-	367
Total Offshore	116	4,066
Onshore		
Drilling and completion	2,168	3,341
Pipeline	196	-
Workovers	1,462	588
Facilities	66	216
Other	539	177
Total Onshore	4,431	4,322
Exploration and Evaluation		
Undeveloped properties	1,132	1,004
Onshore seismic	3,607	1,510
Total exploration and evaluation	4,739	2,514
Drilling rig	3,500	-
Office equipment, computer hardware and software	16	209
	$ 12,802	$ 11,111

In response to low natural gas prices, the Corporation limited its offshore capital expenditure activities to $0.1 million during 2012, compared with $4.1 million in the prior year. Offshore activities were limited to pipeline repairs and the Corporation's abandonment activities (see *"Decommissioning Liabilities"*). Onshore, the Corporation expended $2.2 million on drilling and completion activities and $1.5 million to stimulate four vertical wells and one horizontal well. As a result of these workovers, production increased by approximately 15 bbls/d.

In addition to its planned capital work program, during 2012, the Corporation purchased the Dundee Discovery, a new onshore drilling rig, for approximately $3.5 million. The Dundee Discovery was purchased in order to drill more efficiently than using rigs provided by local service providers, to lower the cost of drilling, and to increase the safety involved in drilling operations. The Dundee Discovery was used to drill two wells in late 2012 confirming the efficiency and safety objectives of the new equipment. The Corporation intends to offer the Dundee Discovery to the industry on a third-party basis.

The Corporation's drill targets in late 2012 were in anticipation of extending the producing area of an oilfield. Each vertical well encountered dolomitic pay, but the quantity of recoverable oil was deemed uneconomic. The Corporation plans to re-enter the second well in the first quarter of 2013, and deviate the wellbore to a more prospective part of the reservoir.

The Corporation expended a further $3.6 million on the acquisition and processing of 2-D and 3-D seismic data, which will be critical in identifying drill candidates.

Reserves

The Corporation retained Deloitte LLP ("Deloitte"), an independent qualified reserves evaluator to prepare a report on the Corporation's working interest of 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, 2012 were determined using the guidelines and definitions set out under National Instrument 51-101. At December 31, 2012, the proved and probable reserves in southern Ontario have increased 2% to 16,358 million boe ("Mboe") from 16,091 Mboe at December 31, 2011. The following table outlines the change in the Corporation's reserves since December 31, 2011.

	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, 2012	65,433	1,815	71	12,792	$ 157,472	$ 12.31
Revisions	4,733	222	(6)	1,004		
Production	(3,640)	(260)	(10)	(877)		
Closing balance, December 31, 2012	66,526	1,777	55	12,919	$ 108,600	$ 8.41
Probable Reserves						
Opening balance, January 1, 2012	14,941	778	31	3,299	$ 38,721	$ 11.74
Revisions	600	44	(4)	140		
Closing balance, December 31, 2012	15,541	822	27	3,439	$ 31,500	$ 9.16
Total proved and probable	82,067	2,599	82	16,358	$ 140,100	$ 8.56
Percentage increase (decrease) in reserves	2%	0%	(20%)	2%		

At December 31, 2011, the Corporation estimated the reserve life index for natural gas and oil at 17.1 years and 7.1 years, respectively. As at December 31, 2012, the reserve life index for natural gas increased to 23.2 years, while the reserve life index for oil increased to 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, 2012 as outlined above.

	Natural Gas	Oil
		Edmonton Par
	Union Parkway	(delivered to Sarnia, ON)
Reserve Prices	CDN$ / Mcf	CDN$ / bbl
2013	4.00	89.15
2014	4.55	88.85
2015	4.85	93.60
2016	5.15	95.35
2017	5.45	93.95
Average five year forecast	4.80	92.18

Impairment of Oil and Gas Properties

During the year ended December 31, 2012, the Corporation recognized a $15.5 million impairment on its oil and gas properties in relation to certain natural gas properties. The impairment charge reflects a reduction in forecasted natural gas prices, as outlined above. In arriving at the amount of impairment, the Corporation estimated the recoverable amount of the natural gas properties using the fair value less costs to sell method, which entails establishing cash flow projections based on proven and probable reserves. In estimating fair value less costs to sell, the Corporation considered transactions within the industry over the past twelve months, long-term views of commodity prices, externally evaluated reserve volumes, and discount rates specific to the natural gas properties. The calculation of the recoverable amount is sensitive to underlying assumptions including production volumes, discount rates and commodity prices. In computing the recoverable amount, future cash flows were adjusted for risks specific to the properties impaired and were discounted using a discount rate of 8%. This discount rate is considered to approximate the weighted average cost of capital of a typical market participant.

2013 Work Program

In 2013, the Corporation plans to spend $8.3 million on its net working interest in capital projects relating to further development of its Southern Ontario Assets.

The Corporation will continue its focus on oil production and oil related projects and is devoting the majority of capital resources to this strategy. Approximately $6.1 million of the $8.3 million will be spent onshore while approximately $0.8 million will be spent offshore primarily in production efficiency related projects. The remaining $1.4 million will be spent on mineral rights required to maintain producing properties and to implement onshore drilling and seismic programs.

The 2013 onshore capital plans include a three well drill and complete program estimated at approximately $2.7 million, together with an additional $0.6 million to address the Corporation's need for increased disposal well capacity. Also, the Corporation will continue to conduct seismic work and plans to spend approximately $2.4 million on these activities in an effort to bolster the existing database of seismic information in support of planned future drilling programs. The remaining $0.4 million of the onshore capital work program will be spent on facility enhancements primarily in the Essex County oil fields.

The 2013 offshore capital plans are focused on projects that will yield the greatest returns in the short term due to continued depressed natural gas prices. The Corporation will be reactivating the company-owned dock located in Port Burwell in conjunction with the planned strategy to abandon a dock and a gas plant located at Port Stanley. This comprehensive project includes dredging of the Port Burwell harbour, and a pipeline exchange to larger diameter pipe, all of which will provide improved access to the central Lake Erie field and improved production efficiencies throughout Lake Erie operations. Capital costs relating to this project are approximately $0.4 million. The remaining $0.4 million for offshore capital projects relate to non-discretionary dry dock inspection costs for two vessels.

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, 2012, the Corporation's estimate of these future costs on an undiscounted basis was approximately $81.3 million, and is forecasted to be incurred over a 50-year period. The Corporation spent $1.0 million in reclamation activities during 2012 and the Corporation anticipates that it will incur a further $1.8 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, 2012, the discounted amount of the Corporation's decommissioning liabilities was $44.7 million. The discount used in calculating the Corporation's decommissioning liabilities is accreted over time. During 2012, the Corporation incurred accretion expense of $0.9 million (2011 – $1.0 million). These amounts have been included in the Corporation's 2012 Consolidated Financial Statements as *"interest expense"*.

Castor Underground Gas Storage Project

The construction of the Castor Project is complete, and is now subject to testing and subsequent commissioning into the Spanish gas system. On July 5, 2012, Escal was granted the provisional commissioning certificate necessary to commence the injection of cushion gas into the Castor facilities. This key milestone signified that the facility is ready for service, subject to the injection of cushion gas and certain subsequent performance testing. The injection of cushion gas was temporarily delayed as Escal worked with the Spanish authorities to ensure the economic viability of the Castor Project. Escal has currently entered into negotiations with a third party for the purchase of cushion gas, and anticipates that cushion gas injection will commence in the first quarter of 2013 and take up to four months to complete.

Share of Loss from Equity Accounted Investment in Escal

The Corporation accounts for its investment in Escal using the equity method. As the Corporation's investment in Escal was nominal, the Corporation did not recognize any equity earnings in respect of its investment in Escal during 2012. In 2011, the Corporation recognized a $13,000 loss relating to this investment, representing its share of losses generated by Escal.

Escal has established a hedging strategy to mitigate its exposure to interest rate risk associated with the project financing for the Castor Project. At December 31, 2012, the fair value of Escal's obligations in respect of these hedging strategies was approximately €140.1 million (2011 – €74.8 million), before associated taxes. Recording its share of Escal's obligations in respect of these hedging contracts would draw the Corporation's investment in Escal to below zero. The Corporation has not recognized its share of these losses, estimated at $38.6 million net of taxes, as it does not have the legal or constructive obligation in respect thereof.

