WE'RE ON FOR YOU.

ENMAX 2014 FINANCIAL REVIEW

CAUTION TO READER

This document contains statements about future events and financial and operating results of ENMAX Corporation and its subsidiaries (ENMAX or the Corporation) that are forward looking. By their nature, forward-looking statements require the Corporation to make assumptions and are subject to inherent risks and uncertainties. There is significant risk that predictions and other forward-looking statements will not prove to be accurate. Readers are cautioned not to place undue reliance on forward-looking statements as a number of factors could cause actual future results, conditions, actions or events to differ materially from financial and operating targets, expectations, estimates or intentions expressed in the forward-looking statements.

When used in this Financial Report, the words “may,” “would,” “could,” “will,” “intend,” “plan,” “anticipate,” “believe,” “seek,” “propose,” “estimate,” “expect” and similar expressions, as they relate to the Corporation or an affiliate of the Corporation, are intended to identify forward-looking statements. Such statements reflect the Corporation’s current views with respect to future events and are subject to certain risks, uncertainties and assumptions. Many factors could cause the Corporation’s actual results, performance or achievements to vary from those described in this Financial Report. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this Financial Report. Intended, planned, anticipated, believed, estimated or expected and other forward-looking statements included in this Financial Report herein should not be unduly relied upon. These statements speak only as of the date of this Financial Report. The Corporation does not intend, and does not assume any obligation, to update these forward-looking statements except as required by law, and reserves the right to change, at any time at its sole discretion, the practice of updating annual targets and guidance. Targets for 2015 are described in the Outlook Section of the Management’s Discussion and Analysis (MD&A).

Factors that could cause actual results to differ materially include, but are not limited to, the following:

- competitive factors and pricing pressures, including electricity supply and demand in the Alberta power market and fluctuations in the pricing of natural gas in the North American market;
- the availability of the Corporation’s generation assets to produce power;
- regulatory developments as they relate to transmission and distribution rate-making and the impact of deregulation in the industry;
- changes in environmental and other legislation;
- human resources, including possible labour disruptions;
- financing and debt requirements, including ability to carry out refinancing activities;
- tax matters, including acceleration or deferral of required cash payments, realization of timing differences and potential reassessments by tax authorities;
- litigation and legal matters;
- business continuity events (including man-made and natural threats);
- economic growth and fluctuations as they relate to the natural-resource-based Alberta economy;
- weather and climate;
- changes in customers’ wants and needs due to evolving technologies and a movement to more environmentally sensitive ways of living; and
- other risk factors discussed herein and listed from time to time in the Corporation’s reports and other public disclosure documents.

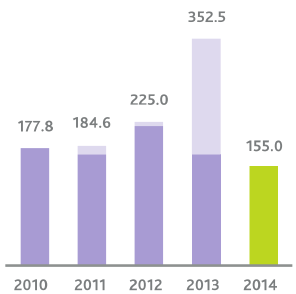
For further information, see the MD&A Section, Risk Management and Uncertainties.

BECAUSE FOCUSED STRATEGY MAKES A STRONG FOUNDATION.

OVERVIEW

NET EARNINGS

($ millions)

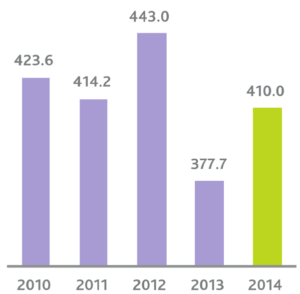


Discontinued operations

Continuing operations

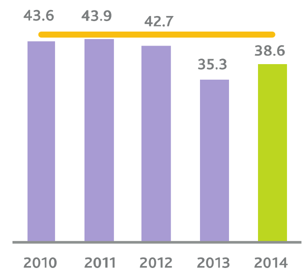
ADJUSTED EBITDA (1)

($ millions)



(1) Non-GAAP financial measure. See discussion that follows in the Management's Discussion & Analysis (MD&A).

DEBT TO TOTAL CAPITALIZATION (1) (%)



Target maximum of 45%

(1) Long-term debt to total capitalization is equal to total long-term debt, including current portions, divided by the sum of long-term debt and shareholder's equity.

OVERALL HIGHLIGHTS

(millions of dollars, except where otherwise noted)	2014	2013
Revenues	**3,348.3**	3,416.6
Operating margin (1)	**767.7**	818.4
Comparable net earnings (1)	**184.8**	173.4
Net earnings	**155.0**	352.5
Net earnings from continuing operations	**155.0**	173.4
Adjusted earnings before interest, income tax, depreciation and amortization (Adjusted EBITDA) (1)	**410.0**	377.7
Earnings before interest and income taxes (EBIT) (1)	**201.4**	204.5
Funds from operations (1)	**386.0**	359.7
Cash flow from operations (1)	**434.3**	204.7
Total assets	**4,841.6**	4,565.5
Return on assets (2)	**7.1%**	7.0%
Return on equity (3)	**7.4%**	7.9%
Total recordable injury frequency (TRIF) (4)	**0.49**	0.90
Capital additions	**616.2**	502.3
Electricity sold to customers (Gigawatt hours [GWh])	**20,653**	20,889
Employees (#) (5)	**1,900**	1,846

(1) Non-GAAP financial measure. See discussion that follows in the Management's Discussion & Analysis (MD&A).

(2) Return on assets (ROA) is equal to net earnings before after-tax interest charges divided by average total assets (adjusted for capital assets under construction and current liabilities) for the year. ROA excludes Kettles Hill Wind Farm (Kettles) impairment of $29.8 million in Q4 2014 and the $175.9 million gain on sale of Envision recorded in Q2 2013.

(3) Return on equity (ROE) is equal to net earnings divided by average shareholder's equity for the year. ROE excludes Kettles impairment of $29.8 million in Q4 2014 and the $175.9 million gain on sale of Envision recorded in Q2 2013.

(4) TRIF indicates the rate of injuries at ENMAX, including lost-time incidents, restricted work injuries and medical aids. It is calculated as the number of injuries multiplied by 200,000 (approximate number of hours worked by 100 workers in a year) divided by total number of hours worked.

(5) Employee count is total employees.

SEGMENT HIGHLIGHTS

ENMAX ENERGY HIGHLIGHTS

(millions of dollars, except where otherwise noted)	2014	2013
Competitive Retail and Generation Business		
Revenue	2,955.6	3,063.3
Total assets	3,050.8	2,881.8
Capital additions	391.8	285.6
EBIT (1)	75.4	116.8
Electricity sold to customers (GWh)	19,069	19,170
Customer satisfaction (2)	80%	82%
Generation volume (GWh)	10,453	12,230

(1) Non-GAAP financial measure. See discussion that follows in the MD&A.

(2) Monthly weighted average of customers rating their interaction with ENMAX Encompass "Very Satisfied" per the customer interaction survey process with Service Quality Management.

ENMAX POWER HIGHLIGHTS

(millions of dollars, except where otherwise noted)	2014	2013
Regulated Business		
Revenue	670.7	653.9
Total assets	1,639.6	1,515.4
Capital additions	200.3	190.3
Rate base (1)	1,300.1	1,152.3
EBIT (2)	90.7	74.6
System average interruption duration index (SAIDI) (3)	0.48	0.43
System average interruption frequency index (SAIFI) (4)	0.99	0.76
Energy delivered (GWh)	9,617	9,473
Electricity sold to customers through regulated rate option (RRO) (GWh)	1,584	1,719
Competitive Construction Business		
Revenue	93.3	71.4
EBIT (2)	7.2	6.8

(1) Rate base refers to the mid-year plant in service rate including working capital and is based on preliminary information. Regulatory true-ups and adjustments could be required in 2015 related to 2014. Transmission accounts for $317.5 million (December 31, 2013 — $251.7 million) and Distributions is $982.6 million (December 31, 2013 — $900.6 million) of the total rate base.

(2) Non-GAAP financial measure. See discussion that follows in the MD&A.

(3) SAIDI equals the total duration of a sustained interruption per average customer during a predefined period of time. A sustained interruption is an interruption in duration greater than or equal to one minute.

(4) SAIFI equals how often the average customer experiences a sustained interruption over a predefined period of time. A sustained interruption is an interruption in duration greater than or equal to one minute.

MANAGEMENT'S DISCUSSION AND ANALYSIS (MD&A)

This MD&A, dated March 19, 2015, is a review of the results of operations of ENMAX Corporation and its subsidiaries (ENMAX or the Corporation) for the year ended December 31, 2014, compared with 2013, and of the Corporation's financial condition and future prospects. This discussion contains forward-looking information that is qualified by reference to and should be read in light of the caution to reader previously mentioned.

ENMAX's consolidated financial statements have been prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). The Corporation will be reporting interim and annual consolidated financial statements in accordance with International Financial Reporting Standards (IFRS), including comparative periods, beginning January 1, 2015.

The Consolidated Financial Statements and MD&A were reviewed by ENMAX's Audit, Finance and Risk Committee (AFRC), and the Consolidated Financial Statements were approved by ENMAX's Board of Directors (the Board). All amounts are in Canadian dollars unless otherwise specified.

The Corporation reports on certain non-GAAP financial measures such as operating margin, EBIT and funds from operations that are used by management to evaluate performance of business units and segments. Because non-GAAP financial measures do not have a standardized meaning, the Corporation has defined and reconciled them with their nearest GAAP measure. For the reader's reference, the definition, calculation and reconciliation of consolidated non-GAAP financial measures is provided in the Non-GAAP Financial Measures section.

CONTENTS

OUR BUSINESS

OVERVIEW AND STRATEGY

ENMAX is a wholly owned subsidiary of The City of Calgary (The City), headquartered in Calgary, Alberta, Canada. We strive to be a leader in Alberta's power industry and endeavour to improve Albertans' quality of life by making, moving and marketing power in a safe, reliable and responsible manner. ENMAX and its predecessors have a proud history of providing Albertans with electricity for over 100 years and continue to explore ways to improve our province's electricity system and provide progressive solutions for our customers.

Our core operations include the competitive generation and sale of electricity across Alberta through ENMAX Energy and regulated transmission and distribution of electricity in the City through ENMAX Power:

- ENMAX Energy is involved with the generation of electricity in Alberta and controls its physical electricity supply through power purchase arrangements (PPAs) and owned generation capacity. It purchases natural gas on the wholesale market with terms and conditions to meet the sales commitments of its retail marketing operations and for the operational requirements of its natural-gas-fuelled generating facilities. Risk-management processes and systems are in place to carefully monitor and manage price and commodity risks inherent in the business. ENMAX Energy is also Alberta's leading competitive electricity retailer. In addition to electricity, ENMAX Energy provides natural gas, renewable energy and value-added services to residential, commercial and industrial customers throughout Alberta.
- ENMAX Power owns and operates electricity transmission and distribution assets in the Calgary service area. In addition, it has the legislated responsibility to provide electricity for customers who elect to stay with the regulated rate option (RRO). RRO is the default rate established by regulation and automatically provided to all eligible customers who have not entered into a contract with a competitive electricity retailer. ENMAX Power also has a competitive business that provides engineering, procurement, construction and maintenance services. ENMAX Power's objective is to maintain the high reliability of its transmission and distribution system while meeting Calgary's growing infrastructure needs.

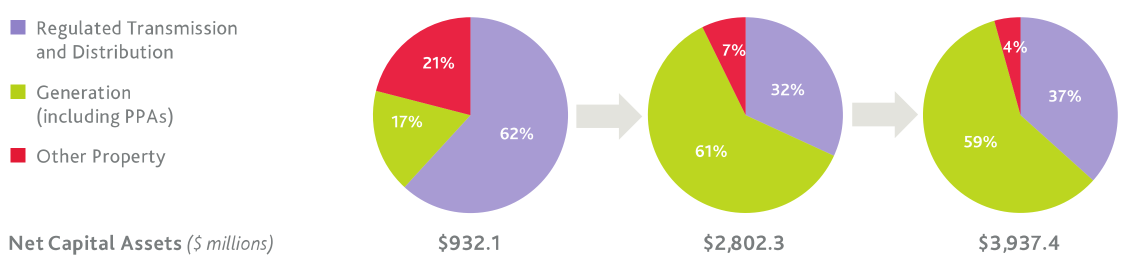
While continuing to keep safety and reliability top of mind, we are building our regulated business by investing in the growing transmission and distribution needs of the city. With this organic growth, the size of the regulated business asset base will significantly increase in the future. Within the ENMAX Energy segment, we will invest in generation assets to meet the growth in demand in the province and to replace generation capacity that will be lost with the expiration of our PPAs at the end of 2020. ENMAX will maintain its long history of relatively stable earnings and dividends through a balanced yet growing portfolio of regulated and competitive assets. A strong focus on customers and stakeholders, process efficiencies, cost controls and capital discipline supports this overall strategy.

We confirm and set corporate initiatives each year to advance our strategies. The objectives and initiatives embedded in our strategy are as follows.

Strategy	Mechanisms
Create a strong foundation for future growth	• Advancing a strong safety culture • Developing employees to deliver strong operational performance today and into the future • Providing excellent customer service • Effectively managing costs • Advancing technology and system solutions to support business needs
Enhance our position as a strong Alberta power generator and retail market leader	• Completing Shepard Energy Centre (Shepard) on budget by first quarter 2015 • Building, acquiring or contracting new generation sources to replace expiring PPAs and creating a highly flexible portfolio of electricity supply • Ensuring strong availability of our generation supply • Working with customers to identify and fulfill needs through a variety of attractive energy products • Supporting commercialization of renewable energy options
Operate and grow a highly reliable electricity infrastructure in Calgary	• Investing in transmission and distribution infrastructure • Maintaining high reliability • Achieving acceptable rates of return through constructive regulatory outcomes

An overall corporate portfolio is created by operating both ENMAX Energy and ENMAX Power. Key to our strategy is balancing this portfolio as we and the Alberta market grow and evolve.

