

BAYTEX

ENERGY CORP.

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BUSINESS ACQUISITION REPORT

JULY 30, 2014

**BAYTEX ENERGY CORP.
BUSINESS ACQUISITION REPORT**

Advisories

Certain terms used herein are defined under the headings "*Selected Definitions and Conversions*". Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101. Unless otherwise indicated, all financial information herein has been presented in Canadian dollars in accordance with generally accepted accounting principles as set by Canadian GAAP.

Readers are urged to read the information under the headings "*Presentation of Financial Information*", "*Non-GAAP Measures*", "*Presentation of Oil and Natural Gas Reserves*" and "*Cautionary Statement Regarding Forward-looking statements*".

Item 1 – Identity of Reporting Issuer

1.1 Name and Address of Issuer

Baytex Energy Corp. ("**Baytex**" or the "**Corporation**") is a corporation amalgamated under the *Business Corporations Act* (Alberta). Baytex's head office is located at Suite 2800, 520 – 3rd Avenue S.W., Calgary, Alberta, T2P 0R3, and its registered office is located at Suite 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

1.2 Executive Officer

The name of the executive officer of Baytex who is knowledgeable about the significant acquisition and this report is Murray J. Desrosiers, Vice President, General Counsel and Corporate Secretary, and his business telephone number is (587) 952-3000.

Item 2 – Details of Acquisition

2.1 Nature of Business Acquired

On June 10, 2014, Baytex completed the acquisition of all of the issued and outstanding shares of Aurora Oil & Gas Limited ("**Aurora**") pursuant to a scheme of arrangement under Australian law (the "**Arrangement**").

Aurora's primary asset is 22,200 net contiguous acres in the Sugarkane Field located in South Texas in the core of the liquids-rich Eagle Ford shale trend. Aurora's first quarter 2014 gross production was 28,671 Boe/d (81% oil and NGLs) of predominantly light, high quality crude oil. The Sugarkane Field has been largely delineated with infrastructure in place which is expected to facilitate future annual production growth. See Schedule C for further information relating to Aurora's business and assets and Schedule A for Aurora's (i) unaudited condensed consolidated financial statements as at March 31, 2014 and for the three months ended March 31, 2014 and 2013, together with the notes thereto, and (ii) audited consolidated financial statements as at December 31, 2013 and 2012 and for the years then ended, together with the notes thereto.

2.2 Acquisition Date

June 10, 2014.

2.3 Consideration

Based on cash consideration payable for Aurora of A\$4.20 (Australian dollars) per share, the total purchase price for the acquisition is estimated at \$2.8 billion (including the assumption of approximately \$0.9 billion of indebtedness).

To partially finance the acquisition, Baytex completed the issuance of 38,433,000 subscription receipts (the "**Subscription Receipts**") at \$38.90 each on February 24, 2014, raising gross proceeds of approximately \$1.5 billion. Upon completion of the Arrangement, each holder of Subscription Receipts became entitled to receive one common share of Baytex for each Subscription Receipt held. Holders of Subscription Receipts also received a payment of \$0.88 in cash per Subscription Receipt, less any applicable withholding taxes, representing the four dividends declared from the date the Subscription Receipts were issued to the date of the closing of the Arrangement.

As a result of the closing of the Arrangement, the gross proceeds of Baytex's US\$800 million private placement offering of senior notes (the "**Notes**") were released from escrow. Approximately US\$745.5 million of the net proceeds from the offering of the Notes were used to purchase the notes tendered and accepted for purchase in Baytex's cash tender offers and consent solicitations for the 9.875% Senior Notes due 2017 (the "**9.875% Notes**") and the 7.50% Senior Notes due 2020 (the "**7.50% Notes**") of Aurora USA Oil & Gas, Inc., a U.S. subsidiary of Aurora ("**Aurora USA**"), which expired at 5:00 p.m. EST on June 10, 2014. Baytex accepted valid tenders and consents from holders of US\$357.1 million in aggregate principal amount of 9.875% Notes, representing 97.84% of the outstanding aggregate principal amount of 9.875% Notes, and US\$293.6 million in aggregate principal amount of 7.50% Notes, representing 97.87% of the outstanding aggregate principal amount of 7.50% Notes.

As a result of the closing of the Arrangement and the completion of the tender offers and consent solicitations for the 9.875% Notes and the 7.50% Notes, the existing credit facilities of Baytex were replaced with a \$1.0 billion revolving unsecured credit facility with a four-year term, a \$200 million unsecured term loan facility with a two-year term and a US\$200 million revolving unsecured credit facility with a four-year term for Aurora USA.

2.4 Effect on Financial Position

There are presently no plans or proposals for material changes in Baytex's business affairs as a result of the Arrangement which may have a significant effect on the results of operating and financial position of Baytex.

2.5 Prior Valuations

No valuation required by securities legislation or a Canadian stock exchange or market to support the consideration payable by Baytex pursuant to the Arrangement has been obtained within the past 12 months by Baytex.

2.6 Parties to Transaction

Aurora was not an "informed person", "associate" or "affiliate" (as each term is defined in securities legislation) of Baytex.

2.7 Date of Report

This business acquisition report is dated July 30, 2014.

Item 3 – Financial Statements

Schedule A contains the unaudited condensed consolidated financial statements of Aurora as at March 31, 2014 and for the three months ended March 31, 2014 and 2013, together with the notes thereto and the audited consolidated financial statements of Aurora as at December 31, 2013 and 2012 and for the years then ended, together with the notes thereto.

Schedule B contains the unaudited pro forma consolidated financial statements of Baytex (after giving effect to the acquisition of Aurora) as at and for the three months ended March 31, 2014 and for the year ended December 31, 2013, together with the notes thereto.

SELECTED DEFINITIONS AND CONVERSIONS

Selected Definitions

"**2013 Acquired Assets**" means the 100% operated WI in approximately 2,700 net acres in the Heard Ranch and Axle Tree blocks in South Texas, together with interests in 11 net producing wells as well as associated interests in field infrastructure and related assets, acquired by Aurora on March 29, 2013 with an effective date of March 1, 2013.

"**AMI**" means area of mutual interest, a contractually defined area in which oil and gas companies hold oil and gas rights.

"**Canadian GAAP**" means generally accepted accounting principles in Canada, which are in effect from time to time and which, since January 1, 2011, have been consistent with International Financial Reporting Standards as issued by the International Accounting Standards Board.

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

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

"**Developed Reserves**" are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

"**Development Costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, Development Costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to: (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building, and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly; (b) drill and equip Development Wells, development type Stratigraphic Test Wells and Service Wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly; (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and (d) provide improved recovery systems.

"**Development Well**" means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

"**Eagle Ford**" means the Eagle Ford shale trend in South Texas, which produces oil, natural gas, natural gas liquids and condensate.

"**gross**" means: (a) in relation to an issuer's interest in production or reserves, its "company gross reserves", which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the issuer; (b) in relation to wells, the total number of wells in which an issuer has an interest; and (c) in relation to properties, the total area of properties in which an issuer has an interest.

"**IFRS**" means International Financial Reporting Standards.

"**Ipanema**" means the Ipanema AMI in the Sugarkane Field.

"**JOA**" means joint operating agreement among co-owners of WIs in a designated field, AMI, unit or lease.

"**Longhorn**" means the Longhorn AMI in the Sugarkane Field.

"**Marathon**" means Marathon Oil EF LLC, a wholly-owned subsidiary of Marathon Oil Corporation.

"**net**" means: (a) in relation to an issuer's interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves; (b) in relation to an issuer's interest in wells, the number of wells obtained by aggregating the issuer's working interest in each of its gross wells; and (c) in relation to an issuer's interest in a property, the total area in which the issuer has an interest multiplied by the working interest owned by the issuer.

"**NI 51-101**" means National Instrument 51-101—*Standards of Disclosure for Oil and Gas Activities*.

"**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.

"**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.

"**Proved plus Probable Reserves**" means Proved Reserves plus Probable Reserves.

"**Reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates.

"**Service Well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

"**Stratigraphic Test Well**" means a drilling effort, geologically directed, to obtain information to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration.

"**Sugarkane Field**" means the Sugarkane natural gas and condensate field within the Eagle Ford and includes the two contiguous fields designated by the Railroad Commission of Texas as the Sugarkane and Eagleville Fields.

"**Undeveloped Reserves**" are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned. In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

"**WI**" means working interest, an interest in an oil and gas lease that gives the owner the right to drill and produce oil and gas on the leased acreage.

Abbreviations

<u>Oil and Natural Gas Liquids</u>	<u>Natural Gas</u>
Bbl barrel	Mcf thousand cubic feet
Bbls..... barrels	MMcf..... million cubic feet
Bbls/d..... barrels per day	Bcf billion cubic feet
Mbbls..... thousand barrels	Mcf/d thousand cubic feet per day
MMbbls million barrels	MMcf/d..... million cubic feet per day
Mstb..... thousand stock tank barrels of oil	MMbtu..... million British Thermal Units
NGLs natural gas liquids	GJ Gigajoule

Other

AECO	the natural gas storage facility located at Suffield, Alberta, connected to TransCanada's Alberta System
API.....	American Petroleum Institute
°API.....	an indication of the specific gravity of crude oil measured on the API gravity scale
BOE or Boe	barrel or barrels of oil equivalent, using the conversion factor of six Mcf of natural gas being equivalent to one barrel of oil
Boe/d.....	barrels of oil equivalent per day
m ³	cubic metres
MBoe	thousand barrels of oil equivalent
Mcfe.....	thousand cubic feet of gas equivalent, using the conversion factor of 1 barrel of oil being equivalent to 6 Mcf of natural gas
MMMBoe.....	million barrels of oil equivalent
RLI.....	reserve life index
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade
WCS	Western Canadian Select heavy oil reference price
000s	thousands
\$000s.....	thousands of dollars
\$MM.....	millions of dollars

The term "Boe" means a barrel of oil equivalent on the basis of 6 Mcf of natural gas to 1 Bbl of oil. The term "Mcfe" means a thousand cubic feet of gas equivalent on the basis of 1 Bbl of oil to 6 Mcf of natural gas. Boes and Mcfes may be misleading, particularly if used in isolation. **A Boe conversion ratio of 6 Mcf: 1 Bbl or an Mcfe conversion ratio of 1 Bbl: 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf: 1Bbl, utilizing a conversion ratio at 6 Mcf: 1 Bbl may be misleading as an indication of value.**

Conversions

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

<u>To Convert From</u>	<u>To</u>	<u>Multiply By</u>
Mcf.....	cubic metres.....	28.174
cubic metres	cubic feet	35.494
Bbls.....	cubic metres.....	0.159
cubic metres	Bbls	6.289
Feet	Metres.....	0.305
Metres	Feet.....	3.281
Miles	kilometres	1.609
kilometres	Miles.....	0.621
Acres	hectares.....	0.405
hectares	Acres	2.471
gigajoules.....	MMbtu.....	0.950
MMbtu	gigajoules	1.0526

PRESENTATION OF FINANCIAL INFORMATION

Unless indicated otherwise, financial information in this report has been prepared in accordance with Canadian GAAP (which, since January 1, 2011, has been consistent with IFRS as issued by the International Accounting Standards Board). Aurora's historical financial statements contained in this report have been prepared in accordance with Australian Accounting Standards, which complies with IFRS as issued by the International Accounting Standards Board.

NON-GAAP MEASURES

References are made herein to "resulting netback" which does not have a standardized meaning prescribed by GAAP and therefore may not be comparable with the calculation of similar measures by other companies. Baytex believes that this measure assists in characterizing its ability to generate cash margin on a unit of production basis. Resulting netbacks referenced in this report are determined by deducting royalties and production costs from the price received for petroleum and natural gas.

PRESENTATION OF OIL AND NATURAL GAS RESERVES

The reserves estimates presented in this report were prepared to comply with Canadian reserves disclosure standards and reserves definitions as set out in NI 51-101, the Canadian Oil and Gas Evaluation Handbook and the definitions contained in the Canadian Securities Administrators Staff Notice 51-324.

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions. Actual reserves and future production from such reserves may be greater than or less than the estimates provided herein.

The recovery and reserves estimates described herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater or less than the estimates provided herein. The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation.

Numbers in the reserves tables and other oil and gas information contained in this report may not add due to rounding.

Natural gas liquids referred to in this report are reported on a combined basis with any condensate as required under NI 51-101.

The information set forth in this report relating to reserves constitutes forward-looking statements which are subject to certain risks and uncertainties. See "*Cautionary Statement Regarding Forward-Looking Statements and Information*".

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

In the interest of providing potential investors with information about Baytex, including management's assessment of future plans and operations, certain statements in this report are "forward-looking statements" within the meaning of the *United States Private Securities Litigation Reform Act of 1995* and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "**forward-looking statements**"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this report speak only as of the date hereof and are expressly qualified by this cautionary statement.

Specifically, this report (including Schedule C thereto) contains forward-looking statements related to but not limited to: the anticipated benefits from the acquisition of Aurora, including our beliefs that the acquisition will be an excellent fit with our business model and will provide shareholders with exposure to projects with attractive capital efficiencies; our expectations that the Aurora assets have infrastructure in place that support future annual production growth and that such assets will provide material production, long-term growth and high quality reserves with upside potential; the net area of Aurora's unproved property that will expire in 2014; and development of Aurora's properties and reserves. Information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

These forward-looking statements are based on certain key assumptions regarding, among other things: our ability to execute and realize on the anticipated benefits of the acquisition of Aurora; petroleum and natural gas prices and pricing differentials between light, medium and heavy gravity crude oils; well production rates and reserve volumes; Baytex's ability to add production and reserves through its exploration and development activities; capital expenditure levels; the receipt, in a timely manner, of regulatory and other required approvals for Baytex's operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; Baytex's ability to develop its crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by us at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: failure to realize the anticipated benefits of the acquisition of Aurora; declines in oil and natural gas prices; risks related to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems; variations in interest rates and foreign exchange rates; risks associated with Baytex's hedging activities; uncertainties in the credit markets may restrict the availability of credit or increase the cost of borrowing; refinancing risk for existing debt and debt service costs; a downgrade of Baytex's credit ratings; the cost of developing and operating Baytex's assets; risks associated with the exploitation of Baytex's properties and Baytex's ability to acquire reserves; changes in government regulations that affect the oil and gas industry; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating petroleum and natural gas reserves; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of Baytex's operations; risks associated with large projects or expansion of Baytex's activities; risks related to heavy oil projects; changes in environmental, health and safety regulations; the implementation of strategies for reducing greenhouse gases; depletion of our reserves; risks associated with the ownership of Baytex's securities, including the discretionary nature of dividend payments and changes in market based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond Baytex's control.

Readers are cautioned that the foregoing list of risk factors is not exhaustive. New risk factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each

such factor on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

The above summary of assumptions and risks related to forward-looking statements in this report has been provided in order to provide potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes. There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law. The forward-looking statements contained in this report are expressly qualified by this cautionary statement.

SCHEDULE A

AURORA HISTORICAL FINANCIAL STATEMENTS

.....
Unaudited Interim Financial Report
For the Three Months Ended
March 31, 2014
.....



Consolidated statement of profit or loss and other comprehensive income

For the three months ended March 31, 2014 and 2013

	Note	Consolidated	
		March 31, 2014	March 31, 2013
		US\$'000	US\$'000
Revenue from continuing operations	4	182,364	127,549
Other income	4	3,136	30
Total income		185,500	127,579
Expenses			
Royalties	4	(47,855)	(34,160)
Production and operating expenses	4	(25,378)	(13,949)
Administration expense		(6,642)	(3,810)
Depletion, depreciation and amortisation expense	4	(22,070)	(17,915)
Share-based payment expense	4	(1,200)	(1,374)
Finance costs	4	(16,093)	(10,677)
Exploration and evaluation costs	4	(36)	(282)
Foreign exchange loss	4	-	(44)
Profit from continuing operations before income tax expense		66,226	45,368
Income tax (expense)	5	(23,179)	(15,757)
Net profit attributable to owners of the Company		43,047	29,611
Other comprehensive income			
Items that may be reclassified to profit or loss:			
Changes in fair value on equity instruments measured at fair value through other comprehensive income		(22)	99
Change in fair value of cash flow hedges		(2,143)	(803)
Other comprehensive (expense) for the period net of tax		(2,165)	(704)
Total comprehensive income for the period attributable to owners of the Company		40,882	28,907
Earnings per share attributable to owners of the Company			
Basic earnings per share (US cents per share)		9.59	6.61
Diluted earnings per share (US cents per share)		9.40	6.49

The above consolidated statement of profit or loss and other comprehensive income should be read in conjunction with the accompanying notes.

Consolidated statement of financial position

As at March 31, 2014

	Note	Consolidated	
		March 31, 2014	December 31, 2013
		US\$'000	US\$'000
Current assets			
Cash and cash equivalents		48,166	42,379
Trade and other receivables	6	80,982	72,989
Total current assets		129,148	115,368
Non-current assets			
Other financial assets	7	188	210
Property, plant and equipment	8	172,263	156,243
Oil and gas properties	9	1,420,674	1,320,180
Derivative financial instruments		-	85
Total non-current assets		1,593,125	1,476,718
Total assets		1,722,273	1,592,086
Current liabilities			
Trade and other payables	11	164,046	205,922
Derivative financial instruments	10	8,678	5,937
Provisions	12	627	506
Total current liabilities		173,351	212,365
Non-current liabilities			
Borrowings	13	765,225	660,976
Deferred tax liabilities	14	167,935	145,684
Derivative financial instruments	10	234	-
Provisions	15	3,181	2,808
Total non-current liabilities		936,575	809,468
Total liabilities		1,109,926	1,021,833
Net assets		612,347	570,253
Equity			
Contributed equity	16	405,065	404,512
Share-based payment reserve		17,537	16,878
Fair value reserve		(7,481)	(7,459)
Foreign exchange reserve		(7,505)	(7,505)
Cash flow hedges reserve		(6,239)	(4,096)
Retained earnings		210,970	167,923
Total equity		612,347	570,253

The above consolidated statement of financial position should be read in conjunction with the accompanying notes

Consolidated statement of changes in equity

For the three months ended March 31, 2014 and 2013

	Contributed Equity	Other Reserve	Accumulated Profits /(Losses)	Total
	US\$'000	US\$'000	US\$'000	US\$'000
Balance at January 1, 2013	405,169	(3,548)	51,493	453,114
Profit for the period	-	-	29,611	29,611
Other comprehensive income				
Change in fair value of equity instruments measured at fair value through other comprehensive income	-	99	-	99
Change in fair value of cash flow hedges	-	(803)	-	(803)
Total comprehensive income for the period	-	(704)	29,611	28,907
Transactions with owners, in their capacity as owners				
Contributed equity net of transaction costs	(13)	-	-	(13)
Options and performance rights expense recognised during the period	-	1,126	-	1,126
Balance as at March 31, 2013	405,156	(3,126)	81,104	483,134
Balance as at January 1, 2014	404,512	(2,182)	167,923	570,253
Profit for the period	-	-	43,047	43,047
Other comprehensive income				
Change in fair value of equity instruments measured at fair value through other comprehensive income	-	(22)	-	(22)
Change in fair value of cash flow hedges	-	(2,143)	-	(2,143)
Total comprehensive income for the period	-	(2,165)	43,047	40,882
Transactions with owners, in their capacity as owners				
Contributed equity net of transaction costs	553	-	-	553
Options and performance rights expense recognised during the period	-	659	-	659
Balance as at March 31, 2014	405,065	(3,688)	210,970	612,347

The above consolidated statement of changes in equity should be read in conjunction with the accompanying notes.

Consolidated statement of cash flows

For the three months ended March 31, 2014 and 2013

	Consolidated	
	March 31, 2014 US\$'000	March 31, 2013 US\$'000
Cash flows from operating activities		
Receipts from oil and gas sales	175,347	144,813
Payments to suppliers and employees	(104,300)	(64,773)
Other revenue	3,134	30
Interest paid	(29,683)	(18,251)
Net cash inflow from operating activities	44,498	61,819
Cash flows from investing activities		
Payments for capitalised oil and gas assets	(132,840)	(201,613)
Payment for property, plant and equipment	(9,723)	(12,777)
Interest received	6	10
Net cash (outflow) from investing activities	(142,557)	(214,380)
Cash flows from financing activities		
Share issue costs	-	(13)
Proceeds from borrowings	104,000	330,000
Repayment of borrowings	-	(60,000)
Borrowing costs	(126)	(8,137)
Net cash inflow from financing activities	103,874	261,850
Net increase in cash and cash equivalents	5,815	109,289
Cash and cash equivalents at the beginning of the financial period	42,379	67,584
Effect of exchange rates on cash holdings in foreign currencies	(28)	(43)
Cash and cash equivalents at the end of the financial period	48,166	176,830

The above consolidated statement of cash flows should be read in conjunction with the accompanying notes.

Notes to the financial statements

For the three months ended March 31, 2014

1. Basis of Preparation

The financial report consists of consolidated financial statements for Aurora Oil & Gas Limited and its subsidiaries ("Group" or "Consolidated Entity").

These general purpose financial statements for the period ended March 31, 2014 have been prepared in accordance with Australian Accounting Standard 134 *Interim Financial Reporting* and the *Corporations Act 2001*.

The interim financial report does not include all the notes of the type normally included in annual financial statements. Accordingly, this financial report should be read in conjunction with the most recent annual financial report for the year ended December 31, 2013 and any public announcements made by the Company during the interim period in accordance with the disclosure requirements of the *Corporations Act 2001*.

The accounting policies adopted are consistent with those of the previous financial period. All references in this report are to US dollars unless otherwise stated.

The Company has considered the impact of new standards not yet effective and does not consider that they would have a material impact on the Company's financial statements.

2. Segment information

Management has determined, based on the reports reviewed by the CEO and the Executive Chairman and used to make strategic decisions, that the Group has one reportable segment being oil and gas exploration and production in the United States of America. The Group's management and administration office is located in Australia.

The CEO and the Executive Chairman review internal management reports on a monthly basis that are consistent with the information provided in the statement of profit or loss and other comprehensive income, statement of financial position and statement of cash flows. As a result no reconciliation is required, because the information as presented is used by the CEO and the Executive Chairman to make strategic decisions.

Reportable segment revenue

Revenue, including interest income, is disclosed below based on the reportable segment:

	Three months ended	
	March 31, 2014 US\$'000	March 31, 2013 US\$'000
Revenue from oil and gas exploration and production	182,358	127,539
Revenue from other corporate activities	3,142	40
	185,500	127,579

Reportable segment assets

Assets are disclosed below based on the reportable segment:

	March 31, 2014 US\$'000	December 31, 2013 US\$'000
Assets from oil and gas exploration and production	1,671,368	1,546,701
Assets from corporate activities:		
Cash and cash equivalents	48,166	42,379
Other corporate assets	2,739	3,006
	1,722,273	1,592,086

Notes to the financial statements

For the three months ended March 31, 2014

2. Segment information (continued)

Reportable segment liabilities

Liabilities are disclosed below based on the reportable segment:

	March 31, 2014	December 31, 2013
	US\$'000	US\$'000
Liabilities from oil and gas exploration and production	1,104,961	1,016,834
Liabilities from corporate activities	4,965	4,999
	1,109,926	1,021,833

Reportable segment profit

Profit / (loss) is disclosed below based on the reportable segment:

	Three months ended	
	March 31, 2014	March 31, 2013
	US\$'000	US\$'000
Profit from oil and gas exploration and production	47,062	34,640
(Loss) from other corporate activities	(4,015)	(5,029)
	43,047	29,611

3. Dividends

No dividend has been paid or is proposed in respect of the period ended March 31, 2014 (March 31, 2013: None).

4. Profit for the period

Profit for the period ended March 31, 2014 includes the following items which are significant because of their nature, size or incidence:

	Three months ended	
<i>Note</i>	March 31, 2014	March 31, 2013
	US\$'000	US\$'000
Income		
<i>Revenue from continuing operations</i>		
Oil and gas sales	184,483	128,092
Realised (loss) on forward commodity price contracts	(2,125)	(553)
Interest	6	10
	182,364	127,549
<i>Other income</i>		
Foreign exchange gain	2	-
Other	3,134	30
	3,136	30
Total Income	185,500	127,579

Notes to the financial statements

For the three months ended March 31, 2014

4. Profit for the period (continued)

		Three months ended	
		March 31, 2014 US\$'000	March 31, 2013 US\$'000
Expenses			
Royalties expense	(i)	(47,855)	(34,160)
Production and operating expense			
Production and other taxes*	(ii)	(9,007)	(5,014)
Operating expenses*	(iii)	(16,371)	(8,935)
Total production and operating expenses		<u>(25,378)</u>	<u>(13,949)</u>
Depletion and depreciation expense			
Depletion	(iv)	(17,883)	(16,035)
Depreciation	(v)	(4,187)	(1,880)
Total depletion and depreciation expense		<u>(22,070)</u>	<u>(17,915)</u>
Share-based payment expense			
Options		(351)	(713)
Performance rights		(849)	(660)
Total share-based payment expenses	(vi)	<u>(1,200)</u>	<u>(1,374)</u>
Finance costs			
Interest expense		(14,604)	(9,708)
Amortisation of borrowing costs		(1,142)	(769)
Amortisation of debt premium and debt discount		(8)	(8)
Other financing fees		(339)	(192)
Total finance costs	(vii)	<u>(16,093)</u>	<u>(10,677)</u>
Exploration and evaluation costs written off	(viii)	<u>(36)</u>	<u>(282)</u>
Foreign exchange loss	(ix)	<u>-</u>	<u>(44)</u>

* Sales and other taxes for the comparative three month period ended March 31, 2013 includes US\$783,177 of ad valorem taxes previously recognised as operating expenses in the Unaudited Interim Financial Report for three months ended March 31, 2013.

- (i) Aurora pays royalties to the owners of the petroleum rights on the land in which the Group owns lease interests. Royalties, as a percentage of production revenue, are payable in accordance with the terms of individual leasehold agreements and are generally payable for the production life of each well within the leasehold area.
- (ii) Production and other taxes include local tax expense and severance tax payable in the State of Texas, USA.
- (iii) Operating expenses include field operating costs and transportation of production.
- (iv) Depletion is calculated based on estimated remaining Proven and Probable reserves.
- (v) Depreciation is calculated using the reducing balance method to allocate the cost of property, plant and equipment over their useful lives.
- (vi) The Group has issued performance rights to key management personnel, including to executive directors, under Aurora's Long Term Incentive Plan ("LTIP"). The group has also issued options to executive management personnel and directors, including non-executive directors. For the three months to March 31, 2014 a performance right expense of US\$849,174 (March 31, 2013: US\$660,263) and an option expense of US\$350,749 (March 31, 2013: US\$713,408) were recognised.

Notes to the financial statements

For the three months ended March 31, 2014

4. Profit for the period (continued)

- (vii) Finance fees were incurred in respect of the senior secured revolving credit facility entered into on November 8, 2011 and the senior unsecured notes issued on February 8, 2012, the follow on notes issued on July 31, 2012 and the senior unsecured notes issued on March 21, 2013.
- (viii) Evaluation costs written off during the period ended March 31, 2014 consisted of evaluation expenditure that could not be directly attributable to the acquisition, construction or production of a qualifying asset providing probable future economic benefits to the entity.
- (ix) During the period ended March 31, 2014 the Consolidated Entity recognised a foreign exchange gain in relation to the retranslation of Australian and Canadian dollar denominated balances.

5. Income tax expense

	Three months ended	
	March 31, 2014 US\$'000	March 31, 2013 US\$'000
(a) Income tax expense		
Current tax	-	-
Deferred tax	23,179	15,757
Income tax expense	23,179	15,757
(b) Reconciliation of income tax expense to prima facie tax payable		
Profit from continuing operations before income tax expense	66,226	45,367
Tax at the Australian statutory tax rate of 30% (March 31, 2013: 30%)	19,868	13,610
Tax effect of amounts that are not deductible (taxable) in calculating taxable income:		
Share-based payment expense	142	189
Foreign exchange gains /(losses) not assessable	(4)	11
Revenue losses not previously recognised now brought to account (Expense)/benefit from a previously unrecognised temporary difference now recognised	(52)	(140)
Income tax rate differences	3,317	2,280
Other non-deductible/(assessable)	(92)	171
Income tax expense	23,179	15,757
(c) Tax expense (income) relating to items of other comprehensive income		
Financial assets at fair value through other comprehensive income	10	(41)
Cash flow hedges	918	344
	928	303

Notes to the financial statements

For the three months ended March 31, 2014

6. Trade and other receivables

	Consolidated	
	March 31, 2014 US\$'000	December 31, 2013 US\$'000
Trade receivables	(i) 80,982	72,989

(i) Trade receivable

Trade receivables represents revenue earned but not yet received from the production and sale of oil, natural gas and natural gas liquids.

(ii) Impaired trade receivables

No Group trade receivables were past due or impaired as at March 31, 2014 (December 31, 2013: Nil) and there is no indication that amounts recognised as trade and other receivables will not be recovered in the normal course of business.

7. Other Financial Assets

	Consolidated	
	March 31, 2014 US\$'000	December 31, 2013 US\$'000
Non-current		
Financial assets at fair value through other comprehensive income	188	210

Significant interest in other financial assets

An interest in a financial asset is considered 'significant' when Aurora holds 5% or more of issued share capital.

Aurora holds a significant interest in Elixir Petroleum Ltd. As at March 31, 2014, Aurora held 33,833,334 fully paid ordinary shares in Elixir Petroleum Ltd (December 31, 2013: 33,833,334), representing approximately 7.84% of its total issued capital. The market value of these securities at March 31, 2014 was US\$187,708 (December 31, 2013: US\$210,135).

Included in the statement of comprehensive income is (US\$22,000) (December 31, 2013: (US\$405,000)) which represents the movement in the financial assets at fair value through other comprehensive income.