From 2010 to 2012, Escal issued shares from treasury with a par value of €14,000. In order to maintain its 33% interest, CLP subscribed for one third of the newly issued par value shares at an aggregate cost of $6,000 (€5,000). During this time, and in order to meet the equity ratios as required by the project financing of the Castor Project, ACS also contributed a share premium of €40.9 million and issued €64.2 million in subordinated loans. CLP has not recognized the benefit of its 33% interest in the share premium as the realization and measurement is subject to a number of risks and uncertainties, including but not limited to, execution risk associated with completion of the project, the availability and terms of future financing arrangements and the 50-year life span of the project.

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 2012, the Corporation provided for an impairment loss relating to its investment in Eurogas International of $1.3 million (2011 – $1.3 million).

Other Items in Consolidated Net Earnings

General and Administrative Expenses

General and administrative expenses incurred during 2012 were $7.0 million, a decrease of $1.5 million from general and administrative expenses of $8.5 million incurred during 2011. General and administrative expenses in the prior year included $0.5 million of transaction costs related to the acquisition of Torque and $0.2 million associated with the transfer of the listing of the Corporation's common shares from the TSX Venture Exchange to the TSX. Stock based compensation also decreased in 2012 to $0.5 million from $0.9 million in 2011, reflecting the aging of the Corporation's stock option plan. There were no other significant changes in the nature of general and administrative expenses incurred by the Corporation on a year-over-year basis.

Interest Expense

The Corporation's interest expense of $4.6 million incurred during 2012 was consistent with interest expense of $4.6 million incurred in 2011. Included in interest expense is $0.9 million (2011 – $1.0 million) of accretion expense associated with the Corporation's decommissioning liability, 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 amount of $5.9 million in 2012 (2011 – $1.2 million recovery), representing an effective income tax rate of 25 % (2011 – 47%). As at December 31, 2012, the Corporation's net deferred income tax assets were $9.3 million (2011 – $3.2 million) and included deferred income tax assets of $9.5 million (2011 – $3.7 million) offset by deferred income tax liabilities of $0.2 million (2011 – $0.5 million).

SELECTED QUARTERLY FINANCIAL INFORMATION

	2012				2011			
	31-Dec	30-Sep	30-Jun	31-Mar	31-Dec	30-Sep	30-Jun	31-Mar
Revenues	$ 7,507	$ 7,359	$ 7,543	$ 8,074	$ 9,459	$ 8,757	$ 9,530	$ 8,072
Net (loss) earnings attributable to owners of the parent	**(13,431)**	**(2,470)**	**(302)**	**(420)**	**985**	**(1,128)**	**937**	**(2,040)**
Basic and fully diluted (loss) earnings per share	$ (0.08)	$ (0.02)	$ -	$ -	$ 0.01	$ (0.01)	$ 0.01	$ (0.01)
Capital expenditures	$ 3,009	$ 3,894	$ 4,532	$ 1,367	$ 4,763	$ 4,109	$ 1,319	$ 920

- 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.
- In the third quarter of 2011, the Corporation completed the acquisition of Torque, increasing revenues in each of the third and fourth quarters of 2011 by approximately $0.5 million. Included in the third quarter of 2011 are $0.4 million of associated transaction costs, with the $0.1 million balance of transaction costs related to Torque being incurred in the fourth quarter of 2011.

- Changes in the fair value of the Corporation's risk management contracts are included in the Corporation's net earnings. These 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:

	2012				2011			
	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	$ 114	$ (354)	$ 1,507	$ 1,260	$ 1,038	$ 1,486	$ 1,939	$ (1,391)

QUARTERLY CONSOLIDATED RESULTS OF OPERATIONS

Three months ended December 31, 2012 compared with the three months ended December 31, 2011

During the three months ended December 31, 2012, the Corporation incurred a net loss attributable to owners of the parent of $13.4 million, compared with net earnings attributable to owners of the parent of $1.0 million earned in the fourth quarter of the prior year. The loss incurred in the fourth quarter includes a $15.5 million impairment on natural gas properties as previously discussed.

For the three months ended December 31,			2012			2011
	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	$ (17,738)	$ (17,738)	$ -	$ 593	$ 593	$ -
Castor Project	(15)	(12)	(3)	(112)	(82)	(30)
Loss from investment in preferred shares of Eurogas International	(323)	(323)	-	(324)	(324)	-
Corporate activities	4,642	4,642	-	798	798	-
Net (loss) earnings for the period	$ (13,434)	$ (13,431)	$ (3)	$ 955	$ 985	$ (30)

Southern Ontario Assets

Net sales in the fourth quarter of 2012 were $7.5 million, a decrease of $2.0 million from net sales of $9.5 million earned in the fourth quarter of the prior year. As illustrated in the following table, net sales were adversely affected both by decreases in production volumes, which accounted for $0.9 million of the overall decrease, and by falling commodity prices, which further decreased net sales by $1.1 million.

	Natural Gas	Oil and Liquids	Total
Net Sales			
Three months ended December 31, 2012	$ 2,984	$ 4,523	$ 7,507
Three months ended December 31, 2011	3,396	6,063	9,459
Net decrease in net sales	$ (412)	$ (1,540)	$ (1,952)
Effect of changes in production volumes	$ (254)	$ (641)	$ (895)
Effect of changes in commodity prices	(158)	(899)	(1,057)
	$ (412)	$ (1,540)	$ (1,952)

The Corporation's average production volume fell to 2,353 boe/d in the fourth quarter of 2012 compared with 2,570 boe/d produced in the fourth quarter of the prior year.

Average daily volume during the three months ended December 31,	2012	2011
Natural gas (Mcf/d)	9,878	10,677
Oil (bbls/d)	684	764
Liquids (bbls/d)	23	27
Total (boe/d)	2,353	2,570

Average daily oil production volumes during the fourth quarter of 2012 were 684 bbls/d, a decrease of 10% from average daily production volumes of 764 bbls/d in the fourth quarter of 2011. The decline in oil production is the result of natural decline and unscheduled maintenance in the fourth quarter of 2012 on six wells due to the buildup of wax.

The Corporation's average natural gas production volumes decreased to 9,878 Mcf/d in the fourth quarter of 2012, compared with 10,677 Mcf/d in the fourth quarter of the prior year. The majority of the reduction is the continued natural decline from the producing gas fields. In addition, the Corporation diverted its resources to onshore oil production in response to the depressed natural gas price environment. Fourth quarter production was also adversely affected by a shut-in of one of the large volume offshore gas wells as a consequence of an unexpected increase in water production. Furthermore, a compressor required an unexpected rebuild, causing a further loss in production during the fourth quarter of 2012.

Revenues from oil and gas sales net of associated royalties were $7.5 million in the fourth quarter of 2012 compared with revenues of $9.5 million earned in the same quarter of the prior year.

For the three months ended December 31,			2012			2011
		Sales	Realized Prices ($ / unit)		Sales	Realized Prices ($ / unit)
Natural gas	$	3,471	3.82	$	3,977	4.05
Oil		5,284	83.97		6,865	97.73
Liquids		94	44.76		176	71.31
		8,849			11,018	
Less: Royalties at 15% (2011 – 14%)		(1,342)			(1,559)	
Net sales	$	7,507		$	9,459	

The Corporation realized an average sales price of $3.82/Mcf for natural gas in the fourth quarter of 2012, compared with $4.05/Mcf realized in the fourth quarter of the prior year. Combined with decreased production volumes, natural gas sales fell to $3.5 million in the fourth quarter of 2012 compared with $4.0 million in the fourth quarter of the prior year.

During the fourth quarter of 2012, the Corporation realized an average sales price of $83.97/bbl on sales of oil compared to $97.73/bbl realized in the same period of the prior year. The decrease in the realized price, compounded by unscheduled maintenance issues as discussed previously, resulted in a 23% decrease in oil revenues to $5.3 million in the fourth quarter of 2012, compared with revenues of $6.9 million in the fourth quarter of the prior year.