TOTAL ASSET ALLOCATION
(%)



OVERALL FINANCIAL PERFORMANCE

SIGNIFICANT TRANSACTIONS IN 2014

GENESEE JOINT VENTURE

In April 2014, ENMAX Energy signed a purchase and sale agreement with Capital Power (G4) Limited Partnership (Capital Power) in support of a joint venture agreement (JVA) to develop, construct, own and operate a natural-gas-fuelled facility west of Edmonton with a generation capacity of up to 1,050 MW. The proposed facility, Genesee 4 and 5, will be built on a site near Capital Power's existing Genesee facility and is expected to utilize the latest high-efficiency gas-fuelled combustion turbine combined cycle technology. ENMAX Energy executed the JVA and associated agreements with Capital Power in July 2014, with terms similar to the Shepard JVA; however, in this case, Capital Power will lead the construction of the project and operate the facility. Subject to the achievement of a number of project milestones and other considerations, we expect construction of the proposed facility to be completed between 2018 and 2020, when additional generation will be required to meet the growing demand in Alberta, as some of Alberta's coal-fired generation is expected to retire.

CAVALIER AND BALZAC ACQUISITION

In September 2014, ENMAX Energy completed the purchase of two natural-gas-fuelled electricity generation assets, increasing electricity generation supply by 170 megawatts (MW). ENMAX Energy purchased 100 per cent of Encana Corporation and its subsidiaries' (Encana) 115 MW natural-gas-fuelled Cavalier plant, near Strathmore, Alberta, for $169.2 million and Encana's 50 per cent interest in a 110 MW gas-fuelled plant, in Balzac, Alberta, for $55.9 million. ENMAX Energy is the operator of the Cavalier plant, and Nexen Inc. will remain the operator of the Balzac facility in which it is a co-owner.

FINANCIAL OVERVIEW

SELECTED CONSOLIDATED FINANCIAL INFORMATION

(millions of dollars, unless otherwise noted)	2014	2013
Total revenue	**3,348.3**	3,416.6
Operating margin (1) (excluding unusual items)	**767.7**	818.4
EBIT (1)	**201.4**	204.5
Adjusted EBITDA (1)	**410.0**	377.7
Comparable net earnings (1)	**184.8**	173.4
Net earnings from continuing operations	**155.0**	173.4
Net earnings	**155.0**	352.5
Funds from operations (1)	**386.0**	359.7
Cash provided by operating activities	**434.3**	204.7
Total assets	**4,841.6**	4,565.5
Long-term debt(2)	**1,610.3**	1,439.0

(1) Non-GAAP financial measure. See discussion that follows in Non-GAAP Financial Measures section.

(2) Includes current portion of long-term debt.

ENMAX's consolidated net earnings for the year ended December 31, 2014, is $155.0 million, compared with $352.5 million for the year ended December 31, 2013. The decrease for the year ended December 31, 2014, is primarily due to the absence of a one-time, non-recurring sale of ENMAX Envision Inc. (Envision) on April 30, 2013, for a gain of $175.9 million.

In the year ended December 31, 2014, we benefited from higher PPAs availability and favourable transmission and distribution margins as a result of the approval of new rates and a ruling on a recovery of earnings on prior period invested transmission capital. Offsetting these favourable impacts were a decrease in electricity margins driven by lower realized prices and decreased realized gains on hedges, an asset impairment loss, an increase in interest expense of $20.7 million upon settlement of interest rate swaps associated with an early repayment of long-term debt and an increase in operations, maintenance and administration (OM&A) costs.

Results of operations are not necessarily indicative of future performance due to fluctuating commodity prices, the performance and retirement of existing generation facilities, and the addition of new generation facilities. Further details on specific operations can be found in the Business Segment Results section of this report.

UNUSUAL ITEMS INCLUDED IN YEAR-OVER-YEAR COMPARISONS

2014 PPA OUTAGES – KEEPHILLS UNIT 2

On January 31, 2014, the Keephills Unit 2 generator was removed from service by its operator, TransAlta Corporation (TransAlta). Keephills Unit 2 provides ENMAX Energy with approximately 340 MW of electricity through a PPAs. On November 27, 2013, TransAlta claimed force majeure under the Keephills PPA with respect to this planned outage. Under a force majeure, ENMAX is not compensated for the outage by the owner for the duration of the outage but is relieved from paying certain capacity charges to the plant owner for the duration of the event The Keephills Unit 2 generator returned to service on March 15, 2014. ENMAX has not accepted or agreed to the claim of force majeure in relation to this outage and anticipates entering into a dispute resolution process with TransAlta in accordance with the terms of the PPA. For the year ended December 31, 2014, the Keephills Unit 2 outage impact was $17.4 million.

2013 PPA OUTAGES – KEEPHILLS UNIT 1

On March 5, 2013, the Keephills Unit 1 generator was removed from service by its operator, TransAlta. Keephills Unit 1 provides ENMAX Energy with approximately 340 MW of electricity through a PPA. On March 26, 2013, TransAlta claimed force majeure under the Keephills PPA. The Keephills Unit 1 generator returned to service on October 5, 2013. ENMAX has not accepted or agreed to the claim of force majeure in relation to this outage, and ENMAX has entered into a dispute resolution process with TransAlta in accordance with the terms of the PPA. For the year ended December 31, 2013, the Keephills Unit 1 outage impact was $127.5 million.

2013 FLOOD RESPONSE

In June 2013, southern Alberta experienced significant flooding. In coordination with the Calgary Emergency Management Agency and government agencies, ENMAX Power disconnected and subsequently restored power to affected customers to ensure the safety of citizens. The disconnection and restoring of power minimized damage to ENMAX Power infrastructure and minimized the impact on citizens and damage to business property. For the year ended December 31, 2013, the flood response impact was, net of recoveries, $3.8 million of operations costs and $3.5 million of capitalized costs.

During the year ended December 31, 2014, ENMAX received insurance proceeds in the amount of $3.3 million related to recovery of expenses and $3.6 million related to replacement of ENMAX Power infrastructure.

EBIT FOR THE YEAR ENDED DECEMBER 31, 2014, COMPARED WITH THE SAME PERIOD IN 2013

(millions of dollars)

EBIT for the year ended December 31, 2013	204.5
Unusual items included in results:	
2014 Keephills Unit 2 outage	(17.4)
2013 Keephills Unit 2 outage	127.5
Flood response	7.1
Increased (decreased) margins attributable to:	
Electricity, excluding Keephills outage	(75.6)
Natural gas	-
Transmission and distribution	32.3
Contractual services and other	(7.4)
Decreased (increased) expenses:	
OM&A	(34.4)
Impairment loss	(34.4)
Foreign exchange	5.3
Amortization	(6.1)
EBIT for the year ended December 31, 2014	201.4

Normalized electricity margins (electricity margins excluding Keephills outages) for the year ended December 31, 2014, decreased $75.6 million to $403.5 million from $479.1 million in the year ended December 31, 2013. The decreased margins in the year ended December 31, 2014, were driven primarily by lower prices realized on sales, decreased realized gains on hedges and higher natural gas prices, as it increased the cost to run our natural-gas-fuelled plants. Additionally, there were mark-to-market losses experienced on our natural gas positions for 2015 fuel supply to our natural-gas-fuelled plants, resulting from the decrease in natural gas prices during December 2014. These decreases were partially offset by higher volumes on commercial and residential fixed-price contracts.

Natural gas margins for the year ended December 31, 2014, were consistent with the prior year at $33.6 million.

For the year ended December 31, 2014, transmission and distribution margins increased $32.3 million to $273.5 million from $241.2 million in 2013. The increased margin for the year ended December 31, 2014, is due primarily to an increase in transmission and distribution tariffs. Contributing to the increase is an Alberta Utilities Commission (AUC) settlement ruling received in December 2014 approving $12.4 million recovery of earnings on transmission capital invested in prior periods.

For the year ended December 31, 2014, contractual services and other revenues (excluding flood insurance proceeds) decreased $7.4 million to $57.1 million from $64.5 million in 2013. The decrease is mainly attributable to the 2013 recognition of cost recoveries associated with ENMAX's disposition of a 50 per cent interest in Shepard to Capital Power LP (CPLP). The decrease in the year ended December 31, 2014, is partially offset by increased activity on commercial developer projects and the increased light, rail and transit (LRT) project work.

Normalized OM&A (excluding flood costs) for the year ended December 31, 2014, increased $34.4 million to $355.5 million from $321.1 million in 2013. The increase in the year ended December 31, 2014, was due to an increase in staff costs, computer-systems-related costs and costs related to billing and collection, offset by a decrease in operating and maintenance expense and advertising expense.

Impairment loss for the year ended December 31, 2014, was $34.4 million as compared to nil in 2014. Kettles was tested for impairment, resulting in property, plant and equipment (PPE), intangible assets and goodwill being impaired. An asset with goodwill is required to be tested annually.

For the year ended December 31, 2014, a net foreign exchange gain of $11.9 million was recognized compared to a gain of $6.6 million in 2013. Foreign exchange gains or losses are primarily the result of net realized and unrealized gains and losses on equipment purchases and service agreements denominated in foreign currencies and associated foreign exchange hedges.

Amortization expense for the year ended December 31, 2014, was $174.2 million compared with $168.1 million in 2013. The increased charges were primarily the result of assets placed into service in 2014.

OTHER NET EARNINGS ITEMS

Interest expense increased $11.2 million to $44.3 million from $33.1 million for the year ended December 31, 2014, compared to the year ended December 31, 2013. On March 17, 2014, $200.6 million of non-recourse term financing and $35.6 million of a fixed-for-floating interest rate swap related to Calgary Energy Centre (CEC) was repaid prior to maturity in September 2026. The increase in the year ended December 31, 2014, interest expense was primarily due to $20.7 million of settlement costs associated with the termination of the interest rate swaps. The increase was partially offset by lower cost of borrowing resulting primarily from the repayment of this debt.

Current and future income tax costs for the year ended December 31, 2014, increased $4.1 million to an expense of $2.1 million from a recovery of $2.0 million for the same period in 2013. The increase in income tax was primarily due to an increase in our provision for tax disputes partially offset by lower income in taxable entities.

For the year ended December 31, 2014, there were no earnings from discontinued operations as compared to $3.2 million in the prior year. Earnings from discontinued operations in the year ended December 31, 2013, relate to the Envision business unit, which was sold April 30, 2013.

OTHER COMPREHENSIVE INCOME (OCI)

OCI illustrates earnings under the assumption of full income recognition of gains and losses on the market value of securities and derivatives otherwise treated as hedges of future period revenues and expenses. ENMAX uses derivatives to hedge electricity, natural gas, interest rate and foreign exchange exposures. For the year ended December 31, 2014, OCI totalled a loss of $27.5 million, compared with gains of $13.3 million for the same period in 2013. OCI for the year ended December 31, 2014, primarily reflects the fair value changes in electricity and natural gas positions and settlement of interest rate swaps and commodity positions.

BUSINESS SEGMENT RESULTS

EBIT

(millions of dollars)	2014	2013
ENMAX Energy [(1)]	**100.4**	116.8
ENMAX Power	**97.9**	81.4
Corporate & intersegment eliminations [(1)]	**3.1**	6.3
EBIT	**201.4**	204.5

(1) Normalized to exclude impact of intercompany transactions with no consolidated impact.

ENMAX ENERGY

STRATEGY

ENMAX Energy, which includes various legal entities and divisions, operates in Alberta's competitive energy market providing electricity, natural gas, district heating, energy management and renewable energy products to residential, commercial and industrial customers.

Our core strategy for ENMAX Energy is to grow our customer base across the province of Alberta and invest in the power generation facilities required to serve our electricity customers. We supply electricity through our own wind and natural-gas-fuelled generation facilities and PPAs at Battle River and Keephills. We balance our energy portfolio requirements through the purchase and sale of electricity and natural gas from and into wholesale Alberta markets. ENMAX Energy provides customers with competitive energy products and services with a focus on longer-term fixed electricity contracts. These contracts link our customer demand to our generating assets, which results in relatively stable margins, even during times of volatile wholesale electricity prices.

ALBERTA'S COMPETITIVE ELECTRICITY MARKET

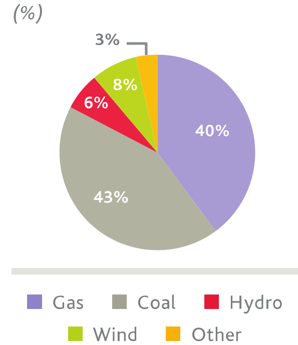
The primary drivers of Alberta's electricity market are economic growth, expected coal plant retirements, changes in environmental regulations, government actions and market participant plans. Coal has been the primary fuel in the electricity market for 50 years; however, existing plants are aging and some are nearing the end of their life.

Under federal greenhouse gas (GHG) legislation, coal–fired plants must shut down at the end of their life, calculated at 45 to 50 years, unless they can meet strict emission standards. Retrofitting to meet these standards is expensive and could be cost prohibitive. The current retirement schedule would change if equivalency agreements allow Alberta to achieve equivalent environmental outcomes without adhering to the coal retirement schedule in the current GHG regulation.