8. Property, plant and equipment

	Consolidated	
	March 31, 2014 US\$'000	December 31, 2013 US\$'000
Production facilities and field equipment		
Production facilities and field equipment at cost	186,470	166,127
Production facilities and field equipment accumulated depreciation	(16,407)	(12,351)
Total production facilities and field equipment	170,063	153,776
Office equipment		
Office equipment at cost	2,973	3,177
Office equipment accumulated depreciation	(773)	(710)
Total office equipment	2,200	2,467
Total property, plant and equipment	172,263	156,243

Notes to the financial statements

For the three months ended March 31, 2014

9. Oil and gas properties

	Consolidated	
	March 31, 2014 US\$'000	December 31, 2013 US\$'000
Producing projects		
At cost	1,502,611	1,361,593
Accumulated depletion	(137,437)	(118,779)
Net carrying value	<u>1,365,174</u>	<u>1,242,814</u>
Development projects		
At cost	55,500	77,366
Net carrying value	<u>55,500</u>	<u>77,366</u>
Total oil and gas properties	<u>1,420,674</u>	<u>1,320,180</u>

A reconciliation of movements in oil and gas properties during the three months ended March 31, 2014 is as follows:

Producing projects

Cost

Opening balance	1,361,593	917,501
Transfer from development projects	22,117	-
Additions	118,700	432,134
Increase in restoration provision	372	1,103
Capitalised borrowing costs	-	8,883
Net movement in prepaid costs	(171)	1,972
Closing balance	<u>1,502,611</u>	<u>1,361,593</u>

Accumulated Depletion and Amortisation

Opening balance	(118,779)	(41,207)
Depletion charge	(17,883)	(74,703)
Amortisation	(775)	(2,869)
Closing balance	<u>(137,437)</u>	<u>(118,779)</u>

Net carrying value

Opening carrying value	<u>1,242,814</u>	876,294
Closing carrying value	<u>1,365,174</u>	<u>1,242,814</u>

Development projects

Cost

Opening balance	77,366	6,079
Transfer to producing projects	(22,117)	-
Additions	118	71,163
Net movements in prepaid costs	133	124
Closing balance	<u>55,500</u>	<u>77,366</u>

Net carrying value

Opening carrying value	<u>77,366</u>	6,079
Closing carrying value	<u>55,500</u>	<u>77,366</u>

Notes to the financial statements

For the three months ended March 31, 2014

10. Derivative financial instruments

	<u>Consolidated</u>	
	<u>March 31, 2014</u>	<u>December 31, 2013</u>
	<u>US\$'000</u>	<u>US\$'000</u>
Forward commodity contracts – cash flow hedges		
Current	8,678	5,937
Non - current	234	(85)
Total derivative financial instrument liabilities	8,912	5,852

Instruments used by the group

The Group is a party to derivative financial instruments entered into in the normal course of business in order to hedge exposure to fluctuations in commodity prices in accordance with the group's financial risk management policies.

Forward commodity price contracts – cash flow hedges

At March 31, 2014, the Group has various oil commodity contracts designated as hedges of expected future oil sales. These contracts are all designated as cash flow hedges and are used to reduce the exposure to a future decrease in the value of oil sales. The outstanding contracts held by the Group at March 31, 2014 are as follows:

Year of delivery	Subject of contract	Reference	Option traded	Barrels	Weighted average US\$ / barrel			Fair value US\$'000
					Strike price	Floor price	Ceiling price	
2014	Oil	Nymex WTI	Swap	1,844,700	93.94	-	-	(7,303)
2014	Oil	Nymex WTI	Zero Cost Collar	180,000	-	80.00	97.88	(681)
2015	Oil	Nymex WTI	Swap	816,000	90.84	-	-	(928)
Total				2,840,700				(8,912)

The hedge contracts are to be settled at a rate of between 152,000 to 285,100 barrels per month in 2014 and 2015.

The portion of the gain or loss on the hedging instrument that is determined to be an effective hedge is recognised in other comprehensive income. When the cash flows occur, the Group adjusts the initial measurement of the component recognised in the statement of financial position by removing the related amount from other comprehensive income.

11. Trade and other payables

	<u>Consolidated</u>	
	<u>March 31, 2014</u>	<u>December 31, 2013</u>
	<u>US\$'000</u>	<u>US\$'000</u>
Trade payables and accruals	164,046	205,922
	164,046	205,922

Trade and other payables are normally settled within 30 days from receipt of invoice. All amounts recognised as trade and other payables, but not yet invoiced, are expected to be settled within the next 12 months.

Notes to the financial statements

For the three months ended March 31, 2014

12. Provisions – Current

	Consolidated	
	March 31, 2014 US\$'000	December 31, 2013 US\$'000
Employee benefits	627	506

13. Borrowings – Non Current

		Consolidated	
		March 31, 2014 US\$'000	December 31, 2013 US\$'000
Secured			
Senior secured syndicated facility	(a)	104,000	-
Unsecured			
Senior unsecured notes	(b)	661,225	660,976
		765,225	660,976

(a) Senior Secured Revolving Credit facility

On November 8, 2011, Aurora USA Oil and Gas Inc. ("Aurora USA"), a wholly owned subsidiary of the Company, signed a US\$300 million credit agreement with a syndicate of banks, pursuant to which funds are available on a revolving basis up to an established amount at a margin of between 2 and 3 per cent over the floating LIBOR rate. The Facility ("Facility") contains negative and affirmative covenants and matures on November 7, 2016.

The funding under the Facility will be provided with availability determined, at a minimum on a semi-annual basis, relative to a borrowing base calculated by reference to proved reserves. The Facility is designed for the borrowing base to increase with Aurora's increased proved reserves, subject to and in accordance with the terms of the credit agreement. During September 2013 the borrowing base was re-determined following the 2013 mid-year reserves update from US\$200 million to US\$300 million.

During February 2014 US\$37 million was drawn from the revolving credit facility and in March 2014 a further US\$67 million was drawn from the facility. The remaining undrawn balance is US\$196 million as at March 31, 2014.

Aurora USA's obligations under the Facility are guaranteed by pledged security from the parent entity, Aurora, and the subsidiaries of Aurora USA. At March 31, 2014, the following investment property remained pledged as security:

Owner / Grantor	Issuer	Percentage Owned	Percentage Pledged	Class of stock
Aurora Oil and Gas Limited	Aurora USA Oil and Gas, Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas, Inc.	Wardanup Oil and Gas, Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas, Inc.	Sugarloaf Oil and Gas, Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas, Inc.	Yallingup Oil and Gas, Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas, Inc.	Trigg Oil and Gas, Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas, Inc.	Aurora USA Development, LLC.	100%	100%	Membership Interest
Aurora USA Oil and Gas, Inc.	ATW Exploration Oil and Gas, Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas, Inc.	Aurora EF Production Company	100%	100%	Common Stock
Aurora USA Oil and Gas, Inc.	EKA 002, Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas, Inc.	EKA 003, Inc.	100%	100%	Common Stock
EKA 003, Inc.	EKA 003, LLC.	100%	100%	Membership Interest
Aurora USA Oil and Gas, Inc.	SIEB Operating, Inc.	100%	100%	Common Stock

The carrying value of assets pledged as securities for non-current borrowings is US\$583,072,000 (December 31, 2013: US\$527,694,000).

Notes to the financial statements

For the three months ended March 31, 2014

13. Borrowings (continued)

In addition to investment property pledged, a negative pledge imposes that certain financial covenants be maintained by Aurora, Aurora USA and its subsidiaries.

(b) Senior unsecured note

On February 8, 2012 Aurora USA, a wholly owned subsidiary of the Company, completed a private offering of unsecured notes ("2017 Senior Note Offering"). Under the 2017 Senior Note Offering, Aurora USA issued an aggregate principal amount of US\$200 million 9.875% senior unsecured notes ("2017 Senior Notes") due February 2017 at an issue price of 98.552% of their face value, resulting in net proceeds of approximately US\$192 million after deduction of the original discount and commissions. The 2017 Senior Notes were issued pursuant to an indenture dated February 8, 2012 by and amongst Aurora USA, the guarantor parties thereto and US Bank National Association, as trustee.

On July 31, 2012 Aurora USA completed a follow on offering of the 2017 Senior Notes, issuing an aggregate principal amount of US\$165 million 9.875% senior unsecured notes due in February 2017 at a premium of 101.5% of their face value, resulting in net proceeds of approximately US\$164 million after addition of premium and deduction of commissions.

On March 21, 2013 Aurora USA completed a new offering of senior unsecured notes ("2020 Senior Note Offering"), issuing an aggregate principal amount of US\$300 million 7.50% senior unsecured notes ("2020 Senior Notes"), due in April 2020 at par, resulting in net proceeds of approximately US\$293 million after deductions of commissions. The 2020 Senior Notes will bear interest at 7.50% per annum and will be payable semi-annually in arrears, beginning October 1, 2013.

(c) Fair value

The carrying amounts and fair value of borrowings at the end of the reporting period are:

	March 31, 2014		December 31, 2013	
	Carrying amount US\$'000	Fair Value US\$'000	Carrying amount US\$'000	Fair Value US\$'000
Secured				
Senior secured syndicated facility	104,000	104,000	-	-
Unsecured				
Senior unsecured notes	661,225	665,000	660,976	665,000
Total borrowings	765,225	769,000	660,976	665,000

The fair value borrowings equal their carrying amount, as the impact of discounting is not significant. The fair value of senior unsecured notes is stated gross of borrowing costs, premium and discount.

Notes to the financial statements

For the three months ended March 31, 2014

14. Deferred tax liabilities

	Consolidated	
	March 31, 2014 US\$'000	December 31, 2013 US\$'000
(a) Deferred tax asset		
<i>Arising from temporary differences attributable to:</i>		
Tax losses ⁽¹⁾		
Australia	1,490	1,046
United States	212,950	203,781
Share issue expense	723	671
Other	9,957	10,002
Available-for-sale financial assets	1,294	1,284
Cash flow hedge	2,465	1,547
Total deferred tax asset	228,879	218,331
Less set off against deferred tax liabilities under set-off provisions (b)	(228,879)	(218,331)
(b) Deferred tax liability		
<i>Arising from temporary differences attributable to:</i>		
Oil and gas properties	(389,556)	(358,816)
Management fees and borrowing costs	(7,258)	(5,199)
Total deferred tax liabilities	(396,814)	(364,015)
Less set off of deferred tax asset under set-off provisions (a)	228,879	218,331
Net deferred tax liabilities	(167,935)	(145,684)
Deferred tax liabilities expected to be settled within 12 months	-	-
Deferred tax liabilities expected to be settled after more than 12 months	(167,935)	(145,684)

1. The deferred tax liabilities arising from accumulated tax losses for US taxpaying entities and on US based oil and gas properties have been calculated at the marginal tax rate of 35%.

15. Provisions – Non-current

	Consolidated	
	March 31, 2014 US\$'000	December 31, 2013 US\$'000
Restoration provision	3,181	2,808

Provisions for future removal and restoration costs are recognised where there is a present obligation as a result of exploration, development, production, transportation or storage activities having been undertaken, and it is probable that an outflow of economic benefits will be required to settle the obligation. Restoration costs are based on the latest estimated future costs as disclosed in the independently prepared reserves report, determined on a discounted basis. The estimated future obligations include the costs of removing facilities, abandoning wells and restoring the affected areas.

Notes to the financial statements

For the three months ended March 31, 2014

16. Contributed equity

	March 31, 2014	December 31, 2013	March 31, 2014	December 31, 2013
	Securities	Securities	US\$'000	US\$'000
Share capital				
Ordinary shares	448,785,778	448,785,778	405,148	405,148
Treasury shares	(42,328)	(247,349)	(83)	(636)
Total contributed equity	448,743,450	448,538,429	405,065	404,512

(a) Ordinary shares

Ordinary shares entitle the holder to participate in dividends and the proceeds on winding up of the Company in proportion to the number of shares held. On a show of hands every holder of ordinary shares present at a meeting or by proxy, is entitled to one vote. Upon poll every holder is entitled to one vote per share held.

(b) Movements in contributed equity:

	Date	Number of Securities	Issue Price	US\$'000
Balance January 1, 2013		447,885,778		405,169
Performance rights exercise	08-Aug-13	900,000	-	-
Share issue costs				(21)
Balance at December 31, 2013		448,785,778		405,148
Balance at March 31, 2014		448,785,778		405,148

(c) Treasury Shares

Treasury shares are shares in Aurora Oil & Gas Limited that are held by the Aurora Oil & Gas Employee Share Trust for the purpose of issuing shares under the Aurora Oil & Gas Limited Long Term Incentive.

	Date	Number of Securities	Issue Price	US\$'000
Balance at January 1, 2013		-		-
Aurora Oil & Gas Employee Share Trust Acquisition	21-Nov-13	(171,293)	A\$2.92	(458)
Aurora Oil & Gas Employee Share Trust Distribution	29-Nov-13	100,000	A\$3.03	277
Aurora Oil & Gas Employee Share Trust Acquisition	6-Dec-13	(176,056)	A\$2.84	(455)
Balance at December 31, 2013		(247,349)		(636)
Aurora Oil & Gas Employee Share Trust Distribution	19-Feb-14	205,021	A\$4.10	(553)
Balance at March 31, 2014		(42,328)		(83)

Notes to the financial statements

For the three months ended March 31, 2014

17. Commitments

Capital expenditure contracted for at the reporting date but not recognised as a liability is as follows:

	Consolidated	
	March 31, 2014	December 31, 2013
	US\$'000	US\$'000
Oil and gas properties		
Payable:		
Within one year	104,929	27,588
Later than one year but not later than five years	-	-
Later than five years	-	-
	104,929	27,588
Property, plant and equipment		
Payable:		
Within one year	6,698	3,586
Later than one year but not later than five years	-	-
Later than five years	-	-
	6,698	3,586
Rent		
Payable:		
Within one year	1,429	1,419
Later than one year but not later than five years	5,832	5,173
Later than five years	876	1,093
	8,137	7,685
Total commitments	119,764	38,859

18. Contingencies

	Consolidated	
	March 31, 2014	December 31, 2013
	US\$'000	US\$'000
Contingent liabilities		
Employee transaction payments	1,277	-

On February 6, 2014, Aurora announced the entering into of a scheme implementation deed with Baytex Energy Corp. ("Baytex"), pursuant to which Baytex will acquire all of the issued and outstanding Ordinary Shares for cash consideration of A\$4.10 per ordinary share pursuant to a scheme of arrangement under the Corporations Act (the "Scheme"). If the Scheme were to be implemented, Aurora would become a wholly-owned subsidiary of Baytex and would be delisted from both the ASX and TSX. In order for the Scheme to be implemented, it must be approved by Aurora shareholders at a special meeting of shareholders that has been called for 21 May 2014 (the "Scheme Meeting"). The Scheme is subject to a number of customary closing conditions, including the receipt of the required regulatory approvals, approval of the requisite majority of Aurora shareholders at Scheme Meeting and the final approving orders of the Australian Court.

Certain individuals have played significant roles in the negotiation of the Scheme Implementation Deed with Baytex and preserving the stability and continuity of operations. Additionally, executive directors would have, in the ordinary course, been entitled to receive an award under Aurora's Long Term Incentive Plan around the time of the Scheme booklet. In recognition of these factors, the Aurora Board (in the absence of Board members to which transaction payments pertain) has resolved to make transaction payments, conditional upon the implementation of the Scheme.

Notes to the financial statements

For the three months ended March 31, 2014

19. Related party transactions

During the three months ended March 31, 2014 there were no related party transactions.

20. Events occurring after reporting date

No event has occurred since March 31, 2014 that would materially affect the operations of the Consolidated Entity, the results of the Consolidated Entity or the state of affairs of the Consolidated Entity not otherwise disclosed in the Consolidated Entity's financial statements.

21. Rounding of amounts

The company satisfies the requirements of Class Order 98/0100 issued by the Australian Investments and Securities Commission relating to "rounding off" of amounts in the directors' report and the financial report to the nearest thousand dollars. Amounts have been rounded off in the directors' report and financial report in accordance with that Class Order.

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2013 Annual Report
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Management Report

Management, in accordance with Australian Accounting Standards including Australian equivalents to International Financial Reporting Standards (AIFRS), has prepared the accompanying consolidated financial statements of Aurora Oil and Gas Limited (Aurora). Financial and operating information presented throughout this report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

BDO Audit (WA) Pty Ltd were appointed by the Company's Board of Directors to conduct an audit of the consolidated financial statements. Their examination included a review and evaluation of Aurora's internal control systems and included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with Australian Accounting Standards including Australian equivalents to compliance with AIFRS ensures that the financial statements of Aurora comply with International Financial Reporting Standards.

The Board of Directors is responsible for ensuring that management fulfils its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit and Risk Management Committee, with assistance from the Reserves Committee regarding the annual evaluation of our petroleum and natural gas reserve. The Audit and Risk Management Committee meets regularly with management and the independent auditors to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit and Risk Management Committee also considers the independence of the external auditors and reviews their fees. The external auditors have access to the Audit and Risk Management Committee without the presence of management.

"Jonathan Stewart"

"Graham Dowland"

Jonathan Stewart
Executive Chairman

Graham Dowland
Finance Director

March 21, 2014

Independent Audit Report



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INDEPENDENT AUDITOR'S REPORT

To the members of Aurora Oil & Gas Limited

Report on the Financial Report

We have audited the accompanying financial report of Aurora Oil & Gas Limited, which comprises the consolidated statement of financial position as at 31 December 2013 and 31 December 2012, the consolidated statement of profit or loss and other comprehensive income, the consolidated statement of changes in equity and the consolidated statement of cash flows for the years then ended, notes comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Report

Management is responsible for the preparation and fair presentation of the financial report in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of the financial report that is free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on the financial report based on our audit. We conducted our audit in accordance with international generally accepted auditing standards. Those standards require that we comply with relevant ethical requirements relating to audit engagements and plan and perform the audit to obtain reasonable assurance about whether the financial report is free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial report. The procedures selected depend on the auditor's judgement, including the assessment of the risks of material misstatement of the financial report, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the company's preparation of the financial report that gives a true and fair view 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 company'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 financial report.

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

BDO Audit (WA) Pty Ltd ABN 79 112 284 787 is a member of a national association of independent entities which are all members of BDO (Australia) Ltd ABN 77 050 110 275, an Australian company limited by guarantee. BDO Audit (WA) Pty Ltd and BDO (Australia) Ltd are members of BDO International Ltd, a UK company limited by guarantee, and form part of the international BDO network of independent member firms. Liability limited by a scheme approved under Professional Standards Legislation (other than for the acts or omissions of financial services licensees) in each State or Territory other than Tasmania.

Independent Audit Report



Opinion

In our opinion, the financial report presents fairly, in all material respects the consolidated financial position of Aurora Oil & Gas Limited as at 31 December 2013 and 31 December 2012 and its performance for the years then ended in accordance with *International Financial Reporting Standards* as disclosed in Note 1.

BDO Audit (WA) Pty Ltd

BDO


Glyn O'Brien

Director

Perth, 21 March 2014

Consolidated Statement of Profit or Loss and Other Comprehensive Income

For the year ended December 31, 2013

	Note	Consolidated	
		December 31, 2013 US\$'000	December 31, 2012 US\$'000
Revenue from continuing operations	(5)	562,766	295,059
Other income	(6)	164	5,008
Total income		562,930	300,067
Expenses			
Royalties	(7)	(149,429)	(77,625)
Production and operating expenses	(7)	(60,766)	(34,581)
Depletion, depreciation and amortisation expense	(7)	(83,632)	(39,161)
Exploration and evaluation costs	(7)	(503)	(4,939)
Finance costs	(7)	(59,493)	(28,027)
Administrative expenses		(23,967)	(15,134)
Share-based payment expenses	(7)	(5,376)	(4,398)
Foreign exchange loss	(7)	(346)	-
Profit from continuing operations before income tax expense		179,418	96,202
Income tax expense	(8)	(62,988)	(37,356)
Net profit attributable to owners of the Company		116,430	58,846
Other comprehensive income			
<i>Items that will not be reclassified to profit or loss</i>			
Changes in fair value on equity instruments measured at fair value through other comprehensive income	(11)	(405)	957
<i>Items that may be reclassified to profit or loss</i>			
Change in fair value of cash flow hedges	(18)	(2,942)	(1,154)
Other comprehensive (expenses) for the year net of tax		(3,347)	(197)
Total comprehensive income for the year attributable to owners of the Company		113,083	58,649
Earnings per share attributable to owners of the Company			
Basic earnings per share (US cents per share)	(24)	25.97	13.60
Diluted earnings per share (US cents per share)	(24)	25.51	13.35

The above consolidated statement of profit or loss and other comprehensive income should be read in conjunction with the accompanying notes.

Consolidated Statement of Financial Position

As at December 31, 2013

	Note	Consolidated	
		December 31, 2013 US\$'000	December 31, 2012 US\$'000
Current assets			
Cash and cash equivalents	(9)	42,379	67,584
Trade and other receivables	(10)	72,989	89,535
Total current assets		115,368	157,119
Non-current assets			
Other financial assets	(11)	210	842
Property, plant and equipment	(12)	156,243	71,063
Oil and gas properties	(13)	1,320,180	882,373
Derivative financial instruments	(18)	85	-
Total non-current assets		1,476,718	954,278
Total assets		1,592,086	1,111,397
Current liabilities			
Trade and other payables	(14)	205,922	180,619
Derivative financial instruments	(18)	5,937	1,535
Provisions	(15)	506	334
Total current liabilities		212,365	182,488
Non-current liabilities			
Borrowings	(16)	660,976	390,453
Deferred tax liabilities	(17)	145,684	83,523
Derivative financial instrument	(18)	-	114
Provisions	(19)	2,808	1,705
Total non-current liabilities		809,468	475,795
Total liabilities		1,021,833	658,283
Net assets		570,253	453,114
Equity			
Contributed equity	(20)	404,512	405,169
Share-based payment reserve	(23)	16,878	12,165
Fair value reserve	(23)	(7,459)	(7,054)
Foreign exchange reserve	(23)	(7,505)	(7,505)
Cash flow hedge reserve	(23)	(4,096)	(1,154)
Retained earnings	(23)	167,923	51,493
Total equity		570,253	453,114

The above consolidated statement of financial position should be read in conjunction with the accompanying notes

On behalf of the Board of Directors:

"Jonathan Stewart"

Jonathan Stewart
Executive Chairman

"Graham Dowland"

Graham Dowland
Finance Director

Consolidated Statement of Changes in Equity

For the year ended December 31, 2013

	Contributed Equity US\$'000	Other Reserve US\$'000	Accumulated Profits / Losses US\$'000	Total US\$'000
Balance as at January 1, 2012	290,194	(7,749)	(7,353)	275,092
Profit for the year	-	-	58,846	58,846
Other comprehensive income				
Change in fair value of equity instruments measured at fair value through other comprehensive income	-	916	-	916
Change in fair value of cash flow hedges	-	(1,154)	-	(1,154)
Recognition of fair value of equity instruments measured at fair value through other comprehensive income on disposal	-	41	-	41
Total comprehensive income for the year	-	(197)	58,846	58,649
Transactions with owners, in their capacity as owners				
Contributed equity net of transaction costs	114,975	-	-	114,975
Options and performance rights expense recognised during the year	-	4,398	-	4,398
Balance as at December 31, 2012	405,169	(3,548)	51,493	453,114
Profit for the year	-	-	116,430	116,430
Other comprehensive income				
Change in fair value of equity instruments measured at fair value through other comprehensive income	-	(405)	-	(405)
Change in fair value of cash flow hedges	-	(2,942)	-	(2,942)
Total comprehensive income for the year	-	(3,347)	116,430	113,083
Transactions with owners, in their capacity as owners				
Contributed equity net of transaction costs	(657)	-	-	(657)
Options and performance rights expense recognised during the year	-	4,713	-	4,713
Balance as at December 31, 2013	404,512	(2,182)	167,923	570,253

The above consolidated statement of changes in equity should be read in conjunction with the accompanying notes.

Consolidated Statement of Cash Flows

For the year ended December 31, 2013

	Consolidated	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Cash flows from operating activities		
Receipts from oil and gas sales	579,260	221,539
Payments to suppliers and employees	(243,023)	(67,433)
Other revenue	141	1,167
Interest paid	(48,148)	(11,151)
Net cash inflow from operating activities	(31) 288,230	144,122
Cash flows from investing activities		
Payments for capitalised oil and gas assets	(482,349)	(452,635)
Payment for property, plant and equipment	(89,062)	(51,352)
Payment of exploration, evaluation and development	-	(4,939)
Payment for other financial assets	-	(252)
Payment for acquisition of subsidiary, net of cash acquired	(21) -	(98,765)
Interest received	52	247
Net cash (outflow) from investing activities	(571,359)	(607,696)
Cash flows from financing activities		
Proceeds from issues of shares	-	120,138
Share issue costs	(21)	(5,163)
Proceeds from borrowings	330,000	394,579
Repayment of borrowings	(60,000)	(39,000)
Borrowing costs	(11,124)	(11,558)
Purchase of shares by Aurora Oil & Gas Employee Share Trust	(804)	-
Net cash inflow from financing activities	258,051	458,996
Net increase / (decrease) in cash and cash equivalents	(25,078)	(4,578)
Cash and cash equivalents at the beginning of the financial year	67,584	70,246
Effect of exchange rates on cash holdings in foreign currencies	(127)	1,916
Cash and cash equivalents at the end of the financial year	(9) 42,379	67,584

The above consolidated statement of cash flows should be read in conjunction with the accompanying notes.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

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Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Aurora Oil & Gas Limited ("Company" or "Aurora") is a company incorporated in Australia whose shares are publicly listed on the Australian Securities Exchange (ASX) and Toronto Stock Exchange (TSX). Aurora is the ultimate parent entity in the group.

The consolidated financial report of the Company for the year ended December 31, 2013 comprises the financial statements for Aurora Oil & Gas Limited and its controlled entities ("Group" or "Consolidated Entity").

Statement of Compliance

This general purpose financial report has been prepared in accordance with Australian Accounting Standards, Accounting Interpretations and other authoritative pronouncements of the Australian Accounting Standards Board, Urgent Issues Group Interpretations and the *Corporations Act 2001*. Aurora is a for profit entity for the purpose of preparing the financial statements.

The financial statements of Aurora Oil & Gas Limited also comply with International Financial Reporting Standards (IFRS) as adopted by the International Accounting Standards Board (IASB).

Basis of Preparation

The financial report of the Consolidated Entity is presented in US dollars, which is the Company's functional currency.

Historical cost convention

These financial statements have been prepared under the historical cost convention, as modified by the revaluation of financial assets at fair value through other comprehensive income.

Critical accounting estimates and significant judgements

The preparation of financial statements requires the use of certain critical accounting estimates. It also requires management to exercise its judgment in the process of applying the Group's accounting policies. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the financial statements are disclosed in note 2.

Adoption of new and revised accounting standards

The following new and revised standards and amendments are applied for the first time in the annual reporting period commencing January 1, 2013. These standards and amendments have no material effect on any of the amounts recognised in the current year or any prior period consolidated financial report:

- AASB 10 Consolidated Financial Statements
- AASB 11 Joint Arrangements
- AASB 12 Disclosure of Interests in Other Entities
- AASB 13 Fair Value Measurement
- AASB 119 Employee Benefits (September 2011) and AASB 2011-10 Amendments to Australian Accounting Standards arising from AASB 119 (September 2011)
- AASB 2011-9 Amendments to Australian Accounting Standards – Presentation of Items of Other Comprehensive Income.

The Group further elected to adopt AASB 2013-3 Amendments to AASB 136 – Recoverable Amount Disclosures for Non-Financial Assets early, which had a small impact on the impairment disclosures.

The nature and effect of each new standard and amendment on the Group's consolidate financial report are described below.

AASB 10: Consolidated Financial Statements

AASB 10 *Consolidated Financial Statements* (AASB 10) was issued in August 2011 and replaces the guidance on control and consolidation in AASB 127 Consolidated and Separate Financial Statements (AASB 127). AASB 10 introduces a new control model, which broadens the situations in which an entity is considered to be controlled by another entity, and is applicable to all subsidiaries. The group has reviewed its investments in other entities and concluded that the assessment to consolidate is consistent under AASB 10 with the assessments made under AASB 127.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

AASB 11: Joint Arrangements

Under AASB 11 *Joint Arrangements* (AASB 11), investments in joint arrangements are classified as either joint operations or joint ventures depending on the contractual rights and obligations of each investor. The group has reviewed its joint operating agreements concluding that these joint arrangements meet the classification criteria of a joint operation under AASB 11. The groups existing accounting policy, as described at note 1(b), and treatment is consistent with the requirements of AASB 11.

AASB 12: Disclosure of Interests in Other Entities

AASB 12 *Disclosure of Interests in Other Entities* (AASB 12) sets out the requirements for disclosure relating to an entity's interests in subsidiaries, joint arrangements, associates and structured entities. Application of this standard by the Group does not affect any of the amounts recognised in the financial statements, but impacts the type of information disclosed in relation to the Group's investments. AASB 12 disclosures are provided in notes 28 and 29.

AASB 13: Fair Value Measurement

AASB 13 *Fair Value Measurement* (AASB 13) aims to improve consistency and reduce complexity by providing a precise definition of fair value and a single framework for fair value measurement and disclosure requirements for use across Australian Accounting Standards. Application of AASB 13 has not materially impacted the fair value measurement of the Group. Additional disclosures, where required, are provided in the individual notes relating to fair valued assets and liabilities.

AASB 119 Employee Benefits

Under revised AASB 119 *Employee Benefits* (AASB 119), employee benefits expected to be settled (as opposed to due to be settled under current standard) wholly within 12 months after the end of the reporting period are short-term benefits, and therefore not discounted when calculating leave liabilities. Annual leave not expected to be used wholly within twelve months of the end of the reporting period will in future be discounted when calculating leave liability. The requirements of the revised AASB 119 *Employee Benefits* are consistent with the Group's existing accounting policy and treatment of annual leave obligations, as disclosed at note 1(m).

Amendments to AASB 101 Presentation of Financial Statements

The amendments to AASB 101 *Presentation of Financial Statements* (AASB 101), as part of AASB 2011-9 Amendments to Australian Accounting Standards – Presentation of Items of Other Comprehensive Income, require that items presented in other comprehensive income that could be reclassified to profit or loss at a future point in time be presented separately from items that will never be reclassified. The amendment affects presentation only.

Several other amendments apply for the first time in 2013, however they do not impact the Group's annual consolidated financial statements.

Accounting Policies

The principal accounting policies adopted in the preparation of the financial report are set out below. These policies have been applied consistently to all the periods presented, unless otherwise stated.

(a) Principles of consolidation

The consolidated financial statements incorporate the assets and liabilities of Aurora Oil & Gas Limited and its controlled entities as at December 31, 2013 and the financial performance of the Company and its controlled entities for the period then ended.

- (i) Controlled entities are all those entities (including special purpose entities) the group is exposed to, or has rights to, variable returns from its involvement with the entity and has the ability to affect those returns through its power to direct the activities of the entity.

The financial statements of the controlled entities are included in the consolidated financial statements from the date on which control is transferred to the Company. They are de-consolidated from the date that control ceases.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(a) Principles of consolidation (continued)

- (ii) Intercompany transactions, balances and unrealised gains or losses on transactions between Group entities are eliminated. Unrealised losses are eliminated unless the transaction provides evidence of the impairment of the assets transferred. Accounting policies of subsidiaries have been changed where necessary to ensure consistency with the policies adopted by the Consolidated Entity.
- (iii) Non-controlling interests in the results and equity of subsidiaries are shown separately in the consolidated statement of profit or loss and other comprehensive income, consolidated statement of changes in equity and consolidated statement of financial position.
- (iv) The acquisition method of accounting is used to account for all business combinations, regardless of whether equity instruments or other assets are acquired. The consideration transferred for the acquisition of a subsidiary comprises the fair values of the assets transferred, the liabilities incurred and the equity interests issued by the group. The consideration transferred also includes the fair value of any pre-existing equity interest in the subsidiary. Acquisition-related costs are expensed as incurred. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are, with limited exceptions, measured initially at their face value at the acquisition date. On an acquisition-by-acquisition basis, the group recognises any non-controlling interest in the acquiree's net identifiable assets.