For the three months ended December 31,			2012			2011
	US$	CAD$	Realized Prices ($)	US$	CAD$	Realized Prices ($)
Natural Gas						
Dawn Hub	3.79	3.76	3.82	3.78	3.85	4.05
NYMEX Henry Hub	3.40	3.37		3.31	3.37	
Oil						
Edmonton Par	n/a	84.47	83.97	n/a	97.74	97.73
West Texas Intermediate	88.01	87.32		93.99	95.62	

The Corporation incurred production expenditures of $3.4 million in the fourth quarter of 2012, an increase of $1.2 million over production costs of $2.2 million incurred during the fourth quarter of 2011. Increases in production expenditures reflect a nonrecurring $0.5 million recovery of offshore operating costs relating to the internal reallocation of offshore drilling costs completed in the fourth quarter of 2011. In addition, during the fourth quarter of 2012, work was undertaken to manage the maintenance issues outlined above.

For the three months ended December 31,							2012						2011
		Natural Gas		Oil and Liquids		Total		Natural Gas		Oil and Liquids		Total	
Production expenditures	$	1,716	$	1,711	$	3,427		$	963	$	1,285	$	2,248
Production expenditures		(per Mcf)		(per bbl)		(per boe)			(per Mcf)		(per bbl)		(per boe)
per unit	$	1.89	$	26.31	$	15.84		$	0.98	$	17.66	$	9.51

Decreased revenues and increased production expenditures resulted in a 37% decrease in field level cash flows to $4.9 million in the fourth quarter of 2012 compared with field level cash flows of $7.8 million earned in the fourth quarter of 2011, with corresponding decreases in field netbacks.

Field Level Cash Flows

For the three months ended December 31,						2012						2011
		Natural Gas		Oil and Liquids		Total		Natural Gas		Oil and Liquids		Total
Total sales	$	3,471	$	5,378	$	8,849	$	3,977	$	7,041	$	11,018
Realized risk management gain		301		550		851		629		1		630
Royalties		(487)		(855)		(1,342)		(581)		(978)		(1,559)
Production expenditures		(1,716)		(1,711)		(3,427)		(963)		(1,285)		(2,248)
Field level cash flows	$	1,569	$	3,362	$	4,931	$	3,062	$	4,779	$	7,841

Field Netbacks

For the three months ended December 31,						2012						2011
		Natural Gas		Oil and Liquids		Total		Natural Gas		Oil and Liquids		Total
		$/Mcf		$/bbl		$/boe		$/Mcf		$/bbl		$/boe
Total sales	$	3.82	$	82.70	$	40.87	$	4.05	$	96.84	$	46.61
Realized risk management gain		0.33		8.46		3.93		0.64		0.01		2.66
Royalties		(0.54)		(13.16)		(6.20)		(0.59)		(13.44)		(6.59)
Production expenditures		(1.89)		(26.31)		(15.84)		(0.98)		(17.66)		(9.51)
Field netbacks	$	1.72	$	51.69	$	22.76	$	3.12	$	65.75	$	33.17

LIQUIDITY AND CAPITAL RESOURCES

Cash Resources Availability

At December 31, 2012, the Corporation had cash of $0.1 million on deposit with Canadian chartered banks. In addition, the Corporation had access to a further $3.6 million pursuant to its $70 million revolving demand credit facility as at December 31, 2012. In July 2012, DELP's credit facility was amended to reduce amounts available pursuant to the credit facility from $80 million to $70 million. There were no other material changes to the terms of the credit facility as a result of the amendment.

Southern Ontario Assets

DELP's credit facility was established with a syndicate of Canadian chartered banks. The credit facility is a direct obligation of DELP and is structured as a revolving demand loan with a tiered interest rate structure that varies based on DELP's net debt to cash flow ratio, as defined in the credit facility. Based on DELP's current ratios, draws on the credit facility bear interest, at DELP's option, at either the bank's prime lending rate plus 3% or, at the bank's then prevailing bankers' acceptance rate plus 4%. At December 31, 2012, the Corporation had drawn $66.4 million against the credit facility, including a letter of credit for $3.3 million, issued in favour of the Ministry of Natural Resources in connection with future abandonment and site restoration obligations. 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, 2012, the Corporation was in compliance with all such covenants.

The Corporation's current cash flows generated from ongoing operating activities, as well as amounts available pursuant to its credit facility, provide the Corporation with sufficient cash flow to support its working capital requirements in the foreseeable future. Furthermore, in October 2012, the Board of Directors conditionally approved a transferable rights offering pursuant to which the Corporation intends to raise approximately $10 million to expand its drilling program, subject to definitive terms and conditions as well as approvals from the TSX and securities regulatory authorities. The Corporation anticipates that the rights offering will be made during the first quarter of 2013.

Dundee Corporation, the Corporation's parent and a 57% shareholder of the Corporation, has agreed to backstop the offering so that it will purchase common shares not otherwise purchased pursuant to the exercise of rights by shareholders. The terms of Dundee Corporation's backstop will be identical in all respects to those of shareholders participating in the rights offering.

In the event that the Corporation determines that it wants to augment its currently planned capital expenditure and drilling program, the Corporation may consider alternative sources of capital, including potential debt or equity issuances.

Spain

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 system 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.

Project financing was completed in July 2010, providing Escal with a 10-year, €1.3 billion credit facility through a syndicate of 19 banks. At December 31, 2012, approximately €1.0 billion had been borrowed pursuant to these arrangements. To provide security for the financing, CLP and ACS have each pledged their respective shares in Escal to the banking syndicate. Other than the pledging of its shares, CLP 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, CLP's interest in Escal will at all times remain at 33%, and CLP will retain the right to 33% of all distributable cash flows, other than cash flows distributed to repay debt.

Outstanding Share Data and Dilutive Securities

At December 31, 2012, the Corporation had 164,651,647 common shares outstanding. In addition, it had granted 3,815,000 stock options to purchase common shares of the Corporation to directors and key management at a weighted average exercise price of $0.77 per share, and it had issued 945,310 deferred share units.

During 2012, the Corporation purchased 23,500 common shares for cancellation pursuant to its normal course issuer bid at an average cost of $0.61 per common share. The Corporation's current normal course issuer bid expires on April 2, 2013.

At February 15, 2013, the Corporation had 164,651,647 common shares outstanding.

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.

On December 31, 2012, the Corporation had issued a letter of credit for $3.3 million (2011 – $3.3 million) in favour of the Ministry of Natural Resources in connection with future abandonment and site restoration costs.

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, 2012.

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				
	2013	2014 to 2015	2016 to 2017	Thereafter	TOTAL
Bank loan	$ 62,633	$ -	$ -	$ -	$ 62,633
Decommissioning liabilities	1,796	2,057	2,143	38,709	44,705
Office, vehicle and equipment leases	334	339	54	-	727
	$ 64,763	$ 2,396	$ 2,197	$ 38,709	$ 108,065

RELATED PARTY TRANSACTIONS

Other than as described in Note 18 to the 2012 Consolidated Financial Statements, there are no other material related party transactions.

BUSINESS RISKS

There are a number of other inherent risks associated with the Corporation's activities and with its current stage of exploration and development. The risks faced by the Corporation are described in the Corporation's 2012 Annual Information Form dated February 15, 2013, 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 information are provided in Notes 3 and 4 to the 2012 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, 2012.

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 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 Chief Financial Officer concluded that as of December 31, 2012, the Corporation's disclosure controls and procedures were effective.

The Chief Executive Officer and Chief Financial Officer of the Corporation have also evaluated whether there were changes to the Corporation's internal control over financial reporting during 2012 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, 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 2013 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 2013 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
February 15, 2013

Management's Responsibility for Financial Statements

The accompanying consolidated financial statements, 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.

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
February 15, 2013

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, 2012 and 2011 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, 2012 and 2011 and its financial performance and its cash flow for the years then ended in accordance with International Financial Reporting Standards.