The retirement of coal assets is a critical factor influencing Alberta's electricity market over the next 20 years. Coal plants generate over half of Alberta's electricity, providing much of the base load. The timing and volume of these retirements determine the need for new generation. By 2030, about 60 per cent of the current coal supply is expected to retire, creating a step-change in the composition of Alberta's electricity generation portfolio.

ALBERTA INSTALLED CAPACITY BY FUEL SOURCE

(%)

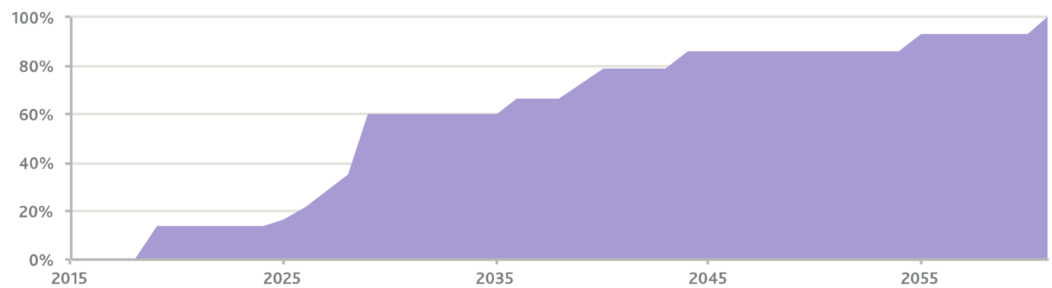


Source: AESO and CIBC World Markets

The retirement schedule removes almost 3,800 MW of coal supply in the next 16 years. For comparison, about 1,450 MW of generation retired in the last 16 years (600 MW was coal-fired). Due to a number of factors, including the availability of natural gas in the Alberta market, expectations are that natural gas generation will be the fuel of choice to replace retiring coal generation.

MANDATED COAL RETIREMENTS

(% of Market Production)



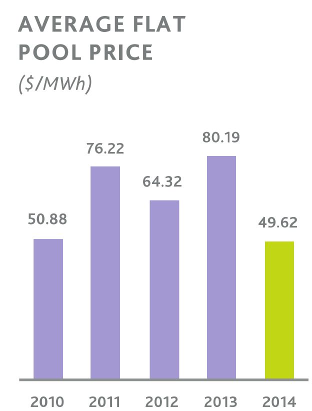
Source: CIBC World Markets

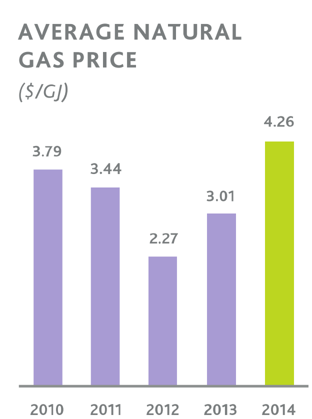
In the competitive Alberta market, changes to demand and supply factors have a direct impact on the market price of electricity, which is a significant factor in a number of areas of our business. Prices are set based on current spot prices, average monthly prices and future expected market prices. In 2014, the average flat pool price was $49.62 per megawatt hour (MWh), a significant decrease from the $80.19 per MWh average in 2013. ENMAX Energy utilizes the fixed-price and volume retail sales market to reduce its exposure to spot price volatility.

Four critical factors can impact electricity prices over the longer term.

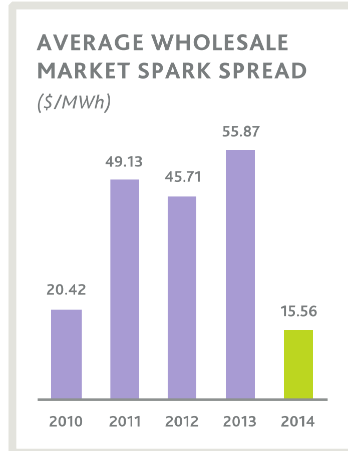
- Demand growth: This is a key element in the timing for new generation builds, and growth is sufficient in most scenarios to require material, new generation build.
- Supply reduction: Significant coal retirements following approximately 50-year legislated plant life with future new supply to be largely natural gas generation.
- Unplanned supply disruptions.
- Natural gas prices: This aspect of the market influences electricity prices as significant amounts of Alberta's current, and future, generation will be natural gas.

The Alberta electricity market price during peak demand periods is often influenced by the price of natural gas. The natural gas market saw average prices increase from $3.01 per gigajoule (GJ) in the year ended December 31, 2013, to $4.26 per GJ in 2014.



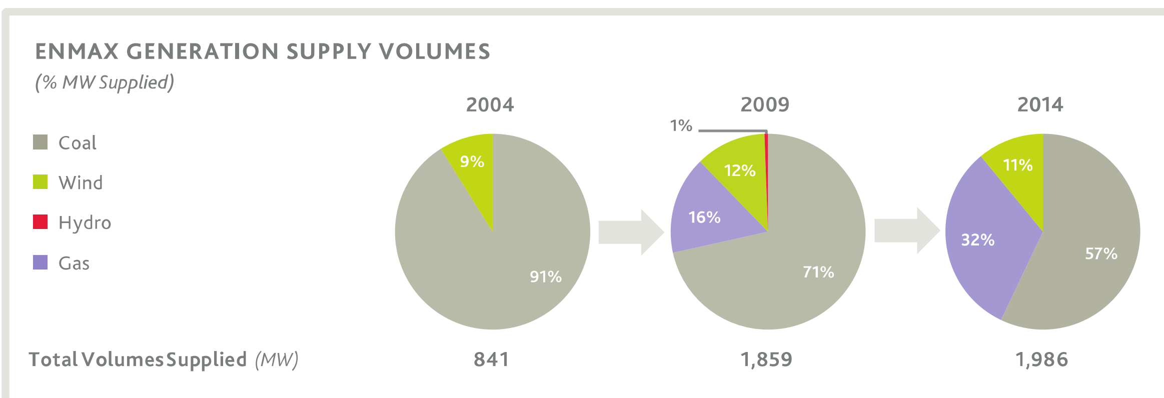


For natural-gas-fuelled facilities, the spark spread is defined as the difference between the market price of electricity and the marginal cost of production (assuming an average combined cycle gas turbine heat rate of 8 GJ per MWh). Profits and all other costs are collected from the spark spread. The term spark spread has become common usage to describe the relative gross margin available in given electricity markets. Based upon an 8 GJ per MWh heat rate combined cycle gas turbine, the average spark spread in Alberta has decreased to $16 in 2014 from $56 in 2013 due to lower market prices for electricity paired with higher average natural gas prices.



ENMAX Energy does not have significant exposure to short-term coal prices for the coal facilities under PPAs as the fuel and input costs for electricity generated at coal-fired facilities are calculated using a pre-determined formula based on Statistics Canada indexes. These include, but are not limited to, the cost of labour, mining machinery and other mining related expenses.

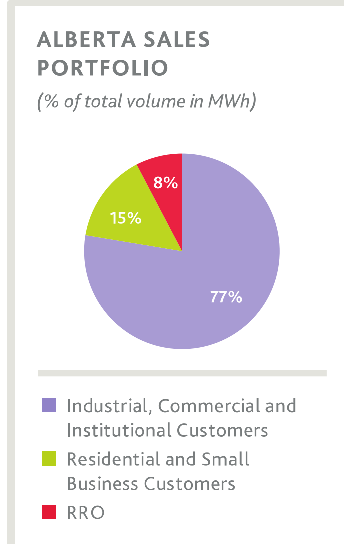
ENMAX's generation portfolio has evolved from 2004 and will continue to evolve with Shepard and the maturing of our PPAs. In 2004, the ENMAX supply portfolio reflected reliance on our PPAs. Our 2014 portfolio represents our investment in wind and natural-gas-fuelled generation facilities since 2003. The supply portfolio will continue to shift from coal to natural-gas-fuelled generation in 2015 with the commissioning of Shepard.



Independent market evaluators consider Alberta's market structure competitive and supportive of growth and rank it second in North America for customer choice and switching. Commercial and industrial customers dominate electricity consumption, representing almost 80 per cent of total demand in the province.

ENMAX serves the full customer spectrum of residential customers to large industrial facilities. This wide customer reach allows us to adjust our approach to products and offerings and customer segments to optimize our overall supply-demand portfolio. Our retail portfolio provides three added values:

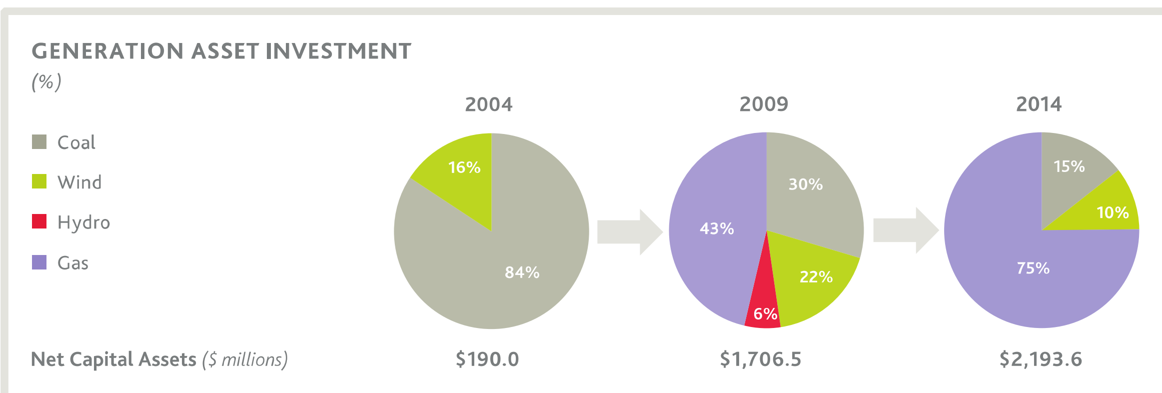
- margin uplift above wholesale market prices;
- term liquidity beyond that available in Alberta's wholesale market; and
- ancillary profitability through index electricity products, natural gas fixed and index options, and other offerings.



BUSINESS UPDATE

As discussed in the Overall Financial Performance section of this MD&A, ENMAX Energy was impacted in 2014 by the Keephills Unit 2 outage and Cavalier and Balzac acquisitions. With respect to the comparative period, the 2013 Keephills Unit 1 outage affected ENMAX Energy results in the year ended December 31, 2013.

ENMAX Energy's generation asset investment has evolved from 2004 and will continue to evolve with our investments into natural-gas-fuelled power generation facilities and expiration of our PPAs. In 2004, the ENMAX Energy electricity supply portfolio reflected wind investment and our PPAs at the time. Our 2014 portfolio represents our investments into natural-gas-fuelled generation facilities and wind.



ENMAX Energy sees strong potential in the role natural gas will play in generating power and reducing the GHG emissions from generating facilities in the coming years. Key to this strategy is the commissioning/construction of the 800 MW Shepard facility located within the Calgary city limits. In 2013, ENMAX Energy sold a 50 per cent interest in the Shepard facility to CPLP. Both parties hold their ownership interests in an unincorporated joint venture with agreement to build, own and operate the facility under a JVA. Under the JVA, ENMAX Energy will continue to provide construction management services to the parties, has been appointed as the operator for the provision of operating and maintenance services and has been appointed as joint venture manager for the provision of accounting and settlement services. An affiliate of CPLP has been appointed as the real-time operator to dispatch each party's electricity entitlement under the Alberta Electric System Operator (AESO) rules. A management committee has been established to manage and govern the joint venture.

At December 31, 2014, nearly 99 per cent of the overall Shepard project work was complete, and approximately $1,350 million of the $1,365 million project budget had been incurred. The project has surpassed 4.2 million hours of construction invested, and on-site safety performance has exceeded our expectations. The project commissioning activities ramped up in the last quarter of 2014, with full commercial operations announced on March 11, 2015. The following table represents ENMAX Energy's fleet of generation as at December 31, 2014.

ENMAX ENERGY'S FLEET OF GENERATION

	Ownership	Capacity Ownership Interest *(MW)*		Fuel
Facility		**2014**	**2013**	
Keephills PPA	100%	**766 (1)**	**766 (1)**	Coal
Battle River PPA (3)	100%	**368 (1)**	**663 (1)**	Coal
Calgary Energy Centre (CEC)	100%	**320**	**320**	Gas
Crossfield Energy Centre (Crossfield)	100%	**144**	**144**	Gas
Cavalier Power Station (Cavalier)	100%	**115**	-	Gas
Balzac Power Station (Balzac) (4)	50%	**55**	-	Gas
Taber Wind Farm (Taber)	100%	**81**	**81**	Wind
McBride Lake Wind Farm (McBride)	50%	**75 (2)**	**75 (2)**	Wind
Kettles	100%	**62**	**62**	Wind
		1,986	**2,111**	

(1) Refers to facility PPA Capacity.

(2) ENMAX has a 50 per cent joint venture ownership interest in McBride and also obtains the other 50 per cent output through a tolling agreement with the other joint venture partner.

(3) As of January 1, 2014, ENMAX capacity ownership represents Battle River Unit 5. Ownership of Units 3 and 4 has reverted back to facility owner.

(4) ENMAX has a 50 per cent interest in this 110 MW natural-gas-fuelled plant.

As at December 31, 2014, ENMAX Energy produced or had exclusive access to 1,986 MW of electricity generation to supply customer demands. In accordance with the terms of the Battle River PPA, Battle River Units 3 and 4 ceased to be part of the PPA at the end of 2013. In January 2014, ENMAX Energy's capacity ownership in this PPA was therefore reduced, from 663 MW to 368 MW, which represents our 100 per cent interest in the output of Battle River Unit 5. The two newly acquired generating facilities, Cavalier and Balzac, have increased ENMAX Energy's fleet generation capacity by 170 MW.