The excess of the consideration transferred and the amount of any non-controlling interest in the acquiree over the fair value of the net identifiable assets acquired is recorded as goodwill. If those amounts are less than the fair value of net identifiable assets of the subsidiary acquired and the measurement of all amounts has been reviewed, the difference is recognised directly in profit or loss as a bargain purchase.

Where settlement of any part of cash consideration is deferred, the amounts payable in the future are discounted to their present value as at the date of exchange. The discount rate used is the entity's incremental borrowing rate, being the rate at which a similar borrowing could be obtained from an independent financier under comparable terms and conditions.

Contingent consideration is classified either as equity or a financial liability. Amounts classified as a financial liability are subsequently remeasured to fair value with changes in fair value recognised in profit or loss.

(b) Joint arrangements

The Group recognises its direct right to, and its share of jointly held assets, liabilities, revenues and expenses of joint operations. These have been incorporated into the financial statements under the appropriate headings. Details of joint operations are set out in note 29.

(c) Segment reporting

Operating segments are reported in a manner consistent with the internal reporting provided to the chief operating decision maker. The chief operating decision makers, who are responsible for allocating resources and assessing performance of the operating segments, have been identified as the CEO and the Executive Chairman.

The CEO and the Executive Chairman review the information within the internal management reports on a monthly basis which is consistent with the information provided in the consolidated financial statements. As a result no reconciliation is required, because the information as presented is used by the CEO and the Executive Chairman to make strategic decisions.

Management has determined, based on the reports reviewed by the CEO and Executive Chairman and used to make strategic decisions, that the Group has one reportable segment being oil and gas exploration and production in the United States of America. The Group's management and administration office is located in Australia. There has been no other impact on the measurement of the company's assets and liabilities.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(d) Foreign currency translation

(i) Functional and presentational currency

Items included in the financial statements of the Group companies are measured using the currency of the primary economic environment in which each company operates ('the functional currency'). The functional currency of the US subsidiaries is US dollars.

The consolidated financial statements are presented in US dollars, which is the Group's functional and presentation currency.

(ii) Translation and balances

Foreign currency transactions are translated into the functional currency of the Group using the exchange rates prevailing at the dates of the transactions.

Foreign currency monetary assets and liabilities denominated in foreign currencies as at the reporting date are translated into the functional currency as at the exchange rate existing at reporting date.

The foreign currency gain or loss on monetary items is the difference between amortised cost in the functional currency at the beginning of the year and the amortised cost in foreign currency translated at the exchange rate at the end of the year.

Non-monetary assets and liabilities that are measured at fair value in a foreign currency are retranslated to the functional currency at the exchange rate at the date that the fair value was determined. Non-monetary items that are measured based on historical cost in a foreign currency are translated using the exchange rate at the date of the transaction.

Foreign currency differences arising on retranslation are generally recognized in profit or loss.

(iii) Group companies

The results and financial position of all the Group companies that have a functional currency different from the presentation currency are translated into the presentation currency as follows:

- assets and liabilities for each statement of financial position presented are translated at the closing rate at the date of the statement of financial position;
- income and expense for each statement of profit or loss and other comprehensive income balance are translated at average exchange rates; and
- exchange differences arising on translation of intercompany payables and/or receivables of foreign operations, in a currency that is not the same as the parent's functional currency, are recognised in the foreign currency translation reserve, as a separate component of equity. These differences are only recognised in the profit or loss upon disposal of the foreign operations.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(e) Revenue recognition

Revenue is recognised at the fair value of consideration received or receivable to the extent that it is probable that economic benefits will flow to the Group and the revenue can be reliably measured.

Revenue is recognised when significant risks and rewards of ownership have been transferred to the customer, recovery of the consideration is probable, there is no continuing management involvement with the goods and the amount of revenue can be measured reliably.

(i) Oil and Gas Sales

Revenue from the sale of oil / condensate, gas and natural gas liquids produced is recognised when the Consolidated Entity has transferred to the buyer the significant risks and rewards of ownership of the products from the following product streams:

- Dry Gas – upon transfer to a third party, typically upon entry to a plant, or at the plant tailgate as it enters a third party sales pipeline;
- Natural Gas Liquids (NGL's) – upon transfer to a third party, typically upon entry to a third party sales pipeline;
- Oil / Condensate – upon transfer of product to purchasers transportation mode, either truck or pipeline.

(ii) Other revenue

Dividend revenue is recognised on a receivable basis. Interest revenue is recognised on a time proportionate basis that takes into account the effective yield on the financial asset.

(iii) Service income

Revenue from the provision of services is recognised when an entity has a legally enforceable right to receive payment for services rendered.

(f) Tax

The income tax benefit/(expense) for the period is the tax payable on the current period's taxable income/(loss) based on the applicable income tax rate for each jurisdiction adjusted by changes in deferred tax assets and liabilities attributable to temporary differences and for unused tax losses.

Deferred income tax is provided in full, using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the consolidated financial statements. However, the deferred income tax is not accounted for if it arises from initial recognition of an asset or liability in a transaction other than a business combination that at the time of the transaction affects neither accounting nor taxable profit or loss. Deferred income tax is determined using tax rates (and laws) that have been enacted or substantially enacted at the reporting date and are expected to apply when the related deferred income tax assets is realised or the deferred income tax liability is settled.

Deferred tax assets are recognised for deductible temporary differences and unused tax losses only if it is probable that future taxable amounts will be available to utilise those temporary differences and losses.

Deferred tax liabilities and assets are not recognised for temporary differences between the carrying amount and tax bases of investments in controlled entities where the Company is able to control the timing of the reversal of the temporary differences and it is probable that the differences will not reverse in the foreseeable future.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to offset current tax assets and liabilities and when the deferred tax balances relate to the same taxation authority. Current tax assets and tax liabilities are offset where the entity has a legally enforceable right to offset and intends either to settle on a net basis or to realise the asset and settle the liability simultaneously.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(f) Tax (continued)

Current and deferred tax balances attributable to amounts recognised directly in other comprehensive income / equity are also recognised directly in other comprehensive income / equity.

The Company and its wholly owned Australian resident entities are part of a tax consolidated group. As a consequence, all members of the tax consolidated group are taxed as a single entity. The head entity within the tax consolidated group is Aurora Oil & Gas Limited.

(g) Impairment of assets

A financial asset not classified as at fair value through profit or loss is assessed at each reporting date to determine whether there is objective evidence that it is impaired. A financial asset is impaired if there is objective evidence of impairment as a result of one or more events that occurred after the initial recognition of the asset, and that the loss event(s) had an impact on the estimated future cash flows of that asset that can be estimated reliably.

Objective evidence that financial assets are impaired include default or delinquency by a debtor, restructuring of an amount due to the Group on terms that the Group would not consider otherwise, indications that a debtor or issuer will enter bankruptcy, adverse changes in the payment status of borrowers or issuers, economic conditions that correlate with defaults or the disappearance of an active market for a security.

(h) Financial instruments

(i) Non-derivative financial assets

The Group recognises financial assets initially on the trade date, which is the date that the Group becomes a party to the contractual provisions of the instrument.

The Group derecognises a financial asset when the contractual rights to the cash flows from the asset expire, or it transfers the rights to receive the contractual cash flows in a transaction in which substantially all the risks and rewards of ownership of the financial asset are transferred. Any interest in such transferred financial assets that is created or retained by the Group is recognised as a separate asset or liability.

Financial assets and liabilities are offset and the net amount presented in the statement of financial position when, and only when, the Group has a legal right to offset the amounts and intends either to settle them on a net basis or to realise the asset and settle the liability simultaneously.

The Group classifies non-derivative financial assets into the following categories:

- *Financial assets at fair value through profit or loss*

A financial asset is classified as at fair value through profit or loss if it is classified as held-for-trading or is designated as such on initial recognition. Financial assets are designated at fair value through profit or loss if the Group manages such investments and makes purchase and sale decisions based on their fair value in accordance with the Group's documented risk management or investment strategy. Attributable transaction costs are recognised in profit or loss as incurred.

Financial assets at fair value through profit or loss are measured at fair value and changes therein, which take into account any dividend income, are recognised in profit or loss.

Financial assets designated at fair value through profit or loss comprise equity securities that otherwise would have been classified as available-for-sale.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(h) Financial instruments (continued)

• *Loans and other receivables*

Loans and receivables are financial assets with fixed or determinable payments that are not quoted in an active market. Such assets are recognised initially at fair value plus any directly attributable costs. Subsequent to initial recognition, loans and receivables are measured at amortised cost using the effective interest method, less any impairment losses.

Loans and receivables comprise cash and cash equivalents and, trade and other receivables.

• *Cash and cash equivalents*

Cash and cash equivalents comprise cash balances and call deposits with maturities of twelve months or less from the acquisition date that are subject to an insignificant risk of changes in their fair value, and are used by the Group in the management of its short-term commitments.

(ii) Non-derivative financial liabilities

The Group recognises financial liabilities initially on the trade date, which is the date that the Group becomes a party to the contractual provisions of the instrument.

The Group derecognises a financial liability when its contractual obligations are discharged, cancelled or expire.

The Group classifies non-derivative financial liabilities into the other financial liabilities category. Such financial liabilities are recognised initially at fair value less any directly attributable transaction costs. Subsequent to initial recognition, these financial liabilities are measured at amortised costs using the effective interest rate method.

Other financial liabilities comprise loans and borrowings and trade and other payables.

(i) Derivatives and hedging activities

Derivatives are initially recognised at fair value on the date a derivative contract is entered into and are subsequently measured to their fair value at the end of each reporting period. The accounting for subsequent changes in fair value depends on whether the derivative is designated as a hedging instrument, and if so, the nature of the item being hedged. The group designates certain derivatives as hedges of a particular risk associated with the cash flow of recognised assets and liabilities and highly probable forecast transactions (cash flow hedges).

The group documents at the inception of the hedging transaction the relationship between hedging instruments and hedged items, as well as its risk management objective and strategy for undertaking various hedge transactions. The group also documents its assessment, both at hedge inception and on an ongoing basis, of whether the derivatives that are used in hedging transactions have been and will continue to be highly effective in offsetting changes in fair value or cash flows of hedged items.

The full fair value of a hedging derivative is classified as a non-current asset or liability when the remaining maturity of the hedged item is more than 12 months; it is classified as a current asset or liability when the remaining maturity of the hedged item is less than 12 months.

(i) *Cash flow hedge*

The effective portion of changes in the fair value of derivatives that are designated and qualify as cash flow hedges is recognised in other comprehensive income and accumulated in reserves in equity. The gain or loss relating to the ineffective portion is recognised immediately in profit or loss within other income or other expense.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(i) Derivatives and hedging activities (continued)

Amounts accumulated in equity are reclassified to profit or loss in the periods when the hedged item affects profit or loss (for instance when the forecast sale that is hedged takes place). When the forecast transaction that is hedged results in the recognition of a non-financial asset (for example, inventory or fixed assets) the gains and losses previously deferred in equity are reclassified from equity and included in the initial measurement of the cost of the asset. The deferred amounts are ultimately recognised in profit or loss as cost of goods sold in the case of inventory, or as depreciation or impairment in the case of fixed assets.

When a hedging instrument expires or is sold or terminated, or when a hedge no longer meets the criteria for hedge accounting, any cumulative gain or loss existing in equity at that time remains in equity and is recognised when the forecast transaction is ultimately recognised in profit or loss. When a forecast transaction is no longer expected to occur, the cumulative gain or loss that was reported in equity is immediately reclassified to profit or loss.

(ii) Derivatives that do not qualify for hedge accounting

Certain derivative instruments do not qualify for hedge accounting. Changes in the fair value of any derivative instrument that does not qualify for hedge accounting are recognised immediately in profit or loss and are included in other income or other expenses.

(j) Inventories

Inventories consist of hydrocarbon stocks. Inventories are valued at the lower of cost and net realisable value. Cost is determined on a weighted average basis and includes direct costs and an appropriate portion of fixed and variable production overheads where applicable.

(k) Property, plant and equipment (other than oil and gas properties)

Property, plant and equipment is stated at cost less accumulated depreciation and impairment. Cost includes expenditure that is directly attributable to the acquisition of the item. In the event that settlement of all or part of the purchase consideration is deferred, cost is determined by discounting the amounts payable in the future to their present value as at the date of acquisition.

Depreciation is provided on property, plant and equipment. Depreciation is calculated on a reducing balance basis so as to write down the net cost or fair value of each asset over its expected useful life to its estimated residual value.

The estimated useful lives, residual values and depreciation method are reviewed at the end of each annual reporting period.

The following estimated useful lives are used in the calculation of depreciation:

Fixtures and fittings	5 years
Plant and equipment	5 - 25 years

(l) Interests in oil and gas properties

(i) Exploration and evaluation expenditure

Expenditure on exploration and evaluation is accounted for in accordance with the area of interest method which is closely aligned to the US GAAP based successful efforts method of accounting for oil and gas exploration and evaluation expenditure.

This approach is strongly linked to the Group's oil and gas reserves determination and reporting process and is considered to most fairly reflect the results of the Group's exploration and evaluation activity because only assets with demonstrable value are carried on the statement of financial position.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(I) Interests in oil and gas properties (continued)

Once a well commences producing commercial quantities of oil and gas, capitalised exploration and evaluation costs are transferred to Oil and Gas Properties – Producing Projects and amortisation commences.

This method allows the costs associated with the acquisition, exploration and evaluation of a prospect to be aggregated on the Consolidated Statement of Financial Position and matched against the benefits derived from commercial production once this commences.

(ii) Costs

Exploration lease acquisition costs relating to greenfield oil and gas exploration provinces are expensed as incurred while the costs incurred in relation to established or recognised oil and gas provinces are initially capitalised and then amortised over the shorter term of the lease or the expected life of the project.

All other exploration and evaluation costs, including general permit activity, geological and geophysical costs and new venture activity costs are charged as expenses as incurred except where:

- the expenditure relates to an exploration discovery that, at the reporting date, had not been recognised as an area of interest as an assessment of the existence or otherwise of economically recoverable reserves has not yet been completed; or
- where there exists an economically recoverable reserve, and it is expected that the capitalised expenditure will be recouped through exploitation of the area of interest, or alternatively, by its sale.

Areas of Interest are recognised at field level. Subsequent to the recognition of an Area of Interest, all further costs relating to the Area of Interest are initially capitalised. Each Area of Interest is reviewed at least bi-annually to determine whether economic quantities of reserves exist or whether further exploration and evaluation work is required to support the continued carry forward of capitalised costs. To the extent it is considered that the relevant expenditure will not be recovered, it is written off.

The costs of drilling exploration and evaluation wells are initially capitalised pending the results of the well. Costs are expensed where the well does not result in the discovery of economically recoverable hydrocarbons. To the extent that it is considered that the relevant expenditure will not be recovered, it is immediately expensed.

In the statement of cash flows, those cash flows associated with the capitalised exploration and evaluation expenditure are classified as cash flows used in investing activities. Exploration and evaluation expenditure expensed is classified as cash flows used in operating activities.

(iii) Prepaid drilling and completion costs

Where the Company has a non-operator interest in an oil or gas property, or has outsourced certain development processes of an operated interest in an oil or gas property, it may periodically be required to make a cash contribution for its share of the operator's/contractors estimated drilling and/or completion costs, in advance of these operations taking place.

Where these contributions relate to a prepayment for exploratory or early stage drilling activity, prior to a decision on the commerciality of a well having been made, the costs are capitalised as prepaid drilling costs within Exploration and Evaluation and/or Development Projects.

Where these contributions relate to a prepayment for well completion, these costs are capitalised as prepaid completion costs within Exploration and Evaluation.

As the operator/contractor notifies the Company as to how funds have been expended, the costs are reclassified from prepaid costs to the appropriate expenditure category.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(l) Interests in oil and gas properties (continued)

(iv) Transfer of capitalised exploration and evaluation expenditure to producing projects (oil and gas properties)

When a well comes into commercial production, accumulated exploration and evaluation expenditure for the relevant Area of Interest is transferred to producing projects and amortised on a units of production basis.

(v) Producing projects

Producing projects are stated at cost less accumulated amortisation and impairment charges. Producing projects include construction, installation or completion of production and infrastructure facilities such as pipelines, transferred exploration and evaluation assets, development wells and the provision for restoration.

(vi) Amortisation and depreciation of producing projects

The Consolidated Entity uses the "units of production" ("UOP") approach when amortising and depreciating field-specific assets. Using this method of amortisation and depreciation requires the Consolidated Entity to compare the actual volume of production to the reserves and then to apply this determined rate of depletion to the carrying value of depreciable asset.

Capitalised producing projects costs relating to commercially producing wells are depreciated/amortised using the UOP basis once commercial quantities are being produced within an area of interest. The reserves used in these calculations are the Proved plus Probable reserves and are reviewed at least annually.

(vii) Future restoration costs

Provision is made in the statement of financial position for the estimated cost of legal and constructive obligations to restore operating locations in the period in which the obligation arises. The estimated costs are capitalised as part of the cost of the related project where recognition occurs upon acquisition of an interest in the operating locations. The carrying amount capitalised is amortised on a unit of production basis during the production phase of the project.

Work scope and cost estimates for restoration are reviewed annually and adjusted to reflect the expected cost of restoration.

Restoration costs are based on the latest estimated future costs as disclosed in the independently prepared reserves report, determined on a discounted basis. The reserves report is prepared by independent engineers at least annually.

The Group accounts for changes in cost estimates on a prospective basis.

(m) Employee benefits

Provision is made for benefits accruing to employees in respect of employee entitlements when it is probable that settlement will be required and these benefits can be measured reliably. These benefits include wages, salaries, annual leave and long service leave.

(i) Short-term employee benefits

Liabilities for wages and salaries, including short-term incentive payments, non-monetary benefits and accumulating annual leave that are expected to be settled wholly within twelve months after the end of the period in which the employees render the related service are recognised in respect of employees' services up to the end of the reporting period and are measured at the amounts expected to be paid when the liabilities are settled.

The obligations are presented as current liabilities in the statement of financial position if the entity does not have an unconditional right to defer settlement for at least twelve months after the reporting date, regardless of when the actual settlement is expected to occur.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(m) Employee benefits (continued)

(ii) Other long-term employee benefits

Provision is made for long service leave and annual leave estimated to be payable to employees on the basis of statutory and contractual requirements. The liability for long service leave and annual leave which is not expected to be settled within twelve months after the end of the period in which the employees render the related service is recognised in the provision for employee entitlements and measured as the present value of expected future payments to be made in respect of services provided by employees up to the end of the reporting period. Expected future payments are discounted using market yields at the end of the reporting period on government bonds with terms and currencies that match, as closely as possible, the estimated future cash outflows.

(iii) Share-based payments

The Group has provided benefits to its employees (including key management personnel) in the form of share-based payments, whereby services were rendered partly or wholly in exchange for shares or rights over shares. The Remuneration Committee has also approved the grant of options or performance rights as incentives to attract executives and to maintain their long term commitment to the Company. These benefits were awarded at the discretion of the board, or following approval by shareholders.

The costs of these equity-settled transactions are measured by reference to the fair value of the equity instruments at the date on which they are granted. The fair value of performance rights granted under the Aurora Oil & Gas Limited performance rights plan is determined using a risked statistical analysis. The fair value of performance rights granted under the Aurora Oil & Gas Limited long term incentive plan is determined using binomial tree and Monte-Carlo simulation valuation models. Further details of performance rights granted under each plan are disclosed in note 26. The fair value of options granted is determined by using a Black-Scholes option pricing technique.

The cost of these equity-settled transactions is recognised, together with a corresponding increase in equity, over the period in which the performance and / or service conditions are fulfilled (the vesting period).

At each subsequent reporting date until vesting, the cumulative charge to the income statement is the product of (i) the fair value at grant date of the award; (ii) the current best estimate of the number of equity instruments that will vest, taking into account such factors as the likelihood of employee turnover during the vesting period and the likelihood of non-market performance conditions being met and (iii) the expired portion of the vesting period.

The charge to the income statement for the period is the cumulative amount as calculated above less the amounts already charged in previous periods. There is a corresponding credit to equity.

Until an equity instrument has vested, any amounts recorded are contingent and will be adjusted if more or fewer equity instruments vest than were originally anticipated to do so. Any equity instrument subject to a market condition is valued as if it will vest irrespective of whether or not that market condition is fulfilled, provided that all other conditions are satisfied.

If the terms of an equity-settled award are modified, as a minimum, an expense is recognised as if the terms had not been modified. An additional expense is recognised for any modification that increases the total fair value of the share based payment arrangement, or is otherwise beneficial to the recipient of the award, as measured at the date of modification.

If an equity-settled transaction is cancelled (other than a grant cancelled by forfeiture when the vesting conditions are not satisfied), it is treated as if it had vested on the date of cancellation, and any expense not yet recognised for the award is recognised immediately. However, if a new equity instrument is substituted for the cancelled award and designated as a replacement award on the date that it is granted, the cancelled and new equity instrument are treated as if they were a modification of the original award, as described in the preceding paragraph.

The dilutive effect, if any, of outstanding options is reflected as additional share dilution in the computation of diluted earnings per share (see note 24).

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(n) Provisions

Provisions are recognised when the Consolidated Entity has a present obligation as a result of a past event, the future sacrifice of economic benefits is probable, and the amount of the provision can be reliably estimated.

The amount recognised as a provision is the best estimate of the consideration required to settle the present obligation at reporting date, taking into account the risks and uncertainties surrounding the obligation. Where a provision is measured using the cash flows estimated to settle the present obligation, its carrying amount is the present value of those cash flows.

When some or all of the economic benefits required to settle a provision are expected to be recovered from a third party, the receivable is recognised as an asset if it is virtually certain that recovery will be received and the amount of the receivable can be measured reliably.

An onerous contract is considered to exist where the Consolidated Entity has a contract under which the unavoidable cost of meeting the contractual obligations exceeds the economic benefits estimated to be received. Present obligations arising under onerous contracts are recognised as a provision to the extent that the present obligation exceeds the economic benefits estimated to be received.

(o) Contributed equity

Ordinary shares are classified as equity.

Incremental costs directly attributable to the issue of new shares or options are shown in equity as a deduction, net of tax, from the proceeds. Incremental costs directly attributable to the issue of new shares or options for the acquisition of a business are not included in the cost of the acquisition as part of the purchase consideration.

If the Company reacquires its own equity instruments, e.g. as the result of a share buy-back, those instruments are deducted from equity and the associated shares are cancelled. No gain or loss is recognised in the profit or loss and the consideration paid, including any directly attributable incremental costs (net of income taxes), is recognised directly in equity.

When share capital recognised as equity is repurchased, the amount of the consideration paid, which includes directly attributable costs, net of any tax effects, is recognised as a deduction from equity. Repurchased shares are classified as treasury shares and are presented in the reserve of own shares. When treasury shares are sold or reissued subsequently, the amount received is recognised as an increase in equity, and the resulting surplus or deficit on the transaction is presented in retained earnings.

(p) Finance costs

Borrowing costs that are not directly attributable to the acquisition, construction or production of a qualifying asset are recognised in profit or loss using the effective interest method.

(q) Good and services tax

Revenues, expenses and assets are recognised net of the amount of goods and services tax (GST), except:

- where the amount of GST incurred is not recoverable from the taxation authority, it is recognised as part of the cost of acquisition of an asset or as part of an item of expense; or
- for receivables and payables which are recognised inclusive of GST.

The net amount of GST recoverable from, or payable to, the taxation authority is included as part of receivables or payables. Cash flows are included in the cash flow statement on a gross basis. The GST component of cash flows arising from investing and financing activities which is recoverable from, or payable to, the taxation authority is classified as operating cash flows.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(r) Earnings per share

(i) Basic earnings per share

Basic earnings per share is calculated by dividing the profit (or loss) attributable to equity holders of the company, excluding any costs of servicing equity other than ordinary shares, by the weighted average number of ordinary shares outstanding during the financial year, adjusted for bonus elements in ordinary shares issued during the year.

(ii) Diluted earnings per share

Diluted earnings per share adjusts the figures used in the determination of basic earnings per share to take into account the after income tax effect of interest and other financing costs associated with dilutive potential ordinary shares and the weighted average number of shares assumed to have been issued for no consideration in relation to dilutive potential ordinary shares.

(s) Rounding of amounts

The Company is of a kind referred to in Class order 98/100, issued by the Australian Securities and Investments Commission, relating to the "rounding off" of amounts in the financial statements. Amounts in the financial statements have been rounded off in accordance with the Class Order to the nearest thousand dollars, or in certain cases, the nearest dollar.

(t) New accounting standards and interpretations

The following Standards and interpretations have recently been issued or amended but are not yet effective and have not been adopted by the Group as at the financial reporting date. The potential effect of these Standards is yet to be fully determined however, it is not expected that the new or amended standards will significantly affect the Group's accounting policies, financial position or performance.

(i) AASB 2011-4 Amendments to Australian Accounting Standards to Remove Individual Key Management Personnel Disclosure Requirements [AASB 124] (effective for annual reporting periods commencing on or after July 1, 2013)

This amendment removes the individual key management personnel disclosure requirements from AASB 124 *Related Party Disclosures*, to achieve consistency with the international equivalent standard and remove duplication with the *Corporations Act 2001*. Detailed key management personnel disclosures will be included in the Group's Remuneration Report for the year beginning on January 1, 2014. Aggregate disclosures will still be required in the notes to the financial statements.

(ii) AASB 2012-2 and AASB 2012-3 Amendments to Australian Accounting Standards - Offsetting Financial Assets and Financial Liabilities (effective for annual reporting periods commencing on or after January 1, 2014).

The amendments do not change the current offsetting rules in AASB 132 *Financial Instruments: Presentation*, but they clarify that the right of set-off must be available today (ie not contingent on a future event) and must be legally enforceable in the normal course of business as well as in the event of default, insolvency or bankruptcy.

(iii) AASB 2013-3 Amendments to AASB 136 – Recoverable Amount Disclosures for Non-Financial Assets (effective for annual reporting periods beginning on or after January 1, 2014).

AASB 2013-3 amends the disclosure requirements in AASB 136 *Impairment of Assets*. The amendments include the requirement to disclose additional information about the fair value measurement when the recoverable amount of impaired assets is based on fair value less costs of disposal.

(iv) AASB 2013-4 Amendments to Australian Accounting Standards – Novation of Derivatives and Continuation of Hedge Accounting [AASB 139] (effective for annual reporting periods commencing on or after January 1, 2014)

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

AASB 2013-4 amends AASB 139 *Financial Instruments: Recognition and Measurement* to permit the continuation of hedge accounting in specified circumstances where a derivative, which has been designated as a hedging instrument, is novated from one counterparty to a central counterparty as a consequence of laws or regulations.

(v) *Annual Improvements to IFRS 2010-2012 Cycle (effective for the annual reporting periods commencing on or after July 1, 2014).*

This standard sets out amendments to International Financial Reporting Standards (IFRS) and the related bases for conclusions and guidance made during the International Accounting Standards Board's Annual Improvements process. These amendments have not yet been adopted by the AASB.

2. CRITICAL ACCOUNTING ESTIMATES AND JUDGEMENTS

In preparing these financial statements the Group has been required to make certain estimates and assumptions concerning future occurrences. There is an inherent risk that the resulting accounting estimates will not equate exactly with actual events and results.

(a) Critical accounting estimates

The carrying amounts of certain assets and liabilities are often determined based on estimates and assumptions of future events. The key estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below.

(i) *Share-based payment transactions*

The Group measures the cost of equity-settled transactions with employees by reference to the fair value of the equity instruments at the date at which they are granted. The fair value is determined using either a binomial tree and Monte-Carlo simulation valuation techniques or a Black Scholes Option Pricing Model, using the assumptions detailed in note 26.

(ii) *Rehabilitation and decommissioning obligations*

The Group estimates the future rehabilitation costs of production facilities, wells and pipelines at different stages of the development and construction of assets or facilities. In most instances, removal of assets occurs many years into the future. This requires judgemental assumptions regarding removal date, future environmental legislation, the extent of restoration activities and the future removal technology available and liability specific discount rates to determine the present value of these cash flows. As at December 31, 2013 rehabilitation obligations have a carrying value of US\$2,808,000 (December 31, 2012: US\$1,705,000).

(iii) *Reserves estimates*

Estimation of reported recoverable quantities of Proven and Probable reserves include judgemental assumptions regarding commodity prices, exchange rates, discount rates and production and transportation costs for future cash flows. It also requires interpretation of complex geological and geophysical models in order to make an assessment of the size, shape, depth and quality of reservoirs and their anticipated recoveries. These factors used to estimate reserves may change from period to period.

Reserve estimates are prepared in accordance with assumption and methodology guidelines outlined in the Canadian Oil and Gas Evaluation Handbook and in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities.

Reserve estimates are used to calculate depletion of producing assets and therefore a change in reserve estimates impacts the carrying value of assets and the recognition of deferred tax assets due to the changes in expected future cash flows (see below)

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

2. CRITICAL ACCOUNTING ESTIMATES AND JUDGEMENTS (CONTINUED)

(a) Critical accounting estimates (continued)

(iv) Depletion and depreciation

In relation to the depletion, depreciation and amortisation of capitalised expenditure related to producing oil and gas properties, the Consolidated Entity uses a unit of production reserve depletion model to calculate depletion, depreciation and amortisation. This method of depletion, depreciation and amortisation necessitates the estimation of the oil and gas reserves over which the carrying value of the relevant assets will be expensed to the profit or loss. The calculation of oil and gas reserves is extremely complex and requires management to make judgements about commodity prices, future production costs and geological structures. The nature of reserve estimation is such that reserves are not intended to be 100% accurate but rather provide a statistically probable outcome in relation to the economically recoverable reserve. As the actual reserve can only be accurately determined once production has ceased, depletion, depreciation and amortisation expensed during the production may not on a year to year basis accurately reflect the actual percentage of reserve depleted. However, over the entire life of the producing assets all capitalised costs will be expensed to the profit or loss.

(v) Impairment of assets

In the absence of readily available market prices, the recoverable amounts of assets are determined by discounting the expected future net cash flows from production and comparing these to the carrying value of the relevant asset or group of assets to determine the asset's net present value. The calculation of net present value is based on assumptions concerning discount rates, reserves, future production profiles, commodity prices and costs.

3. FINANCIAL RISK MANAGEMENT

The financial risks that arise during the normal course of Aurora's operations comprise market risk, credit risk and liquidity risk. In managing financial risk, it is Aurora's policy to seek a balance between the potential adverse effects of financial risks on Aurora's financial performance and position, and the "upside" potential made possible by exposure to these risks and by taking into account the costs and expected benefits of the various risk management methods available to manage them.

General objectives, policies and processes

Aurora's Board is responsible for approving Aurora's policies on risk oversight and management and ensuring management has developed and implemented effective risk management and internal control. Whilst maintaining ultimate responsibility for financial risk management, the Board has delegated the responsibility for ensuring that management has designed processes that ensure the effective implementation of the objectives and policies to the Audit and Risk Management Committee. The Audit and Risk Management Committee receives reports as required from the Chief Financial Officer and other relevant Executives in which they review the effectiveness of the processes implemented and the appropriateness of the objectives and policies it sets.