(signed) PricewaterhouseCoopers LLP
Chartered Accountants, Licensed Public Accountants
Toronto, Canada
February 15, 2013

DUNDEE ENERGY LIMITED
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(expressed in thousands of Canadian dollars)

	Note	As at December 31, 2012	As at December 31, 2011
ASSETS			
Current			
Cash		$ 125	$ 2,556
Accounts receivable	6	3,775	5,116
Prepaids		1,198	1,532
Inventory		350	621
Investments	7	541	579
Derivative financial assets	11	215	1,616
		6,204	12,020
Non-current			
Oil and gas properties	8	154,150	171,384
Equity accounted investment in Escal	15	-	-
Deferred income taxes	17	9,277	3,182
		$ 169,631	$ 186,586
LIABILITIES			
Current			
Bank loan	9	$ 62,633	$ 59,191
Accounts payable and accrued liabilities	18	5,340	10,000
Taxes payable (recoverable)		25	(30)
Decommissioning liabilities	10	1,796	1,985
		69,794	71,146
Non-current			
Decommissioning liabilities	10	42,909	42,303
		112,703	113,449
SHAREHOLDERS' EQUITY			
Equity Attributable to Owners of the Parent			
Share capital	12	104,838	104,854
Contributed surplus	12	7,086	6,631
Deficit		(52,161)	(35,538)
Accumulated other comprehensive loss		(3,082)	(3,114)
		56,681	72,833
Non-controlling interest		247	304
		56,928	73,137
		$ 169,631	$ 186,586

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

Commitments (Note 19)

On behalf of the Board,

(signed) Ned Goodman
Director

(signed) Garth A.C. MacRae
Director

DUNDEE ENERGY LIMITED
CONSOLIDATED STATEMENTS OF OPERATIONS

For the years ended December 31, 2012 and 2011
(expressed in thousands of Canadian dollars, except per share amounts)

	Note		2012		2011
REVENUES					
Oil and gas sales		$	35,874	$	42,176
Royalties			(5,391)		(6,358)
Net sales			30,483		35,818
Production expenditures	14		(13,483)		(12,957)
Depreciation and depletion	8		(15,003)		(15,435)
General and administrative	13, 14, 18		(7,044)		(8,526)
Gain on fair value changes of risk management contracts	11		2,527		3,072
Loss on fair value changes in financial instruments	7		(38)		(196)
Impairment on oil and gas properties	8		(15,500)		-
Impairment loss on financial instruments	7		(1,286)		(1,286)
Interest income			1,468		1,498
Interest expense	9, 10		(4,588)		(4,557)
Foreign exchange (loss) gain			(116)		118
LOSS BEFORE SHARE OF LOSS FROM EQUITY ACCOUNTED INVESTMENT AND INCOME TAXES			(22,580)		(2,451)
Share of loss from equity accounted investment	15		-		(13)
LOSS BEFORE INCOME TAXES			(22,580)		(2,464)
Income tax recovery (expense)	17				
Current			(163)		-
Deferred			6,063		1,151
			5,900		1,151
NET LOSS FOR THE YEAR		$	(16,680)	$	(1,313)
NET LOSS ATTRIBUTABLE TO:					
Owners of the parent		$	(16,623)	$	(1,246)
Non-controlling interest			(57)		(67)
		$	(16,680)	$	(1,313)
BASIC AND DILUTED NET LOSS PER SHARE	16	$	(0.10)	$	(0.01)

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, 2012 and 2011
(expressed in thousands of Canadian dollars)

	Note		2012		2011
NET LOSS FOR THE YEAR		$	(16,680)	$	(1,313)
Other comprehensive loss					
Share of other comprehensive loss from equity accounted investment	15		-		(4,466)
Less: Associated taxes			32		496
Other comprehensive income (loss) for the year			32		(3,970)
COMPREHENSIVE LOSS FOR THE YEAR		$	(16,648)	$	(5,283)
COMPREHENSIVE LOSS ATTRIBUTABLE TO:					
Owners of the parent			(16,591)		(4,172)
Non-controlling interest			(57)		(1,111)
		$	(16,648)	$	(5,283)

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, 2012 and 2011
(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, 2010	$ 97,746	$ 5,345	$ 401	$ (34,286)	$ (188)	$ 1,415	$ 70,433
For the year ended December 31, 2011							
Acquisition of common shares for cancellation pursuant to normal course issuer bid (Note 12)	(22)	-	-	(6)	-	-	(28)
Shares issued on private placement financing (Note 12)	6,012	-	-	-	-	-	6,012
Shares issued on acquisition (Note 5)	1,118	-	-	-	-	-	1,118
Net loss	-	-	-	(1,246)	-	(67)	(1,313)
Stock based compensation (Note 13)	-	706	179	-	-	-	885
Other comprehensive loss	-	-	-	-	(2,926)	(1,044)	(3,970)
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 12)	(16)	-	-	-	-	-	(16)
Net loss	-	-	-	(16,623)	-	(57)	(16,680)
Stock based compensation (Note 13)	-	316	139	-	-	-	455
Other comprehensive income	-	-	-	-	32	-	32
Balance, December 31, 2012	$ 104,838	$ 6,367	$ 719	$ (52,161)	$ (3,082)	$ 247	$ 56,928

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, 2012 and 2011
(expressed in thousands of Canadian dollars)

	Note	2012	2011
OPERATING ACTIVITIES			
Net loss for the year		$ (16,680)	$ (1,313)
Adjustments for:			
Share of loss from equity accounted investment	15	-	13
Depreciation and depletion	8	15,003	15,435
Loss on fair value changes in financial instruments	7	38	196
Impairment on oil and gas properties	8	15,500	-
Impairment loss on financial instruments	7	1,286	1,286
Loss (gain) on fair value changes of risk management contracts	11	1,401	(2,069)
Deferred income taxes	17	(6,063)	(1,151)
Stock based compensation	13	455	885
Reclamation expenditures	10	(993)	(1,047)
Other		(339)	(260)
		9,608	11,975
Changes in:			
Accounts receivable		1,331	611
Accounts payable and accrued liabilities		(3,746)	2,801
Taxes recoverable		55	-
Prepaids		334	(135)
Inventory		271	281
CASH PROVIDED FROM OPERATING ACTIVITIES		7,853	15,533
FINANCING ACTIVITIES			
Advanced from (repayment of) bank loan arrangements	9	3,442	(4,609)
Issuance of common shares	12	-	6,012
Acquisition of common shares for cancellation	12	(16)	(28)
CASH PROVIDED FROM FINANCING ACTIVITIES		3,426	1,375
INVESTING ACTIVITIES			
Acquisition of Torque	5	-	(6,012)
Investment in oil and gas properties	8	(13,710)	(9,864)
CASH USED IN INVESTING ACTIVITIES		(13,710)	(15,876)
(DECREASE) INCREASE IN CASH		(2,431)	1,032
CASH, BEGINNING OF YEAR		2,556	1,524
CASH, END OF YEAR		$ 125	$ 2,556
Interest paid		$ 3,645	$ 3,533
Income taxes paid		$ 108	$ -

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

For the years ended December 31, 2012 and December 31, 2011
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 Dundee Place, 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, 2012, Dundee Corporation was the principal shareholder of the Corporation.

Dundee Energy's operating interests include its 100% ownership interest in 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 45% working interest in the Sfax permit offshore Tunisia.

2. BASIS OF PREPARATION

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") as outlined in Part 1 of the Handbook of the Canadian Institute of Chartered Accountants. These consolidated financial statements were approved by the Board of Directors for issue on February 15, 2013.

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 consist of 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 no longer recognized 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 an asset to a third party. Financial liabilities are no longer recognized 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 and 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 the 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 all of 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 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 each reporting date, the Corporation assesses whether there is objective evidence that financial assets carried at amortized cost are impaired. Objective evidence may include significant or prolonged depreciation in the trading value of equity securities, 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. An impairment loss on financial assets 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. When technical feasibility and commercial viability of a project is demonstrable, the costs are reclassified as oil and gas 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.

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 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.

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.

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

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 2011, the IASB issued amendments to IFRS 9, extending the mandatory effective date for implementation of IFRS 9, which is now effective for annual periods beginning on or after January 1, 2015, although early adoption is permitted, with varying transitional arrangements dependent on the date of initial application.