The remaining power and all natural gas required to meet ENMAX Energy's consumer electricity and natural gas demand are acquired through the competitive wholesale power and natural gas markets. During times when ENMAX Energy has excess generation capacity, energy is sold to the market.

ENMAX Energy is the preferred electricity retailer for many industrial, commercial and institutional customers across Alberta. This includes federal and provincial government facilities, school districts, health care facilities, large industrial customers and commercial enterprises across a variety of industries. Customers of all sizes continue to choose ENMAX Energy for its high-touch, consultative service model and flexible, competitively priced energy products. We continue to inform and empower Albertans to explore competitive rate options through EasyMax® and to help businesses manage their power needs by providing competitive and customized energy products. ENMAX Energy provides customers with creative and competitive alternative energy products and services. The Home Solar program introduced in 2011 continues as an option for customers. This program was developed for Albertans looking for a competitive solution for incorporating renewable energy into their homes.

As a wholesale market participant, PPA buyer and competitive retailer, ENMAX Energy is subject to the rules and regulations of the competitive electricity market, including codes of conduct (which establish, among other things, limits on the sharing of information between the regulated and competitive business units within ENMAX). As with other market participants, our compliance with these rules and regulations is subject to scrutiny by the Market Surveillance Administrator (MSA).

KEY BUSINESS STATISTICS	2014	2013
Market heat rate – flat average (MWh/GJ)	**11.66**	26.64
Average wholesale market spark spread ($/MWh) (1)	**15.56**	55.87
Average flat pool price ($/MWh)	**49.62**	80.19
Average natural gas price ($/GJ)	**4.26**	3.01
Generation volume (Gigawatt hours [GWh])	**10,453**	12,230
Electricity sold (GWh)	**19,069**	19,170
Natural gas sold (terajoules [TJ])	**54,290**	50,807

(1) Assuming an average combined cycle gas turbine heat rate of 8 GJ per MWh.

In 2014, ENMAX Energy experienced a decrease in the market heat rate, average wholesale market spread and average flat pool price from 2013 levels. The decreases are attributed to lower settled power pool prices in the market and the impact of increased natural gas fuel costs due to colder weather early in 2014.

ENMAX Energy sold 19,069 GWh of electricity to customers in the current year compared with 19,170 GWh in 2013. The minor decrease is primarily due to variable priced contract volumes offset by higher fixed price contract volumes.

ENMAX Energy's natural gas customers purchased 54,290 TJ of natural gas in 2014, compared with 50,807 TJ in 2013. This increase in volume is due primarily to the impact of cold weather in the first quarter of 2014 and an increased number of customers.

FINANCIAL RESULTS

ENMAX Energy recorded EBIT of $100.4 million for the year ended December 31, 2014, compared with EBIT of $116.8 million in the prior year.

EBIT FOR THE YEAR ENDED DECEMBER 31, 2014, COMPARED WITH THE SAME PERIOD IN 2013

(millions of dollars)

EBIT for the year ended December 31, 2013	116.8
Unusual item included in results:	
2014 Keephills Unit 2 outage	(17.4)
2013 Keephills Unit 1 outage	127.5
2013 Flood response	0.1
Increased (decreased) margins attributable to:	
Electricity, excluding Keephills outage	(73.9)
Natural gas	0.3
Contractual services and other revenues	(9.9)
Decreased (increased) expenses:	
OM&A (1)	(11.2)
Impairment loss	(34.4)
Foreign exchange	5.3
Amortization	(2.8)
EBIT for the year ended December 31**, 2014**	100.4

(1) Normalized to exclude impact of intercompany transactions with no consolidated impact.

For the year ended December 31, 2014, Keephills Unit 2 resulted in an unfavourable impact of $17.4 million compared with Keephills Unit 1 unfavourable impact of $127.5 million in the same period in 2013. See the Unusual Items Included in Results section of this report for further details.

Normalized electricity margins for the year ended December 31, 2014, decreased $73.9 million to $382.9 million compared with the $456.8 million recorded in 2013. The decreased margins in the year ended December 31, 2014, were driven primarily by lower prices realized on sales, decreased realized gains on hedges and higher natural gas prices, which contributed to lower electricity margins as it increased the cost to run our natural-gas-fuelled plants. Additionally, there was mark-to-market losses experienced on our natural gas positions for 2015 fuel supply to our natural-gas-fuelled plants, resulting from the decrease in natural gas prices during December 2014.

Natural gas margins increased $0.3 million to $34.6 million for the year ended December 31, 2014, compared with $34.3 million for the year ended December 31, 2013. Throughout 2014, natural gas margins were higher than prior periods due to the higher realized sales prices and higher volumes sold. In the fourth quarter of 2014, a decrease in the realized sales prices with lower volume sold offset the higher prices and the increased margins experienced in the prior three quarters.

Contractual services margin and other revenues decreased $9.9 million in the year ended December 31, 2014, to $20.6 million compared to $30.5 million in the year ended December 31, 2013. The decrease in margins in the year ended December 31, 2014, was mainly due to the recognition of the recovery of costs associated with ENMAX's joint venture with CPLP in March and September of 2013.

OM&A expenses (excluding flood costs) for the year ended December 31, 2014, increased $11.2 million to $188.4 million compared with $177.2 million in 2013. The increase in OM&A for the year ended December 31, 2014, was driven primarily by an increase in expenses related to billing and collection costs, maintenance of assets, provisions on receivables and professional fees related to business development and arbitrations with respect to our PPAs. These increases were partially offset by a decrease in advertising costs.

Impairment loss for the year ended December 31, 2014, was $34.4 million as compared to nil in 2014. Kettles was tested for impairment, resulting in PPE, intangible assets and goodwill being impaired.

For the year ended December 31, 2014, we experienced a foreign exchange gain of $11.9 million compared to a gain of $6.6 million in 2013. Foreign exchange gains or losses are primarily the result of realized and unrealized gains or losses on equipment purchases and service agreements denominated in foreign currencies and associated hedges.

Amortization expense for the year ended December 31, 2014, was $109.4 million, compared with $106.6 million in 2013. The increase is primarily due to new assets acquired or placed in service.

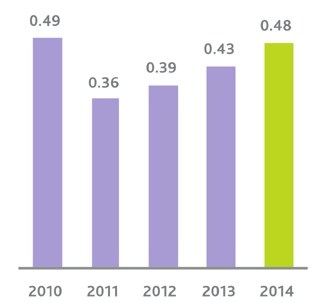
ENMAX POWER

STRATEGY

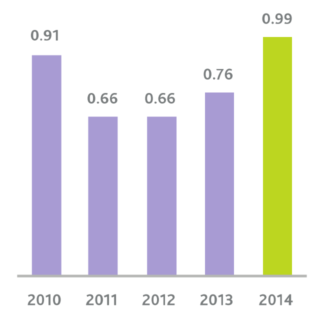
ENMAX Power's highest priority is providing safe, reliable delivery of electricity to Calgarians.

For duration and frequency of power service interruptions, we are a top quartile performer amongst other Canadian utilities. System average interruption duration index (SAIDI) is an industry measurement to express the average duration of a customer outage. SAIDI is equal to the total duration of a sustained interruption per average customer during a predefined period of time. A sustained interruption is an interruption in duration greater than or equal to one minute. The average outage duration time in 2014 was 0.48 hours. System average interruption frequency index (SAIFI) is an industry measurement to express how often an outage may be experienced by a customer. SAIFI equals how often the average customer experiences a sustained interruption over a predefined period of time. The average number of interruptions increased in 2014 to nearly one or 0.99, when we compare to prior year results. This increase is largely attributed to a snowstorm that occurred in September 2014. Calgary and surrounding areas experienced heavy, wet snowfall that resulted in downed trees and power lines. ENMAX Power deployed crews during and after the snowfall, focusing on restoring power quickly and safely.

SYSTEM AVERAGE INTERRUPTION DURATION INDEX



SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX



ENMAX Power continues to invest in its electric transmission and distribution system infrastructure to meet Calgary's growing needs. This includes expansion of the distribution system, reinforcement of the transmission system and replacement of aging infrastructure in both systems. Distribution projects include investments in system infrastructure to accommodate residential, commercial and industrial growth, as well as the replacement and modification of existing assets required to meet industry safety and reliability standards. Transmission projects include capacity upgrades to existing substations, new substations and transmission lines to deliver reliable electricity to meet the growing demand within Calgary.

ALBERTA'S REGULATED INDUSTRY

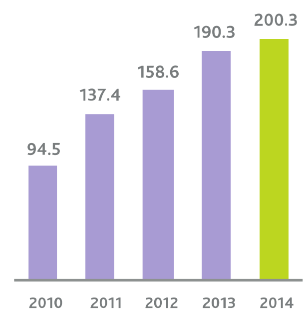
ENMAX Power owns, operates and maintains the distribution and transmission system in Calgary. In a utility environment, it is more efficient to have a single provider in each service area, as it is expensive to build and maintain distribution and transmission networks. This makes the electric transmission and distribution systems a natural monopoly, which remains regulated in Alberta's restructured electricity system. Electric utility companies providing transmission services in the province own, operate, build and maintain the system of high-voltage power lines and other electrical equipment that move power from generation plants to towns, cities and large industrial customers. Distribution systems move electric energy from the high voltage transmission system to customers' homes and workplaces. Distribution power lines and facilities operate at 25 kilovolts or less. Most Albertans receive electricity from such distribution lines.

The AUC regulates investor-owned electric, gas and water utilities, and some municipally owned electric utilities such as ENMAX Power, making certain that Albertans receive safe and reliable utility service at just and reasonable rates. The rates approved by the AUC allow ENMAX Power to recover costs such as the design, maintenance, construction and financing of the electric system that delivers energy to customers. All of ENMAX Power's costs approved by the AUC make up ENMAX Power's revenue requirement.

In July 2014, ENMAX Power filed an application requesting approval of the 2014 and 2015 revenue requirements for its transmission utility and its 2014 revenue requirement for its distribution utility. In December 2014, the AUC issued an initial decision on ENMAX Power's revenue requirement. In February 2015, ENMAX Power filed a compliance filing that, once approved, will finalize the revenue requirement that ENMAX will collect from customers through distribution rates charged in ENMAX's distribution service territory.

ENMAX POWER CAPITAL ADDITIONS

(Capital additions net of contributions in aid of construction)



ENMAX Power intends to apply for a performance-based regulation (PBR) term for its distribution utility to be effective in 2015. Assuming the AUC approves the application, the distribution rates approved by the AUC in 2014 will be adjusted in subsequent years by a rate of inflation (I Factor) less an offset (X Factor) to reflect the productivity improvements that its distribution utility can be expected to achieve during the PBR plan period. In much the same way as prices in competitive industries are established in a competitive market, prices adjusted by I-X reflect industry-wide conditions that would produce industry price changes in a competitive market. ENMAX Power's actual performance under PBR will depend on how its own performance compares to the industry's inflation and productivity measures.

All electric distribution utilities in Alberta regulated by the AUC are subject to PBR. The AUC has indicated that it is their "expectation that the adoption of a PBR plan will make the regulatory system more efficient over time as the Commission, interveners and companies become more familiar with it. At the same time the Commission expects that, under PBR, customers will experience lower rates than they would have had if the current rate base rate-of-return framework had continued unchanged."

BUSINESS UPDATE

ENMAX Power filed the 2014–2015 Transmission General Tariff Application and 2014 Phase I Distribution Tariff Application with the AUC on July 25, 2013. In this application we sought approval of transmission revenue requirements of $68.3 million and $76.0 million for 2014 and 2015, respectively, and a distribution revenue requirement of $310.9 million for 2014. An oral hearing occurred in July 2014 and we received the AUC decision in the fourth quarter of 2014. We expect to file a subsequent application in 2015 that will contain ENMAX Power's proposal for our new performance-based rates for future years for ENMAX Power's distribution business. ENMAX Power's transmission business will continue earning its revenue requirement approved by the AUC using a traditional a cost of service (COS) rate-making model whereby the AUC will set ENMAX Power's transmission revenue requirement based on ENMAX Power's forecast costs. This regulatory structure for our transmission and distribution tariffs is expected to be similar to other electric utilities in Alberta.

As a result of unanticipated accelerated growth in transmission capital expenditures and capital additions during the formula-based rates (FBR) period (2007–2013), the approved FBR formula for transmission operations did not provide a reasonable opportunity to earn our target ROE. Using certain "re-opener" provisions approved by the AUC in Decision 2009-035, in 2012, ENMAX Power filed an application seeking approval to recover prior years' earnings shortfalls for capital invested in prior periods. ENMAX Power reached a negotiated settlement with intervener groups in December 2014 that was approved by the AUC, and a recovery of $12.4 million was recorded for the year ended 2014.