Aurora's Audit and Risk Management Committee oversees how management monitors compliance with the Group's risk management policies and procedures and reviews the adequacy of the risk management framework in relation to the risks faced by Aurora.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

3. FINANCIAL RISK MANAGEMENT (CONTINUED)

These disclosures are not, nor are they intended to be an exhaustive list of risks to which Aurora is exposed.

Financial instruments

The group holds the following financial instruments:

	Consolidated	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Financial assets		
Cash and cash equivalents	42,379	67,584
Trade receivables	72,989	89,535
Financial assets at fair value through other comprehensive income	210	842
Derivative financial instruments	85	-
Prepaid development and lease acquisition expenses	2,096	-
	117,759	157,961
Financial liabilities		
Trade and other payables	205,922	180,619
Borrowings	660,976	390,453
Derivative financial instruments	5,937	1,649
	872,835	572,721

(a) Market risk

Market risk arises from Aurora's exposure to commodity price risk and the use of interest bearing and foreign currency financial instruments. It is a risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in interest rates (interest rate risk), foreign exchange rates (currency risk) or oil, condensate, natural gas liquids and natural gas prices (commodity price risk) and share price risk (price risk).

(i) Commodity price risk

The Group is exposed to commodity price risk arising from fluctuations in the prices of oil, condensate, natural gas liquids and natural gas. The demand for, and prices of, oil, condensate, natural gas liquids and natural gas are dependent on a variety of factors, including:

- Supply and demand;
- Weather conditions;
- The price and availability of alternative fuels;
- Actions taken by governments and international cartels; and
- Global economic and political developments.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

3. FINANCIAL RISK MANAGEMENT (CONTINUED)

(a) Market risk (continued)

The Board recognises that through the normal course of its business activities, the Company is exposed to various market risks, including commodity risk. To manage commodity price risk the Board established a hedging committee during the year ended December 31, 2012 to implement and manage effective hedges of commodity price pursuant to Board approved levels. To manage the Group's commodity price risk exposure during the year ended December 31, 2013, the Group entered into cash settled commodity swap and zero cost collar hedging arrangements with financial institutions, as disclosed at note 18 – Derivative financial instruments.

Sensitivity analysis – change in US\$ oil price

The following table demonstrates the estimated sensitivity to a US\$10 increase / decrease in the oil price, with all variables held constant, on post tax profit and equity. These sensitivities should not be used to forecast the future effect of movement in the oil price on future cash flows.

	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Impact on post-tax profits		
US\$ oil / condensate ⁽¹⁾ price + \$10	22,240	26,470
US\$ oil / condensate ⁽¹⁾ price - \$10	(22,240)	(26,470)
Impact on equity		
US\$ oil / condensate ⁽¹⁾ price + \$10	22,240	26,470
US\$ oil / condensate ⁽¹⁾ price - \$10	(22,240)	(26,470)

⁽¹⁾ The impact on post-tax profits and equity resulting from a US\$10 movement in Gas or NGL prices is not considered material.

(ii) Foreign exchange risk

The functional currency of the Group is US dollars and the Group operates in the US, however maintains corporate listings in Australia and in Canada. The Group is exposed to foreign exchange risk arising from fluctuations in the US dollar and Australian dollar, and US dollar and Canadian dollar at parent entity level on cash balances.

Foreign exchange risk arises from future commercial transactions and recognised assets and liabilities denominated in a currency that is not the entity's functional currency. The exposure to risks is measured using sensitivity analysis and cash flow forecasting.

The Board has formed the view that it would not be beneficial for the Group to purchase forward contracts or other derivative financial instruments to hedge this foreign exchange risk, other than on an ad hoc basis for significant foreign currency transactions. Factors which the Board considered in arriving at this position included, the expense of purchasing such instruments and the inherent difficulties associated with forecasting the timing and quantum of Australian and Canadian dollar cash inflows and outflows, compared to the relatively low volume and value of commercial transactions and recognised assets and liabilities denominated in a currency which is not US dollars.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

3. FINANCIAL RISK MANAGEMENT (CONTINUED)

(a) Market risk (continued)

The Group's exposure to foreign currency risk at the end of the reporting period, expressed in US dollars, was as follows:

	December 31, 2013		
	AUD US\$'000	CAD US\$'000	Total US\$'000
Financial assets			
Cash and cash equivalents	952	127	1,079
Trade and other receivables	326	3	329
Other financial assets	210	-	210
Total financial assets	1,488	130	1,618
Financial liabilities			
Trade and other payables	2,106	4	2,110
Total financial liabilities	2,106	4	2,110

Sensitivity analysis – change in Australian / US dollar exchange rate and Canadian / US dollar exchange rate

The following table demonstrates the estimated sensitivity to a 10% increase/decrease in the Australian/US dollar exchange rate and a 10% increase/decrease in the Canadian/US dollar exchange rate, with all variables held consistent, on post tax profit and equity. These sensitivities should not be used to forecast the future effect of movement in the US dollar exchange rate on future cash flows.

	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Impact on post-tax profits		
AUD/US\$ + 10%	(62)	(39)
AUD/US\$ - 10%	62	18
CAD/US\$ + 10%	13	110
CAD/US\$ - 10%	(13)	(104)
Impact on equity		
AUD/US\$ + 10%	(62)	(39)
AUD/US\$ - 10%	62	18
CAD/US\$ + 10%	13	110
CAD/US\$ - 10%	(13)	(104)

A hypothetical change of 10% in the Australian dollar and Canadian dollar exchange rates was used to calculate the Group's sensitivity to foreign exchange rate movements as this is management's estimate of possible rate movements over the coming year taking into account current market conditions and past volatility (December 31, 2012: 10%).

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

3. FINANCIAL RISK MANAGEMENT (CONTINUED)

(a) Market risk (continued)

(iii) Interest rate risk

As at and during the year ended December 31, 2013 the Group had interest-bearing assets and liabilities, being liquid funds on deposit, a drawn down balance from the senior secured revolving credit facility and senior unsecured notes. As such, the Group's income and operating cash flows (other than interest income from funds on deposit and interest expense from the senior secured revolving credit facility) are somewhat dependent on changes in market interest rates. The Board manages the Group's exposure to interest rate risk by regularly assessing the company's exposure, taking into account funding requirements and selecting appropriate instruments to manage its exposure.

Sensitivity analysis – change in interest rates

Based on the financial instruments held at reporting date, with all other variables assumed to be held constant, the table below sets out the notional effect on consolidated profit after tax for the year and on equity at reporting date under varying hypothetical changes in prevailing interest rates:

	Consolidated	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Impact on post-tax profit		
Hypothetical 90 basis points ⁽¹⁾ increase in interest	5,604	2,677
Hypothetical 90 basis points ⁽¹⁾ decrease in interest	(5,604)	(2,677)
Impact on equity		
Hypothetical 90 basis points ⁽¹⁾ increase in interest	(5,604)	2,677
Hypothetical 90 basis points ⁽¹⁾ decrease in interest	5,604	(2,677)

⁽¹⁾ A hypothetical change of 90 basis points was used to calculate the Group's sensitivity to future interest rate movements as this figure approximates the movement in bond yields published by the Reserve Bank of Australia for bonds with a 12 month maturity (December 31, 2012: 0.90%).

The weighted average effective interest rate of funds on deposit is 0.05% (December 31, 2012: 0.08%). The weighted average interest rate of borrowings is 8.80% (December 31, 2012: 9.875%).

(iv) Price risk

The Group is exposed to equity securities price risk in relation to its financial assets at fair value through other comprehensive income. The carrying value of investments at December 31, 2013 is US\$210,000 (December 31, 2012: US\$842,000).

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

3. FINANCIAL RISK MANAGEMENT (CONTINUED)

(a) Market risk (continued)

Sensitivity analysis – change in share price

In the table below movements in share price are assumed to be short-term market movement related and the movement in the fair value would be recognised in the statement of profit or loss and other comprehensive income.

	Consolidated	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Impact on post-tax profit		
Hypothetical 50% ⁽¹⁾ increase in price	-	-
Hypothetical 20% ⁽¹⁾ decrease in price	-	-
Impact on equity		
Hypothetical 50% ⁽¹⁾ increase in price	105	421
Hypothetical 50% ⁽¹⁾ decrease in price (December 31, 2012: hypothetical 20%)	(105)	(168)

⁽¹⁾ Management has determined that the above hypothetical outcomes are the most appropriate estimation of share price movements given the current market and economic conditions.

(b) Credit risk

Credit risk arises from cash and cash equivalents and deposits with financial institutions, derivative financial instruments, as well as trade receivables and non-current oil and gas assets as a significant portion of these assets consist of interests in projects operated by a single US public company.

The Board are of the opinion that the credit risk arising as a result of this concentration of the Group's assets is more than offset by the potential benefits to be gained through continuing to build on the Group's relationship with the operator of its existing projects.

The maximum exposure to credit risk at the reporting date is the carrying amount of the assets as summarised below, none of which are impaired or past due. The Group has a number of recourse options available in the event of counterparty default, including but not limited to de facto security over jointly held assets.

	Consolidated	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Cash and cash equivalents	42,379	67,584
Trade receivables	72,989	89,535
Derivative financial instruments	85	-
Prepaid development and lease acquisition expenses	2,096	-
Total	117,549	157,119

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

3. FINANCIAL RISK MANAGEMENT (CONTINUED)

(b) Credit risk (continued)

The credit quality of financial assets that are neither past due nor impaired can be assessed by reference to external credit ratings (if available) or to historical information about counterparty default rates.

	Consolidated	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Cash at bank and short-term bank deposits		
<i>Held with Australian banks and financial institutions</i>		
AA Rated	5,186	2,080
<i>Held with US banks and financial institutions⁽¹⁾</i>		
AA Rated	-	-
A Rated	37,193	65,278
BBB Rated	-	226
Total	42,379	67,584
Trade receivables		
<i>Counterparties with external credit ratings</i>	-	-
<i>Counterparties without external credit ratings⁽²⁾</i>		
Group 1	-	-
Group 2	72,989	89,535
Group 3	-	-
Total	117,464	157,119
Derivative financial instruments		
A- Rated	85	-
Prepaid development and lease acquisition expenses		
<i>Counterparties without external credit ratings⁽²⁾</i>		
Group 2	2,096	-

⁽¹⁾ To manage exposure to credit risk from cash and cash equivalent financial assets, it was the Group's policy during 2013 to deposit only with banks and financial institutions with a minimum independent rating of 'AA'. Due to the current prevailing market conditions in the US, depositing of cash and cash equivalents for US domicile subsidiaries with banks or financial institutions with a minimum 'AA' rating was not achievable. To mitigate this risk, cash and cash equivalents have been deposited in the US with products carrying the 100% Government guarantee.

⁽²⁾ Group 1 – new customers (less than 6 months).
Group 2 – existing customers (more than 6 months) with no defaults in the past.
Group 3 – existing customers (more than 6 months) with some defaults in the past. All defaults were fully recovered.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

3. FINANCIAL RISK MANAGEMENT (CONTINUED)

(c) Liquidity risk

Prudent liquidity management involves the maintenance of sufficient cash, marketable securities, committed credit facilities and access to capital markets. It is the policy of the Board to ensure that the Group is able to meet its financial obligations and maintain the flexibility to pursue attractive investment opportunities through ensuring the Group has sufficient working capital, available credit lines and preserving or resetting the 15% share issue limit available to the Company under the ASX Listing Rules.

(i) Financing arrangements

On November 8, 2011, Aurora USA Oil and Gas Inc. ("Aurora USA"), a wholly owned subsidiary of the Company, signed a credit agreement with a syndicate of banks, pursuant to which up to US\$300 million is available on a revolving basis (refer to note 16 – Borrowings).

(ii) Maturities of financial liabilities

As at December 31, 2013 the Group had total financial liabilities of US\$872,835,000 (December 31, 2012: US\$572,721,000). This comprised non interest-bearing trade creditors and accruals with a maturity of less than 6 months, interest bearing borrowings with maturities between 4 and 7 years and derivative financial instruments with maturities between 1 month and 2 years.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

3. FINANCIAL RISK MANAGEMENT (CONTINUED)

(c) Liquidity risk (continued)

The table below analyses the Group's financial liabilities into relevant maturity groupings. The amounts disclosed in the table are the contractual undiscounted cash flows. Balance due within 12 months equals the carrying amount as the impact of discounting is not significant.

Contractual maturities of financial liabilities	Consolidated				Carrying Amount US\$'000
	Less than 12 months US\$'000	Between 1 and 5 years US\$'000	Over 5 years US\$'000	Total contractual cash flows US\$'000	
At December 31, 2013					
Non derivative					
Non-interest bearing	205,922	-	-	205,922	205,922
Borrowings – fixed rate	-	365,000	300,000	917,814	660,976
Borrowings - variable rate	-	-	-	300	-
Total non derivative	205,922	365,000	300,000	1,124,036	866,898
Derivatives					
Gross settled forward commodity price contracts – cash flow hedges:					
(inflow)	(300)	-	-	(300)	(300)
outflow	6,237	-	-	6,237	6,237
Total derivative	5,937	-	-	5,937	5,937
At December 31, 2012					
Non derivative					
Non-interest bearing	180,619	-	-	180,620	180,619
Borrowings – fixed rate	-	365,000	-	513,125	360,453
Borrowings - variable rate	-	30,000	-	33,071	30,000
Total non derivative	180,619	395,000	-	726,816	571,072
Derivatives					
Gross settled forward commodity price contracts – cash flow hedges:					
– (inflow)	(534)	-	-	(534)	(534)
– outflow	2,069	114	-	2,183	2,183
Total derivative	1,535	114	-	1,649	1,649

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

3. FINANCIAL RISK MANAGEMENT (CONTINUED)

(d) Fair value estimation

The fair value of financial assets and liabilities held by the Group must be estimated for recognition, measurement and / or disclosure purposes. The Group measures fair values by level, per the following fair value measurement hierarchy:

- (i) quoted prices (unadjusted) in active markets for identical assets or liabilities (level 1);
- (ii) inputs other than quoted prices included within level 1 that are observable for the asset or liability, either directly (as prices) or indirectly (derived from prices) (level 2); and
- (iii) inputs for the asset or liability that are not based on observable market data (unobservable inputs) (level 3).

Other financial assets

The Group's investment in equity securities is measured under level 1 disclosure requirements. The fair value of US\$210,000 (December 31, 2012: US\$842,000) was determined based on the securities quoted market closing bid price.

The fair value of financial instruments traded in active markets (such as financial assets at fair value through other comprehensive income) is based on quoted market prices at the reporting date. The quoted market price used for financial assets held by the Group is the current bid price.

Derivative financial instruments

Derivative financial instruments are measured under level 2 disclosure requirements. The fair value of forward commodity contracts is calculated based on the terms of maturity of each contract by discounting estimated future cash flows determined by using inputs of quoted market prices in the futures market on the reporting dates.

Trade receivables and trade payables

The carrying values (net of any applicable impairment provision) of trade receivables and payables are assumed to approximate their fair values due to their short-term nature.

(e) Capital risk management

The Group manages its capital to ensure entities in the Group will be able to continue as a going concern while maximising the potential return to shareholders.

The capital structure of the Group is considered to include the total equity plus borrowings, which at December 31, 2013 was US\$1,231 million (December 31, 2012: US\$844 million). In determining the funding mix of debt and equity (total borrowings / total equity), consideration is given to the relative impact of the gearing ratio on the ability of the Group to service loan interest and repayment schedules, credit facility covenants and also to generate adequate free cash available for corporate and oil and gas production and development activities.

The capital of Group subsidiary entities is subject to externally imposed guarantees for the senior secured revolving credit facility (refer to note 16 – Borrowings).

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

4. SEGMENT INFORMATION

Management has determined, based on the reports reviewed by the CEO and the Executive Chairman and used to make strategic decisions, that the Group has one reportable segment being oil and gas exploration and production in the United States of America. The Group's management and administration office is located in Australia.

The CEO and the Executive Chairman review internal management reports on a monthly basis that are consistent with the information provided in the statement of profit or loss and other comprehensive income, statement of financial position and statement of cash flows. As a result no reconciliation is required, because the information as presented is used by the CEO and the Executive Chairman to make strategic decisions.

	December 31, 2013 US\$'000	December 31, 2012 US\$'000
<i>Reportable segment revenue</i>		
Revenue, including interest income, is disclosed below based on the reportable segment:		
Revenue from oil and gas exploration and production	562,714	294,812
Revenue from other corporate activities	216	5,255
	562,930	300,067
<i>Reportable segment assets</i>		
Assets are disclosed below based on the reportable segment:		
Assets from oil and gas exploration and production	1,546,701	1,041,143
Assets from corporate activities:		
Cash and cash equivalents	42,379	67,584
Other corporate assets	3,006	2,670
	1,592,086	1,111,397
<i>Reportable segment liabilities</i>		
Liabilities are disclosed below based on the reportable segment:		
Liabilities from oil and gas exploration and production	1,016,834	655,090
Liabilities from corporate activities	4,999	3,193
	1,021,833	658,283
<i>Reportable segment profit</i>		
Profit / (loss) is disclosed below based on the reportable segment:		
Profit from oil and gas exploration and production	144,813	74,016
(Loss) from other corporate activities	(28,383)	(15,170)
	116,430	58,846

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

5. REVENUE

	Consolidated	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
From continuing operations		
<i>Sales revenue</i>		
Oil and gas sales	565,494	294,936
Realised (loss) on forward commodity price contracts	(2,780)	(124)
	562,714	294,812
<i>Other revenue</i>		
Interest	52	247
Total revenue from continuing operations	562,766	295,059

6. OTHER INCOME

	Notes	Consolidated	
		December 31, 2013 US\$'000	December 31, 2012 US\$'000
Foreign exchange gain	(i)	-	3,042
Net gain on sale of available-for-sale financial assets		-	770
Net gain on foreign currency derivatives not qualifying as hedges		-	1,167
Other		164	29
Total other income		164	5,008

(i) During the year ended December 31, 2012 the Consolidated Entity recognised a foreign exchange gain in relation to the retranslation of Australian and Canadian dollar denominated balances.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

7. EXPENSES

Profit before income tax includes the following specific expenses:

	Notes	Consolidated	
		December 31, 2013 US\$'000	December 31, 2012 US\$'000
Royalties expense	(i)	149,429	77,625
Production and operating expense			
Sales taxes	(ii)	18,668	10,073
Operating expenses	(iii)	42,098	24,508
Total production and operating expenses		60,766	34,581
Depreciation and depletion expense			
Depletion	(iv)	74,703	35,959
Depreciation	(v)	8,929	3,202
Total depletion and depreciation expense		83,632	39,161
Share-based payment expenses			
Options		2,338	3,857
Performance rights		3,038	541
Total share-based payment expense	(vi)	5,376	4,398
Finance costs			
Interest expense		53,862	24,539
Amortisation of borrowing costs		4,370	2,638
Amortisation of debt premium and debt discount		32	289
Other financing fees		1,229	561
Total finance costs	(vii)	59,493	28,027
Exploration and evaluation costs written off	(viii)	503	4,939
Foreign exchange loss	(ix)	346	-

- (i) Aurora pays royalties to the owners of the petroleum rights on the land in which the Group owns lease interests. Royalties, as a percentage of production revenue, are payable in accordance with the terms of individual leasehold agreements and are generally payable for the production life of each well within the leasehold area.
- (ii) Sales taxes include local state tax expense and severance tax payable in the State of Texas, USA.
- (iii) Operating expenses include field operating costs and transportation of production.
- (iv) Depletion is calculated based on estimated remaining Proven and Probable reserves.
- (v) Depreciation is calculated using the reducing balance method to allocate the cost of property, plant and equipment over their useful lives.
- (vi) The Group has issued performance rights to key management personnel, including to executive directors, under Aurora's Long Term Incentive Plan ("LTIP"). The group has also issued options to executive management personnel and directors, including non-executive directors. For the year ended December 31, 2013 a performance right expense of US\$3,037,999 (December 31, 2012: US\$540,602) and an option expense of US\$2,337,738 (December 31, 2012: US\$3,857,063) were recognised.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

7. EXPENSES (CONTINUED)

- (vii) Finance fees were incurred in respect of the senior secured revolving credit facility entered into on November 8, 2011, the senior unsecured notes issued on February 8, 2012, the follow on notes issued on July 31, 2012 and the new offering of senior unsecured notes issued on March 21, 2013.
- (viii) Evaluation costs written off during the year ended December 31, 2013 consisted of evaluation expenditure that could not be directly attributable to the acquisition, construction or production of a qualifying asset providing probable future economic benefits to the entity.
- (ix) During the year ended December 31, 2013 the Consolidated Entity recognised a foreign exchange loss in relation to the retranslation of Australian and Canadian dollar denominated balances.

8. INCOME TAX EXPENSE

	Consolidated	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
(a) Income tax expense		
Current tax	-	-
Deferred tax	62,988	37,356
Income tax expense	62,988	37,356
(b) Reconciliation of income tax expense to prima facie tax payable		
Profit from continuing operations before income tax expense	174,418	96,202
Tax at the Australian statutory tax rate of 30% (December 31, 2012: 30%)	53,825	28,861
Tax effect of amounts that are not deductible (taxable) in calculating taxable income		
Share-based payment expense	774	1,157
Foreign exchange (gains) / losses not assessable / deductible	85	(1,026)
Revenue losses not previously recognised now brought to account (Expense) / benefit from a previously unrecognised temporary difference now recognised	(251)	(357)
Income tax rate differences	(904)	3,205
Other non-allowable deductions	9,149	5,359
Income tax expense	310	157
	62,988	37,356
(c) Tax expense (income) relating to items of other comprehensive income		
Financial assets at fair value through other comprehensive income	(225)	1,509
Cash flow hedges	1,051	495
	826	2,004

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

9. CASH AND CASH EQUIVALENTS

	Consolidated	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
<i>Held with Australian banks and financial institutions</i>		
Cash at bank and in hand	5,097	1,976
Deposits at call	89	104
<i>Held with US banks and financial institutions</i>		
Cash at bank and in hand	37,193	65,504
	42,379	67,584

(a) Risk exposure

The Group's exposure to interest rate risk is discussed at Note 3 – Financial Risk Management. The maximum exposure to credit risk at the end of the reporting period is the carrying amount of each class of cash and cash equivalents mentioned above.

(b) Deposits at call

Deposits at call held with Australian banks and financial institutions earn interest at 3.34% floating rate (December 31, 2012: 4.40%).

Cash held with US banks earns interest at rates between 0% and 0.50%.

10. TRADE AND OTHER RECEIVABLES

	Consolidated	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Trade receivables	72,989	89,535

(a) Trade receivables

Trade receivables represents revenue earned but not yet received from the production and sale of oil, condensate, natural gas and natural gas liquids.

(b) Impaired trade receivables

No Group trade receivables were past due or impaired as at December 31, 2013 (December 31, 2012: Nil) and there is no indication that amounts recognised as trade and other receivables will not be recovered in the normal course of business.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

11. OTHER FINANCIAL ASSETS

	Consolidated	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Financial assets at fair value through other comprehensive income	210	842

(a) Significant interest in other financial assets

An interest in a financial asset is considered 'significant' when Aurora holds 5% or more of issued share capital.

Aurora holds a significant interest in Elixir Petroleum Ltd. As at December 31, 2013, Aurora held 33,833,334 fully paid ordinary shares in Elixir Petroleum Ltd (December 31, 2012: 33,833,334), representing approximately 7.84% of its total issued capital. The market value of these securities at December 31, 2013 was US\$210,135 (December 31, 2012: US\$842,000).

Included in the statement of profit or loss and other comprehensive income is US\$(405,000) (December 31, 2012: US\$957,000) which represents the movement in the financial assets at fair value through other comprehensive income.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

12. PROPERTY, PLANT AND EQUIPMENT

	Consolidated	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Production facilities and field equipment		
Production facilities and field equipment at cost	166,127	73,685
Production facilities and field equipment accumulated depreciation	(12,351)	(3,876)
Total production facilities and field equipment	153,776	69,809
Reconciliation of movement in production facilities and field equipment		
Balance at the beginning of the financial period	69,809	20,588
Additions	92,442	52,217
Transfer from oil and gas properties	-	-
Depreciation expense	(8,475)	(2,996)
Total production facilities and field equipment	153,776	69,809
Office equipment		
Office equipment at cost	3,177	1,510
Office equipment accumulated depreciation	(710)	(256)
Total office equipment	2,467	1,254
Reconciliation of movement in office equipment		
Balance at the beginning of the financial period	1,254	731
Additions	1,667	729
Depreciation expense	(454)	(206)
Total office equipment	2,467	1,254
Total property, plant and equipment	156,243	71,063

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

13. OIL AND GAS PROPERTIES

	Consolidated	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Producing projects		
At cost	1,361,593	917,501
Accumulated depletion	(118,779)	(41,207)
Net carrying value	1,242,814	876,294
Development projects		
At cost	77,366	6,079
Net carrying value	77,366	6,079
Total oil and gas properties	1,320,180	882,373

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

13. OIL AND GAS PROPERTIES (CONTINUED)

A reconciliation of movements in oil and gas properties during the year ended December 31, 2013 is as follows:

	Tangible Costs US\$'000	Intangible Costs US\$'000	Prepaid Drilling, Completion and Lease Acquisition Costs US\$'000	Total US\$'000
PRODUCING PROJECTS				
Cost				
Balance at January 1, 2012	12,425	250,686	12,560	275,671
Additions	51,998	595,602	-	647,600
Increase in restoration provision	-	1,140	-	1,140
Capitalised borrowing costs ⁽¹⁾	-	5,650	-	5,650
Net movement in prepaid costs	-	-	(12,560)	(12,560)
Balance at December 31, 2012	64,423	853,078	-	917,501
Additions	28,748	403,386	-	432,134
Increase in restoration provision	-	1,103	-	1,103
Capitalised borrowing costs ⁽¹⁾	-	8,883	-	8,883
Net movement in prepaid costs	-	-	1,972	1,972
Balance at December 31, 2013	93,171	1,266,450	1,972	1,361,593
Accumulated depletion				
Balance at January 1, 2012	(162)	(3,381)	-	(3,543)
Depletion charge	(2,525)	(33,434)	-	(35,959)
Amortisation ⁽²⁾	-	(1,705)	-	(1,705)
Balance at December 31, 2012	(2,687)	(38,520)	-	(41,207)
Depletion charge	(5,112)	(69,591)	-	(74,703)
Amortisation ⁽²⁾	-	(2,869)	-	(2,869)
Balance at December 31, 2013	(7,799)	(110,980)	-	(118,779)
Net carrying value				
Balance at December 31, 2012	61,736	814,558	-	876,294
Balance at December 31, 2013	85,372	1,155,470	-	1,242,814

(1) In accordance with the Group's policy at note 1(p), borrowing costs are capitalised where it is probable that they will result in future economic benefits to the entity and the costs can be measured reliably. Borrowing costs have been specifically capitalised in respect of oil and gas properties as the intended use of funding provided from the senior secured revolving credit facility and the first issue of high yield bonds is the Group's drilling program at the Sugarkane field.

(2) Borrowing costs are amortised to profit or loss over the term of the loan facility.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

13. OIL AND GAS PROPERTIES (CONTINUED)

	Tangible Costs US\$'000	Intangible Costs US\$'000	Prepaid Drilling, Completion and Lease Acquisition Costs US\$'000	Total US\$'000
DEVELOPMENT PROJECTS				
Cost				
Balance at January 1, 2012	-	-	-	-
Additions	-	6,079	-	6,079
Balance at December 31, 2012	-	6,079	-	6,079
Additions	-	71,163	-	71,163
Net movement in prepaid costs	-	-	124	124
Balance at December 31, 2013	-	77,242	124	77,366
Net carrying value				
Balance at December 31, 2012	-	6,079	-	6,079
Balance at December 31, 2013	-	77,242	124	77,366

14. TRADE AND OTHER PAYABLES

	Consolidated	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Trade payables and accruals	205,922	180,619

Trade and other payables are normally settled within 30 days from receipt of invoice. Information about the Group's exposure to foreign exchange risk on financial instruments is provided in Note 3. All amounts recognised as trade and other payables, but not yet invoiced, are expected to be settled within the next 12 months.

15. PROVISIONS – CURRENT

	Consolidated	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Employee Benefits	506	334

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

16. BORROWINGS – NON CURRENT

		Consolidated	
		December 31, 2013 US\$'000	December 31, 2012 US\$'000
Secured			
Senior secured syndicated facility	(a)	-	30,000
Unsecured			
Senior unsecured notes	(b)	660,976	360,453
Total		660,976	390,453

(a) Senior Secured Revolving Credit facility

On November 8, 2011, Aurora USA Oil and Gas Inc. ("Aurora USA"), a wholly owned subsidiary of the Company, signed a US\$300 million credit agreement with a syndicate of banks, pursuant to which funds are available on a revolving basis up to an established amount at a margin of between 2 and 3 per cent over the floating LIBOR rate. The Facility ("Facility") contains negative and affirmative covenants and matures on November 7, 2016.

The funding under the Facility will be provided with availability determined, at a minimum on a semi-annual basis, relative to a borrowing base calculated by reference to proved reserves. The Facility is designed for the borrowing base to increase with Aurora's increased proved reserves, subject to and in accordance with the terms of the credit agreement. During September 2013 the borrowing base was re-determined following the 2013 mid-year reserves update to US\$300 million.

On November 28, 2012, US\$30 million was drawn down under the Facility and a further US\$30 million was drawn down on February 21, 2013. On March 25, 2013 a total of US\$60 million was re-paid, leaving the full borrowing base of US\$300 million undrawn as at December 31, 2013.

Aurora USA's obligations under the Facility are guaranteed by pledged security from the parent entity, Aurora, and the subsidiaries of Aurora USA. At December 31, 2013, the following investment property was pledged as security:

Owner / Grantor	Issuer	Percentage Owned	Percentage Pledged	Class of stock
Aurora Oil & Gas Limited	Aurora USA Oil and Gas, Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas, Inc.	Wardanup Oil and Gas, Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas, Inc.	Sugarloaf Oil and Gas, Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas, Inc.	Yallingup Oil and Gas, Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas, Inc.	Trigg Oil and Gas, Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas, Inc.	Aurora USA Development, LLC.	100%	100%	Membership Interest
Aurora USA Oil and Gas, Inc.	ATW Exploration Oil and Gas, Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas, Inc.	Aurora EF Production Company	100%	100%	Common Stock
Aurora USA Oil and Gas, Inc.	EKA 002, Inc.	100%	100%	Common Stock
Aurora USA Oil and Gas, Inc.	EKA 003, Inc.	100%	100%	Common Stock
EKA 003, Inc.	EKA 003, LLC.	100%	100%	Membership Interest

The carrying value of assets pledged as securities for non-current borrowings is US\$564,368,000 (December 31, 2012: US\$307,910,000).