IFRS 10, "Consolidated Financial Statements" ("IFRS 10")

IFRS 10 requires an entity to consolidate an investee when it is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Under existing IFRS, consolidation is required when an entity has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. IFRS 10 replaces SIC-12, *"Consolidation—Special Purpose Entities"* and parts of IAS 27, *"Consolidated and Separate Financial Statements"* ("IAS 27"). This standard is effective for annual periods beginning on or after January 1, 2013, with early adoption permitted.

IFRS 11, "Joint Arrangements" ("IFRS 11")

IFRS 11 requires a venturer to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting whereas, for a joint operation, the venturer will recognize its share of the assets, liabilities, revenues and expenses of the joint operation. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interests in joint ventures. IFRS 11 supersedes IAS 31, *"Interests in Joint Ventures"*, and SIC-13, *"Jointly Controlled Entities—Non-monetary Contributions by Venturers".* This standard is effective for annual periods beginning on or after January 1, 2013, with early adoption permitted.

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 disclosures and also introduces significant additional disclosure requirements that address the nature of, and risks associated with, an entity's interests in other entities. This standard is effective for annual periods beginning on or after January 1, 2013, with early adoption permitted.

IFRS 13, "Fair Value Measurement" ("IFRS 13")

IFRS 13 is a comprehensive standard for fair value measurement and disclosure requirements for use across all IFRS standards. The new standard clarifies that fair value is the price that would be received to sell an asset, or paid to transfer a liability in an orderly transaction between market participants, at the measurement date. It also establishes disclosures about fair value measurement. Under existing IFRS, guidance on measuring and disclosing fair value is dispersed among the specific standards requiring fair value measurements and in many cases does not reflect a clear measurement basis or consistent disclosures. This standard is effective for annual periods beginning on or after January 1, 2013, with early adoption permitted.

Amendments to Other Standards

In addition to the issuance of new standards as detailed above, there have also been amendments to existing standards, including IAS 1, *"Presentation of Financial Statements"* ("IAS 1"), IAS 16, *"Property, Plant and Equipment"* ("IAS 16"), IAS 27, *"Consolidated and Separate Financial Statements"*, IAS 28, *"Investments in Associates and Joint Ventures"* ("IAS 28"), IFRS 7, *"Financial Instruments: Disclosures"* ("IFRS 7"), IAS 32 *"Financial Instruments: Presentation"* ("IAS 32") and IAS 34, *"Interim Financial Reporting"* ("IAS 34").

The amendments to IAS 1 will require that entities group items presented in OCI based on an assessment of whether such items may or may not be reclassified to earnings at a subsequent date. Amendments to IAS 1 are applicable to annual periods beginning on or after July 1, 2012, with early adoption permitted. In May 2012, IAS 1 was further amended to require the presentation of an additional, opening statement of financial position when an entity applies an accounting policy retrospectively, or makes a retrospective restatement or reclassification and to clarify the disclosure requirements such that certain comparative information is only required if it has a material effect upon the information that is presented in the statement of financial position. This additional amendment is effective for annual periods beginning on or after January 1, 2013, with early adoption permitted.

IAS 16 was amended in May 2012 to provide further clarity on accounting for spare parts and servicing equipment. Before the amendment, IFRS required the classification of spare parts and servicing equipment as inventory. The amendment clarifies that these items should be classified as property, plant and equipment if they meet the definition pursuant to IAS 16. Amendments to IAS 16 are effective for annual periods beginning on or after January 1, 2013, with early adoption permitted.

The amended IAS 27 addresses accounting for subsidiaries, jointly controlled entities and associates in non-consolidated financial statements. IAS 28 has been amended to include joint ventures in its scope and to address the changes in IFRS 10 through 13 as outlined above. Amendments to IAS 27 and IAS 28 are applicable to annual periods beginning on or after January 1, 2013, with early adoption permitted.

Amendments to IFRS 7 require the disclosure of information that will enable 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. Amendments to IFRS 7 are applicable to annual periods beginning on or after January 1, 2013, with retrospective application required.

The amendments to IAS 32 clarify the criteria that should be considered in determining whether an entity has a legally enforceable right of set off in respect of its financial instruments. Amendments to IAS 32 are applicable to annual periods beginning on or after January 1, 2014, with retrospective application required. Early adoption is permitted. In May 2012, IAS 32 was further amended to clarify the treatment of income taxes relating to distributions and transaction costs. This additional amendment is effective for annual periods beginning on or after January 1, 2013, with early adoption permitted.

IAS 34 was amended in May 2012 to align the disclosure requirements for segmented assets and segmented liabilities in interim financial reports with those of IFRS 8, *"Operating Segments"*. Under the amendment, IAS 34 requires a measure of total assets and liabilities for an operating segment in interim financial statements if such information is regularly provided to the chief operating decision maker and there has been a material change in those measures since the last annual financial statements. This additional amendment is effective for annual periods beginning on or after January 1, 2013, with early adoption permitted.

The Corporation has not completed its assessment of the impact that the new and amended standards will have on its consolidated financial statements or whether to early adopt any of the new requirements.

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 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 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 recoverable 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 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 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 exploration and evaluation activities on these 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 phase. All pre-development costs relating to the Castor Exploration Permit in Spain are 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 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 obligation is 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. 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, require 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

Financial instruments are recorded on the consolidated statement of financial position at values that are representative of or approximate fair value. Management uses judgment in its assessment of fair values and imprecision in determining fair value may affect the amount of net earnings 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 they continue to be appropriate.

5. BUSINESS COMBINATIONS

2011 – Acquisition of Torque Energy Inc.

On August 4, 2011, the Corporation completed the acquisition of Torque Energy Inc. ("Torque"), a Canadian-based oil and natural gas company that was engaged in the exploration, development and acquisition of oil and natural gas properties, primarily in southern Ontario, Canada.

The fair value of the purchase consideration for Torque was $7,130,000 including (i) cash of $6,012,000 and (ii) the issuance of 1,346,926 fully paid common shares of the Corporation at a price of $0.83 per share (Note 12). Aggregate transaction costs associated with the acquisition of Torque were $385,000 and were charged to the Corporation's consolidated statements of operations as incurred. A summary of the allocation of the aggregate consideration transferred to the fair value of the various identifiable assets and liabilities acquired is as follows:

Net assets acquired		
Oil and gas properties	$	10,076
Accounts receivable		1,024
Prepaids		147
		11,247
Bank loan		(1,429)
Accounts payable and accrued liabilities		(519)
Decommissioning liability		(2,169)
	$	7,130
Aggregate consideration transferred:		
Cash	$	6,012
1,346,926 common shares of the Corporation issued at $0.83 per common share		1,118
	$	7,130

On December 1, 2011, the Corporation converged the assets and operations acquired pursuant to the Torque transaction with its existing business in southern Ontario.

6. ACCOUNTS RECEIVABLE

As at December 31,		2012		2011
Customers for oil and natural gas production	$	2,635	$	3,728
Working interest partners		174		417
Amounts receivable from Escal		966		971
	$	3,775	$	5,116

7. INVESTMENTS

As at December 31,		2012		2011
Publicly listed equity securities	$	241	$	279
Investment in Lake Erie Limited Partnership		300		300
Preferred shares of Eurogas International		32,150		32,150
Less: Impairment		(32,150)		(32,150)
		-		-
Accrued dividends on preferred share investment in Eurogas International		5,667		4,381
Less: Impairment		(5,667)		(4,381)
		-		-
	$	541	$	579

At each of December 31, 2012 and December 31, 2011, 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, 2012, 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, 2012, the Corporation recognized an impairment loss of $1,286,000 (2011 – $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, 2012, the Corporation recognized an unrealized loss from changes in fair value relating to publicly listed equity securities of $38,000 (2011 – $196,000).

The Corporation holds a 21.66% interest in Lake Erie Limited Partnership, a limited partnership with oil and natural gas rights in Ontario. As its investment in the Lake Erie Limited Partnership does not have a quoted market price and fair value cannot be reliably measured, the Corporation carries its investment at original cost.