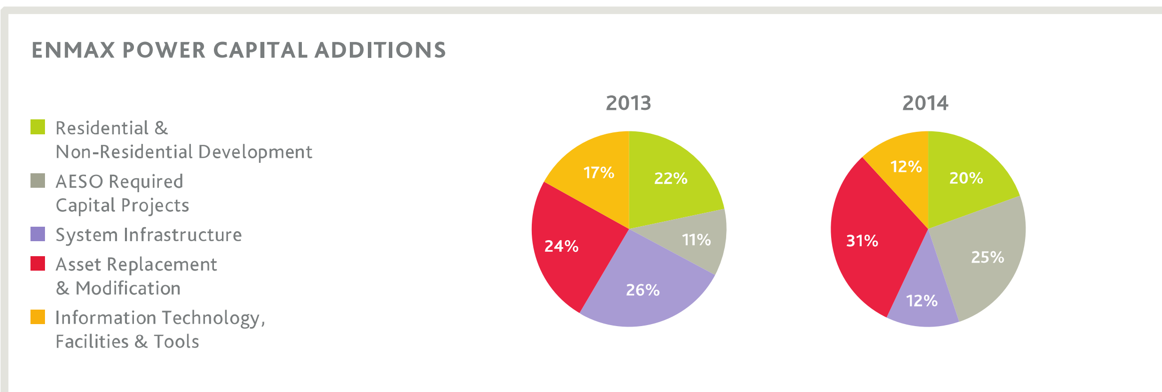
ENMAX Power is currently participating in an AUC-initiated generic proceeding for Alberta return on RRO providers regarding energy price setting plans (EPSPs). The current EPSPs expired June 30, 2014. An oral hearing concluded in October 2014 and further direction was received in March 2015. ENMAX Power will be submitting a compliance filing in the second quarter of 2015. The new plans approved by the AUC in this proceeding will set the methodology for calculating the monthly energy rates to be charged to RRO customers going forward.

ENMAX POWER CAPITAL ADDITIONS

(millions of dollars)

Residential and non-residential development	52.3
AESO required capital projects	68.3
System infrastructure	32.7
Asset replacement & modification	83.6
Information technology, facilities and tools	31.9
Customer contributions	(68.5)
ENMAX Power capital spending	200.3

During the year ended December 31, 2014, we continued to execute our capital plans to meet the increasing need for electricity in Calgary while continuing to offer the same level of reliable service.



In 2014, our underground residential development (URD) group supported construction of 3,960 residential lots in Calgary. In 2013, the URD group supported construction of 2,007 residential lots, which was the lowest number compared to the five previous years. In 2013, construction schedules for developers experienced delays for various reasons related to the 2013 Calgary flood, whereas 2014 benefited from a number of developments deferred from 2013.

KEY BUSINESS STATISTICS	2014	2013
Electricity sold through the RRO (GWh)	**1,584**	1,719
Distribution volumes (GWh)	**9,617**	9,473
Regulated ROE—Distribution [(1)]	**7.7%**	8.0%
Regulated ROE—Transmission [(1)]	**7.8%**	5.9%
Rate base—Distribution [(1)]	**982.6**	900.6
Rate base—Transmission [(1)]	**317.5**	251.7
Local access fees collected on behalf of The City *($ millions)*	**131.3**	129.3

(1) These numbers are based on preliminary information. Rate base is referring to mid-year plant in service including working capital. Regulatory true-ups and adjustments could be required in 2015 related to 2014.

ENMAX Power's regulatory return was determined using the AUC-directed deemed capital structure of 59 per cent debt to 41 per cent equity for the distribution business and 63 per cent debt to 37 per cent equity for the transmission business. ENMAX Power's target ROE as determined by the AUC is 8.75 per cent, and this level of return may either be exceeded or not met based on actual performance by ENMAX Power. We anticipate that we will receive an AUC decision regarding the revised deemed capital structure and allowed ROE for 2013 and 2014 in the first half of 2015.

RRO electricity volumes sold decreased to 1,584 GWh in the year ended December 31, 2014, compared with 1,719 GWh in 2013. The lower demand was seen as a result of a decrease in customers on the RRO.

Total electricity delivered in the Calgary service area for the year was higher than prior periods. Electricity volumes of 9,617 GWh were delivered during the year ended December 31, 2014, compared to 9,473 GWh in 2013. The increase was primarily due to an increase in the number of sites serviced.

Increase in transmission earnings is primarily due to the approval of a higher revenue requirement in the general tariff application, which was approved by the AUC in 2014.

FINANCIAL RESULTS

ENMAX Power's financial results are driven by tariffs approved by the AUC for the regulated transmission, distribution and RRO businesses and by earnings from its competitive power services business. The regulated segment accounted for 85 per cent of ENMAX Power's total revenue in the year ended December 31, 2014, compared with 88 per cent in 2013.

ENMAX Power recorded EBIT of $97.9 million for the year ended December 31, 2014, compared with $81.4 million in the prior year.

EBIT FOR THE YEAR ENDED DECEMBER 31, 2014, COMPARED WITH THE SAME PERIOD IN 2013

(millions of dollars)

EBIT for the year ended December 31, 2013	81.4
Unusual item included in results:	
2013 Flood response	7.0
Increased (decreased) margins attributable to:	
Electricity	(1.3)
Transmission and distribution	32.3
Contractual services and other	1.6
Increased expenses:	
OM&A	(20.0)
Amortization	(3.1)
EBIT for the year ended December 31, 2014	**97.9**

Electricity margins from RRO customers decreased $1.3 million to $22.3 million for the year ended December 31, 2014, compared with $23.6 million in 2013. This decreased margin was primarily the result of a decrease in sales volumes as more customers took advantage of competitive offers.

Transmission and distribution margins consist of amounts charged for wire services net of electrical grid charges and local access fees. Transmission and distribution margins increased $32.3 million to $273.5 million for the year ended December 31, 2014, compared with $241.2 million for the year ended December 31, 2013. The increased margin in the year ended December 31, 2014, is due primarily to an increase in approved rates. In July 2013, ENMAX submitted a COS filing seeking an increase in the transmission tariff for 2014 and 2015. We received AUC's decision on the application in December 2014. In addition to the approved revenue requirement increase, the increased margin in the year ended December 31, 2014, is due primarily to a negotiated settlement decision in the fourth quarter of 2014 approving recovery of earnings on transmission capital invested in prior years. The impact of this decision is an increase in margins of $12.4 million for the year ended December 31, 2014.

For the year ended December 31, 2014, margins for contractual services and other revenues (excluding flood insurance proceeds) increased $1.6 million to $30.8 million compared with $29.2 million last year. The increase in margins for the year ended December 31, 2014, is mainly due to increased activity on commercial developer projects and increased LRT project work.

Normalized OM&A expenses (excluding flood costs) for the year ended December 31, 2014, totalled $172.1 million, compared with $152.1 million in 2013. The increase in OM&A costs for the year ended December 31, 2014, were driven primarily by higher staff costs as a result of annual staff compensation adjustments and additional employees to support the growth of Calgary's electrical system. Additionally, there was increased spending related to maintenance of internal hardware and software within the office.

Amortization for the year ended December 31, 2014, totaled $59.9 million, compared with $56.8 million in 2013. The increase was the net result of amortization related to new assets put into service and was partially offset by a decrease in the asset base from older assets concluding their depreciable lives.

CORPORATE AND INTERSEGMENT ELIMINATIONS

ENMAX Corporate provides billing and customer care services, shared services and financing to ENMAX Power and ENMAX Energy. During the year ended December 31, 2014, EBIT for ENMAX Corporate decreased to $3.1 million, as compared with $6.3 million in the prior year (normalized to exclude impact of intercompany transactions).

SELECTED QUARTERLY FINANCIAL DATA

	2014				2013			
(millions of dollars)	Fourth	Third	Second	First	Fourth	Third	Second[2]	First
Total revenue	**796.0**	**782.4**	767.4	1,002.5	897.1	803.5	872.6	843.4
Operating margin [1]	**195.6**	**179.9**	200.9	177.2	232.4	149.9	128.9	180.6
EBIT [1]	**16.6**	**56.2**	70.2	58.4	101.6	30.1	6.7	66.1
Net earnings	**18.2**	**37.3**	63.6	35.9	88.3	20.7	185.2	58.3

(1) Non-GAAP financial measure. See discussion that follows in the MD&A.

(2) The sale of Envision occurred in the second quarter of 2013, with a gain of $175.9 million recorded in the quarter.

Many variables must be considered regarding the seasonality of revenue, operating margin, EBIT and net earnings. In the fourth quarter of 2014, there were decreases in total revenue, operating margin, EBIT and earnings compared to the fourth quarter of 2013. The decreases were mainly attributable to Kettles impairment loss and decrease in realized electricity and natural gas prices. In the second and third quarters of 2014, operating margin increased due to greater availability of electricity from PPAs compared to 2013 and the impact of rate increases, versus the comparative quarters in the prior year. In the first quarter of 2014, revenues increased as a result of higher natural gas sales due to increased demand and prices. The decreased net earnings during the first quarter reflect the $20.7 million of settlement costs associated with the termination of interest rate swaps. Overall, the majority of the business does not experience extreme cyclical activities that would allow identification of common variations quarter over quarter.

Electricity volumes sold and electricity volumes distributed to industrial and institutional customers are not generally seasonal in nature. While customers can have seasonal requirements, the seasonal requirements of one customer base can be offset by another, resulting in relatively flat demand over the course of a year. Overall volumes are predominantly cyclical on a 24-hour period. In contrast, residential volumes sold and distributed peak in the winter, with a higher demand for heat, resulting in higher revenues during winter months. Volume requirements of commercial customers peak in the summer, with higher demand for air conditioning. This is offset by a lower demand in the residential market during the summer. Over longer periods of time, volumes can fluctuate with general economic activity and population growth. Unusual items and events may have an impact on seasonal expectations.

Natural gas volumes and prices are correlated seasonally as a result of weather patterns. Natural gas consumption and prices will increase with extreme weather typically seen in the winter. As well, natural gas prices can rise in extreme hot weather in the summer as peak electricity demand results in increased natural-gas-fuelled generation. Revenue levels tend to decline in the fall and spring due to unfavourable trends in natural gas prices and volumes during those times of year.

FOURTH QUARTER FINANCIAL RESULTS

EBIT FOR THE THREE MONTHS ENDED DECEMBER 31, 2014 COMPARED WITH THE SAME PERIOD IN 2013

(millions of dollars)

EBIT for the period ended December 31, 2013	101.6
Unusual item included in 2013 results:	
2013 Keephills Unit 1 outage	2.4
2013 Flood response	3.2
Decreased margins attributable to:	
Electricity	(23.0)
Natural gas	(2.6)
Transmission and distribution	(11.0)
Contractual services and other	(3.1)
Decreased (increased) expenses:	
OM&A	(15.7)
Impairment loss	(34.4)
Foreign exchange	1.6
Amortization	(2.4)
EBIT for the period ended December 31, 2014	**16.6**

In the fourth quarter of 2014, net earnings decreased $70.1 to $18.2 million compared with $88.3 million in the same three-month period in 2013. EBIT decreased $85.0 million to $16.6 million from $101.6 million.

In the fourth quarter, normalized electricity margins (electricity margin excluding Keephills outage) were $95.4 million compared with $118.4 million in the same period in 2013. The $23.0 million decrease in margins were driven primarily by lower realized prices on sales, decreased realized gains on hedges and mark-to-market losses on our natural gas positions for 2015 fuel supply to our natural-gas-fuelled plants.

For the three months ended December 31, 2014, natural gas margins decreased $2.6 million to $9.6 million from $12.2 million in the comparable period in 2013. This is mainly attributable to the decrease natural gas realized prices and decrease volume sold in the fourth quarter of 2014, resulting from the warmer weather as compared with the same period in 2013.

For the regulated business, transmission and distribution margins decreased $11.0 million to $73.0 million compared to $84.0 million in the three months ended December 31, 2013. The decreased margin in the three months ended December 31, 2014, is due primarily to lower realized volumes related to system access services versus the same period in 2013.

Contractual services margin and other revenue (contractual services and other revenue margin excluding flood insurance proceeds) was $14.3 million in the fourth quarter of 2014 as compared with $17.4 million in the fourth quarter of 2013. The decrease is mainly attributable to increased warranty expenses as several projects progressed to final stages of completion.

Normalized OM&A costs (OM&A costs excluding flood costs) increased $15.7 million to $103.7 million in the fourth quarter of 2014, compared with the costs of $88.0 million incurred in the fourth quarter of 2013. This increase was a combination of increase in staff costs, computer-systems-related costs, and costs related to billing, collection and provisions on receivables.

Impairment loss for the year ended December 31, 2014, was $34.4 million as compared to nil in 2014. Kettles was tested for impairment, resulting in PPE, intangible assets and goodwill being impaired.

For the three months ended December 31, 2014, a net foreign exchange gain of $5.2 million was experienced as compared to a gain of $3.6 million in the same period of 2013. This was due primarily to gains on the foreign exchange positions related to the long-term service agreements (LTSAs).

Amortization costs increased $2.4 million to $46.1 million in the three months ended December 31, 2014, compared with $43.7 million in the same period in 2013. The increase was due to an increase in net capital additions during the year and acquisition of two generating facilities in September 2014.

Interest costs amounted to $7.7 million in the fourth quarter of 2014 compared with $7.0 million in the same period in 2013. The slight increase in interest costs is due to acquiring new debt offset by the repayment of the CEC debt in March 2014.

For the three months ended December 31, 2014, income tax expenses decreased to a recovery of $9.3 million compared with an expense of $6.3 million in the same period in 2013. The decrease was mainly due to lower income in taxable entities.

The following table outlines investments in capital additions during the fourth quarter of 2014.

CAPITAL ADDITIONS

(millions of dollars)	
Transmission and distribution networks	58.0
Generation projects	45.1
Other	6.7
Capital additions	109.8

In the fourth quarter, the Corporation made $24.0 million of regularly scheduled repayments on its long-term debt. In addition, the final $15.0 million dividend installment was paid to The City, which resulted in payment in full of the 2014 declared dividend of $60.0 million.