In addition to investment property pledged, a negative pledge imposes that certain financial covenants be maintained by Aurora, Aurora USA and its subsidiaries.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

16. BORROWINGS – NON CURRENT (CONTINUED)

(b) Senior unsecured notes

On February 8, 2012 Aurora USA, a wholly owned subsidiary of the Company, completed a private offering of unsecured notes ("2017 Senior Note Offering"). Under the 2017 Senior Note Offering, Aurora USA issued an aggregate principal amount of US\$200 million 9.875% senior unsecured notes ("2017 Senior Notes") due February 2017 at an issue price of 98.552% of their face value, resulting in net proceeds of approximately US\$192 million after deduction of the original discount and commissions. The 2017 Senior Notes were issued pursuant to an indenture dated February 8, 2012 by and amongst Aurora USA, the guarantor parties thereto and US Bank National Association, as trustee.

On July 31, 2012 Aurora USA completed a follow on offering of the 2017 Senior Notes, issuing an aggregate principal amount of US\$165 million 9.875% senior unsecured notes due in February 2017 at a premium of 101.5% of their face value, resulting in net proceeds of approximately US\$164 million after addition of premium and deduction of commissions.

On March 21, 2013 Aurora USA completed a new offering of senior unsecured notes ("2020 Senior Note Offering"), issuing an aggregate principal amount of US\$300 million 7.50% senior unsecured notes ("2020 Senior Notes"), due in April 2020 at par, resulting in net proceeds of approximately US\$293 million after deductions of commissions. The 2020 Senior Notes will bear interest at 7.50% per annum and will be payable semi-annually in arrears, beginning October 1, 2013.

(c) Fair value

The carrying amounts and fair value of borrowings at the end of the reporting period are:

	December 31, 2013		December 31, 2012	
	Carrying amount US\$'000	Fair Value US\$'000	Carrying amount US\$'000	Fair Value US\$'000
Secured				
Senior secured syndicated facility	-	-	30,000	30,000
Unsecured				
Senior unsecured notes	660,976	665,000	360,453	365,000
Total borrowings	660,976	665,000	390,453	395,000

The fair value of borrowings equal their face value, as the impact of discounting is not significant. The fair value of senior unsecured notes is stated before taking into account borrowing costs, premium and discount.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

17. DEFERRED TAX LIABILITIES

	Consolidated	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
(a) Deferred tax asset		
<i>Arising from temporary differences attributable to:</i>		
Tax losses ⁽¹⁾		
Australia	1,046	216
United States	203,781	142,967
Share issue expense	671	464
Other	10,002	8,492
Available-for-sale financial assets	1,284	1,509
Cash flow hedge	1,547	495
Total deferred tax asset	218,331	154,143
Less set off of deferred tax liabilities under set-off provisions (b)	(218,331)	(154,143)
(b) Deferred tax liability		
<i>Arising from temporary differences attributable to:</i>		
Oil and gas properties	(358,816)	(232,547)
Management fees and borrowing costs	(5,199)	(5,119)
Total deferred tax liabilities	(364,015)	(237,666)
Less set off of deferred tax asset under set-off provisions (a)	218,331	154,143
Net deferred tax liabilities	(145,684)	(83,523)
Deferred tax liabilities expected to be settled within 12 months	-	-
Deferred tax liabilities expected to be settled after more than 12 months	(145,684)	(83,523)

⁽¹⁾ The deferred tax liabilities arising from accumulated tax losses for US taxpaying entities and on US based oil and gas properties have been calculated at the marginal tax rate of 35%.

18. DERIVATIVE FINANCIAL INSTRUMENTS

	Consolidated	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Forward commodity contracts – cash flow hedges		
Current	5,937	1,535
Non - current	(85)	114
Total derivative financial instrument liabilities	5,852	1,649

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

18. DERIVATIVE FINANCIAL INSTRUMENTS (CONTINUED)

Instruments used by the group

The Group is a party to derivative financial instruments entered into in the normal course of business in order to hedge exposure to fluctuations in commodity prices in accordance with the Group's financial risk management policies.

Forward commodity price contracts – cash flow hedges

At December 31, 2013, the Group has various oil commodity contracts designated as hedges of expected future oil sales. These contracts are all designated as cash flow hedges and are used to reduce the exposure to a future decrease in the value of oil sales. The outstanding contracts held by the Group at December 31, 2013 are as follows:

Year of delivery	Subject of contract	Reference	Option traded	Barrels	Weighted average US\$ / barrel			Fair value US\$'000
					Strike price	Floor price	Ceiling price	
2014	Oil	Nymex WTI	Swap	1,834,300	93.07	-	-	(5,293)
2014	Oil	Nymex WTI	Zero Cost Collar	270,000	-	80.00	98.67	(644)
2015	Oil	Nymex WTI	Swap	258,000	90.99	-	-	85
Total				2,362,300				(5,852)

The hedge contracts are to be settled at a rate of between 127,000 to 236,900 barrels per month in 2014 and 2015.

The portion of the gain or loss on the hedging instrument that is determined to be an effective hedge is recognised in other comprehensive income. When the cash flows occur, the Group adjusts the initial measurement of the component recognised in the statement of financial position by removing the related amount from other comprehensive income.

19. PROVISIONS – NON-CURRENT

	Consolidated	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Restoration provision	2,808	1,705
Reconciliation of movement in restoration provision		
Balance at the beginning of the financial year	1,705	565
Provision made during the year	1,103	1,140
Balance at the end of the financial year	2,808	1,705

Provisions for future removal and restoration costs are recognised where there is a present obligation as a result of exploration, development, production, transportation or storage activities having been undertaken, and it is probable that an outflow of economic benefits will be required to settle the obligation. Restoration costs are based on the latest estimated future costs as disclosed in the independently prepared reserves report, determined on a discounted basis. The estimated future obligations include the costs of removing facilities, abandoning wells and restoring the affected areas.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

20. CONTRIBUTED EQUITY

	December 31, 2013 Securities	December 31, 2012 Securities	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Share capital				
Ordinary shares	448,785,778	447,885,778	405,148	405,169
Treasury shares	(247,349)	-	(636)	-
Total contributed equity	448,538,429	447,885,778	404,512	405,169

(a) Ordinary shares

Ordinary shares entitle the holder to participate in dividends and the proceeds on winding up of the Company in proportion to the number of shares held. On a show of hands every holder of ordinary shares present at a meeting or by proxy, is entitled to one vote. Upon poll every holder is entitled to one vote per share held.

(b) Movements in contributed equity:

	Date	Number of Securities	Issue Price	US\$'000
Balance January 1, 2012		411,655,343		290,194
Placement	16-May-12	15,802,816	A\$3.55	54,721
Placement	16-May-12	18,000,000	C\$3.55	61,359
Placement	28-Jun-12	1,137,619	A\$3.55	4,058
Performance rights exercised	15-Aug-12	390,000	-	-
Performance rights exercised	20-Aug-12	900,000	-	-
Share issue costs				(5,163)
Balance at December 31, 2012		447,885,778		405,169
Performance rights exercised	08-Aug-13	900,000	-	-
Share issue costs				(21)
Balance at December 31, 2013		448,785,778		405,148

(c) Treasury Shares

Treasury shares are shares in Aurora Oil & Gas Limited that are held by the Aurora Oil & Gas Employee Share Trust for the purpose of issuing shares under the Aurora Oil & Gas Limited Long Term Incentive Plan (see note 26 for further information regarding the Long Term Incentive Plan).

	Date	Number of Securities	Issue Price	US\$'000
Balance January 1, 2012		-		-
Balance at December 31, 2012		-		-
Aurora Oil & Gas Employee Share Trust Acquisition	21-Nov-13	(171,293)	A\$2.92	(458)
Aurora Oil & Gas Employee Share Trust Distribution	29-Nov-13	100,000	A\$3.03	277
Aurora Oil & Gas Employee Share Trust Acquisition	6-Dec-13	(176,056)	A\$2.84	(455)
Balance at December 31, 2013		(247,349)		(636)

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

21. BUSINESS COMBINATION

(a) Summary of acquisition

On April 30, 2012 Aurora Oil & Gas Limited ("Aurora") announced an unconditional on-market cash offer of A\$0.45 per share for all issued ordinary shares of ASX listed Eureka Energy Limited ("Eureka"). On June 30, 2012 Aurora had acquired 75.03% of the issued share capital of Eureka, and it was determined that control existed on this date. On August 13, 2012 Aurora completed the compulsory acquisition of Eureka on the same terms as the on market offer dated April 30, 2012, and is now the registered holder of 100% of Eureka's issued share capital. On August 23, 2012 Eureka was removed from the official list of ASX Limited.

Details of the purchase consideration, the net assets acquired and the fair value of net assets acquired are as follows:

	US\$'000
Purchase consideration (refer to (b) below):	
Cash paid	106,136
Fair value of shares owned prior to the on-market cash offer	3,405
Total purchase consideration	109,541

The assets and liabilities recognised from the unaudited financial statements of the acquiree as a result of the acquisition are as follows:

	Fair value US\$'000
Cash and cash equivalents	7,371
Trade and other receivables	1,636
Property, plant and equipment	360
Oil and gas properties	164,664
Trade and other payables	(8,830)
Borrowings	(9,000)
Deferred tax liability	(46,526)
Provisions	(134)
Net identifiable assets acquired	109,541

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

21. BUSINESS COMBINATION (CONTINUED)

(a) Summary of acquisition (continued)

Revenue and profit contribution

If the acquisition had occurred on January 1, 2012, consolidated revenue and profit for the year ended December 31, 2012 would have been US\$299,805,000 and US\$61,055,000 respectively. These amounts have been calculated using the group's accounting policies and by adjusting the results of the subsidiary to reflect the additional depletion that would have been charged assuming the fair value adjustments to oil and gas properties had been applied from January 1, 2012, together with the consequential tax effects.

(b) Purchase consideration

	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Outflow of cash to acquire subsidiary, net of cash acquired		
Cash consideration	-	106,136
Less: Balances acquired		
Cash	-	7,371
Outflow of cash – investing activity	-	98,765

Acquisition related costs

Acquisition related costs \$1,892,000 were included in evaluation expenses in the 2012 Statement of profit or loss and other comprehensive Income and in operating cash flows in the Statement of cash flows.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

22. OPTIONS AND PERFORMANCE RIGHTS

As at reporting date the Group has the following classes of options and performance rights on issue:

			December 31, 2013 Number	December 31, 2012 Number	Exercise Price	Expiry
Type 18	AUTAZ	Performance Rights (PRP)	-	900,000	n/a	19-Feb-15
Type 19	AUTAI	Options	150,000	150,000	A\$1.60	9-Nov-15
Type 20	AUTAI	Options	150,000	150,000	A\$1.85	9-Nov-15
Type 21	AUTAI	Options	150,000	150,000	A\$2.10	9-Nov-15
Type 22	AUTAZ	Options	600,000	600,000	A\$1.60	24-Jan-16
Type 23	AUTAZ	Options	600,000	600,000	A\$1.85	24-Jan-16
Type 24	AUTAZ	Options	600,000	600,000	A\$2.10	24-Jan-16
Type 25	AUTAK	Options	250,000	250,000	A\$3.00	30-Apr-15
Type 26	AUTAK	Options	250,000	250,000	A\$3.50	30-Apr-16
Type 27	AUTAK	Options	250,000	250,000	A\$4.00	30-Apr-17
Type 28	AUTAK	Options	500,000	500,000	A\$3.28	30-May-16
Type 29	AUTAK	Options	250,000	250,000	A\$3.28	30-May-16
Type 30	AUTAK	Options	500,000	500,000	A\$3.58	30-May-16
Type 31	AUTAK	Options	250,000	250,000	A\$3.58	30-May-16
Type 32	AUTAK	Options	300,000	300,000	A\$3.76	30-Sep-15
Type 33	AUTAK	Options	350,000	350,000	A\$4.10	30-Sep-16
Type 34	AUTAK	Options	350,000	350,000	A\$4.45	30-Sep-17
Type 35	AUTAO	2011 LTIP Award	-	49,396	n/a	01-Jan-15
Type 36	AUTAO	2011 LTIP Award	84,356	98,795	n/a	01-Jan-15
Type 37	AUTAO	2011 LTIP Award	168,710	197,586	n/a	01-Jan-15
Type 38	AUTAO	LTIP Sign On Award	-	100,000	n/a	19-Oct-15
Type 39	AUTAO	LTIP Sign On Award	100,000	100,000	n/a	19-Oct-15
Type 40	AUTAO	LTIP Sign On Award	100,000	100,000	n/a	19-Oct-15
Type 41	AUTAK	Options – Sign On Award	250,000	250,000	A\$4.00	19-Oct-17
Type 42	AUTAK	Options – Sign On Award	250,000	250,000	A\$4.50	19-Oct-18
Type 43	AUTAK	Options – Sign On Award	250,000	250,000	A\$5.00	19-Oct-19
Type 44	AUTAO	2012 LTIP Award	-	5,962	n/a	01-Jan-15
Type 45	AUTAO	2012 LTIP Award	9,669	11,923	n/a	01-Jan-15
Type 46	AUTAO	2012 LTIP Award	19,339	23,847	n/a	01-Jan-15
Type 47 / 50	AUTAO	2012 LTIP Award	-	-	n/a	01-Jan-15
Type 48 / 51	AUTAO	2012 LTIP Award	164,133	-	n/a	01-Jan-15
Type 49 / 52	AUTAO	2012 LTIP Award	328,265	-	n/a	01-Jan-15
Type 64	AUTAK	Options – Sign On Award	100,000	-	A\$3.24	15-May-17

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

22. OPTIONS AND PERFORMANCE RIGHTS (CONTINUED)

			December 31, 2013 Number	December 31, 2012 Number	Exercise Price	Expiry
Type 65	AUTAK	Options – Sign On Award	100,000	-	A\$3.47	15-May-18
Type 66	AUTAK	Options – Sign On Award	100,000	-	A\$3.85	15-May-19
Type 67	AUTAK	Options – Sign On Award	100,000	-	A\$4.24	15-May-20
Type 59 / 60 / 61	AUTAO	LTIP Sign On Award	100,000		n/a	1-Jan-17
Type 62 / 63	AUTAO	LTIP Sign On Award	100,000		n/a	1-Jan-17
Type 53 / 56	AUTAO	2013 LTIP Award	125,851	-	n/a	01-Jan-16
Type 54 / 57	AUTAO	2013 LTIP Award	251,703	-	n/a	01-Jan-16
Type 55 / 58	AUTAO	2013 LTIP Award	503,405	-	n/a	01-Jan-16
Type 68	AUTAK	Options	250,000	-	A\$3.64	16-Oct-18
Type 69	AUTAK	Options	250,000	-	A\$3.97	16-Oct-18
Total			9,205,431	7,837,509		

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

22. OPTIONS AND PERFORMANCE RIGHTS (CONTINUED)

(a) Options and performance rights

The options and performance rights are not listed and carry no dividend or voting rights. Upon exercise, each option or performance right is convertible into one ordinary share to rank pari passu in all respects with the Company's existing fully paid ordinary shares.

(b) Movements in the number of options and performance rights on issue during the year:

	Date	Award			Number
Balance at December 31, 2011					7,690,000
Granted during the year:	1-Feb-12	2011 LTIP Award	Type 35 / 36 / 37	AUTAO	348,574
	18-Oct-12	LTIP Sign On Award	Type 38 / 39 / 40	AUTAO	300,000
	18-Oct-12	LTIP Sign On Award	Type 41 / 42 / 43	AUTAK	750,000
	31-Dec-12	2012 LTIP Award	Type 44 / 45 / 46	AUTAO	41,732
Exercised during the year:	15-Aug-12	Performance Rights (PRP)	Type 18	AUTAZ	(390,000)
	20-Aug-12	Performance Rights (PRP)	Type 18	AUTAZ	(900,000)
Lapsed during the year:	20-Apr-12	2011 LTIP Award	Type 35, 36, 37	AUTAO	(1,987)
	17-May-12	2011 LTIP Award	Type 35, 36, 37	AUTAO	(810)
Balance at December 31, 2012					7,837,509
Granted during the year:	1-Jan-13	2013 LTIP Award	Type 53 / 54 / 55	AUTAO	472,638
	4-Jan-13	2012 LTIP Award	Type 47 / 48 / 49	AUTAO	194,776
	27-Mar-13	2013 LTIP Award	Type 53 / 54 / 55	AUTAO	53,529
	30-Apr-13	2013 LTIP Award	Type 53 / 54 / 55	AUTAO	30,960
	30-May-13	LTIP Sign On Award	Type 59 / 60 / 61 / 62 / 63	AUTAO	200,000
	15-May-13	2013 LTIP Award	Type 53 / 54 / 55	AUTAO	35,331
	29-May-13	2012 LTIP Award	Type 50 / 51 / 52	AUTAO	448,186
	29-May-13	2013 LTIP Award	Type 56 / 57 / 58	AUTAO	446,693
	30-May-13	Options (Under LTIP)	Type 64 / 65 / 66 / 67	AUTAK	400,000
	16-Oct-13	Options (Under LTIP)	Type 68 / 69	AUTAK	500,000
Exercised during the year	1-Jan-13	2012 LTIP Award	Type 44	AUTAO	(5,962)
	1-Jan-13	2012 LTIP Award	Type 47	AUTAO	(22,997)
	15-Mar-13	2011 LTIP Award	Type 35	AUTAO	(49,396)
	29-May-13	2012 LTIP Award	Type 50	AUTAO	(48,020)
	08-Aug-13	Performance Rights (PRP)	Type 18	AUTAZ	(900,000)

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

22. OPTIONS AND PERFORMANCE RIGHTS (CONTINUED)

	Date	Award			Number
	29-Nov-13	LTIP Sign On Award	Type 38	AUTAO	(100,000)
Lapsed during the year	1-Jan-13	2013 LTIP Award	Type 47	AUTAO	(4,828)
	15-Apr-13	2013 LTIP Award	Type 53 / 54 / 55	AUTAO	(2,326)
	29-May-13	2012 LTIP Award	Type 50	AUTAO	(16,007)
	14-Jun-13	2013 LTIP Award	Type 53 / 54 / 55	AUTAO	(5,782)
	15-Jul-13	2012 LTIP Award	Type 45 / 46	AUTAO	(1,718)
	15-Jul-13	2013 LTIP Award	Type 53 / 54 / 55	AUTAO	(4,496)
	16-Aug-13	2011 / 2012 LTIP Awards	Type 36 / 37 / 51 / 52	AUTAO	(100,313)
	16-Aug-13	2013 LTIP Award	Type 56 / 57 / 58	AUTAO	(76,989)
	29-Aug-13	2012 LTIP Award	Type 45 / 46	AUTAO	(1,499)
	29-Aug-13	2013 LTIP Award	Type 53 / 54 / 55	AUTAO	(3,768)
	27-Sept-13	2012 LTIP Award	Type 45 / 46	AUTAO	(812)
	27-Sept-13	2013 LTIP Award	Type 53 / 54 / 55	AUTAO	(5,443)
	1-Oct-13	2013 LTIP Award	Type 53 / 54 / 55	AUTAO	(54,955)
	11-Oct-13	2011 / 2012 LTIP Awards	Type 36 / 37 / 45 / 46	AUTAO	(4,447)
	11-Oct-13	2013 LTIP Award	Type 53 / 54 / 55	AUTAO	(4,433)
Balance at December 31, 2013					9,205,431

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

23. RESERVES AND ACCUMULATED LOSSES

	Consolidated	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
(a) Share based payment reserve		
Balance at the beginning of the financial period	12,165	7,767
Share-based payment expense	5,376	4,398
Performance rights settlements	(663)	-
Closing balance	16,878	12,165
(b) Fair value reserve		
Balance at the beginning of the financial period	(7,054)	(8,011)
Change in financial assets at fair value through other comprehensive income	(630)	(593)
Recognition of fair value of equity instruments measured at fair value through other comprehensive income on disposal	-	41
Deferred tax	225	1,509
Closing balance	(7,459)	(7,054)
(c) Foreign exchange reserve		
Balance at the beginning of the financial period	(7,505)	(7,505)
Currency translation differences arising during the period/year	-	-
Closing balance	(7,505)	(7,505)
(d) Cash flow hedge reserve		
Balance at the beginning of the financial period	(1,154)	-
Change in derivative financial instruments at fair value through other comprehensive income	(3,993)	(1,649)
Deferred tax	1,051	495
Closing balance	(4,096)	(1,154)
(e) Retained earnings / (accumulated losses)		
Balance at the beginning of the financial period	51,493	(7,353)
Net profit for the year	116,430	58,846
Closing balance	167,923	51,493

Notes to the Consolidated Financial Statements

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24. EARNINGS PER SHARE

	Consolidated	
	December 31, 2013 US Cents	December 31, 2012 US Cents
(a) Earnings per share attributable to members of the Company		
Basic earnings per share	25.97	13.60
Diluted earnings per share	25.51	13.35
(b) Earnings used in calculation of basic / diluted earnings per share	US\$'000	US\$'000
Net Profit after tax	116,430	58,846
(c) Weighted average number of ordinary shares used as the denominator in calculating:	Shares	Shares
Basic shares	448,244,294	432,588,491
Diluted shares	456,428,258	439,407,647

25. DIVIDENDS

No dividend has been paid or is proposed in respect of the year ended December 31, 2013 (2012: None).

26. SHARE BASED PAYMENTS

At December 31, 2013 the Group has the following share-based payment arrangements

(a) Performance rights

During the year ended December 31, 2013 the Company had in existence two long term incentive plans, the Aurora Oil & Gas Limited Performance Rights Plan (PRP) which was approved by shareholders at the general meeting held on February 19, 2010, and the Aurora Oil & Gas Limited Long Term Incentive Plan (LTIP) which was established in 2011 and approved by the shareholders at the annual general meeting on May 29, 2012.

Awards of performance rights are no longer made under the PRP and consequently the Company terminated the PRP subsequent to year end.

(i) Performance Rights Plan (PRP)

The PRP was designed to align the interests of executives with shareholders by providing direct participation in the benefits of future Company performance over the medium to long term.

The participants of the plan during 2013 were:

- Jonathan Stewart

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

26. SHARE BASED PAYMENTS (CONTINUED)

(a) Performance rights (continued)

Under the PRP, participants were granted performance rights which only vested if certain performance standards (as disclosed in the Remuneration Report) were met and the executive remained employed by the Company to the end of the vesting period. The selection of suitable performance benchmarks was considered critical to securing the objective of the PRP, and hurdles were set at significantly higher levels than those prevailing at the time of structuring the PRP.

The fair value of performance rights granted was calculated using a risked statistical analysis. This expense has been apportioned pro-rata to reporting periods where vesting periods apply.

Movement in the number of performance rights granted under the PRP:

Grant Date	Expiry Date	Balance at start of the year	Granted during the year	Exercised during the year	Net other changes	Balance at end of the year	Vested and exercisable at end of the year
		Number	Number	Number	Number	Number	Number
At December 31, 2013							
19-Feb-2010	19-Feb-2015	900,000	-	(900,000)	-	-	-
At December 31, 2012							
19-Feb-2010	19-Feb-2015	2,190,000	-	(1,290,000)	-	900,000	-

The weighted average share price at the date of exercise during the year ended December 31, 2013 was A\$3.29 (December 31, 2012: A\$3.48).

(ii) Long Term Incentive Plan (LTIP)

The objectives of the LTIP are to align the interest of shareholders and employees, and as an incentive to attract and retain key management, including Executive KMP's. Participants' invitation to participate in the LTIP, the awards granted, and their terms and conditions, are determined by the Board on the recommendation of the Remuneration and Nomination Committee (RNC). The terms of LTI's awarded to executive management include specific performance hurdles in order to match such awards with the actual circumstances of the Company at a given point in time.

Vesting of performance rights is dependent upon the participant remaining in employment until the vesting date. The number of performance rights that will vest to executive management level participants is also dependent upon Aurora Oil & Gas Limited's total return to shareholders (TSR) ranking within a peer group determined on an annual basis by the RNC, over the test period. The peer group for 2013 and 2012 represented 11 Australian energy companies (ASX listed) and 4 Canadian oil and gas companies (TSX listed). Performance rights are granted under the plan for no consideration.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

26. SHARE BASED PAYMENTS (CONTINUED)

Upon vesting it is at the Board's discretion on the recommendation of the RNC as to whether each performance right is converted into one ordinary share or settled in cash. The cash settled value of each performance right is determined as the volume weighted average trading price of Shares sold on the ASX over the last 5 trading days immediately before the relevant settlement date. The settlement date is determined by the Board, and must be within 30 days of vesting date.

Fair value of LTIP performance rights was calculated using binomial tree and Monte-Carlo simulation valuation models. This expense has been apportioned pro-rata to reporting periods where vesting periods apply.

Key inputs to the binomial tree and Monte-Carlo simulation valuation models used in the calculation of each grant of long term incentive performance rights during the year ended December 31, 2013 were as follows:

	Expected price volatility ⁽¹⁾	Exercise price	Vest date	Expiry date	Share price at grant date	Risk free interest rate ⁽²⁾	Fair value per performance right
Grant date: January 1, 2013							
Type 53A: AUTAO	45%	N/a	1-Jan-14	1-Jan-16	A\$3.63	2.63%	US\$2.03
Type 53B: AUTAO	N/a	N/a	1-Jan-14	1-Jan-16	A\$3.63	N/a	US\$3.77
Type 54A: AUTAO	45%	N/a	1-Jan-15	1-Jan-16	A\$3.63	2.62%	US\$2.24
Type 54B: AUTAO	N/a	N/a	1-Jan-15	1-Jan-16	A\$3.63	N/a	US\$3.77
Type 55A: AUTAO	45%	N/a	1-Jan-16	1-Jan-16	A\$3.63	2.66%	US\$2.41
Type 55B: AUTAO	N/a	N/a	1-Jan-16	1-Jan-16	A\$3.63	N/a	US\$3.77
Grant date: January 4, 2013							
Type 47A: AUTAO	45%	N/a	1-Jan-13	1-Jan-18	A\$3.63	2.72%	US\$1.91
Type 47B: AUTAO	N/a	N/a	1-Jan-13	1-Jan-18	A\$3.63	N/a	US\$3.80
Type 48A: AUTAO	45%	N/a	1-Jan-14	1-Jan-18	A\$3.63	2.63%	US\$2.10
Type 48B: AUTAO	N/a	N/a	1-Jan-14	1-Jan-18	A\$3.63	N/a	US\$3.80
Type 49A: AUTAO	45%	N/a	1-Jan-15	1-Jan-18	A\$3.63	2.62%	US\$2.30
Type 49B: AUTAO	N/a	N/a	1-Jan-15	1-Jan-18	A\$3.63	N/a	US\$3.80
Grant date: March 27, 2013⁽⁴⁾							
Type 53A: AUTAO	45%	N/a	1-Jan-14	27-Mar-18	A\$3.74	2.85%	US\$2.06
Type 53B: AUTAO	N/a	N/a	1-Jan-14	27-Mar-18	A\$3.74	N/a	US\$3.92
Type 54A: AUTAO	45%	N/a	1-Jan-15	27-Mar-18	A\$3.74	2.87%	US\$2.30
Type 54B: AUTAO	N/a	N/a	1-Jan-15	27-Mar-18	A\$3.74	N/a	US\$3.92
Type 55A: AUTAO	45%	N/a	1-Jan-16	27-Mar-18	A\$3.74	2.93%	US\$2.47
Type 55B: AUTAO	N/a	N/a	1-Jan-16	27-Mar-18	A\$3.74	N/a	US\$3.92
Grant date: May 15, 2013⁽⁴⁾							
Type 53A: AUTAO	45%	N/a	1-Jan-14	15-May-18	A\$2.92	2.49%	US\$0.85
Type 53B: AUTAO	N/a	N/a	1-Jan-14	15-May-18	A\$2.92	N/a	US\$2.89
Type 54A: AUTAO	45%	N/a	1-Jan-15	15-May-18	A\$2.92	2.50%	US\$1.28

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

26. SHARE BASED PAYMENTS (CONTINUED)

	Expected price volatility ⁽¹⁾	Exercise price	Vest date	Expiry date	Share price at grant date	Risk free interest rate ⁽²⁾	Fair value per performance right
Type 54B: AUTAO	N/a	N/a	1-Jan-15	15-May-18	A\$2.92	N/a	US\$2.89
Type 55A: AUTAO	45%	N/a	1-Jan-16	15-May-18	A\$2.92	2.56%	US\$1.49
Type 55B: AUTAO	N/a	N/a	1-Jan-16	15-May-18	A\$2.92	N/a	US\$2.89
Grant date: May 30, 2012							
Type 59: AUTAO	N/a	N/a	15-May-14	30-May-18	A\$3.08	N/a	US\$2.96
Type 60: AUTAO	N/a	N/a	15-May-15	30-May-18	A\$3.08	N/a	US\$2.96
Type 61: AUTAO	N/a	N/a	15-May-16	30-May-18	A\$3.08	N/a	US\$2.96
Type 62: AUTAO	N/a	N/a	15-May-17	30-May-18	A\$3.08	N/a	US\$2.96
Type 63: AUTAO	45%	N/a	15-May-17	30-May-18	A\$3.08	2.74%	US\$2.02
Grant date: January 4, 2013 – valuation grant date: May 29, 2013⁽³⁾							
Type 50A: AUTAO	N/a	N/a	1-Jan-13	4-Jan-18	A\$3.01	N/a	US\$1.45
Type 50B: AUTAO	N/a	N/a	1-Jan-13	4-Jan-18	A\$3.01	N/a	US\$2.89
Type 51A: AUTAO	45%	N/a	1-Jan-14	4-Jan-18	A\$3.01	2.45%	US\$0.92
Type 51B: AUTAO	N/a	N/a	1-Jan-14	4-Jan-18	A\$3.01	N/a	US\$2.89
Type 52A: AUTAO	45%	N/a	1-Jan-15	4-Jan-18	A\$3.01	2.55%	US\$1.34
Type 52B: AUTAO	N/a	N/a	1-Jan-15	4-Jan-18	A\$3.01	N/a	US\$2.89
Grant date: January 1, 2013 – valuation grant date: May 29, 2013⁽³⁾							
Type 56A: AUTAO	45%	N/a	1-Jan-14	1-Jan-16	A\$3.01	2.45%	US\$0.95
Type 56B: AUTAO	N/a	N/a	1-Jan-14	1-Jan-16	A\$3.01	N/a	US\$2.89
Type 57A: AUTAO	45%	N/a	1-Jan-15	1-Jan-16	A\$3.01	2.55%	US\$1.65
Type 57B: AUTAO	N/a	N/a	1-Jan-15	1-Jan-16	A\$3.01	N/a	US\$2.89
Type 58A: AUTAO	45%	N/a	1-Jan-16	1-Jan-16	A\$3.01	2.63%	US\$1.56
Type 58B: AUTAO	N/a	N/a	1-Jan-16	1-Jan-16	A\$3.01	N/a	US\$2.89

⁽¹⁾ Expected price volatility is based on the historical volatility adjusted for any expected changes to future volatility due to publicly available information.

⁽²⁾ Risk free rate of securities with comparable terms to maturity.

⁽³⁾ The grant of 2012 and 2013 LTI's were approved by shareholders at the Annual General Meeting held on May 29, 2013. LTI performance rights were granted to executive employees in respect of 2013 on January 1, 2013 and in respect of 2012 on January 4, 2013, however in accordance AASB 2: Share-based Payments, grant date for valuation purposes is determined with reference to the date of shareholder approval for the incentive plan.