8. OIL AND GAS PROPERTIES

	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, 2010							
Cost	$ 107,172	$ 23,408	$ 20,256	$ 4,525	$ 6,611	$ 837	$ 162,809
Accumulated depreciation and depletion	(5,194)	(926)	(554)	(12)	(673)	-	(7,359)
Net carrying value, December 31, 2010	101,978	22,482	19,702	4,513	5,938	837	155,450
Year ended December 31, 2011							
Carrying value December 31, 2010	101,978	22,482	19,702	4,513	5,938	837	155,450
Acquisitions (Note 5)	6,948	-	1,166	55	4	1,903	10,076
Net additions	5,868	1,909	2,007	-	(3,861)	5,188	11,111
Remeasure decommissioning liability (Note 10)	10,182	-	-	-	-	-	10,182
Depreciation and depletion	(11,945)	(2,033)	(1,288)	(25)	(144)	-	(15,435)
Net carrying value, December 31, 2011	113,031	22,358	21,587	4,543	1,937	7,928	171,384
At December 31, 2011							
Cost	130,170	25,317	23,429	4,580	2,754	7,928	194,178
Accumulated depreciation and depletion	(17,139)	(2,959)	(1,842)	(37)	(817)	-	(22,794)
Net carrying value, December 31, 2011	113,031	22,358	21,587	4,543	1,937	7,928	171,384
Year ended December 31, 2012							
Carrying value December 31, 2011	113,031	22,358	21,587	4,543	1,937	7,928	171,384
Net additions	3,630	286	3,592	-	555	4,739	12,802
Remeasure decommissioning liability (Note 10)	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	89,853	20,907	23,835	4,517	2,371	12,667	154,150
At December 31, 2012							
Cost	134,267	25,603	27,021	4,580	3,309	12,667	207,447
Accumulated depreciation, depletion and impairment	(44,414)	(4,696)	(3,186)	(63)	(938)	-	(53,297)
Net carrying value, December 31, 2012	$ 89,853	$ 20,907	$ 23,835	$ 4,517	$ 2,371	$ 12,667	$ 154,150

Impairment of Oil and Gas Properties

During the year ended December 31, 2012, the Corporation recognized an impairment of $15,500,000 on its oil and gas properties in relation to certain natural gas CGUs. The impairment charge reflects a reduction in forecasted natural gas prices as at December 31, 2012.

The Corporation determined the recoverable amount using the fair value less costs to sell method based on cash flow projections on proven and probable reserves. In determining fair value less costs to sell, the Corporation considered recent transactions within the industry, long-term views of commodity prices, externally evaluated reserve volumes, and discount rates specific to the CGU. The calculation of the recoverable amount is sensitive to the assumptions regarding production volumes, discount rates and commodity prices. In computing the recoverable amount, future cash flows were adjusted for risks specific to the CGU and discounted using a discount rate of 8%.

Selected key price forecasts used in the estimation of the value of commercial reserves as of December 31, 2012 are as follows:

Reserve Prices	Natural Gas Union Parkway CDN$ / Mcf
2013	4.00
2014	4.55
2015	4.85
2016	5.15
2017	5.45
Average five year forecast	4.80

9. BANK LOAN

Credit Facility, Dundee Energy Limited Partnership

DELP has established a credit facility for $70,000,000 (December 31, 2011 – $80,000,000) with a Canadian 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. Based on DELP's current ratios, draws on the credit facility bear interest, at DELP's option, at either the bank's prime lending rate plus 3.0% for loans or letters of credit, or, for bankers' acceptances, at the bank's then prevailing bankers' acceptance rate plus 4.0%. DELP is subject to a standby fee of 0.50% on unused amounts under the credit facility.

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, 2012, the Corporation was in compliance with all such covenants.

As at December 31,		2012		2011
Prime rate loans	$	3,100	$	3,500
Bankers' acceptances		60,000		56,000
Less: Unamortized discount		(467)		(309)
	$	62,633	$	59,191
Letter of credit (Note 10)	$	3,270	$	3,270

At December 31, 2012, DELP had drawn $66,370,000 (December 31, 2011 – $62,770,000) pursuant to the credit facility, including $3,270,000 (December 31, 2011 – $3,270,000) issued in the form of a letter of credit (Note 10). Available credit under the credit facility at December 31, 2012 was $3,630,000. During the year ended December 31, 2012, the Corporation incurred interest expense relating to the credit facility, including bank charges, arrangement fees and standby fees of $3,642,000 (2011 – $3,469,000).

Credit Facility, Torque Energy Inc.

As part of the acquisition of Torque (Note 5), the Corporation assumed a $6,100,000 revolving demand credit facility. The credit facility was fully repaid and cancelled on December 22, 2011.

10. 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 in southern Ontario, including the oil and gas properties acquired pursuant to the acquisition of Torque (Note 5). 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,		2012		2011
Undiscounted future obligations, beginning of year	$	83,739	$	80,123
Acquisition (Note 5)		-		4,621
Effect of changes in estimates		(1,468)		42
Liabilities settled (reclamation expenditures)		(993)		(1,047)
Undiscounted future obligations, end of year	$	81,278	$	83,739

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,		2012		2011
Discount rates applied to future obligations		*1.13% - 2.27%*		*0.95% - 2.42%*
Inflation rate		*2.00%*		*2.00%*
Discounted future obligations, beginning of year	$	44,288	$	31,960
Acquisition (Note 5)		-		2,169
Effect of changes in estimates and				
remeasurement of discount rates		467		10,182
Liabilities settled (reclamation expenditures)		(993)		(1,047)
Accretion		943		1,024
Discounted future obligations, end of year	$	44,705	$	44,288
Current	$	1,796	$	1,985
Non-current		42,909		42,303
	$	44,705	$	44,288

As required by statute, the Corporation has provided the Ontario Ministry of Natural Resources with a letter of credit in respect of future abandonment costs. At December 31, 2012 and December 31, 2011, the amount of the letter of credit was $3,270,000 (Note 9).

11. RISK MANAGEMENT CONTRACTS

During the year ended December 31, 2012, 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 and loss"* and were measured at fair value with changes in fair value recorded in net earnings in the period in which they occur.

The Corporation has determined that the fair value of risk management contracts at December 31, 2012 resulted in an asset balance of $215,000 (December 31, 2011 – asset balance of $1,616,000). All outstanding risk management contracts entered into by the Corporation expired on December 31, 2012 and settled at their fair value in January 2013.

During the year ended December 31, 2012, the Corporation recognized a gain of $2,527,000 (2011 – $3,072,000) from changes in the fair value of risk management contracts.

12. SHARE CAPITAL

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.

Issued and Outstanding

			Contributed Surplus	
	Number of Common Shares Outstanding	Share Capital	Option Reserve (Note 13)	DSUP Reserve (Note 13)
Outstanding, December 31, 2010	156,118,453	$ 97,746	$ 5,345	$ 401
Transactions during the year ended December 31, 2011				
Stock based compensation	-	-	706	179
Redeemed pursuant to issuer bid	(33,512)	(22)	-	-
Shares issued on private placement financing	7,243,280	6,012	-	-
Shares issued on acquisition (Note 5)	1,346,926	1,118	-	-
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

Normal Course Issuer Bid

On March 30, 2011, the Corporation established a normal course issuer bid through the facility of the TSX from April 1, 2011 to March 31, 2012. On March 30, 2012, the Corporation received regulatory approval to continue the terms of its normal course issuer bid from April 3, 2012 to April 2, 2013 (the "Amended NCIB"). Subject to certain conditions, the Corporation may purchase up to a maximum of 8,232,582 common shares pursuant to the Amended NCIB, representing approximately 5% of its common shares outstanding immediately prior to approval of the Amended NCIB.

During the year ended December 31, 2012, the Corporation purchased 23,500 (2011 – 33,512) common shares, having an aggregate stated capital value of $16,000 (2011 – $22,000) for cancellation pursuant to these arrangements. The Corporation paid $16,000 or $0.61 per share (2011 – $28,000 or $0.85 per share) to retire these shares. Any excess of the purchase price over the value of stated capital was recorded as an increase in the deficit.

Private Placement Financing

On August 2, 2011, the Corporation completed a private placement financing with Dundee Corporation, the Corporation's parent. The private placement consisted of the issuance of 7,243,280 common shares issued from treasury at a price of $0.83 per share for gross proceeds of approximately $6,012,000. The net proceeds from the private placement were used to fund the cash portion of the aggregate consideration transferred for the acquisition of Torque (Note 5).