NON-GAAP FINANCIAL MEASURES

We provide non-GAAP financial measures in the MD&A. These measures do not have any standard meaning prescribed by GAAP and may not be comparable to similar measures presented by other companies. The purpose of these financial measures and their reconciliation to GAAP financial measures are shown below. These non-GAAP measures are consistent with the measures used in the previous year.

OPERATING MARGIN

Year ended December 31 *(millions of dollars)*	2014	2013
Electricity margins	**403.5**	479.1
Natural gas margins	**33.6**	33.6
Transmission and distribution margins	**273.5**	241.2
Contractual services margins (1) and other revenue	**57.1**	64.5
Operating margin (non-GAAP financial measure), excluding unusual items	**767.7**	818.4
Deduct:		
Unusual item: 2014 Keephills Unit 2 outage	**17.4**	-
Unusual item: 2013 Keephills Unit 1 outage	**-**	127.5
Unusual item: 2013 Flood response	**(3.3)**	3.8
OM&A, impairment loss, foreign exchange, amortization, interest and income taxes	**598.6**	513.7
Net earnings from continuing operations (GAAP financial measure)	**155.0**	173.4

(1) Contractual services margins include earnings from distributed generation; meter reading and data management services for non-Calgary municipalities; water meter reading; pole and duct rentals; service locates; streetlight repairs; LRT monitoring; mapping record management; engineering, procurement, construction and maintenance services; utility trenching; construction and maintenance of LRT systems; self-retailing services; and billing services.

Operating margin is a useful measure of business performance, as changes in the market price of electricity and natural gas purchased for resale affect revenue and cost of sales equally. ENMAX Energy's strategy links the cost of supply to longer-term demand contracts, which results in relatively stable margins even during times of volatile wholesale prices and revenue levels. Therefore, operating margins better reflect profitability than revenue levels alone.

COMPARABLE NET EARNINGS

Year ended December 31 *(millions of dollars)*	2014	2013
Comparable net earnings	**184.8**	173.4
Adjustments:		
Impairment	**(34.4)**	-
Tax recoveries related to impairment	**4.6**	-
Gain on sale of subsidiary	**-**	175.9
Net earnings from discontinued operations, net of tax	**-**	3.2
Net earnings (GAAP financial measure)	**155.0**	352.5

Comparable net earnings is a useful measure to provide comparability between years for transactions that are not deemed to be representative of performance during the year such as impairment losses and gain or loss on disposal of assets.

ADJUSTED EBITDA

Year ended December 31 *(millions of dollars)*	2014	2013
Adjusted EBITDA (non-GAAP financial measure)	410.0	377.7
Deduct:		
Impairment loss	34.4	-
EBITDA from discontinued operations	-	5.1
Standardized EBITDA (non-GAAP financial measure)	375.6	372.6
Deduct:		
Amortization	174.2	168.1
Interest	44.3	33.1
Income tax expense (recovery)	2.1	(2.0)
Net earnings from continuing operations (GAAP financial measure)	155.0	173.4

EBITDA is a useful measure of business performance, as it provides an indication of the cash flow results generated by primary business activities without consideration as to how those activities are financed and amortized, or how the results are taxed in various business jurisdictions. EBITDA is also used to evaluate certain debt coverage ratios. Adjusted EBITDA is a measure to improve comparability between years for transactions that are not deemed to be representative of performance during the year such as impairment losses and EBITDA from discontinued operations.

EBIT

Year ended December 31 *(millions of dollars)*	2014	2013
EBIT (non-GAAP financial measure)	201.4	204.5
Deduct:		
Interest	44.3	33.1
Income tax expense (recovery)	2.1	(2.0)
Net earnings from continuing operations (GAAP financial measure)	155.0	173.4

EBIT is a useful measure of business performance, as it provides an indication of the operating results generated by primary business activities, including the costs of amortization. It does not consider how those activities are financed or how the results are taxed in various business jurisdictions.

FUNDS FROM OPERATIONS

Year ended December 31 *(millions of dollars)*	2014	2013
Funds from operations (non-GAAP financial measure)	386.0	359.7
Changes in non-cash working capital	47.1	(136.2)
Employee future benefits	1.2	(4.7)
Cash flow from continuing operations	434.3	218.8
Cash flow from assets held for sale	-	(14.1)
Cash provided by operating activities (GAAP financial measure)	434.3	204.7

Funds from operations are used as an additional metric of cash flow without regard to changes in our non-cash working capital.

TOTAL INTEREST COST

Year ended December 31 *(millions of dollars)*	2014	2013
Total interest cost (non-GAAP financial measure)	67.2	88.8
Capitalized interest	(49.4)	(57.9)
Other non-interest financing costs	5.8	4.1
Interest expense, excluding swaps settlement	23.6	35.0
Interest rate swaps settlement	20.7	-
Ineffective portion of interest rate swaps	-	(1.9)
Interest expense (GAAP financial measure)	44.3	33.1

Total interest cost is used in determining interest coverage ratios.

FINANCIAL CONDITION

SIGNIFICANT CHANGES IN THE CORPORATION'S FINANCIAL CONDITION

(millions of dollars, except % change)	December 31, 2014	December 31, 2013	$ Change	% Change	Explanation for Change
ASSETS					
Cash and cash equivalents	16.7	80.6	(63.9)	(79%)	Refer to Liquidity and Capital Resources Section.
Accounts receivable	606.5	665.5	(59.0)	(9%)	Decrease due to timing of receipts, decreased electricity sales prices and collection of AUC decisions in rates.
PPE	3,483.7	3,022.6	461.1	15%	Acquisition of an interest in two natural-gas-fuelled facilities, capital expenditures, net of retirements, dispositions, amortization and impairments.
PPAs	316.7	369.5	(52.8)	(14%)	Amortization of PPAs.
Goodwill	-	16.0	(16.0)	(100%)	Kettles was assessed for impairment resulting in goodwill being impaired in Q4 2014.
LIABILITIES AND SHAREHOLDER'S EQUITY					
Other assets/liabilities [(1)] [(2)]	48.5	13.9	34.6	249%	Fair value of hedging instruments and settlement of interest rate swap.
Long-term debt [(2)]	1,610.3	1,439.0	171.3	12%	Acquisition of $232.1 million of Alberta Capital Finance Authority (ACFA) debt and $200.0 million Series 3 private debenture partially offset by repayment of $200.6 million of non-recourse financing and regular principal repayments.

(1) Net asset and liability positions.

(2) Includes current and long-term amounts.

LIQUIDITY AND CAPITAL RESOURCES

SHARE CAPITAL

As at December 31, 2014 and 2013 (millions of dollars, except share amounts)	Number of Shares	Amount
Authorized:		
Unlimited number of common shares		
Issued and outstanding:		
Issued on incorporation (one dollar)	1	–
Issued on transfer of net assets from Calgary Electric System (CES)	1	278.2
Issued on transfer of billing and customer care assets from The City in 2001	1	1.9
	3	**280.1**

CAPITALIZATION

As at December 31 (millions of dollars)	2014	2013
Long-term debt (1)	**1,610.3**	1,439.0
Shareholder's equity		
Share capital	**280.1**	280.1
Retained earnings	**2,281.4**	2,186.4
Accumulated other comprehensive loss	**(33.8)**	(6.3)
Total shareholder's equity	**2,527.7**	2,460.2
Total capitalization (long-term debt plus shareholder's equity)	**4,138.0**	3,899.2

(1) Includes the current portion of long-term debt of $62.6 million (December 31, 2013—$63.7 million). Maturity dates range from May 2015 to June 2039.

TOTAL LIQUIDITY AND CAPITAL RESERVES

As at December 31 (millions of dollars)	2014	2013
Committed and available bank credit facilities	**1,150.0**	1,150.0
Letters of credit issued:		
Power pool purchases	**65.3**	85.2
Energy trading	**37.5**	34.5
Regulatory commitments	**87.5**	105.9
Asset commitments	**2.0**	3.1
PPAs	**56.7**	75.2
	249.0	303.9
Overdraft facilities	**27.3**	-
Remaining available bank facilities	**873.7**	846.1
Cash on hand	**16.7**	80.6
Total liquidity and capital reserves	**890.4**	926.7

The decrease in total liquidity and capital reserves for the year ended December 31, 2014, is attributed primarily to a decrease in cash on hand and increase in overdraft facilities, largely driven by increased investing activities in 2014. This cash-on-hand decrease and short-term financing increase is partially offset by the impact of the decrease in PPAs subsequent to Battle River Units 3 and 4 capacity ownership reverting back to ATCO Power on January 1, 2014. Further offset to the decrease in total liquidity and capital reserves is lower regulatory commitments due to timing of recoveries from rate payers.

LONG-TERM DEBT

As at December 31 *(millions of dollars)*	2014	2013
Long-term debt [(1)] consisting of:		
Alberta Capital Finance Authority (ACFA) debentures, with remaining terms of:		
Less than 5 years	**63.2**	34.0
6–10 years	**85.8**	122.4
11–15 years	**21.8**	14.4
16–20 years	**269.7**	187.1
21–25 years	**648.3**	557.6
Private debentures		
Series 1, remaining term of 3.5 years, bullet maturity on June 19, 2018	**298.5**	298.2
Series 3, remaining term of 10.0 years, bullet maturity on December 5, 2024	**198.5**	-
Non-recourse term financing, with remaining term of 2.0 years	**19.9**	220.5
Promissory note, remaining term of 12.0 years	**4.6**	4.8
	1,610.3	1,439.0

(1) Includes current portion of long-term debt of $62.6 million (December 31, 2013— $63.7 million). Maturity dates range from May 2015 to June 2039.

CONTRACTUAL OBLIGATIONS THAT MAY IMPACT THE CORPORATION'S FINANCIAL CONDITION

As at December 31, 2014 *(millions of dollars)*	Total	Less than 1 year	1–3 years	4–5 years	After 5 years
Total debt [(1)]	1,610.3	62.6	133.0	411.1	1,003.6
Operating leases	57.4	9.7	19.3	7.6	20.8
Purchase obligations [(2)]	64.2	30.5	16.6	8.9	8.2
Asset retirement obligations	20.1	-	-	-	20.1
Other long-term obligations [(3)]	30.0	-	16.8	6.2	7.0
Total contractual obligations	**1,782.0**	**102.8**	**185.7**	**433.8**	**1,059.7**

(1) Total debt includes short-term debt and excludes interest payments.

(2) Purchase obligations means an agreement to purchase goods or services that is enforceable and legally binding on ENMAX that specifies all significant terms, including fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transaction.

(3) Other long-term obligations means other long-term liabilities reflected on the Corporation's balance sheet.

CAPITAL STRATEGY

CREDIT METRICS

As at December 31	2014	2013
Long-term debt to total capitalization (1)	38.6%	35.3%
Debt to EBITDA (2)	3.9X	2.6X
EBITDA to total interest (3)	6.0X	6.1X

(1) As at year end, long-term debt (including current portion) to total capitalization is equal to long-term debt divided by total long-term debt plus shareholder's equity. If cash were netted against the debt, the ratio as at December 31, 2014, would be 38.2 per cent (December 31, 2013 — 33.3 per cent).

(2) Debt to EBITDA is equal to long-term debt (including current portion) divided by EBITDA for the year. If cash were netted against the debt, the ratio as at December 31, 2014, would be 3.9X (December 31, 2013 — 2.5X).

(3) EBITDA to total interest is equal to EBITDA for the year divided by total interest cost (non-GAAP financial measures) calculated for the year.

The business is funded with a view to maintaining a conservative capital structure in line with our strategy of maintaining a stable, investment grade credit rating. We have set long-term target ratios for long-term debt to total capitalization at a maximum of 45 per cent, a debt to EBITDA ratio at a maximum of 3.5 times and an EBITDA to total interest coverage ratio at 5 times or better. Very low electricity prices, asset outages and high capital expenditures associated with significant construction projects or other factors could result in targets not being reached for short periods of time. Targets are managed using a long-term view and are set at more conservative levels than actual debt covenants. Standard & Poor's has assigned ENMAX a BBB+ rating with a stable outlook. Dominion Bond Rating Services has assigned a credit rating of A (low). These ratings provide reasonable access to debt capital markets.

The principal financial covenant in our credit facilities is debt to capitalization. As at December 31, 2014, we are non-compliant with financial covenants for Kettles related to non-recourse financing classified as long-term debt on the balance sheet. The carrying amount of the debt as at December 31, 2014, is $19.9 million.

CASH PROVIDED BY OPERATING ACTIVITIES

Funds from operations for the year ended December 31, 2014, were $386.0 million, compared with $359.7 million in 2013. For the year ended December 31, 2014, the increased funds generated year-over-year were primarily due to higher cash generating earnings from continuing operations, recovery of future income taxes as compared with an expense in prior year and a positive change in the unrealized market value of financial contracts due to settlement of interest rate swaps.

Cash provided by operating activities for the year ended December 31, 2014, was $434.3 million compared to $204.7 million in 2013. The increase in the year ended December 31, 2014, was driven by the decrease of accounts receivable (which was lower due to timing of payments and collection of AUC decision rates) and higher cash generating earnings from continuing operations in 2014. The increase was also attributable to the significant decrease in accounts payable in the prior year resulting in a negative change in non-cash working capital.

INVESTING ACTIVITIES

The following table outlines investment in capital additions for the year ended December 31, 2014.