⁽⁴⁾ 2013 LTI's were granted to new executive employees upon commencement of employment.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

26. SHARE BASED PAYMENTS (CONTINUED)

Key inputs to the binomial tree and Monte-Carlo simulation valuation models used in the calculation of each grant of long term incentive performance rights during the year ended December 31, 2012 were as follows:

	Expected price volatility ⁽¹⁾	Exercise price	Vest date	Expiry date	Share price at grant date	Risk free interest rate ⁽²⁾	Fair value per performance right
Grant date: February 1, 2012 – valuation grant date: May 29, 2012⁽³⁾							
Type 35A: AUTAO	55%	N/a	15-Feb-12	1-Jan-15	A\$3.42	2.74%	US\$3.47
Type 35B: AUTAO	N/a	N/a	15-Feb-12	1-Jan-15	A\$3.42	N/a	US\$2.46
Type 36A: AUTAO ⁽⁴⁾	45%	N/a	1-Jan-14	1-Jan-15	A\$3.89	2.79%	US\$2.84
Type 36B: AUTAO ⁽⁴⁾	N/a	N/a	1-Jan-14	1-Jan-15	A\$3.89	N/a	US\$4.05
Type 37A: AUTAO ⁽⁴⁾	45%	N/a	1-Jan-15	1-Jan-15	A\$3.89	2.65%	US\$2.83
Type 37B: AUTAO ⁽⁴⁾	N/a	N/a	1-Jan-15	1-Jan-15	A\$3.89	N/a	US\$4.05
Grant date: May 29, 2012⁽⁵⁾							
Type 35A: AUTAO	55%	N/a	15-Feb-12	1-Jan-15	A\$3.42	2.74%	US\$3.47
Type 35B: AUTAO	N/a	N/a	15-Feb-12	1-Jan-15	A\$3.42	N/a	US\$2.46
Type 36A: AUTAO ⁽⁴⁾	45%	N/a	1-Jan-14	1-Jan-15	A\$3.89	2.79%	US\$2.84
Type 36B: AUTAO ⁽⁴⁾	N/a	N/a	1-Jan-14	1-Jan-15	A\$3.89	N/a	US\$4.05
Type 37A: AUTAO ⁽⁴⁾	45%	N/a	1-Jan-15	1-Jan-15	A\$3.89	2.65%	US\$2.83
Type 37B: AUTAO ⁽⁴⁾	N/a	N/a	1-Jan-15	1-Jan-15	A\$3.89	N/a	US\$4.05
Grant date: October 18, 2012							
Type 38: AUTAO	N/a	N/a	18-Oct-13	19-Oct-15	A\$3.94	N/a	US\$4.09
Type 39: AUTAO	N/a	N/a	18-Oct-14	19-Oct-15	A\$3.94	N/a	US\$4.09
Type 40: AUTAO	N/a	N/a	18-Oct-15	19-Oct-15	A\$3.94	N/a	US\$4.09
Grant date: December 31, 2012							
Type 44A: AUTAO	45%	N/a	1-Jan-13	1-Jan-16	A\$3.63	2.63%	US\$1.89
Type 45A: AUTAO	45%	N/a	1-Jan-14	1-Jan-16	A\$3.63	2.62%	US\$2.07
Type 46A: AUTAO	45%	N/a	1-Jan-15	1-Jan-16	A\$3.63	2.66%	US\$2.27

⁽¹⁾ Expected price volatility is based on the historical volatility adjusted for any expected changes to future volatility due to publicly available information.

⁽²⁾ Risk free rate of securities with comparable terms to maturity.

⁽³⁾ The LTIP was approved by shareholders at the Annual General Meeting held on May 29, 2012. LTIP performance rights were granted to employees and executive employees on February 1, 2012, however in accordance AASB 2: Share-based Payments, grant date for valuation purposes is determined with reference to the date of shareholder approval for the incentive plan.

⁽⁴⁾ On November 8, 2012 a modification was made to the vesting conditions of type 36 and type 37 performance rights, to extend the test dates for the performance hurdle, to ensure the TSR hurdle is tested over the full vesting period. In accordance with AASB 2: Share-based Payments, type 36 and type 37 performance rights were revalued immediately prior and immediately subsequent to the modification being made. The resultant value increment is recognised over the remaining vesting period.

⁽⁵⁾ Both the LTIP and the number of performance rights granted under the LTIP to directors were approved by shareholders at the Annual General Meeting held on May 29, 2012.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

26. SHARE BASED PAYMENTS (CONTINUED)

Movement in the number of performance rights granted under LTIP during the year ended December 31, 2013:

Grant Date	Expiry Date	Exercise Price A\$	Balance at start of the year Number	Granted during the year Number	Exercised during the year Number	Forfeited during the year Number	Balance at end of the year Number	Vested and exercisable at end of the year Number
At December 31, 2013								
1-Feb-2012	1-Jan-2015	N/a	96,877	-	(13,839)	(1,714)	81,324	-
29-May-2012	1-Jan-2015	N/a	248,900	-	(35,557)	(41,600)	171,743	-
18-Oct-2012	18-Oct-2015	N/a	300,000	-	(100,000)	-	200,000	-
31-Dec-2012	1-Jan-2015	N/a	41,732	-	(5,962)	(6,762)	29,008	-
1-Jan-2013	1-Jan-2016	N/a	-	472,638	-	(81,203)	391,435	-
4-Jan-2013	1-Jan-2015	N/a	-	194,776	(22,997)	(4,830)	166,949	-
27-Mar-2013	1-Jan-2016	N/a	-	53,529	-	-	53,529	-
30-Apr-2013	1-Jan-2016	N/a	-	30,960	-	-	30,960	-
15-May-2013	1-Jan-2016	N/a	-	35,331	-	-	35,331	-
29-May-2013	1-Jan-2015	N/a	-	448,186	(48,020)	(74,718)	325,448	-
29-May-2013	1-Jan-2016	N/a	-	446,693	-	(76,989)	369,704	-
30-May-2013	1-Jan-2017	N/a	-	200,000	-	-	200,000	-
Total			687,509	1,882,113	(226,375)	(287,816)	2,055,431	-

Movement in the number of performance rights granted under LTIP during the year ended December 31, 2012:

Grant Date	Expiry Date	Exercise Price A\$	Balance at start of the year Number	Granted during the year Number	Exercised during the year Number	Forfeited during the year Number	Balance at end of the year Number	Vested and exercisable at end of the year Number
At December 31, 2012								
1-Feb-2012	1-Jan-2015	N/a	-	99,674	-	(2,797)	96,877	-
29-May-2012	1-Jan-2015	N/a	-	248,900	-	-	248,900	-
18-Oct-2012	18-Oct-2015	N/a	-	300,000	-	-	300,000	-
31-Dec-2012	1-Jan-2015	N/a	-	41,732	-	-	41,732	-
Total			-	690,306	-	(2,797)	687,509	-

The weighted average remaining contractual life of performance rights outstanding at December 31, 2013 was 1.70 years (December 31, 2012: 2.27 years).

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For the year ended December 31, 2013

26. SHARE BASED PAYMENTS (CONTINUED)

(b) Options

Options over ordinary shares in Aurora Oil & Gas Limited were granted as remuneration, with shareholder approval where required, to the following non-executive directors, executive directors and other executives as follows:

Recipient	December 31, 2013		December 31, 2012	
	Grant date	Number of options granted	Grant date	Number of options granted
Douglas Brooks	-	-	18-Oct-12	750,000
John Atkins ⁽¹⁾	16-Oct-13	500,000	-	-
David Lucke ⁽²⁾	30-May-13	400,000	-	-

⁽¹⁾ Mr Atkins was appointed to the Board on June 3, 2013.

⁽²⁾ Mr Lucke was appointed Chief Financial Officer on May 15, 2013 and resigned subsequent to year end on March 9, 2014.

The fair value of options granted during the year was calculated using the Black Scholes options pricing model. The expense is apportioned pro-rata to reporting periods where vesting periods apply. Key inputs to the Black Scholes options pricing model used in the calculation of each grant of options during the year ended December 31, 2013 were as follows:

	Expected price volatility ⁽¹⁾	Exercise price	Vest date	Expiry date	Share price at grant date	Risk free interest rate ⁽²⁾	Fair value per option
Grant date: May 30, 2013							
Type 64: AUTAK	45%	A\$3.24	15-May-14	15-May-17	A\$3.08	2.53%	US\$0.83
Type 65: AUTAK	45%	A\$3.47	15-May-15	15-May-18	A\$3.08	2.66%	US\$0.93
Type 66: AUTAK	45%	A\$3.85	15-May-16	15-May-19	A\$3.08	2.82%	US\$0.99
Type 67: AUTAK	45%	A\$4.24	15-May-17	15-May-20	A\$3.08	2.96%	US\$1.05
Grant date: October 16, 2013							
Type 68: AUTAK	45%	A\$3.64	18-Aug-14	16-Oct-18	A\$3.26	3.50%	US\$0.92
Type 69: AUTAK	45%	A\$3.97	18-Aug-15	16-Oct-19	A\$3.26	3.50%	US\$0.92

Key inputs to the Black Scholes options pricing model used in the calculation of each grant of options during the year ended December 31, 2012 were as follows:

	Expected price volatility ⁽¹⁾	Exercise price	Vest date	Expiry date	Share price at grant date	Risk free interest rate ⁽²⁾	Fair value per option
Grant date: October 18, 2012							
Type 41: AUTAK	50%	A\$4.00	19-Oct-13	19-Oct-17	A\$3.94	2.50%	US\$1.60
Type 42: AUTAK	50%	A\$4.50	19-Oct-14	19-Oct-18	A\$3.94	2.50%	US\$1.67
Type 43: AUTAK	50%	A\$5.00	19-Oct-15	19-Oct-19	A\$3.94	2.50%	US\$1.74

⁽¹⁾ Expected price volatility is based on the historical volatility adjusted for any expected changes to future volatility due to publicly available information.

⁽²⁾ Risk free rate of securities with comparable terms to maturity.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

26. SHARE BASED PAYMENTS (CONTINUED)

Movement in the number of options on issue:

Grant Date	Expiry Date	Exercise Price A\$	Balance at start of the year Number	Granted during the year Number	Exercised during the year Number	Forfeited during the year Number	Balance at end of the year Number	Vested and exercisable at end of the year Number
At December 31, 2013								
16-Oct-13	16-Oct-18	3.64 – 3.97	-	500,000	-	-	500,000	-
30-May-13	15-May-17 to 15-May-20	3.24 – 4.24	-	400,000	-	-	400,000	-
18-Oct-12	19-Oct-17 to 19-Oct-19	4.00 – 5.00	750,000	-	-	-	750,000	250,000
3-Jun-11	30-Sept-15 to 30-Sept-17	3.76 – 4.45	1,000,000	-	-	-	1,000,000	650,000
30-May-11	30-May-16	3.28 – 3.58	1,500,000	-	-	-	1,500,000	750,000
29-Apr-11	30-April-15 to 30-Apr-17	3.00 – 4.00	750,000	-	-	-	750,000	500,000
24-Jan-11	24-Jan-16	1.60 – 2.10	1,800,000	-	-	-	1,800,000	1,200,000
9-Nov-10	9-Nov-15	1.60 – 2.10	450,000	-	-	-	450,000	300,000
Total			6,250,000	900,000	-	-	7,150,000	3,650,000
Weighted average exercise price			A\$3.11	A\$3.76	N/a	N/a	A\$3.19	A\$2.80
At December 31, 2012								
18-Oct-12	19-Oct-17 to 19-Oct-19	4.00 – 5.00	-	750,000	-	-	750,000	-
3-Jun-11	30-Sept-15 to 30-Sept-17	3.76 – 4.45	1,000,000	-	-	-	1,000,000	300,000
30-May-11	30-May-16	3.28 – 3.58	1,500,000	-	-	-	1,500,000	750,000
29-Apr-11	30-April-15 to 30-Apr-17	3.00 – 4.00	750,000	-	-	-	750,000	250,000
24-Jan-11	24-Jan-16	1.60 – 2.10	1,800,000	-	-	-	1,800,000	600,000
9-Nov-10	9-Nov-15	1.60 – 2.10	450,000	-	-	-	450,000	300,000
Total			5,500,000	750,000	-	-	6,250,000	2,200,000
Weighted average exercise price			A\$2.92	A\$4.50	N/a	N/a	A\$3.11	A\$2.64

No options were exercised or expired during the year ended December 31, 2013 (December 31, 2012: nil).

The weighted average remaining contractual life of share options outstanding at the end of the year was 2.89 years (December 31, 2012: 3.49 years).

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

26. SHARE BASED PAYMENTS (CONTINUED)

(c) Expense arising from share-based payment transactions

The total expense arising from share-based payment transactions recognised during the reporting period as part of employee benefit expense were as follows:

	Consolidated	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Options issued	2,338	3,857
Performance rights issued under PRP	5	32
Performance rights issued under LTIP	3,033	509
	5,376	4,398

27. KEY MANAGEMENT PERSONNEL DISCLOSURE

(a) Key management personnel of Aurora Oil & Gas Limited

Name and positions held of key management personnel at any time during the financial year are as follows:

Name	Position
Mr. Jonathan Stewart	Executive Chairman
Mr. Douglas Brooks ⁽¹⁾	Chief Executive Officer
Mr. Graham Dowland	Finance Director
Mr. Ian Lusted ⁽²⁾	Technical Director
Mr. Gren Schoch ⁽³⁾	Non-Executive Director
Ms. Fiona Harris	Non-Executive Director
Mr. Alan Watson	Non-Executive Director
Mr. William Molson	Non-Executive Director
Mr. John Atkins ⁽⁴⁾	Non-Executive Director
Mr. David Lucke ⁽⁵⁾	Chief Financial Officer
Mr. Michael Verm	Chief Operating Officer

⁽¹⁾ Mr Brooks was appointed to the Board on June 3, 2013.

⁽²⁾ Mr Lusted resigned as Technical Director on August 8, 2013 and resigned as an employer on August 16, 2013.

⁽³⁾ Mr Schoch resigned subsequent to year end on February 6, 2014.

⁽⁴⁾ Mr Atkins was appointed as Non-Executive Director on June 3, 2013.

⁽⁵⁾ Mr Lucke was appointed as Chief Financial Officer on May 15, 2013 and resigned subsequent to year end on March 9, 2014.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

27. KEY MANAGEMENT PERSONNEL DISCLOSURE (CONTINUED)

(b) Key management personnel compensation

	Consolidated	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Short-term employee benefits	5,425	4,023
Post-employment benefits	118	222
Share-based payments	4,321	3,735
	9,864	7,980

Information regarding individual directors and executives' compensation and some equity instruments disclosures as permitted by Corporations Regulation 2M.3.03 is provided in the remuneration report section of the directors' report.

Apart from the details disclosed in this note, no director has entered into a material contract with Aurora or the consolidated entity since the end of the previous financial year and there were no material contracts involving directors' interests existing at year end. For details of other transactions with key management personnel, refer to note 32 – Related Party transactions.

(c) Equity instrument disclosure relating to key management personnel

(i) Options and performance rights provided as remuneration and shares issued on exercise of such options

Details of options and performance rights provided as remuneration and shares issued on the exercise of such options, together with terms and conditions of the options and performance rights, can be found at note 26.

(ii) Option and performance right holdings

The number of options and performance rights over ordinary shares in the company held during the financial year by each director of Aurora Oil & Gas Limited and other key management personnel of the group, including their personally related parties, are set out below:

December 31, 2013	Balance at start of the year	Granted as compensation	Exercised	Net other changes	Balance at the end of the year	Vested and exercisable	Unvested
Directors of Aurora Oil & Gas Limited							
Jonathan Stewart							
Performance rights PRP	900,000	-	(900,000)	-	-	-	-
Performance rights LTIP ⁽⁶⁾	152,279	589,821	(54,385)	(10,877)	676,838	-	676,838
Balance at December 31, 2013	1,052,279	589,821	(954,385)	(10,877)	676,838	-	676,838
Graham Dowland							
Options	1,050,000	-	-	-	1,050,000	700,000	350,000
Performance rights LTIP ⁽⁶⁾	48,088	159,571	(14,920)	(2,683)	190,056	-	190,056
Balance at December 31, 2013	1,098,088	159,571	(14,920)	(2,683)	1,240,056	700,000	540,056
Ian Lusted⁽¹⁾							
Performance rights LTIP ⁽⁶⁾	48,533	145,487	(14,272)	(179,748)	-	-	-
Balance at December 31, 2013	48,533	145,487	(14,272)	(179,748)	-	-	-

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

27. KEY MANAGEMENT PERSONNEL DISCLOSURE (CONTINUED)

December 31, 2013	Balance at start of the year	Granted as compensation	Exercised	Net other changes	Balance at the end of year	Vested and exercisable	Unvested
Gren Schoch⁽²⁾							
Options	750,000	-	-	-	750,000	500,000	250,000
Balance at December 31, 2013	750,000	-	-	-	750,000	500,000	250,000
Fiona Harris							
Options	500,000	-	-	-	500,000	250,000	250,000
Balance at December 31, 2013	500,000	-	-	-	500,000	250,000	250,000
Alan Watson							
Options	500,000	-	-	-	500,000	250,000	250,000
Balance at December 31, 2013	500,000	-	-	-	500,000	250,000	250,000
William Molson							
Options	500,000	-	-	-	500,000	250,000	250,000
Balance at December 31, 2013	500,000	-	-	-	500,000	250,000	250,000
John Atkins⁽³⁾							
Options	-	500,000	-	-	500,000	-	500,000
Balance at December 31, 2013	-	500,000	-	-	500,000	-	500,000
Douglas Brooks⁽⁴⁾							
Performance rights LTIP	300,000	119,628	(100,000)	-	319,628	-	319,628
Options	750,000	-	-	-	750,000	250,000	500,000
Balance at December 31, 2013	1,050,000	119,628	(100,000)	-	1,069,628	250,000	819,628
Other key management personnel of the Group							
Michael Verm							
Performance rights LTIP	22,103	82,550	(7,624)	(1,489)	95,540	-	95,540
Options	1,000,000	-	-	-	1,000,000	650,000	350,000
Balance at December 31, 2013	1,022,103	41,275	(7,624)	(1,489)	1,095,540	650,000	445,540
David Lucke⁽⁵⁾							
Performance rights LTIP	-	235,331	-	-	235,331	-	235,331
Options	-	400,000	-	-	400,000	-	400,000
Balance at December 31, 2013	-	635,331	-	-	635,331	-	635,331

⁽¹⁾ Mr Lusted resigned from the Board on August 8, 2013 and resigned as an employee on August 16, 2013.

⁽²⁾ Mr Schoch resigned subsequent to year end on February 6, 2014.

⁽³⁾ Mr Atkins was appointed to the Board on June 3, 2013.

⁽⁴⁾ Mr Brooks was appointed to the Board on June 3, 2013.

⁽⁵⁾ Mr Lucke was appointed as Chief Financial Officer on May 15, 2013 and resigned subsequent to year end on March 9, 2014.

⁽⁶⁾ The exercised LTIP performance rights, representing the vested 2011 and 2012 Tranche 1 LTI awards, were cash settled.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

27. KEY MANAGEMENT PERSONNEL DISCLOSURE (CONTINUED)

December 31, 2012	Balance at start of the year	Granted as compensation	Exercised	Net other changes	Balance at the end of year	Vested and exercisable	Unvested
Directors of Aurora Oil & Gas Limited							
Jonathan Stewart							
Performance rights PRP	1,800,000	-	(900,000)	-	900,000	-	900,000
Performance rights LTIP	-	152,279	-	-	152,279	-	152,279
Balance at December 31, 2012	1,800,000	152,279	(900,000)	-	1,052,279	-	1,052,279
Graham Dowland							
Options	1,050,000	-	-	-	1,050,000	350,000	700,000
Performance rights LTIP	-	48,088	-	-	48,088	-	48,088
Balance at December 31, 2012	1,050,000	48,088	-	-	1,098,088	350,000	748,088
Ian Lusted							
Performance rights PRP	390,000	-	(390,000)	-	-	-	-
Performance rights LTIP	-	48,533	-	-	48,533	-	48,533
Balance at December 31, 2012	390,000	48,533	(390,000)	-	48,533	-	48,533
Gren Schoch							
Options	750,000	-	-	-	750,000	250,000	500,000
Balance at December 31, 2012	750,000	-	-	-	750,000	250,000	500,000
Fiona Harris							
Options	500,000	-	-	-	500,000	250,000	250,000
Balance at December 31, 2012	500,000	-	-	-	500,000	250,000	250,000
Alan Watson							
Options	500,000	-	-	-	500,000	250,000	250,000
Balance at December 31, 2012	500,000	-	-	-	500,000	250,000	250,000
William Molson							
Options	500,000	-	-	-	500,000	250,000	250,000
Balance at December 31, 2012	500,000	-	-	-	500,000	250,000	250,000
Other key management personnel of the Group							
Michael Verm							
Performance rights LTIP	-	22,103	-	-	22,103	-	22,103
Options	1,000,000	-	-	-	1,000,000	300,000	700,000
Balance at December 31, 2012	1,000,000	22,103	-	-	1,022,103	300,000	722,103
Douglas Brooks⁽¹⁾							
Performance rights LTIP	-	300,000	-	-	300,000	-	300,000
Options	-	750,000	-	-	750,000	-	750,000
Balance at December 31, 2012	-	1,050,000	-	-	1,050,000	-	1,050,000

(1) Mr Brooks was appointed as Chief Executive Officer on October 18, 2012.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

27. KEY MANAGEMENT PERSONNEL DISCLOSURE (CONTINUED)

(iii) Share holdings

The numbers of shares in the Company held during the financial year by each director of Aurora Oil & Gas Limited and other key management personnel of the Group, including their personally related parties, are set out below. No shares were granted during the year ended December 31, 2013 as compensation (December 31, 2012: nil).

Year ended December 31, 2013	Balance at start of the year	Exercise of options / performance rights	On-market trade	Net other changes	Balance at the end of year
Directors of Aurora Oil & Gas Limited					
Jonathan Stewart	19,746,321	900,000	(900,000)	-	19,746,321
Douglas Brooks ⁽¹⁾	14,000	60,764	16,000	-	90,764
Graham Dowland	2,203,828	-	30,000	-	2,233,828
Ian Lusted ⁽²⁾	1,421,950	-	20,000	-	N/a
Gren Schoch ⁽³⁾	5,996,554	-	250,000	-	6,246,554
Fiona Harris	150,000	-	-	-	150,000
Alan Watson	1,050,000	-	-	-	1,050,000
William Molson	1,512,390	-	-	-	1,512,390
John Atkins ⁽⁴⁾	N/a	-	-	20,000	20,000
Other key management personnel of the Group					
Michael Verm	14,700	-	16,000	-	30,700
David Lucke ⁽⁵⁾	-	-	-	-	-

(1) Mr Brooks was appointed to the Board on June 3, 2013.

(2) Mr Lusted resigned from the Board on August 8, 2013 and resigned as an employee on August 16, 2013.

(3) Mr Schoch resigned subsequent to year end on February 6, 2014.

(4) Mr Atkins was appointed to the Board on June 3, 2013.

(5) Mr Lucke was appointed Chief Financial Officer on May 15, 2013 and resigned subsequent to year end on March 9, 2014.

Year ended December 31, 2012	Balance at start of the year	Exercise of options / performance rights	On-market trade	Net other changes	Balance at the end of year
Directors of Aurora Oil & Gas Limited					
Jonathan Stewart ⁽¹⁾	18,446,321	900,000	-	400,000	19,746,321
Graham Dowland	2,203,828	-	-	-	2,203,828
Ian Lusted	1,031,950	390,000	-	-	1,421,950
Gren Schoch ⁽¹⁾	5,396,554	-	100,000	500,000	5,996,554
Fiona Harris ⁽¹⁾	100,000	-	10,000	40,000	150,000
Alan Watson ⁽¹⁾	952,381	-	-	97,619	1,050,000
William Molson ⁽¹⁾	1,412,390	-	-	100,000	1,512,390
Other key management personnel of the Group					
Michael Verm	14,700	-	-	-	14,700
Douglas Brooks ⁽²⁾	-	-	14,000	-	14,000

(1) On June 28, 2012, shareholder approval was granted for the purchase of 1,137,619 ordinary shares by certain directors of the Company, at an issue price of A\$3.55 per share.

(2) Mr Brooks was appointed as Chief Executive Officer on October 18, 2012.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

28. CONSOLIDATED ENTITIES

(a) Significant investments in subsidiaries

The consolidated financial statements incorporate the assets, liabilities and results of the following subsidiaries in accordance with the accounting policy described in note 1(a).

Name of Entity	Jurisdiction of Incorporation / Formation	Class of Equity Interest	Equity Holding	
			December 31, 2013 %	December 31, 2012 %
Aurora USA Oil and Gas, Inc. (formerly Corpus Christi Gas, Inc.)	Delaware	Common	100	100
Wardanup Oil and Gas, Inc.	Delaware	Common	100	100
Sugarloaf Oil and Gas, Inc.	Delaware	Common	100	100
Yallingup Oil and Gas, Inc.	Delaware	Common	100	100
Trigg Oil and Gas, Inc.	Delaware	Common	100	100
Aurora USA Development, LLC.	Texas	Membership interest	100	100
ATW Exploration Oil and Gas, Inc.	Delaware	Common	100	100
Eureka Energy Limited	Australia	Ordinary	100	100
Kiana Projects Pty Ltd	Australia	Ordinary	100	100
Hosston Holdings Pty Ltd	Australia	Ordinary	100	100
Hosston Oil and Gas, Inc. ⁽¹⁾	Delaware	Common	-	100
EKA 002, Inc.	Delaware	Common	100	100
EKA 003, Inc.	Delaware	Common	100	100
EKA 003, LLC.	Delaware	Membership interest	100	100
Aurora EF Production ⁽²⁾	Delaware	Common	100	-
Aurora Oil and Gas (Ontario) Limited	Ontario	Common	100	-
SIEB Operating, Inc. ⁽³⁾	Delaware	Common	100	-
Aurora Oil & Gas Employee Share Trust ⁽⁴⁾	Australia	Controlled	-	-

(1) During January, 2013 Hosston Oil and Gas, Inc. merged with and into Sugarloaf Oil and Gas, Inc.

(2) On February 27, 2013 the Company incorporated Aurora EF Production Company.

(3) On November 12, 2013 the Company incorporated SIEB Operating, Inc.

(4) On September 11, 2013 the Company executed the trust deed for Aurora Oil & Gas Employee Share Trust.

During January 2013 Aurora Oil & Gas Limited (Aurora) completed the multi-step restructure of certain indirect US subsidiaries which had commenced during the previous year, with the merger of Hosston Oil and Gas, Inc. into Sugarloaf Oil and Gas, Inc.

The ultimate aim of the restructure was to continue to streamline the administration of the Aurora Group structure, by reducing the number of Aurora entities based in the US that hold interests in identical wells and other assets. On December 31, 2012 West Black Lake Oil and Gas, Inc. and Aurora West Coast Oil and Gas, Inc., merged with and into Sugarloaf Oil and Gas, Inc., Meelup Oil and Gas, Inc. merged with and into Yallingup Oil and Gas, Inc. and Mullaloo Oil and Gas, Inc. merged with and into Trigg Oil and Gas, Inc.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

28. CONSOLIDATED ENTITIES (CONTINUED)

(b) Transactions with controlled entities

Aurora Oil and Gas Limited provides working capital to its controlled entities. Transactions between Aurora and other controlled entities in the wholly owned Group during the year ended December 31, 2013 consisted of:

- Working capital advanced by Aurora Oil & Gas Limited;
- Provision of services by Aurora Oil & Gas Limited; and
- Expenses paid by Aurora Oil & Gas Limited on behalf of its controlled entities.

The above transactions were made interest free with no fixed terms for the repayment of principal on amounts advanced by Aurora Oil & Gas Limited.

Details of transactions with controlled entities during the year are as follows:

	Company	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Sale of goods and services		
Management fees and expense recharges to subsidiaries	6,524	6,811
Loans to subsidiaries		
Balance at beginning of the year	25,916	1,688
Loans advanced	7,757	26,828
Loans repaid	(12,791)	(2,600)
Balance at end of year	20,882	25,916

29. JOINTLY CONTROLLED ASSETS

At reporting date, the Group has non-operating working interests in joint operating agreements for the following projects:

Project	Activity	Working Interest*	
		December 31, 2013	December 31, 2012
Sugarloaf	Sugarkane field development (USA)	28.1%	28.1%
Ipanema	Sugarkane field development (USA)	36.4%	36.4%
Longhorn	Sugarkane field development (USA)	31.9%	31.9%
Excelsior	Sugarkane field development (USA)	9.14%	9.14%

* Working interest denotes the percentage share of costs to be borne by the Group in relation to its interest in projects. The working interest and net revenue interests (working interests after the deduction of royalty interests) are subject to varying terms in the relevant agreements for each project.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

29. JOINTLY CONTROLLED ASSETS (CONTINUED)

Project	Activity	Working Interest*	
		December 31, 2013	December 31, 2012
Flour Bluff	Gas field development and production project (USA)	20.0%	20.0%
North Belridge	Oil wells (USA)	32.5%	32.5%
Pan De Azucar	Oil exploration and development (USA)	-	100%
Black Jack Springs	Oil exploration and development (USA)	9.4%	9.4%
Brioche	Oil exploration and development (USA)	100%	100%
Trinity West	Oil and gas exploration project (USA)	91.1%	-

Interests in the Pan De Azcar, Black Jack Springs and Brioche projects were acquired as part of the corporate transaction completed during the year ended December 31, 2012.

The total carrying value of Aurora's interest in assets held by jointly controlled projects at reporting date is US\$1,221,585,000 (December 31, 2012: US\$952,182,000).

30. PARENT ENTITY FINANCIAL INFORMATION

Select financial information of the parent entity, Aurora Oil & Gas Limited, is set out below:

(a) Summary financial information

The individual financial statements for the parent entity show the following aggregate amounts:

	Company	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Current assets	5,169	3,018
Total assets	396,219	353,981
Current liabilities	2,413	2,877
Total liabilities	46,667	2,877
Contributed equity	405,148	405,169
Share-based payment reserve	17,046	13,004
Fair value reserve	(7,459)	(7,054)
Accumulated losses	(65,183)	(60,015)
Total equity	349,552	351,104
(Loss) for the year	(5,167)	(4,583)
Total comprehensive (loss) for the year	(5,572)	(3,626)

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

30. PARENT ENTITY FINANCIAL INFORMATION (CONTINUED)

(b) Guarantees entered into by the parent entity

The parent entity has provided a guarantee by way of pledged security, in respect of a senior secured revolving credit facility entered into by Aurora USA Oil and Gas Inc. with a syndicate of banks on November 8, 2011. The parent entity has pledged its 100 per cent ownership interest in Aurora USA Oil and Gas Inc. (refer to note 16 – Borrowings).