13. 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, 2012, the Corporation granted 400,000 (2011 – nil) stock options at an average exercise price of $0.60 per option. The average fair value of the options granted during 2012 was $0.31 and was estimated at the grant date using an option pricing model with the following assumptions:

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

A summary of the status of the stock option component of the Corporation's SIP as at December 31, 2012 and 2011 and the changes during the years then ended is as follows:

	2012		2011	
	Stock Options	Weighted Average Exercise Price	Stock Options	Weighted Average Exercise Price
Options outstanding, beginning of year	5,665,000	$ 0.92	6,125,000	$ 0.98
Granted	400,000	0.60	-	-
Forfeited	(2,250,000)	1.12	(460,000)	1.65
Options outstanding, end of year	3,815,000	$ 0.77	5,665,000	$ 0.92
Exercisable options	3,548,332	$ 0.79	4,593,332	$ 0.95

Option Price	Options Outstanding	Options Exercisable	Contractual Life Remaining (Years)
At $0.54	200,000	200,000	0.79
At $0.60	400,000	133,332	4.34
At $0.81	3,215,000	3,215,000	2.83

During the year ended December 31, 2012, the Corporation recognized stock based compensation expense of $316,000 (2011 – $706,000) 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, 2012, the Corporation issued 341,480 (2011 – 248,830) deferred share units with a fair value on the date of issuance of $139,000

(2011 – $179,000). The deferred share units were issued in settlement of outstanding directors' fees payable. At December 31, 2012, the Corporation had 945,310 (2011 – 603,830) 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.

As at December 31,	2012	2011
Number of deferred share units outstanding, beginning of year	603,830	355,000
Granted	341,480	248,830
Number of deferred share units outstanding, end of year	945,310	603,830

14. GENERAL AND ADMINISTRATIVE EXPENSES AND PRODUCTION EXPENDITURES BY NATURE

General and Administrative Expenses

For the year ended December 31,		2012		2011
Salary and salary-related	$	4,287	$	4,321
Stock based compensation		455		885
Corporate and professional fees		2,712		3,293
General office		1,542		1,578
Exploration and development costs		1,022		848
Capitalization of general and administrative costs		(2,974)		(2,399)
	$	7,044	$	8,526

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 year ended December 31,		2012		2011
Labour	$	4,116	$	4,593
Materials, equipment and supplies used		4,414		4,137
Transportation		1,317		1,267
Utilities		1,795		1,737
Rental and lease payments		933		867
Other		908		356
	$	13,483	$	12,957

15. 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 provides a continuity of the Corporation's investment in Escal during the years ended December 31, 2012 and 2011.

As at December 31,		2012		2011
Carrying value, beginning of year	$	-	$	4,476
Transactions during the year ended December 31				
New investment		-		3
Share of losses		-		(13)
Share of other comprehensive loss		-		(4,466)
Carrying value, end of year	$	-	$	-

The following table summarizes financial information about Escal's assets, liabilities, net earnings and other comprehensive loss as at and for the years ended December 31, 2012 and 2011. 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. As Escal has not commenced operations, it does not report any material revenues.

		2012		2011
Assets	$	1,979,550	$	1,474,129
Liabilities		(2,101,356)		(1,565,965)
Net assets		(121,806)		(91,836)
Net income (loss)		57		(40)
Other comprehensive loss				
Cumulative translation (loss) gain		(876)		5,004
Loss on interest rate hedge contracts		(58,754)		(104,096)

During the year ended December 31, 2012, Escal issued 39 par value shares for €2,000 (2011 – 99 par value shares for €5,000). To maintain its proportionate interest in Escal, CLP acquired 13 of the newly issued shares (2011 – 33) for a nominal amount (2011 – $3,000; €2,000). In addition and in order to comply with minimum equity to debt ratio requirements, the majority shareholder in Escal also contributed an issuance premium on the newly issued shares of €5,774,000 (2011 – €14,659,000) and it issued €15,400,000 (2011 – €43,300,000) 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, execution risk associated with the construction of the project, the availability and terms of future financing arrangements and the 50-year life span of the project.

Escal has established a hedging strategy to mitigate its exposure to interest rate risk associated with its project financing agreement. At December 31, 2012, the fair value of Escal's obligations in respect of these hedging strategies was approximately €140,104,000 (2011 – €74,790,000). Recognition of these losses draws the Corporation's carrying value in Escal to zero. At December 31, 2012, the Corporation had not recorded a liability of $38,552,000 (2011 – $28,562,000) related to additional losses incurred by Escal, as it does not have the legal or constructive obligation in respect thereof.

16. NET LOSS PER SHARE

For the year ended December 31,		2012		2011
Net loss for the year attributable to owners of the parent	$	(16,623)	$	(1,246)
Weighted average number of common shares outstanding		164,653,361		159,664,319
Basic and diluted net loss per common share	$	(0.10)	$	(0.01)

Per share amounts are computed by dividing the loss for the year by the weighted average number of common shares outstanding of 164,653,361 (2011 – 159,664,319). The effect of common share purchase options and of deferred share units on the net loss per share is not reflected, as it is considered anti-dilutive.

17. INCOME TAXES

During the year ended December 31, 2012, the Corporation recognized an income tax recovery amount of $5,900,000 (2011 – $1,151,000), the major components of which include the following items:

For the year ended December 31,		2012		2011
Current income tax expense				
Current year resource tax	$	70	$	-
Adjustments in respect of prior years		93		-
		163		-
Deferred income tax recovery				
Origination and reversal of timing differences		(6,118)		(1,156)
Adjustments in respect of prior years		55		5
		(6,063)		(1,151)
Income tax recovery	$	(5,900)	$	(1,151)

The income tax recovery amount on the Corporation's loss before income taxes differs from the income tax recovery amount that would arise using the combined Canadian federal and provincial statutory tax rate of 26% (2011 – 28%), as a result of the following items:

For the year ended December 31,		2012		2011
Loss before tax at statutory rate of 26% (2011 – 28%)	$	(5,985)	$	(696)
Effect on taxes of:				
Non-deductible expenses		43		408
Adjustments in respect of prior years		148		5
Changes in substantively enacted income tax rates		(177)		-
Benefit of losses not previously recognized		-		(1,098)
Other differences		71		230
Income tax recovery	$	(5,900)	$	(1,151)

Following the acquisition of Torque (Note 5), the Corporation initiated an assessment of possible income tax strategies that would allow for the utilization of certain tax pools, the benefits of which were not previously recognized by Torque or the Corporation because of uncertainties as to recoverability. The subsequent convergence of Torque's assets and operations with those of the Corporation's existing business in southern Ontario allowed for the recognition of these tax pools and accordingly, during the year ended December 31, 2011, the Corporation recognized an income tax recovery amount of $1,098,000.

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, 2010	$ 588	$ 886	$ 363	$ 193	$ 92	$ 101	$ 2,223
(Charged) credited to the statement of operations	(576)	1,118	615	(15)	(46)	(101)	995
(Charged) credited to the statement of comprehensive loss	-	-	-	-	-	481	481
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

Deferred Tax Liabilities	Partnership Deferred Income	Equity Accounted Investment	Other	TOTAL
Balance, December 31, 2010	$ (587)	$ (86)	$ (15)	$ (688)
(Charged) credited to the statement of operations	587	2	(433)	156
(Charged) credited to the statement of comprehensive loss	-	-	15	15
Balance, December 31, 2011	-	(84)	(433)	(517)
(Charged) credited to the statement of operations	-	(5)	366	361
(Charged) credited to the statement of comprehensive loss	-	-	-	-
Balance, December 31, 2012	$ -	$ (89)	$ (67)	$ (156)

As at December 31, 2012, the Corporation had $143,000 of operating loss carry forwards (2011 – $47,000). There are no loss carry forwards expiring prior to 2017.

18. RELATED PARTY TRANSACTIONS

Other than as disclosed elsewhere in these consolidated financial statements, related party transactions and balances as at and for the years ended December 31, 2012 and 2011 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, 2012, the Corporation incurred costs of $1,355,000 (2011 – $1,133,000) in respect of these arrangements.