CAPITAL ADDITIONS

(millions of dollars)	
Transmission and distribution networks	200.3
Generation projects	166.7
Generating assets [(1)]	225.1
Other	24.1
Capital additions	616.2

(1) On September 16, 2014, we acquired two natural-gas-fuelled generating facilities: Cavalier in the amount of $169.2 million and Balzac in the amount of $55.9 million.

Continued investment in information technology will allow ENMAX to comply with regulations and effectively operate the business in line with the Corporation's strategy to maintain the reliability and cost effectiveness of its technology infrastructure while meeting the challenges of obsolescence and growth.

FINANCING ACTIVITIES

We made regularly scheduled long-term debt principal payments of $58.8 million during the year ended December 31, 2014, compared with $61.1 million in 2013.

At December 31, 2014, cash and cash equivalents amounted to $16.7 million compared with $80.6 million at December 31, 2013. At December 31, 2014, there was nil in commercial paper, consistent with outstanding commercial paper at December 31, 2013, and $27.3 million of overdraft on bank accounts compared with no overdrafts on bank accounts at December 31, 2013.

On March 5, 2014, a dividend of $60.0 million was declared payable to The City in quarterly installments throughout 2014. All quarterly installments of this dividend were paid by the end of 2014. On March 19, 2015, a dividend of $56.0 million was declared payable to The City in four quarterly installments. We have historically paid The City annual dividends of at least the higher of 30 per cent of the prior year's net earnings or $30 million. Dividends for a fiscal year are established in the first quarter of the same fiscal year. The payment and level of future dividends on the common shares will be affected by such factors as financial performance and liquidity requirements.

On March 17, 2014, we repaid $200.6 million of non-recourse term financing and $35.6 million of a fixed-for-floating interest rate swap related to CEC prior to maturity in September 2026. In addition, we settled back-to-back swaps that were initially executed as a hedging relationship in relation to the fixed-for-floating swap. Settlement costs of $20.7 million associated with the termination of the interest rate swaps were recorded as interest expense.

On June 15, 2014, we obtained $232.1 million of 5, 10, 20 and 25 year debentures from The City through arrangements with the ACFA (2013 – $140.6 million 5, 10, 20 and 25 year debentures) to fund ongoing investment relating to regulated transmission and distribution assets in the Calgary service area.

On July 11, 2014, our unsecured credit facilities were amended. The total unsecured credit facilities remain at $1,150.0 million, with $900.0 million in bilateral credit facilities and $250.0 million of syndicated credit facilities. The letter of credit tranches were increased from $300.0 million to $375.0 million capacity and extended by one year to July 20, 2017. Additionally, the $775.0 million operating tranches were extended by two years to July 20, 2019.

On December 5, 2014, we acquired $200.0 million of Series 3 Debentures to assist with general purpose corporate financing. The $200.0 million of Series 3 Debentures is for a 10-year term with an effective coupon rate of 3.805 per cent.

On March 12, 2015, our unsecured credit facilities were further amended. The total unsecured credit facilities were reduced by $300.0 million to $850.0 million, with $600.0 million in bilateral credit facilities and $250.0 million of syndicated credit facilities. The letter of credit tranches now amount to $300.0 million of the capacity with no change to the July 20, 2017 expiry and the operating tranches expiring on July 20, 2019 now stand at $550.0 million.

FUTURE ACCOUNTING CHANGES

IFRS

On February 13, 2008, the Accounting Standard Board of Canada (AcSB) confirmed the changeover to International Financial Reporting Standards (IFRS). The AcSB has issued amendments to this directive that allowed entities subject to rate regulation to delay adoption of IFRS until January 1, 2015. ENMAX adopted IFRS on January 1, 2015, and will commence reporting on this basis in the first quarter of 2015 with comparative prior year data restated to IFRS. The term GAAP in this report refers to GAAP prior to adoption of IFRS. IFRS uses a conceptual framework similar to GAAP but there are differences in recognition, measurement and disclosures.

With the initial decision to adopt IFRS in Canada, we executed on a conversion plan for the Corporation and have since maintained a state of readiness. Ongoing work includes:

- assessing the impact of recently issued, but not yet effective, IFRS standards on processes and systems;
- monitoring system solutions;
- evaluating the impact of IFRS changes on disclosure controls and Internal Controls over Financial Reporting (ICFR);
- enhancing internal IFRS training; and
- working with users of our financial statements to explain the changes in our accounting policies and financial results arising from IFRS.

IFRS 1 also requires that comparative financial information be provided. As a result, the first date at which the Corporation began applying IFRS was January 1, 2014 (the "transition date"). IFRS 1 requires that a first-time adopter use the same accounting policies in its opening IFRS statement of financial position and for all subsequent periods presented in its first IFRS financial statements. The adoption of IFRS includes full retrospective application of all IFRS standards which are effective at the end of its first IFRS reporting period, which will be December 31, 2015. In order to facilitate an effective adoption of IFRS, there are a number of discretionary exemptions as well as mandatory exceptions from retrospective application of a number of IFRS standards.

A. MANDATORY EXCEPTIONS TO RETROSPECTIVE APPLICATION

The mandatory exceptions applied from full retrospective application of IFRS are described below.

I. HEDGE ACCOUNTING

In accordance with IFRS 1, an entity shall not reflect in its opening IFRS statement of financial position a hedging relationship of a type that does not qualify for hedge accounting in accordance with IAS 39

Financial Instruments: Recognition and Measurement. If, before the date of transition to IFRS, an entity had designated a transaction as a hedge but the hedge does not meet the conditions for hedge accounting in IAS 39, the entity shall discontinue hedge accounting. This exception did not result in any changes for the Corporation.

II. ESTIMATES

In accordance with IFRS 1, an entity's estimates under IFRS at the date of transition to IFRS must be consistent with estimates made for the same date under previous GAAP, unless there is objective evidence that those estimates were in error. The Corporation's IFRS estimates as of January 1, 2014, were consistent with its GAAP estimates for the same date, except to reflect any difference in accounting policies.

III. DERECOGNITION OF FINANCIAL INSTRUMENTS

In accordance with IFRS 1, a first-time adopter shall apply the requirements within IAS 39 prospectively from the transition date unless it chooses to apply the derecognition guidance retrospectively from a date of its election. The Corporation has elected to apply derecognition of financial instruments prospectively from January 1, 2014, the date of transition. Based on the election, there were no significant adjustments required as a result of derecognition.

B. ELECTED EXEMPTIONS FROM FULL RETROSPECTIVE APPLICATION

I. BUSINESS COMBINATIONS

The Corporation has applied the business combinations exemption in IFRS 1 to not apply IFRS 3 *Business Combinations* retrospectively to past business combinations. Accordingly, the Corporation has not restated business combinations that took place prior to the transition date.

II. DEEMED COSTS

At the date of transition to IFRS, the Corporation has elected to measure the $1,534.6 million in rate-regulated PPE and $20.1 million in rate-regulated intangible assets as deemed cost. The carrying amount under GAAP included the effects of rate-regulation as permitted under GAAP.

III. TRANSFER OF ASSETS FROM CUSTOMERS

At transition to IFRS, the Corporation has elected to apply transitional provisions as outlined in IFRIC 18 – *Transfers of assets from customers.* The Corporation has recognized the balance of contributions in aid of construction as deferred revenue and amortized into income on a systematic basis. Under GAAP, contributions in aid of construction were netted against the cost of PPE.

IV. LEASES

IFRIC 1 allows an exemption from applying IFRIC 4 – *Determining whether an arrangement contains a lease* at the date of transition to IFRS if the same determination was made at a previous date in accordance with another GAAP. The Corporation has elected to apply this exemption not to reassess historical leases already assessed under GAAP.

V. DECOMMISSIONING LIABILITIES

IFRS 1 provides a first-time adopter with a simplified approach to calculate the cost of PPE associated with decommissioning an asset at the transition date. The decommissioning liability must be calculated as follows:

• the liability must be measured in accordance with IAS 37 *Provisions, Contingent Liability and Contingent Assets* at transition;

• estimate the amount that would have been included in the cost of the asset when the liability first arose by discounting the liability to that date using its best estimate of historical risk-adjusted discount rates; and

• calculate the accumulated amortization on that amount, as at the transition date to IFRS.

The Corporation has elected to calculate the decommissioning liability and associated cost of PPE as of January 1, 2014, using the approach described above.

C. RECONCILIATION OF CONSOLIDATED BALANCE SHEET AT JANUARY 1, 2014, THE DATE OF TRANSITION FROM GAAP TO IFRS

January 1, 2014 (millions of dollars)		GAAP	Measurement Adjustments	Reclassification Adjustments	IFRS
ASSETS					
Cash and cash equivalents		80.6	-	-	80.6
Accounts receivable	(4)	665.5	-	(81.9)	583.6
Income taxes receivable		96.9	-	-	96.9
Deferred income tax asset	(1)	8.7	-	(8.7)	-
Current portion of financial assets	(2)	-	(3.0)	29.6	26.6
Other current assets	(2)	42.6	0.4	(29.6)	13.4
		894.3	(2.6)	(90.6)	801.1
Property, plant and equipment	(a)(c)(d)(g)(5)	3,022.6	(18.6)	334.7	3,338.7
Power purchase arrangements	(d)(e)	369.5	(94.4)	-	275.1
Intangible assets	(f)	124.3	(9.1)	-	115.2
Goodwill	(d)	16.0	(16.0)	-	-
Employee future benefits	(b)	22.8	(22.8)	-	-
Deferred Income tax assets	(a)(c)(d)(e)(g)(h)(1)	59.0	18.6	7.0	84.6
Financial assets	(h)(2)	-	(2.1)	26.4	24.3
Other long-term assets	(2)(4)	57.0	-	(28.2)	28.8
TOTAL ASSETS		4,565.5	(147.0)	249.3	4,667.8
REGULATORY DEFERRAL ACCOUNT DEBIT BALANCES	(4)	-	-	83.7	83.7
TOTAL ASSETS AND REGULATORY DEFERRAL ACCOUNT DEBIT BALANCES		4,565.5	(147.0)	333.0	4,751.5
LIABILITIES					
Accounts payable and accrued liabilities	(4)	436.8	-	(1.9)	434.9
Deferred income tax liabilities	(1)	0.5	-	(0.5)	-
Current portion of long-term debt		63.7	-	-	63.7
Current portion of financial liabilities	(3)	-	-	29.0	29.0
Other current liabilities	(g)(3)	52.8	5.1	(29.0)	28.9
		553.8	5.1	(2.4)	556.5
Long-term debt		1,375.3	-	-	1,375.3
Deferred income tax liabilities	(a)(c)(1)	100.1	(15.8)	(1.2)	83.1
Post-employment benefits	(b)	-	43.2	-	43.2
Financial liabilities	(3)	-	-	47.9	47.9
Deferred revenue	(5)	-	-	334.7	334.7
Other liabilities	(g)(3)	60.7	23.6	(47.9)	36.4
Asset retirement obligations	(g)	15.4	34.5	-	49.9
TOTAL LIABILITIES		2,105.3	90.6	331.1	2,527.0
REGULATORY DEFERRAL ACCOUNT CREDIT BALANCES	(4)	-	-	1.9	1.9
SHAREHOLDER'S EQUITY					
Share capital		280.1	-	-	280.1
Retained earnings	(a) to (g)	2,186.4	(236.5)	-	1,949.9
Accumulated other comprehensive income (loss)	(h)	(6.3)	(1.1)	-	(7.4)
		2,460.2	(237.6)	-	2,222.6
TOTAL LIABILITIES, REGULATORY DEFERRAL ACCOUNT CREDIT BALANCES AND SHAREHOLDER'S EQUITY		4,565.5	(147.0)	333.0	4,751.5

EXPLANATION OF THE PRELIMINARY MEASUREMENT ADJUSTMENTS IN THE TABLE ABOVE

a. PPE

(i) PPE (Major overhaul and inspection costs)

Under GAAP, major overhauls and inspection costs were treated as maintenance expense in the period the costs are incurred. IFRS specifically requires that major overhauls and inspections, required at regular intervals to restore the condition of a fixed asset to continue to operate, be capitalized as a separate component and depreciated over the period to the next scheduled major inspection or overhaul.

On transition, historical major overhauls and inspection costs were capitalized, resulting in prepaids increase of $0.4 million and carrying value of PPE increase of $1.5 million, offset by a tax impact of $0.4 million. The net increase to opening retained earnings was $1.5 million on transition date.

(ii) PPE (Derecognition)

GAAP does not specifically require the carrying amount of parts which are replaced to be derecognized. IFRS specifically requires derecognition of the replaced parts regardless of whether the replaced parts have been depreciated separately.

On transition, the carrying amount of replaced parts totaling $7.3 million were derecognized. The tax impact of this adjustment was $1.8 million, resulting in a net decrease in retained earnings of $5.5 million.

(iii) PPE (Pre-operating costs)

GAAP allows incidental revenues and costs to be included in the costs of the assets being built. IFRS requires the income and related expenses of incidental operations, which are not necessary to bring an item to the location and condition necessary for it to be capable of operating in the manner intended by management, to be recognized in profit or loss.

On transition, net incidental revenues previously capitalized to a project were credited to retained earnings, resulting in net increase in PPE of $1.7 million. The tax impact of this adjustment was $0.4 million resulting in a net increase in retained earnings of $1.3 million.

b. POST-RETIREMENT BENEFITS

Under GAAP, the corridor approach allows the deferral of actuarial remeasurement gains and losses to be amortized over the expected average remaining service period of active employees. IFRS does not allow the corridor approach and all actuarial remeasurement gains and losses are immediately recognized to other comprehensive income.