(c) Contingent liabilities of the parent entity

The parent entity did not have any contingent liabilities as at December 31, 2013 (December 31, 2012: nil).

(d) Expenditure commitments

The parent entity has contracted the following amounts for expenditure at December 31, 2013, for which no amounts have been provided for in the financial statements:

	Company	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Rent		
Payable:		
Within one year	378	615
Later than one year but not later than five years	1,265	1,890
Later than five years	-	-
	1,643	2,505

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

31. RECONCILIATION OF PROFIT AFTER INCOME TAX TO NET CASH INFLOW FROM OPERATING ACTIVITIES

	Consolidated	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Net Profit for the year	116,430	58,846
(i) Add / (less) non-cash items		
Depreciation, depletion and amortisation	83,632	39,161
Amortisation of borrowing costs and debt premium / discount	4,402	2,927
Exploration and evaluation costs expensed	-	4,939
Share based payment expense	5,376	4,398
Net gain on sale of available for sale assets	-	(770)
Net foreign exchange losses / (gains)	294	(3,146)
(ii) Add / (less) items classified as investment / financing activities:		
Net interest	(52)	(247)
Borrowing costs	1,229	563
(iii) Change in assets and liabilities during the financial year		
Decrease / (increase) in receivables	16,546	(73,273)
(Decrease) / increase in payables	(2,787)	73,126
Increase in deferred tax liability	62,988	37,356
Increase in employee provisions	172	242
Net cash provided by operating activities	288,230	144,122

As at December 31, 2013, the undrawn balance available to the Group under the senior secured revolving credit facility current borrowing base was US\$300,000,000 (December 31, 2012: US\$120,000,000) (refer to note 16).

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

32. RELATED PARTY TRANSACTIONS

Transactions with related parties are on normal commercial terms and conditions no more favourable than those available to other parties unless otherwise stated.

(a) Key management personnel

Disclosures relating to key management personnel are set out in Note 27.

(b) Subsidiaries

Interests in subsidiaries are set out in Note 28.

(c) Transactions with wholly-owned controlled entities

Aurora advanced interest free loans to wholly-owned controlled entities. In addition to these loans, Aurora paid expenses on behalf of its controlled entities and provided support services to Aurora USA Oil and Gas Limited and Eureka Energy Limited on commercial terms. These additional advances were made interest free with no fixed terms for repayment.

(d) Transactions with other related parties

No transactions with other related parties have been entered into in respect of the year ended December 31, 2013 (December 31, 2012: None).

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

33. REMUNERATION OF AUDITORS

During the year the following fees were paid or payable for services provided by the auditor of the Consolidated Entity, its related practices and non-related audit firms:

	Consolidated	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
(a) BDO Audit (WA) Pty Ltd for:		
(i) Audit and assurance services		
Audit and review of financial statements	319	345
Due diligence services	37	87
Total remuneration of BDO Audit (WA) Pty Ltd	356	432
(b) BDO Corporate Finance (WA) Pty Ltd for:		
(i) Valuation services		
Notice of meeting disclosure consulting	-	2
Total remuneration of BDO Corporate Finance (WA) Pty Ltd	-	2
(c) BDO Canada LLP for:		
(i) Other services		
Financial Statement language translation services	-	58
Total remuneration of BDO Canada LLP	-	58
Total auditors' remuneration	356	492

It is the Group's policy to engage BDO on assignments additional to their statutory audit duties where BDO's expertise and experience with the Group are important. These assignments are principally due diligence reporting on acquisitions, language translation services, notice of meeting disclosure services or where BDO is awarded assignments on a competitive basis. It is the Group's policy to seek competitive tenders for all major consulting projects.

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

34. CONTINGENCIES

The Consolidated Entity has no material contingent assets or liabilities as at reporting date.

35. COMMITMENTS

Capital expenditure contracted for at the reporting date but not recognised as a liability is as follows:

	Consolidated	
	December 31, 2013 US\$'000	December 31, 2012 US\$'000
Oil and gas properties		
Payable:		
Within one year	27,588	38,912
Later than one year but not later than five years	-	-
Later than five years	-	-
	27,588	38,912
Property, plant and equipment		
Payable:		
Within one year	3,586	2,484
Later than one year but not later than five years	-	-
Later than five years	-	-
	3,586	2,484
Rent		
Payable:		
Within one year	1,419	845
Later than one year but not later than five years	5,173	2,077
Later than five years	1,093	-
	7,685	2,922
Total commitments	38,859	44,318

Notes to the Consolidated Financial Statements

For the year ended December 31, 2013

36. EVENTS OCCURRING AFTER REPORTING DATE

The following events occurred subsequent to the end of the year:

- (a) On February 3, 2014 Aurora Oil & Gas Limited advised the market of its year end 2013 reserves which have been evaluated by independent engineers at Ryder Scott Company LP and which comply with the reporting requirements of Canadian National Instrument 51-101 *Standards of Disclosure for Oil & Gas Activities* and the Petroleum Resources Management System (SPE-PRMS) as required by Australian Securities Listing Rule 5 - *Additional Reporting on Mining and Oil & Gas Production and Exploration Activities*. Full disclosure and explanation of results can be found in the announcement dated February 3, 2014.
- (b) On February 7, 2014 Aurora Oil & Gas Limited announced that it had entered into a Scheme Implementation Deed with Baytex Energy Corp. ("Baytex"). If the Scheme is implemented, Baytex will, via a wholly owned subsidiary, acquire all of the issued and outstanding ordinary shares of Aurora for A\$4.10 cash per share. Implementation of the Scheme is subject to the satisfaction of a number of customary conditions. The Directors unanimously recommend Aurora shareholders vote in favour of the Scheme, and intend to vote all shares that they control in favour of the Scheme, in the absence of a Superior Proposal and subject to an Independent Expert concluding that the Scheme is in the best interests of shareholders.

Other than as disclosed above, no event has occurred since December 31, 2013 that would materially affect the operations of the Consolidated Entity, the results of the Consolidated Entity or the state of affairs of the Consolidated Entity not otherwise disclosed in the Consolidated Entity's financial statements.

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SCHEDULE B

BAYTEX PRO FORMA FINANCIAL STATEMENTS

Unaudited Pro forma Consolidated Financial Statements

Baytex Energy Corp.

*As at and for the three months ended March 31, 2014 and for the year
ended December 31, 2013*

Foreword

UNAUDITED *PRO FORMA* CONSOLIDATED FINANCIAL STATEMENTS

The following unaudited *pro forma* consolidated financial statements give effect to the acquisition (the “Acquisition”) by Baytex Energy Corp. (“Baytex or the “Corporation”) of Aurora Oil & Gas Limited and its subsidiaries (collectively, “Aurora”) under the acquisition method of accounting and the financial restructuring (the “Financing”). The unaudited *pro forma* consolidated statement of financial position gives effect to the Acquisition and the Financing as if both had closed on March 31, 2014. The unaudited *pro forma* consolidated statements of income and comprehensive income for the three months ended March 31, 2014 and for the year ended December 31, 2013 give effect to the Acquisition and the Financing as if both had closed on January 1, 2013.

The unaudited *pro forma* consolidated financial statements are presented for illustrative purposes only. The *pro forma* adjustments are based upon available information and certain assumptions that we believe are reasonable in the circumstances, as described in the notes to the unaudited *pro forma* consolidated financial statements.

The unaudited *pro forma* consolidated financial statements are based on Baytex’s and Aurora’s consolidated financial statements as at and for the three months ended March 31, 2014 and for the year ended December 31, 2013. Aurora’s consolidated financial statements have been translated from United States dollars to Canadian dollars. The unaudited *pro forma* consolidated financial statements, including the notes thereto, are qualified in their entirety by reference to, and should be read in conjunction with, Baytex’s historical consolidated financial statements and the related notes thereto, which are available on SEDAR and the historical consolidated financial statements of Aurora, including the notes thereto, which are included elsewhere in this Business Acquisition Report.

The *pro forma* information presented, including allocation of purchase price, is based on preliminary estimates of fair values of assets acquired and liabilities assumed, available information and assumptions and may be revised as additional information becomes available. The actual adjustments to the consolidated financial statements upon the closing of the Acquisition and the Financing will depend on a number of factors, including additional information available and the net assets of Aurora on the closing date of the Acquisition. Therefore, the actual adjustments will differ from the *pro forma* adjustments, and the differences may be material. For example, the final purchase price allocation is dependent on, among other things, the finalization of asset and liability valuations as well as reserve evaluations. A final determination of these fair values will reflect an independent third-party valuation. This final valuation will be based on the actual net tangible and intangible assets and liabilities of Aurora that exist as of the closing date of the Acquisition. Any final adjustment may change the allocation of purchase price, which could affect the fair value assigned to the assets and liabilities and could result in a change to the unaudited *pro forma* consolidated financial statements. The allocation of the purchase price does not include the Financing, which is presumed to occur immediately following the Acquisition.

Pro forma adjustments are necessary to reflect the purchase price and purchase accounting adjustments based on preliminary estimates of the fair values of the Aurora net assets acquired. The unaudited *pro forma* consolidated financial statements do not reflect all operating efficiencies and cost savings that may be realized with respect to the combined companies.

Baytex Energy Corp.
Pro forma Consolidated Statement of Financial Position
As at March 31, 2014
(Unaudited)
(In thousands of Canadian dollars)

	Baytex Energy Corp.	Aurora Oil & Gas Limited [4b]	Note	<i>Pro forma</i> adjustments	<i>Pro forma</i> consolidated
ASSETS					
Current assets					
Cash and cash equivalents	\$ 2,340	\$ 53,238		-	\$ 55,578
Trade and other receivables	182,711	89,717		-	272,428
Crude oil inventory	1,977	-		-	1,977
Other assets	36,662	-	[4o]	(36,662)	-
Financial derivatives	33,681	-		-	33,681
Assets held for sale	75,693	-		-	75,693
	333,064	142,955		(36,662)	439,357
Non-current assets					
Exploration and evaluation assets	155,212	-	[4c]	215,953	371,165
Oil and gas properties	2,321,187	1,760,673	[4c]	1,119,478	5,201,338
Other plant and equipment	29,699	-		-	29,699
Other assets	-	-	[4h], [4o]	9,800	9,800
Goodwill	37,755	-	[4c]	501,462	539,217
	\$ 2,876,917	\$ 1,903,628		\$ 1,810,031	\$ 6,590,576
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities					
Trade and other payables	\$ 261,782	\$ 182,013		-	\$ 443,795
Dividends payable to shareholders	27,817	-		-	27,817
Financial derivatives	29,076	9,592		-	38,668
Liabilities related to assets held for sale	12,124	-		-	12,124
	330,799	191,605		-	522,404
Non-current liabilities					
Bank loan	300,564	114,951	[4f]	484,551	900,066
			[4c], [4e],		
Long-term debt	458,387	730,852	[4f]	151,424	1,340,663
Asset retirement obligations	224,891	3,516		-	228,407
			[4c], [4d],		
Deferred income tax liability	270,703	185,619	[4f], [4g],	433,567	889,889
Financial derivatives	1,469	259	[4i]	-	1,728
	1,586,813	1,226,801		1,069,542	3,883,156
Shareholders' equity					
Shareholders' capital	2,046,549	447,718	[4j]	(447,718)	3,471,376
			[4a], [4d],		
			[4o]	1,424,827	
Contributed surplus	43,563	-		-	43,563
Reserves	-	(4,076)	[4j]	4,076	-
Accumulated other comprehensive loss	11,691	-		-	11,691
			[4f], [4g],		
Deficit	(811,699)	233,185	[4j], [4o]	(240,696)	(819,210)
	1,290,104	676,827		740,489	2,707,420
	\$ 2,876,917	\$ 1,903,628		\$ 1,810,031	\$ 6,590,576

Baytex Energy Corp.
Pro forma Consolidated Statement of Income and Comprehensive Income
For the three months ended March 31, 2014
(Unaudited)
(In thousands of Canadian dollars, except for per share amounts)

	Baytex Energy Corp.	Aurora Oil & Gas Limited	Note	Pro forma adjustments	Pro forma consolidated
		[4b]			
Revenues, net of royalties	\$ 310,929	\$ 141,952		\$ -	\$ 452,881
Expenses					
Production and operating	68,835	11,694		-	80,529
Transportation and blending	44,903	6,372		-	51,275
Exploration and evaluation	10,610	40		-	10,650
Depletion and depreciation	88,593	24,354	[4n]	58,352	171,299
General and administrative	11,899	7,329		-	19,228
Share-based compensation	7,855	1,324		-	9,179
Financing costs	12,589	17,759	[4e], [4f]	1,488	31,835
Loss on financial derivatives	(7,078)	-		-	(7,078)
Foreign exchange loss	4,518	-		-	4,518
	242,724	68,872		59,840	371,435
Net income before income taxes	68,205	73,080		(59,840)	81,446
Income tax expense					
Deferred income tax expense	20,364	25,578	[4e], [4f], [4n]	(17,663)	28,279
	20,364	25,578		(17,663)	28,279
Net income attributable to shareholders	47,841	47,502		(42,177)	53,167
Other comprehensive income					
Changes in fair value of equity instruments and cash flow hedges	-	2,389		-	2,389
Foreign currency translation adjustment	(10,207)	-		-	(10,207)
Comprehensive Income	\$ 58,048	\$ 45,113		\$ (42,177)	\$ 60,985
Weighted average common shares outstanding					
Basic	125,939		[4k]	38,434	164,373
Diluted	127,250		[4k]	38,434	165,684
Earnings per common share					
Basic	\$ 0.38		[4k]	\$	0.32
Diluted	\$ 0.38		[4k]	\$	0.32

Baytex Energy Corp.
Pro forma Consolidated Statement of Income and Comprehensive Income
For the year ended December 31, 2013
(Unaudited)
(In thousands of Canadian dollars, except for per share amounts)

	Baytex Energy Corp.	Aurora Oil & Gas Limited [4b]	<i>Note</i>	<i>Pro forma</i> adjustments	<i>Pro forma</i> consolidated
Revenues, net of royalties	\$ 1,115,410	\$ 406,639		\$ -	\$ 1,522,049
Expenses					
Production and operating	275,519	28,154		-	303,673
Transportation and blending	158,841	15,202		-	174,043
Exploration and evaluation	10,286	518		-	10,804
Depletion and depreciation	328,953	86,133	[4n]	160,387	575,473
General and administrative	45,461	24,684		-	70,145
Share-based compensation	32,341	5,537		-	37,878
Financing costs	50,335	61,272	[4e], [4f]	7,003	118,610
Loss on financial derivatives	13,132	-		-	13,132
Foreign exchange loss	3,906	356		-	4,262
Gain on divestiture of oil and gas properties	(21,011)	-		-	(21,011)
	897,763	221,856		167,389	1,287,008
Net income before income taxes	217,647	184,783		(167,389)	235,041
Income tax expense					
Current income tax recovery	(6,821)	-		-	(6,821)
Deferred income tax expense	59,623	64,871	[4e], [4f], [4n]	(46,193)	78,301
	52,802	64,871		(46,193)	71,480
Net income attributable to shareholders	164,845	119,912		(121,196)	163,561
Other comprehensive income					
Changes in fair value of equity instruments and cash flow hedges	-	3,447		-	3,447
Foreign currency translation adjustment	(13,946)	-		-	(13,946)
Comprehensive Income	\$ 178,791	\$ 116,465		\$ (121,196)	\$ 174,060
Weighted average common shares outstanding					
Basic	123,749		[4k]	38,434	162,183
Diluted	125,394		[4k]	38,434	163,828
Earnings per common share					
Basic	\$ 1.33		[4k]	\$	1.01
Diluted	\$ 1.32		[4k]	\$	1.00

BAYTEX ENERGY CORP.

Notes to Unaudited *Pro Forma* Consolidated Financial Statements

As at and for the three months ended March 31, 2014 and for the year ended December 31, 2013

(in thousands of Canadian dollars, unless otherwise stated)

1. BASIS OF PRESENTATION

The accompanying unaudited *pro forma* consolidated financial statements give effect to the acquisition (the “Acquisition”) by Baytex Energy Corp. (“Baytex” or the “Corporation”) of Aurora Oil & Gas Limited and its subsidiaries (collectively, “Aurora”) as described in the short form prospectus dated February 18, 2014 (the “Prospectus”) and the financial restructuring (the “Financing”) as described in the offering memorandum dated May 29, 2014 (the “Offering Memorandum”). The accompanying unaudited *pro forma* consolidated financial statements have been prepared by management of Baytex and are derived from the unaudited and audited consolidated financial statements of Baytex as at and for the three months ended March 31, 2014 and for the year ended December 31, 2013, respectively, and the unaudited and audited consolidated financial statements of Aurora as at and for the three months ended March 31, 2014 and for the year ended December 31, 2013, respectively.

The accompanying unaudited *pro forma* consolidated financial statements utilize accounting policies that are consistent with those disclosed in the unaudited consolidated financial statements of Baytex as at and for the three months ended March 31, 2014 and the audited consolidated financial statements as at and for the year ended December 31, 2013 and are prepared in accordance with accounting principles generally accepted in Canada which are consistent with International Financial Reporting Standards as issued by the International Accounting Standards Board.

The accompanying unaudited *pro forma* consolidated statement of financial position reflect the Acquisition and Financing as if both were effected on March 31, 2014, and the unaudited *pro forma* consolidated statements of income and comprehensive income reflect the Acquisition and Financing as if both were effected January 1, 2013. The accompanying unaudited *pro forma* consolidated financial statements are not necessarily indicative of the results that would have been achieved if the transactions reflected therein had been completed on the dates indicated or the results which may be obtained in the future. For instance, the actual purchase price allocation will reflect the fair value, at the purchase date, of the assets acquired and liabilities assumed based upon the Corporation's evaluation of such assets and liabilities following the closing of the Acquisition and, accordingly, the final purchase price allocation may differ materially from the preliminary allocation reflected herein. Specifically, the unaudited *pro forma* consolidated statements, the purchase price and the purchase price allocation do not reflect changes in Aurora's working capital or borrowings subsequent to March 31, 2014, nor changes in exchange rates subsequent to March 31, 2014.

The accompanying unaudited *pro forma* consolidated financial statements should be read in conjunction with the description of the Acquisition and the financing thereof and the Financing as provided in this Business Acquisition Report; the audited and unaudited consolidated financial statements of Aurora, including the notes thereto, included in this Business Acquisition Report; and the audited and unaudited consolidated financial statements of Baytex, including the notes thereto, which are available on SEDAR.

The underlying assumptions for the *pro forma* adjustments provide a reasonable basis for presenting the significant financial effect directly attributable to the Acquisition and the Financing. These *pro forma* adjustments are tentative and are based on currently available financial information and certain estimates and assumptions. The actual adjustments to the consolidated financial statements will depend on a number of factors. Therefore, it is expected that the actual adjustments will differ from the *pro forma* adjustments, and the differences may be material.

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Notes to Unaudited *Pro Forma* Consolidated Financial Statements

As at and for the three months ended March 31, 2014 and for the year ended December 31, 2013

(in thousands of Canadian dollars, unless otherwise stated)

2. DESCRIPTION OF ACQUISITION TRANSACTION

Pursuant to an agreement and plan of a merger between Baytex, certain Baytex subsidiaries and Aurora, Baytex indirectly purchased all of the outstanding common shares of Aurora for Australian \$4.20 per share. The acquisition cost includes the purchase of all outstanding shares, including shares issued for stock options and performance shares which vest upon the acquisition; assumption of Aurora's existing debt, which was valued at approximately \$846 million as at March 31, 2014; and costs directly associated with the transaction estimated at \$41 million, after tax.

The accompanying unaudited *pro forma* consolidated financial statements disclose that the Acquisition was financed through the proceeds from a \$1.5 billion common share issuance with the balance funded through additional debt of \$543 million (as further described below).

3. DESCRIPTION OF FINANCING TRANSACTION

On April 22, 2014, Baytex commenced cash tender offers and consent solicitations relating to the US\$665 million (face value) of senior notes of Aurora USA Oil & Gas, Inc. (a wholly-owned subsidiary of Aurora) (the "Aurora Senior Notes") for early redemption of these instruments immediately following the completion of the Acquisition, financed by Baytex's immediate issuance of US\$800 million principal amount of senior unsecured notes. Baytex received valid tender offers and consent solicitations on substantially all of the Aurora Senior Notes.

The accompanying unaudited *pro forma* consolidated financial statements provide details on the Financing, including the deferred tax asset and incremental interest and tax savings on the Replacement Notes (as further described below).

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Notes to Unaudited *Pro Forma* Consolidated Financial Statements

As at and for the three months ended March 31, 2014 and for the year ended December 31, 2013

(in thousands of Canadian dollars, unless otherwise stated)

4. *PRO FORMA* ASSUMPTIONS AND ADJUSTMENTS

[a] Purchase Price and Financing Structure

The following is the purchase price and financing structure for the Acquisition and the Financing that have been reflected in the accompanying unaudited *pro forma* consolidated financial statements.

Cost of Acquisition

Unadjusted purchase price	\$	1,919,173
Assumed long-term debt of Aurora (Notes 2 and 3)		845,803
Purchase price	\$	2,764,976
Acquisition costs, before tax (Note 4[g])		52,000
Financing costs, before tax (Note 4[h])		9,800
Cost of acquisition	\$	2,826,776

Funding Requirements of Acquisition

Purchase price	\$	2,764,976
Assumed long-term debt of Aurora (Notes 2 and 3)		(845,803)
Common share issuance costs, before tax (Note 4[d])		93,623
Acquisition costs, before tax (Note 4[g])		52,000
Financing costs, before tax (Note 4[h])		9,800
Cash acquired		(53,238)
Net funding requirements	\$	2,021,358

Cost of Financing

Excess of tender offer over principal amount	\$	87,468
Accrued interest on senior notes of Aurora, before tax		17,673
Financing costs on replacement notes, before tax (Note 4[h])		19,185
Cost of financing	\$	124,326

Funding Requirements of Financing

Tender of unsecured senior notes (Note 4[f])	\$	806,716
Accrued interest on senior notes of Aurora, before tax		17,673
Financing costs on replacement notes, before tax (Note 4[h])		19,185
Net funding requirements	\$	843,574

Assumed Financing Structure of Acquisition and Financing

Assumed Aurora long-term debt, after refinancing (Note 4[f])	\$	843,574
Assumed long-term debt of Aurora, not refinanced		114,951
Common share issuance, net of issuance costs, before tax (Note 4[d])		1,401,421
Baytex working capital related to Acquisition (Note 4[o])		36,662
Incremental long-term debt (Note 4[e])		542,889
	\$	2,939,497

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Notes to Unaudited *Pro Forma* Consolidated Financial Statements

As at and for the three months ended March 31, 2014 and for the year ended December 31, 2013

(in thousands of Canadian dollars, unless otherwise stated)

4. *PRO FORMA* ASSUMPTIONS AND ADJUSTMENTS (Continued)

[b] Aurora consolidated financial statements – presentation currency and reclassifications

The figures presented on the consolidated statement of financial position and the consolidated statements of income and comprehensive income for Aurora have been adjusted from those reported by Aurora to reflect the translation from United States dollars to Canadian dollars and certain presentation reclassifications. The adjustments are more fully described below.

The assets and liabilities of Aurora, which has a US dollar functional and presentation currency, were converted to Canadian dollars for *pro forma* reporting purposes at the exchange rate in effect as at the date of the unaudited *pro forma* consolidated statement of financial position. Revenue and expenses of Aurora's operations are translated at the average exchange rate in effect during the reporting period. The following exchange rates were utilized for the unaudited *pro-forma* consolidated financial statements:

Balance Sheet (US\$ to C\$)

Spot rate – March 31, 2014	1.1053
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Income Statement (US\$ to C\$)

Average rate – January 1, 2013 to December 31, 2013	1.0299
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Average rate – January 1, 2014 to March 31, 2014	1.1035
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The purchase price has been converted from Australian dollars to Canadian dollars at 1AUD = \$0.9756 Canadian which was the exchange rate on March 31, 2014.

BAYTEX ENERGY CORP.

Notes to Unaudited *Pro Forma* Consolidated Financial Statements

As at and for the three months ended March 31, 2014 and for the year ended December 31, 2013

(in thousands of Canadian dollars, unless otherwise stated)

4. *PRO FORMA* ASSUMPTIONS AND ADJUSTMENTS (Continued)

[b] Aurora consolidated financial statements – presentation currency and reclassifications (Continued)

Pro forma Consolidated Statement of Financial Position

As at March 31, 2014

(Unaudited)

	As published Aurora Oil & Gas Limited	Note	Classification adjustments	Currency Translation adjustments	<i>Pro forma</i> Aurora Oil & Gas Limited
	USD				CAD
ASSETS					
Current assets					
Cash and cash equivalents	\$ 48,166		-	\$ 5,072	\$ 53,238
Trade and other receivables	80,982	[4m]	188	8,547	89,717
	129,148		188	13,619	142,955
Non-current assets					
Other financial assets	188	[4m]	(188)	-	-
Property, plant and equipment	172,263		(172,263)	-	-
Oil and gas properties	1,420,674		172,263	167,736	1,760,673
Derivative financial instruments	-		-	-	-
	\$ 1,722,273		\$ -	\$ 181,355	\$ 1,903,628
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities					
Trade and other payables	\$ 164,046	[4m]	627	\$ 17,340	\$ 182,013
Derivative financial instruments	8,678		-	914	9,592
Provisions	627	[4m]	(627)	-	-
	173,351		-	18,254	191,605
Non-current liabilities					
Borrowing - Facility	104,000		-	10,951	114,951
Borrowing - Debentures	661,225		-	69,627	730,852
Deferred tax liabilities	167,935		-	17,684	185,619
Derivative financial instruments	234		-	25	259
Provisions	3,181		-	335	3,516
	1,109,926		-	116,876	1,226,802
Shareholders' equity					
Contributed equity	405,065		-	42,653	447,718
Share-based payment reserves	17,537		-	1,847	19,384
Fair value reserve	(7,481)		-	(788)	(8,269)
Foreign exchange reserve	(7,505)		-	(790)	(8,295)
Cash flow hedges reserve	(6,239)		-	(658)	(6,897)
Retained Earnings	210,970		-	22,215	233,185
	612,347		-	64,479	676,826
	\$ 1,722,273		\$ -	\$ 181,355	\$ 1,903,628

BAYTEX ENERGY CORP.

Notes to Unaudited *Pro Forma* Consolidated Financial Statements

As at and for the three months ended March 31, 2014 and for the year ended December 31, 2013

(in thousands of Canadian dollars, unless otherwise stated)

4. *PRO FORMA* ASSUMPTIONS AND ADJUSTMENTS (Continued)

[b] Aurora consolidated financial statements – presentation currency and reclassifications (Continued)

Pro forma Consolidated Statement of Income and Comprehensive Income
For the three months ended March 31, 2014
(Unaudited)

	As published Aurora Oil & Gas Limited	Note	Classification adjustments	Currency Translation adjustments	Pro forma consolidated Aurora Oil & Gas Limited
	USD				CAD
Revenues, net of royalties	\$ 182,364	[4m]	\$ (56,862)	\$ 12,989	\$ 138,491
Other income	3,136		-	325	\$ 3,461
Expenses					
Royalties	47,855	[4m]	(47,855)	-	-
Production and operating expenses	25,378	[4m]	(14,781)	1,097	11,694
Transportation expenses	-	[4m]	5,774	598	6,372
Administrative expenses	6,642		-	687	7,329
Depletion, depreciation and amortization	22,070		-	2,284	24,354
Share-based payment expense	1,200		-	124	1,324
Finance costs	16,093		-	1,666	17,759
Exploration and evaluation costs	36		-	4	40
	119,274		(56,862)	6,460	68,872
Net income before income taxes	66,226		-	6,854	73,080
Income tax expense	23,179		-	2,399	25,578
Net income attributable to shareholders	43,047		-	4,455	47,502
Other comprehensive income					
Changes in fair value of equity instruments	22		-	2	24
Changes in fair value of cash flow hedges	2,143		-	222	2,365
Comprehensive Income	\$ 40,882		\$ -	\$ 4,231	\$ 45,113

BAYTEX ENERGY CORP.

Notes to Unaudited *Pro Forma* Consolidated Financial Statements

As at and for the three months ended March 31, 2014 and for the year ended December 31, 2013

(in thousands of Canadian dollars, unless otherwise stated)

4. *PRO FORMA* ASSUMPTIONS AND ADJUSTMENTS (Continued)

[b] Aurora consolidated financial statements – presentation currency and reclassifications (Continued)

Pro forma Consolidated Statement of Income and Comprehensive Income
For the year ended December 31, 2013
(Unaudited)

	As published Aurora Oil & Gas Limited	Note	Classification adjustments	Currency Translation adjustments	<i>Pro forma</i> consolidated Aurora Oil & Gas Limited
	USD				CAD
Revenue from continuing operations	\$ 562,766	[4m]	\$ (168,097)	\$ 11,801	\$ 406,470
Other income	164			5	169
Expenses					
Royalties	149,429	[4m]	(149,429)	-	-
Production and operating expenses	60,766	[4m]	(33,429)	817	28,154
Transportation expenses	-	[4m]	14,761	441	15,202
Administrative expenses	23,967		-	717	24,684
Depletion, depreciation and amortization	83,632		-	2,501	86,133
Share-based payment expense	5,376		-	161	5,537
Finance costs	59,493		-	1,779	61,272
Exploration and evaluation costs	503		-	15	518
Foreign exchange loss	346		-	10	356
	383,512		(168,097)	6,441	221,856
Net income before income taxes	179,418		-	5,365	184,783
Income tax expense	62,988		-	1,883	64,871
Net income attributable to owners of the Company	116,430		-	3,482	119,912
Other comprehensive income					
Changes in fair value of equity instruments	405		-	12	417
Changes in fair value of cash flow hedges	2,942		-	88	3,030
Comprehensive Income	\$ 113,083		\$ -	\$ 3,382	\$ 116,465

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Notes to Unaudited *Pro Forma* Consolidated Financial Statements

As at and for the three months ended March 31, 2014 and for the year ended December 31, 2013

(in thousands of Canadian dollars, unless otherwise stated)

4. *PRO FORMA* ASSUMPTIONS AND ADJUSTMENTS (Continued)

[c] Allocation of net purchase price

The net purchase price has been allocated to the estimated fair values of Aurora's net assets and liabilities as at March 31, 2014 in accordance with the acquisition method, as follows:

	Aurora	Fair Value and Other Adjustments		Net Total
Assets acquired:				
Cash and cash equivalents	\$ 53,238	-	\$	53,238
Accounts receivable	89,717	-		89,717
Total current assets	142,955	-		142,955
Exploration and evaluation assets	-	215,953		215,953
Oil and gas assets and other assets	1,760,673	1,119,478		2,880,151
	<u>\$1,903,628</u>	<u>1,335,431</u>	\$	<u>3,239,059</u>
Liabilities assumed:				
Accounts payable and other current liabilities	\$ 182,013	-	\$	182,013
Financial derivatives	9,592	-		9,592
Total current liabilities	191,605			191,605
Long-term debt	845,803	93,085		938,888
Asset retirement obligation	3,516	-		3,516
Deferred income tax liability	185,619	501,462		687,081
Financial Derivatives	259	-		259
	<u>\$1,226,802</u>	<u>594,547</u>	\$	<u>1,821,349</u>
Net assets at fair value, as at March 31, 2014				<u>1,417,711</u>
Purchase price, before assumed debt				<u>1,919,173</u>
Goodwill			\$	<u>501,463</u>

The fair value adjustment of the Oil and gas assets and Exploration and evaluation assets reflect the value of the resources acquired based on management's assessment of future prices, development timing, production profiles and risk. The fair value of the Long-term debt reflects trading values of the two tranches of Aurora notes and the receipt of cash on the exercise of Aurora options upon change of control. The Goodwill and the Deferred income tax liability result from the difference between the accounting basis and the tax basis of the assets acquired. The Goodwill is not deductible for tax purposes.