Accounts Payable and Accrued Liabilities

Included in accounts payable and accrued liabilities at December 31, 2012 are amounts owing to the Corporation's parent, Dundee Corporation, and to Dundee Corporation's subsidiaries of $762,000 (2011 – $4,516,000).

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 brokerage firm and 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 (Note 12) 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 year ended December 31, 2012 and 2011 are shown below:

For the year ended December 31,		2012		2011
Directors' fees and executive consulting	$	548	$	540
Stock based compensation		193		331
Benefits		26		23
	$	767	$	894

During the year ended December 31, 2012, the Corporation paid a previously accrued amount of $500,000 to a director of Dundee Corporation in respect of the director's involvement in the Castor underground gas storage project (Note 15).

19. 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,		2012		2011
Less than 1 year	$	334	$	340
Between 1 and 5 years		392		629
Thereafter		-		-

20. 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, 2012 and 2011, the carrying value of the Corporation's financial instruments approximated their fair value.

As at December 31,		2012		2011
Financial Assets				
Fair value through profit and loss				
Investments	$	541	$	579
Risk management contracts		215		1,616
Loans and receivables				
Cash		125		2,556
Accounts receivable		3,775		5,116
Financial Liabilities				
Amortized cost				
Bank loan		(62,633)		(59,191)
Accounts payable and accrued liabilities		(5,340)		(10,000)

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 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,	2012	2011
Level 1 – Investments in publicly listed securities	$ 241	$ 279
Level 2 – Risk management contracts	215	1,616
Level 3 – Investments in private equity securities	300	300

The level 3 financial assets are comprised of the Corporation's interest in Lake Erie Limited Partnership (Note 7). There were no other transactions in level 3 financial assets.

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, and with its working interest partners in oil and natural gas development and production activities. In addition, included in accounts receivable is a loan receivable from Escal, its 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 66%, 14%, 10% and 8% (2011 – 58%, 16%, 13% and 12%) of total revenue. Of the Corporation's individual accounts receivable due from customers, approximately 58% (2011 – 64%) was due from one marketer.

Amounts receivable from working interest partners 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 $341,000 (2011 – $245,000), 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 $17,000 (2011 – $17,000), 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, 2011 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 11). 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 (2011 – $185,000) before associated taxes. There are no outstanding natural gas risk management contracts at December 31, 2012. During 2011, a $0.10 change to the price of natural gas on a per thousand cubic foot basis would result in a change in net earnings of $236,000 before associated taxes. The results of this sensitivity analysis should not be considered to be predictive of future performance. Changes in the fair value of the derivative crude oil and natural gas contracts cannot generally be extrapolated because the relationship of changes in certain variables to changes in fair value may not be linear.

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 $363,000 (2011 – $296,000).

The Corporation also incurs interest rate risk through its holdings of certain investments. The Corporation did not hold any investments in 2012 and 2011 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, 2012.

		Carrying Amount	Contractual Term to Maturity
Bank loan	$	62,633	Demand facility
Accounts payable and accrued liabilities		5,340	Typically due within 20 to 90 days
Current portion of decommissioning liabilities		1,796	Expected settlement in 2013
	$	69,769	

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, 2013, after which the Corporation may request annual renewal periods, subject to approval by the lender. At December 31, 2012, 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.

21. 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, 2012 and December 31, 2011

For the year ended December 31,	Southern Ontario 2012	Southern Ontario 2011	Spain 2012	Spain 2011	Corporate 2012	Corporate 2011	TOTAL 2012	TOTAL 2011
REVENUES								
Oil and gas sales	$ 35,874	$ 42,176	$ -	$ -	$ -	$ -	$ 35,874	$ 42,176
Royalties	(5,391)	(6,358)	-	-	-	-	(5,391)	(6,358)
Net sales	30,483	35,818	-	-	-	-	30,483	35,818
Production expenditures	(13,483)	(12,957)	-	-	-	-	(13,483)	(12,957)
Depreciation and depletion	(14,993)	(15,421)	-	-	(10)	(14)	(15,003)	(15,435)
General and administrative	(4,683)	(4,985)	(219)	(237)	(2,142)	(3,304)	(7,044)	(8,526)
Gain on fair value changes of risk management contracts	2,527	3,072	-	-	-	-	2,527	3,072
Loss on fair value changes in financial instruments	-	-	-	-	(38)	(196)	(38)	(196)
Impairment of oil and gas properties	(15,500)	-	-	-	-	-	(15,500)	-
Impairment loss on financial instruments	-	-	-	-	(1,286)	(1,286)	(1,286)	(1,286)
Interest income	174	205	-	-	1,294	1,293	1,468	1,498
Interest expense	(4,585)	(4,538)	(1)	(1)	(2)	(18)	(4,588)	(4,557)
Foreign exchange (loss) gain	(110)	128	(6)	(10)	-	-	(116)	118
(LOSS) EARNINGS BEFORE SHARE OF LOSS FROM EQUITY ACCOUNTED INVESTMENT AND INCOME TAXES	(20,170)	1,322	(226)	(248)	(2,184)	(3,525)	(22,580)	(2,451)
Share of loss from equity accounted investment	-	-	-	(13)	-	-	-	(13)
(LOSS) EARNINGS BEFORE INCOME TAXES	(20,170)	1,322	(226)	(261)	(2,184)	(3,525)	(22,580)	(2,464)
Income tax recovery (expense)								
Current	-	-	-	-	(163)	-	(163)	-
Deferred	-	-	-	-	6,063	1,151	6,063	1,151
	-	-	-	-	5,900	1,151	5,900	1,151
NET (LOSS) EARNINGS FOR THE YEAR	$ (20,170)	$ 1,322	$ (226)	$ (261)	$ 3,716	$ (2,374)	$ (16,680)	$ (1,313)
NET (LOSS) EARNINGS ATTRIBUTABLE TO:								
Owners of the parent	$ (20,170)	$ 1,322	$ (169)	$ (194)	$ 3,716	$ (2,374)	$ (16,623)	$ (1,246)
Non-controlling interest	-	-	(57)	(67)	-	-	(57)	(67)
	$ (20,170)	$ 1,322	$ (226)	$ (261)	$ 3,716	$ (2,374)	$ (16,680)	$ (1,313)

Segmented Net Assets as at December 31, 2012 and December 31, 2011

	Southern Ontario		Spain		Corporate		TOTAL	
As at December 31,	2012	2011	2012	2011	2012	2011	2012	2011
ASSETS								
Current								
Cash	$ 76	$ 1,856	$ 7	$ 15	$ 42	$ 685	$ 125	$ 2,556
Accounts receivable	2,809	4,142	966	974	-	-	3,775	5,116
Prepaids	1,195	1,529	3	3	-	-	1,198	1,532
Inventory	350	621	-	-	-	-	350	621
Investments	300	300	-	-	241	279	541	579
Derivative financial assets	215	1,616	-	-	-	-	215	1,616
	4,945	10,064	976	992	283	964	6,204	12,020
Non-current								
Oil and gas properties	154,097	171,326	-	-	53	58	154,150	171,384
Equity accounted investment in Escal	-	-	-	-	-	-	-	-
Deferred income taxes	-	-	-	-	9,277	3,182	9,277	3,182
	$ 159,042	$ 181,390	$ 976	$ 992	$ 9,613	$ 4,204	$ 169,631	$ 186,586
LIABILITIES								
Current								
Bank loan	$ 62,633	$ 59,191	$ -	$ -	$ -	$ -	$ 62,633	$ 59,191
Accounts payable and accrued liabilities	4,029	4,530	29	528	1,282	4,942	5,340	10,000
Taxes payable (recoverable)	-	-	-	-	25	(30)	25	(30)
Decommissioning liabilities	1,796	1,985	-	-	-	-	1,796	1,985
	68,458	65,706	29	528	1,307	4,912	69,794	71,146
Non-current								
Decommissioning liabilities	42,909	42,303	-	-	-	-	42,909	42,303
	$ 111,367	$ 108,009	$ 29	$ 528	$ 1,307	$ 4,912	$ 112,703	$ 113,449
SEGMENTED NET ASSETS	$ 47,675	$ 73,381	$ 947	$ 464	$ 8,306	$ (708)	$ 56,928	$ 73,137

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