The allocation of the purchase price does not include effects of the Financing, which occurred immediately following the Acquisition.

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Notes to Unaudited *Pro Forma* Consolidated Financial Statements

As at and for the three months ended March 31, 2014 and for the year ended December 31, 2013

(in thousands of Canadian dollars, unless otherwise stated)

4. PRO FORMA ASSUMPTIONS AND ADJUSTMENTS (Continued)

[d] Common share issuance

Financing for the Acquisition consists of the issuance of approximately 38.4 million Baytex common shares at \$38.90 per share for gross proceeds of approximately \$1.5 billion. Underwriting costs are estimated at 4% of gross proceeds in the aggregate (or approximately \$60 million) and a dividend equivalent amount of approximately \$33.8 million relating to common shares held in escrow as subscription receipts was paid upon the issuance of common shares and together, will result in a corresponding deferred income tax benefit of approximately \$23.4 million based on the Corporation's statutory income tax rate of 25%.

[e] Incremental long-term debt on acquisition

Financing for the Acquisition consists of the issuance of approximately \$543 million of debt, primarily drawn on the new extendible syndicated loan facility which was increased to \$1.2 billion from \$850 million and the new term loan of \$200 million. Estimated debt issuance costs of approximately \$9.8 million will be deferred and amortized over the life of the debt instruments and included in financing costs (note 4h). The interest rate is estimated at 4%, which would result in incremental interest expense for the year ended December 31, 2013 and for the three months ended March 31, 2014 of \$21.7 million and \$5.4 million, respectively, and would result in corresponding deferred income tax benefits of \$5.4 million and \$1.4 million, respectively, based on the Corporation's statutory income tax rate of 25%.

[f] Incremental long-term debt on financing

On April 22, 2014, Baytex commenced cash tender offers and consent solicitations relating to any and all of the US\$365 million current outstanding principal amount of 9.875% Senior Notes due 2017 (the "9.875% Notes") and the US\$300 million current outstanding principal amount of 7.50% Senior Notes due 2020 (the "7.50% Notes") of Aurora USA Oil & Gas, Inc. As at June 11, 2014, Baytex had received valid tender offers and consent solicitations on 97.84% of the outstanding aggregate principal amount of 9.875% Notes and 97.87% of the outstanding aggregate principal amount of 7.50% Notes. These early tender offers paid a premium to holders of US\$1,107.34 and US\$1,138.97 per US\$1,000 principal amount of 9.875% Notes and 7.50% Notes, respectively. Total cost to complete the tender offers was approximately \$806.7 million. The redemption of the Aurora Senior Notes resulted in a corresponding deferred income tax asset of approximately \$30.6 million derived from the premium paid on the redemption of the Aurora Senior Notes and utilizing Aurora's U.S. statutory income tax rate of 35%.

The Financing consists of the issuance by Baytex of US\$400 million principal amount of senior unsecured notes bearing interest at 5.125%, payable semi-annually with principal repayment in 2021 and US\$400 million principal amount of senior unsecured notes bearing interest at 5.625%, payable semi-annually with principal repayment in 2024 (the "Replacement Notes"). Estimated debt issue costs of \$19.2 million were incurred for the Replacement Notes upon issuance (note 4h) and Baytex estimates interest costs of approximately US\$43.0 million per year, which would result in an interest savings of approximately \$14.7 million and \$3.9 million for the year ended December 31, 2013 and for the three months ended March 31, 2014, respectively, compared to the Aurora Senior Notes. The Replacement Notes would also result in incremental income tax benefits of approximately \$15.4 million and \$4.1 million for the year ended December 31, 2013 and for the three months ended March 31, 2014, respectively.

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4. *PRO FORMA* ASSUMPTIONS AND ADJUSTMENTS (Continued)

[g] Acquisition costs

Acquisition costs are estimated at approximately \$52 million, or approximately \$41 million, net of deferred income tax. Acquisition costs are composed of estimated costs to acquire Australian dollars, accounting, tax, legal and other costs associated with the completion of the Acquisition.

[h] Financing costs

Financing costs for the year ended December 31, 2013 and for the three months ended March 31, 2014 reflects the financing costs relating to the Acquisition and the Financing. Financing costs relating to the Acquisition will be deferred and amortized over their respective terms. Financing costs relating to the Financing are netted against long-term debt and amortized to profit and loss using the effective interest rate.

Financing Costs on the Acquisition and Financing	
Acquisition (note 4e)	\$ 9,800
Financing (note 4f)	19,185
Total	\$ 28,985

[i] Income taxes

Income taxes applicable to the *pro forma* adjustments are calculated at Baytex's average tax rates of 25% (Canadian rate) and 35% (US rate) for the year ended December 31, 2013 and for the three months ended March 31, 2014. The deferred income tax asset and liability is the cumulative amount of tax applicable to temporary differences between the accounting and tax values of assets and liabilities. Deferred income tax assets and liabilities are measured at the tax rates expected to apply when these differences reverse. For the purpose of the accompanying unaudited *pro forma* consolidated financial statements, deferred income tax rates of 25% (Canadian rate) and 35% (US rate) have been used.

[j] Aurora historical shareholders' equity

The historical shareholders' equity of Aurora, which includes retained earnings, share-based payment reserves, certain other reserves and contributed equity, has been eliminated.

[k] Earnings per common share

The calculation of the *pro forma* earnings per common share for the year ended December 31, 2013, and for the three months ended March 31, 2014 reflects the issuance of approximately 38.4 million Baytex common shares as if the issuance had taken place as at January 1, 2013.

[l] Aurora long-term incentive plan

The purchase price of Aurora includes the payment of approximately \$17.5 million related to stock options and performance rights held by Aurora employees and directors.

[m] Reclassifications to conform presentation

Certain amounts on the income statement of Aurora were reclassified to conform with the presentation of Baytex. Royalties of US\$149.4 million and US\$47.9 million were reclassified from Royalties to Revenue, net of royalties for the year ended December 31, 2013 and for the three months ended March 31, 2014, respectively. Royalties of US\$18.7 million and US\$9.0 million were reclassified from Production and operating expenses to Revenue, net of royalties for the year ended December 31, 2013 and

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4. *PRO FORMA* ASSUMPTIONS AND ADJUSTMENTS (Continued)

for the three months ended March 31, 2014, respectively. Transportation expenses of US\$14.8 million and US\$5.8 million were reclassified from Production and operating expenses to Transportation and blending expenses for the year ended December 31, 2013 and for the three months ended March 31, 2014, respectively. The statement of financial position of Aurora has been adjusted to reclassify Other financial assets, comprised of an equity investment in a public company, to Trade and other receivables and to reclassify Provisions – Current liabilities to Trade and other payables. Property, plant, and equipment have been reclassified to Oil and gas properties.

[n] Depletion

Baytex includes future development costs as part of the depletable base in the estimate of depletion expense, but Aurora does not. Both practices are acceptable under IFRS and the adjustment was made to provide consistency and comparability.

[o] Underwriter fees and financing costs

Certain underwriter fees and financing costs were incurred prior to March 31, 2014. The underwriter fees have been reclassified as an offset to share issue proceeds in share capital (see note 4d) and the financing costs will be deferred and amortized over their respective terms (see note 4h).

SCHEDULE C

INFORMATION CONCERNING AURORA

General

Aurora is an oil and natural gas company active exclusively in the United States. Its primary asset consists of approximately 22,200 net (80,200 gross) acres in the Sugarkane Field located in South Texas in the core of the liquids-rich Eagle Ford. Aurora's first quarter 2014 gross production averaged 28,671 Boe/d (81% oil and NGLs). The Sugarkane Field has been largely delineated with infrastructure in place which will facilitate future production growth. In addition, Aurora holds approximately 14,000 net acres in the Eaglebine play regionally on trend with the Eagle Ford.

Description of Principal Properties

The Sugarkane Field

Aurora's principal focus of operation has been on the development of its interests in the Sugarkane Field. The Sugarkane Field was discovered in 2006 and covers an identified area exceeding 200,000 acres. The Sugarkane Field covers a multicounty area consisting of Karnes, Live Oak, Atascosa, Bee, DeWitt, Dimmit, Frio, Gonzales, LaSalle, McMullen, Wilson and Zavala counties in South Texas and includes both the Sugarkane and Eagleville field designations as established by the Railroad Commission of Texas. The reservoir lies between the Austin Chalk formation and the Buda formation prevalent along the Texas Gulf Coast and South Texas.

Unconventional shale production is typically characterized by high initial central production rates, followed by steep decline rates and prolonged "tail" production profiles. The majority of Aurora's acreage is located in the central portion of the Eagle Ford shale trend. Aurora's acreage holdings sit primarily within the condensate-rich window, extending into the volatile oil window to the northwest at lesser depths. The Sugarkane Field is over-pressured (having a pressure gradient of 0.8 psi/f), enhancing both the initial production rates and estimated ultimate recoverable reserves per well. The combination of high liquids content and high production rate results in attractive economics for development wells. Based on realized commodity pricing achieved by Aurora for the year ended December 31, 2013, approximately 94% of the production revenue Aurora generated related to oil and natural gas liquids sales, with the balance being natural gas production revenue.

Non-Operated Assets

Aurora has WIs in approximately 77,400 gross acres across four AMIs in the Sugarkane Field, together with interests in wells, field infrastructure and related assets in those AMIs. Marathon is the operator of all the acreage and other assets in these Sugarkane Field AMIs. Approximately 97% of this non-operated acreage is held by production.

Operated Assets

On March 29, 2013, Aurora acquired the 2013 Acquired Assets, which sit across approximately 2,800 gross acres comprised of two consolidated blocks (being Heard Ranch and Axle Tree Ranch), located within the liquids-rich zone of the Eagle Ford shale trend and are either adjacent or very proximate to Aurora's existing Sugarkane Field AMIs operated by Marathon. This acreage is 100% held by production. Aurora is the operator of the 2013 Acquired Assets.

Land Holdings

Aurora has varying WIs in the four AMIs within the Sugarkane Field: (i) Sugarloaf; (ii) Longhorn; (iii) Ipanema; and (iv) Excelsior. Aurora has a 100% WI in the 2013 Acquired Assets. Such WIs and approximate gross acreage and net acreage as at December 31, 2013 are set out in the table below:

	<u>Working Interest</u>	<u>Gross Acreage</u>	<u>Net Acreage</u>
Sugarloaf AMI.....	28.1%	24,000	6,750
Longhorn AMI.....	31.9%	28,500	9,100
Ipanema AMI.....	36.4%	4,800	1,750
Excelsior AMI	9.1%	20,100	1,800
Operated Acreage	100.0%	2,800	2,800
Total Sugarkane Field Acreage		<u>80,200</u>	<u>22,200</u>

Operating Arrangements for Aurora's Principal Properties

The operations within each Sugarkane Field AMI are governed by a JOA, and Aurora's interests within each of the Sugarloaf, Longhorn, and Ipanema AMIs are also subject to farmout arrangements. Aurora's interests and operations in respect of the 2013 Acquired Assets are not subject to any JOAs or farmout agreements.

Farmout arrangements provide an incentive to operators to drill a producing well in exchange for a WI in those wells and generally in that AMI. Under Aurora's farmout arrangements, Aurora has no WIs in the farmout wells until payout on each separate farmout program is achieved, but this does not impact its post-farmout WIs on any other wells in the same contract area. Payout occurs when the farmee receives from WI revenues, net of operating costs, an amount equal to the costs incurred by the farmee within each separate farmout program. The farmee is entitled to receive a 100% priority return from each farmout program until repayment of all costs plus an amount equal to a 12% internal rate of return on such costs. Aurora's WIs are presented above on the basis of interests in the contract area (on a post-payout basis) and not on a per-well basis. Once each farmout program reaches payout, Aurora starts to receive an interest of production from the wells within that farmout program as per the farmout agreements. As at December 31, 2013, three wells in the Longhorn AMI and one well in the Ipanema AMI had not yet reached payout. Payout has been achieved on all farmout wells in Sugarloaf and Aurora is receiving revenue based on its WIs in three wells that had been subject to farmout.

A JOA grants authority to, and delineates the responsibilities of, the partner acting as the operator in the AMI and other participating parties. A JOA also outlines the rights that WI holders are entitled to, including participation in wells, access to newly acquired leases within a specified area, revenue distributions and access to information. Marathon is the operator under each JOA governing the four Sugarkane Field AMIs. The terms of the JOA for each of the AMIs are substantially similar and are described in more detail below.

Cost and Production Sharing

Under each JOA, the operator generally incurs the initial costs for drilling operations and related costs, including equipment expenses, labor expenses, royalties, expenses for title examinations, legal expenses, taxes and insurance expenses. The operator has the right to be reimbursed from the other parties to the relevant JOA, and who have elected to participate, in proportion to each of their WIs and may request payment of certain expenses and estimated capital costs in advance. Similarly, production of oil and natural gas from the relevant AMI is shared among the participants in the AMI in proportion to each participant's WI in that AMI, subject to any farmout, royalty or other agreements impacting a party's WI. Aurora's current WI is 28.1% in Sugarloaf, 31.9% in Longhorn, 36.4% in Ipanema and 9.1% in Excelsior.

The operator has no obligation under the JOA to provide a schedule of long-term future operations or expenses. However, the operator has established and provided to Aurora a 2014 drilling program and budget and Aurora expects to be provided with notice of any significant variations to the program.

Operations by Parties and Forfeiture of WIs

The operator generally establishes the drilling program; however, each party to a JOA has the right at any time to propose the drilling of a new well or other reworking of existing wells in the relevant AMI. The proposing party must consult with the other parties to the JOA at least 30 days prior to providing notice of such proposal to the other parties, which notice must include or be accompanied by an itemized report detailing, among other things, the estimated cost of the proposed operations. After receiving notice of such a proposal, the other parties to the JOA have 30 days (or 24 hours, if a rig is on location) to consent to participating in the cost of the proposed operations. If a party does not consent or reply within the required time period, such party will not have to pay any costs associated with the proposed operations. However, such non-consenting party will relinquish its rights to the production of oil and gas from the proposed operations. Under the terms of the JOA, and subject to the following paragraph, such non-consenting party will relinquish its interest in the production until the consenting parties are reimbursed for their costs and expenses in the proposed operations, including costs for equipment, and for an additional amount, which generally ranges from one and a half to four times the costs and expenses for the operations. Once these reimbursement amounts are paid, the WI of the non-consenting party is restored.

However, notwithstanding the previous paragraph, in certain circumstances, any non-consenting party relinquishes all rights to the production of oil and gas from the proposed operations:

- under the Sugarloaf JOA and the Longhorn JOA, the non-consenting party will lose all operating rights and WIs in a proposed new well and in the 1,920 acres surrounding such well not otherwise held by production by the parties;
- under the Excelsior JOA, the non-consenting party will lose all operating rights and WIs in a proposed new well that is drilled outside a previously drilled unit or on acreage not held by production and in the 1,920 acres surrounding such well not otherwise held by production by the parties;
- under each JOA, the non-consenting party will lose all interests in farmout rights or leases if the proposed operations are "obligatory," being operations (such as the drilling of a new well) commenced to prevent the expiration of a lease or leases that would otherwise expire within six months; and
- under the Excelsior JOA and the Sugarloaf JOA, if a party elects not to participate in the acquisition of 3-D seismic data in an AMI (or fails to make timely payment of its share of the costs to acquire such data after having elected to participate), the participating parties will have the right to select 1,920 acres in the AMI, which is not already held in production, but which is covered by the seismic data. The non-participating party will be prohibited from participating in any drilling operations as long as the participating parties own any leasehold rights in such 1,920 acre tract and, once the acquisition of the seismic data is complete, shall assign all of its operating rights and WI in such 1,920 acre tract to the participating parties.

The operator shall perform all of the proposed work for the consenting parties where less than all parties participate in operations; provided, however, that if the operator is a non-consenting party and there is no drilling rig already present at the proposed location of the operations, the consenting parties must either formally request that the operator commence operations or designate one of the consenting parties as operator for such proposed work.

Failure of Title

Under each of the JOAs, any losses incurred through title failures are shared jointly between all parties to the JOA in proportion to their WIs. In effect, these provisions provide that even though Aurora was not a party to the original leases underlying a particular AMI, it will share in any loss of those leases that may occur as a result of title problems.

Acquisition of Additional Interests in an AMI

If a party to a JOA acquires or obtains the right to acquire from anyone not a party to the JOA any additional leasehold or other oil and gas interest within the AMI, that party must notify the other parties of the acquisition of such interests or a right to acquire such interests and the other parties may mutually agree to acquire such interests in proportion to their WIs. If all parties to the JOA agree to participate in such acquisition, in proportion to their WIs in the AMIs, such interests will become subject to the terms of the JOA. Further, if all parties to the JOA acquire additional interests that become subject to the JOA, the parties have agreed to assign or reserve for the party to the JOAs who was the original operator an overriding royalty with respect to the acquired interest (subject to a cap that ranges from 4% to 6%).

Divestments

Aurora is generally able to divest its WIs in the JOAs; however, under the Sugarloaf, Ipanema and Longhorn JOAs, any assignment is subject to the written consent of the party to the JOA who was the original operator, which must not be unreasonably withheld upon receipt of proof that the proposed assignee is financially capable of fulfilling its obligations in respect of the WI. Additionally, under each of the Longhorn and Ipanema JOAs, Aurora must provide notice to the operator of any proposed divestment of WIs and the operator will have a pre-emptive right to acquire any such interests on the same terms as proposed, except in the case of assignments by way of mortgage and except in the case of divestment by way of merger or reorganization or pursuant to the sale of all or substantially all of Aurora's assets to an affiliate or to a third party that has a controlling shareholder.

Default

Under the JOAs, the operator and other parties in each JOA have a first priority lien in Aurora's oil and gas rights in the relevant AMI and a security interest in its share of oil and gas when extracted and in all equipment purchased under the relevant JOA. If Aurora fails to fully discharge its financial obligations, including making payments in advance to the operator as described above, it will be in default under the JOAs. Subject to certain cure periods, upon default, Aurora may be sued for damages, its production revenues may be directed to the operator and Aurora may be deemed to be a non-consenting party with respect to certain wells.

Resignation or Removal of Operator

Under each of the JOAs, the operator may resign at any time on written notice and will be deemed to resign if it terminates its legal existence, is no longer capable of serving as operator or it no longer owns an interest in the area subject to the JOA. Such resignation or deemed resignation is effective on the first day of the calendar month following a 90 day period from the date of written notice or the date of deemed resignation, as applicable, unless a replacement operator is selected by the parties prior to that date. The operator can be removed if it fails to or refuses to carry out its duties under the JOA or becomes insolvent and two or more of the non-operating parties holding a majority of the WIs in the relevant contract area vote to remove the operator.

Where an operator has resigned or has been removed under the foregoing circumstances, the replacement operator shall be selected from all the parties holding WIs in the relevant contract area, by an affirmative vote of two or more parties owning a majority of the WIs. An operator that has resigned, but not an operator that has been removed by the other parties, is able to participate in the voting for a replacement.

Leasehold Interests and Royalties

In Texas, mineral rights may be held privately or by the government. To drill wells or produce oil and gas, a company must either own the mineral rights or lease them from the mineral rights holder. Generally, Aurora's leases are for a period of five years. Marathon, as operator, has the responsibility of managing the lease administration for Aurora's Sugarkane Field AMI's, while Aurora manages the lease administration on the operated acreage.

Aurora has an interest in numerous individual leases from private lessors across its four Sugarkane Field AMIs and the 2013 Acquired Assets within the Sugarkane Field, each of which is current (typically a bonus and delay rental

was paid upon entering the lease with no such additional payments required within the primary term of the lease). The undeveloped portion of the leasehold under these leases generally expires between 2014 and 2015. The leases contain provisions requiring that the acreage be developed within a specified lease period or else it must be re-leased. The development provisions of these leases generally require the drilling of one or more wells that produce hydrocarbons from which the mineral owners derive royalties. Each producing well will hold a certain amount of land while it is still producing, hence the reference to "land held by production". The specific details of each lease and royalty rate are different as they are individually negotiated but, in general, the net revenue interests for the WI participants on Aurora's acreage, including Aurora, range from 70-75% with an average across Aurora's current acreage of approximately 74%.

Over time, each field designated by the Railroad Commission of Texas (the governing body for oil and gas in Texas) will have its own rules depending on the individual characteristics of the field. Approximately half of the Sugarkane Field has been designated as a natural gas field and the remainder as an oil field. Under those designations operators are able to hold a certain number of acres around every producing well drilled (depending on the well length) per the specific field rules. The rules currently in effect for natural gas wells within the Sugarkane Field allow each well to hold up to 320 acres plus an additional 200 acres for each 1,000 feet of horizontal well. A typical 5,000 foot horizontal well is therefore able to hold up to 1,320 acres, although units are generally 600 to 900 acres. The northern half of the Sugarkane Field falls within two Railroad Commission designated fields: Eagleville I Field; and Eagleville II Field. These fields have been designated as oil fields. Under the relevant field rules, operators are able to hold on average 320 acres for wells with lateral lengths of 5,000 feet plus additional acreage for longer laterals.

Wells

Aurora's wells produce light and medium oil, NGLs (including condensate) and natural gas, with the ratio of gas to liquids production varying by well. The gas to liquids ratio observed across the gas condensate wells to-date varies between 60 and 400 Bbls per MMcf. The volatile oil wells produce at approximately one Mcf/Bbl.

The following table sets out the number of producing and non-producing wells net to Aurora's WI, both before royalties and after royalties, in the Sugarkane Field.

Aurora Net Wells as at December 31, 2013	Before royalties	After royalties
Producing.....	103.2	76.1
Drilled, not producing.....	7.7	5.7
Total Net Wells.....	110.9	81.8

The following table summarizes the status of wells in the Sugarkane Field in which Aurora had a WI (excluding farmout wells), categorized by location, as of December 31, 2013.

	Sugarloaf	Longhorn	Ipanema	Excelsior	Axle tree	Heard ranch	Total
Producing.....	97	178	7	86	11	8	387
Workover.....	-	-	-	-	-	-	-
Fracture Stimulation	-	-	-	-	-	2	2
Completions.....	3	13	-	10	-	1	27
Drilling	2	4	-	2	-	1	9
Total.....	102	195	7	98	11	12	425

Production

During the year ended December 31, 2013, Aurora's average daily production rate was approximately 21,300 Boe/d gross. During the three months ended March 31, 2014, Aurora's average daily production rate was approximately 28,671 Boe/d gross.

The following table summarizes Aurora's share of average daily gross production for each of the periods indicated.

Product Type	Financial year ended December 31, 2013			
	Three months ended	Three months ended	Three months ended	Three months ended
	Mar 31, 2013	Jun 30, 2013	Sept 30, 2013	Dec 31, 2013
Light and Medium Oil				
Average daily production (Bbls/d).....	6,385	7,974	8,718	10,905
Prices received (US\$/Bbl).....	105.29	94.33	102.30	94.62
Royalties paid (US\$/Bbl).....	28.05	25.99	27.58	24.49
Production costs (US\$/Bbl) ¹	11.61	9.97	11.94	11.68
Resulting netback (US\$/Bbl) ²	65.63	63.37	62.77	58.44
Natural Gas Liquids				
Average daily production (Bbls/d).....	3,003	3,434	4,139	4,499
Prices received (US\$/Bbl).....	33.00	31.50	30.21	33.58
Royalties paid (US\$/Bbl).....	8.78	8.35	8.06	8.74
Production costs (US\$/Bbl).....	3.77	3.17	3.36	2.92
Resulting netback (US\$/Bbl) ²	20.45	19.98	18.78	21.92
Condensate Gas Liquids				
Average daily production (Bbls/d).....	5,556	4,824	4,356	4,716
Prices received (US\$/Bbl).....	101.52	98.23	102.75	90.27
Royalties paid (US\$/Bbl).....	27.44	26.93	27.86	23.51
Production costs (US\$/Bbl) ¹	11.09	8.85	10.69	9.78
Resulting netback (US\$/Bbl) ²	62.99	62.45	64.20	56.97
Natural Gas				
Average daily production (MMcf/d).....	22.26	24.87	25.35	27.35
Prices received (US\$/MMcf).....	3,670	4,040	3,810	3,730
Royalties paid (US\$/MMcf).....	970	1,060	1,010	980
Production costs (US\$/MMcf) ¹	360	360	360	300
Resulting netback (US\$/MMcf) ²	2,340	2,620	2,450	2,450

¹ The calculation of production costs allocates operating costs on a prorated basis from production volumes in Boe's.

² The netbacks have been calculated as the price received subtracting royalties and production costs.

Although there were 391 producing wells on the Sugarloaf, Ipanema, Excelsior and Longhorn AMI's during the year ended December 31, 2013, due to farm-out arrangements, Aurora did not have an interest in production in four of these wells during the entirety of that period.

The following table discloses Aurora's net production volumes for the year ended December 31, 2013 based on 365 days for each product type from the Sugarkane Field.

	Light and medium oil (Bbls)	Natural gas liquids (Bbls)	Natural gas (Mcf)	Combined (BOE)
Total:.....	3,596,337	1,016,396	6,733,234	5,734,938

Exploration and Development Activities

The following table summarizes the results of exploration and development activities during the year ended December 31, 2013.

	# of Wells Development*		# of Wells Exploratory	
	Gross	Net	Gross	Net
Light and Medium Oil	127	41.9	-	-
Natural Gas	44	10.7	-	-
Service	-	-	-	-
Stratigraphic Test	-	-	1	0.4
Dry	-	-	-	-
Total	171	52.6	1	0.4

* These wells commenced production during 2013 or completed their farmout payout period.

Properties with No Attributed Reserves

The following table sets forth the gross and net acres of unproved properties held by Aurora, as of December 31, 2013, and the net area of unproved property for which Aurora expects its rights to expire during the next year.

<u>Location</u>	<u>Gross Acres</u>	<u>Net Acres</u>	<u>Net Acres to Expire in 2014*</u>
South Texas, Flour Bluff Field	1,400	280	-
California, North Belridge	125	40	-
South Texas, Pan de Azucar and Brioché	87	8	-
East Texas, Trinity West	15,000	14,000	6,920
TOTAL	16,612	14,328	6,920

* The expiry net acres include acreage that can be extended under existing options or continuous development provided for in certain leases and agreements.

Other than immaterial abandonment costs liability for two wells at North Belridge, Aurora does not have work commitments on the above lands.

Infrastructure

There has been considerable focus on the installation of the required infrastructure to allow for full field development in the Sugarkane Field. On Aurora's non-operated acreage, it has participated in the installation and ownership of nine centralized processing facilities ("CPFs") across the Sugarkane Field, which provide the following capability:

- infield gathering systems between well locations and the CPFs;
- processing equipment for the treatment of natural gas and compression allowing injection into the transportation system that moves the product to refineries for NGL processing;
- processing equipment for oil treatment and on-site storage in preparation for either injection into oil pipelines that have contracted volumes and run across the field or for export via trucks to local refineries;
- saline water wells, centralized ponds, disposal wells and buried distribution pipework allowing water to be sent to fracture locations throughout Aurora's leasehold interests in the Sugarkane Field and produced fracturing water to be recovered and recycled for future wells; and

- natural gas lift capability for longer term production maintenance of shallower wells in the volatile oil window.

During 2012, there was considerable focus by Aurora on the installation of the required infrastructure to allow for full field development and the vast majority of the corresponding field gathering system was installed (over 300 miles of pipework).

The gas export system downstream of the CPFs was predominantly built in 2011, with the most recent CPFs having now been tied in. At the end of 2012, an additional interconnect allowed gas exports to a third processing facility and increased the field take away capacity to over 100 MMbtu/day. During 2012, the Three Rivers oil pipeline, which crosses the Excelsior and Longhorn AMIs, was commissioned.

On the Heard Ranch and Axle Tree Ranch properties comprising Aurora's operated acreage, Aurora is in the process of installing CPFs and gathering systems to manage production expected from the development plans of these assets. In particular, the Axle Tree Ranch development includes two amine treatment plants to process hydrogen sulphide (up to 6,000 parts per million from some wells) out of the natural gas to render it suitable for sale or field use. Untreated natural gas is sold through the Regency sour gas line commissioned in November 2013.

Marketing and Sales of Production

Production from Aurora's leases is moved from individual well test facilities via inter field transfer lines to CPFs where oil, condensate, natural gas liquids and natural gas are treated to sales quality, products are metered and gas compressed up to pipeline inlet pressure specification. Afterwards, treated production is sold either at the lease or moved via truck or pipeline to the particular market for sale.

Currently, Aurora's share of production from the Sugarkane Field AMIs is marketed and sold on its behalf by Marathon, the operator. Under the terms of Aurora's JOAs, it has the right to separately dispose of its share of hydrocarbon production from its AMIs under different arrangements, including, without limitation, through different agents. Aurora is responsible for marketing and sales of hydrocarbon production from its operated acreage.

Aurora's oil, condensate, NGLs and natural gas are sold under a variety of arrangements with the realized price in reference to a range of local prevailing spot markets adjusted for gravity, quality, local conditions and any relevant costs incurred.

Reserves

The following table sets forth as at December 31, 2013 Aurora's proved and probable reserves as estimated by Baytex's internal non-independent qualified reserves evaluator in accordance with Canadian reserves disclosure standards and reserves definitions as set out in NI 51-101.

Reserves Category	Aurora as at December 31, 2013 (Baytex Internal Estimate)	
	Gross (MBoe)	Net (MBoe)
Proved:		
Proved Developed Producing.....	30,000	22,200
Proved Developed Non-Producing.....	-	-
Proved Undeveloped.....	76,694	56,754
Total Proved.....	106,694	78,954
Probable	59,876	44,308
Total Proved plus Probable	166,570	123,262

The reserve information in the foregoing table is derived from estimates prepared by Baytex's internal non-independent qualified reserves evaluator for the purpose of making an offer to acquire Aurora and, as a result, do not include much of the information included in Form 51-101F1 of NI 51-101. See "*Presentation of Oil and Natural Gas Reserves*" for more information about how these reserves are calculated and the assumptions upon which these reserves are based. The estimation and classification of reserves are inherently uncertain and require the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions. The reserves information has not been updated for any depletion since December 31, 2013, or to reflect updated price assumptions for changes in oil and natural gas prices since that date. See "*Cautionary Statement Regarding Forward-Looking Statements*".