On transition, $66.0 million of unamortized actuarial losses were charged to retained earnings. Since ENMAX's pension plan is held in a tax-exempt entity, there was no tax effect on this adjustment.

c. BUSINESS COMBINATIONS

Under GAAP, business combinations entered into prior to January 1, 2011, were measured at their fair value at the date of acquisition with any excess of the purchase price over the fair value of the net assets acquired recognized as goodwill. Any deficiency of the purchase price below the fair value of the net assets acquired was recorded as negative goodwill in the period of acquisition, as a reduction to PPE. Under IFRS, any excess of the purchase price over the fair value of the net assets acquired is recognized as goodwill while any deficiency of the purchase price below the fair value of the net assets acquired is recorded as a gain in the period of acquisition.

On transition date, PPE increased by $170.5 million and accumulated amortization of $28.9 million were recognized in the carrying value of PPE. The adjustment resulted in a tax impact of $36.3 million; retained earnings increased by $105.3 million on transition date. Subsequent to the negative goodwill reversal, an impairment charge was determined on the assets (see note d).

d. IMPAIRMENT TESTING

Under GAAP, the impairment test for, PPE generally involved two steps. Under step one, the asset's carrying value is compared with undiscounted future cash flows to determine if an impairment exists. If an impairment exists, step two requires the impairment amount to be determined by comparing the asset's carrying value with the discounted future cash flows. Impairment charges could not be reversed under GAAP. Under IFRS, the impairment test is a one-step process in which the carrying value of a cash generating unit (CGU) is compared to its recoverable amount. The recoverable amount is the greater of i) fair value less cost of disposal and ii) value in use. Value in use is calculated by discounting future cash flows. Impairment charges related to PPE may be reversed if circumstances change. Impairments related to goodwill cannot be reversed.

On transition, the Corporation tested certain PPE with impairment indicators and goodwill for impairment. For the purpose of impairment testing, goodwill was allocated to the Kettles CGU which represents the lowest level within the Corporation at which the goodwill is monitored for internal management purposes.

The recoverable amount for the Corporation's CGUs was determined based on a value in use calculation, with the exception of the District Energy, Kettles and Bonnybrook Energy Centre CGUs, which were determined based on a fair value less costs of disposal calculation. Value in use was calculated by discounting future cash flow projections that are based on the Corporation's internal budget. In arriving at its forecasts, management considered past experience, economic trends such as inflation and industry and market trends. In determining fair value less costs of disposal, recent market transactions were taken into account and if these were not available, then a valuation model was used.

The discount rate used in the calculation of value in use represented a pre-tax weighted average cost of capital (WACC). The WACC is an estimate of the overall required rate of return and serves as the basis for developing an appropriate discount rate.

PPE was impaired by $176.1 million, PPA was impaired by $3.4 million and goodwill was impaired by $16.0 million as of January 1, 2014. The reduction to PPE, PPA and goodwill has a tax impact of $38.0 million, net opening retained earnings decreased by $157.5 million. As required by IFRS, the impairment was charged first to reduce any goodwill and then pro-rata to remaining assets of that CGU. The following table illustrates the impairment to goodwill and PPE by CGU as of January 1, 2014. The discount rates used to calculate value in use ranged between 6.62% and 8.72%.

Cash generating unit	Impairment to goodwill	Impairment to PPE or PPA	Total impairment
(millions of dollars)			
Kettles	16.0	-	16.0
Battle River	-	3.4	3.4
CEC	-	95.8	95.8
District Energy	-	27.6	27.6
Bonnybrook	-	52.7	52.7
Total	**16.0**	**179.5**	**195.5**

e. PPA AMORTIZATION

Under GAAP, PPA are amortized on a straight line basis over the contract term. Under IFRS, PPA can be amortized over a shorter term based on the expected use of the assets.

On transition, accumulated amortization increased by $91.0 million with a tax impact of $22.7 million. The net decrease to retained earnings was $68.3 million.

f. WEBSITE

Under GAAP, if upgrades and enhancements of a website meet the definition of betterment (i.e., enhance the service potential of an intangible asset), those costs could be capitalized. Under IFRS, only website development costs which can be demonstrated to generate probable future economic benefits (generating revenues) can be recognized as intangibles. A website that is developed solely to promote or advertise an entity's products or services would not meet the condition for recognition.

On transition, $9.1 million of website development costs included in intangibles were charged to retained earnings with no tax impact, as the intangibles are held in a tax-exempt entity.

g. PROVISIONS

(i) Provisions (Asset retirement obligation)

Under GAAP, asset retirement obligations (ARO) are calculated by estimating the future cash outflows and discounting them using a credit adjusted risk-free rate. Changes in the net present value of the future retirement obligation were included as accretion expense. Under IFRS, asset retirement obligations are calculated using risk-adjusted future cash flows discounted using the risk-free rate at each reporting period. Changes in the net present value of the future retirement obligations are included in finance expenses.

On transition, ARO assets of $20.0 million have been recognized in the carrying value of PPE. The ARO liability increased by $34.5 million. The tax impact of this adjustment is $3.6 million, resulting in a net decrease of $10.9 million to opening retained earnings on transition.

(ii) Provisions (Constructive obligation)

Under GAAP, constructive obligations are recognized only if required by a specific standard. Under IFRS, a provision is recognized as constructive obligation if there is a probable outflow of resources and the amount can be estimated reliably.

On transition, the Corporation recognized constructive obligation related to the expected cost of profit-sharing and bonus payments. Bonus liability increased by $8.7 million with no deferred tax impact.

(iii) Provisions (Onerous contracts obligation)

Under GAAP, a provision for an onerous contract is recognized only when required by a specific standard. Under IFRS, a provision is recognized for an onerous contract when the costs of meeting the obligations under the contract exceed the benefits to be derived.

On transition, the Corporation recognized $20.0 million of onerous liability for certain contracts related to an impaired CGU. The tax impact related to this adjustment was $5.0 million, resulting in a net decrease in retained earnings of $15.0 million.

h. FINANCIAL INSTRUMENTS

GAAP requires an entity to document its basis for concluding that a contract is for the receipt or delivery of a non-financial item in accordance with its expected purchase, sale and usage requirements. Under IFRS, the documentation requirement does not exist.

On transition, ENMAX was able to reverse one of its contracts which was treated as mark-to-market through OCI. This contract is for the physical delivery of electricity to a retail customer and meets the requirements of "own use" under IFRS. The adjustment on transition is a decrease to long-term financial assets of $1.5 million. In addition, a $0.4 million decrease of deferred income tax liability and a decrease of $1.1 million of AOCI is recognized on transition.

EXPLANATION OF THE PRELIMINARY RECLASSIFICATION ADJUSTMENTS IN THE TABLE ABOVE

1. Reclassification adjustment (1) reclassifies the current portion of deferred income tax asset (liability) from current to long-term in accordance with IAS 1 *Presentation of Financial Statements*.
2. IAS 1 requires the statement of financial position to include separate line item for financial assets that are included in other current assets and other assets under GAAP.
3. IAS 1 requires the statement of financial position to include separate line item for financial liabilities that are included in other current liabilities and other liabilities under GAAP.
4. IFRS 14 requires separate disclosure in the statement of financial position for (a) the total of all regulatory deferral account debit balances and (b) the total of all regulatory deferral account credit balances.
5. IFRIC 18 requires contributions from customers for PPE be classified as deferred revenues, versus netted against property, PPE under previous GAAP.

Significant ongoing impacts of IFRS are expected as follows:

Area	**Income Statement and Statement of Financial Position Impact**	**Cash Flow Statement Impact**	**Other Differences**
Impairment	Transition impairment reserves will reduce future amortization. Impairment reserves and reversals will create earnings volatility.	No impact on cash flow.	Additional disclosures are required. Tests for indicators of impairment will occur more frequently.
Rate regulated assets and liabilities	The impact of regulatory balances is separately presented on both the balance sheet and the income statement.	No impact on cash flow.	Segment disclosure will include a reconciliation to reflect the impact of IFRS requirement of segregating rate regulated activities.
Employee benefits (Pension)	Actuarial gains and losses are recognized immediately in other comprehensive income.	No impact on cash flow.	Additional disclosures are required.
Intangibles and PPAs	Transition adjustments will decrease amortization charges into the future.	No impact on cash flow.	Additional disclosures are required.

CRITICAL ACCOUNTING ESTIMATES

Since a determination of the value of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of the Corporation's consolidated financial statements requires the use of estimates and assumptions. Accounting policies have been developed to ensure appropriate implementation and interpretation of accounting rules, and complex situations are addressed using careful judgment and research. Adjustments to previous estimates that impact net income are recorded in the period they become known.

The significant accounting policies adopted by the Corporation are described in Note 2 in the Notes to the Consolidated Financial Statements. ENMAX's critical accounting estimates are related to revenue recognition, allowance for doubtful accounts, amortization expense, asset impairment, asset retirement obligations, provisions for income taxes, employee future benefits, financial instruments and interest during construction (IDC). The estimates and assumptions made in these areas can be highly uncertain at the time the estimate or assumption is made. Different or changing estimates and assumptions could potentially have a material impact on ENMAX's financial position or results of operations. These critical estimates are described in the following discussion.

REVENUE RECOGNITION

The majority of the Corporation's revenue is derived from the sale of electricity. The various systems and procedures used by third parties to provide load and settlement data to retailers across the province are required to completely and accurately capture all customer movement, load classification and consumption data. By regulation, wire service providers are not required to submit final load settlement data on customer electricity usage until four months after the month in which such electricity was consumed. There are a number of variables in the calculation of these estimates, and the underlying energy settlement processes within the Alberta electric systems and ENMAX are complex. These estimates are necessary since the regulatory environment in which we operate often requires amounts to be recorded at estimated values until finalization and adjustment pursuant to subsequent regulatory decisions or other regulatory proceedings. Estimates for unbilled consumption averaged $103.5 million (2013 – $124.1 million) at the end of each month and adjustments of estimated revenues to actual billings averaged $2.0 million (2013 – $2.1 million), representing an average of 2 per cent of the estimates for 2014 and 2013. Reconciliation of settled volumes for 2014 will continue in 2015 based on the timing of receipt of settlement data. These estimates affect accrued electricity revenues and accrued electricity costs of ENMAX Energy.

The presentation of our revenues, margins and OM&A both in the current period and comparative periods have been adjusted to include billing recoveries related to electricity, natural gas and penalty revenues that were previously netted against OM&A expense. To illustrate the impact of reclassification for the year ended December 31, 2014, the reclassification adjustment resulted in an increase in electricty revenue of $35.2 million, natural gas revenue of $8.6 million, other revenue of $8.7 million, electricity costs of $0.3 million and OM&A of $52.2 million. This presentation change does not impact net earnings. The change in presentation has been applied to the comparative periods presented.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

The allowance for doubtful accounts reflects an estimate of the accounts receivable that are ultimately expected to be uncollectible. It is based on a number of factors, including the aging of accounts receivable, historical write-offs, assessments of the collectability of amounts from individual customers and general economic conditions. Our allowance account averaged $9.5 million (2013 – $7.2 million) and at each internal reporting period was within the range of $7.8 million to $19.1 million (2013 – $6.1 million to $7.9 million). The estimate of the allowance affects ENMAX Energy’s and ENMAX Power’s accounts receivable and OM&A.

AMORTIZATION EXPENSE

Amortization is an estimate to allocate the cost of an asset over its estimated useful life on a systematic and rational basis. Estimating the appropriate useful lives of assets requires significant judgment and is generally based on estimates of life characteristics of common assets. The ranges of amortization assumptions used in measuring our amortization expense are outlined in Note 2 in the Notes to the Consolidated Financial Statements.

ASSET IMPAIRMENT

PPE makes up a significant portion of our total assets. The majority of those assets are involved in the generation of electricity. We consider several factors that could indicate an impairment of its assets, including significant underperforming operating results, significant changes in the use of the asset and significant negative economic trends. When an indication of impairment is identified, we estimate the fair value of certain assets. Estimates of fair values for these assets are based on undiscounted cash flow techniques, which rely on a number of assumptions such as the amount of future cash flows that will be generated from the asset, expected future prices for inputs and outputs and expected usage of the asset. An impairment loss, if justified, would be recorded as the excess of the carrying amount of the asset over its fair value.

ASSET RETIREMENT OBLIGATIONS

Measurement of our asset retirement obligations involves the use of estimates with respect to the amount and timing of asset retirements, the extent of site remediation required, discount rates, inflation rates and related future cash flows. Each individual asset requires a separate analysis of these methodology inputs and thus quantification of the range of assumptions used would not be meaningful on a cumulative basis.

PROVISION FOR INCOME TAXES

Income taxes and amounts in lieu of income taxes are determined based upon estimates of current income taxes and estimates of future taxes resulting from temporary tax differences. Future income tax assets are assessed to determine the likelihood that they will be recovered from future taxable income. To the extent that recovery is not considered more likely than not, a valuation allowance will be recorded and charged against income in the period that the allowance is created or revised.

EMPLOYEE FUTURE BENEFITS

We have a defined benefit (DB) pension plan and post-retirement benefits that are provided to certain employees. The cost of these benefits recognized in the financial statements are subject to estimates around many factors, including, but not limited to, assumptions of future return on plan assets, retirement age, mortality rates, discount rates, future health care costs, salary escalation rates and claims experiences. The significant actuarial assumptions used in measuring our accrued benefit obligation and net benefit plan expense are outlined in Note 14 in the Notes to the Consolidated Financial Statements.

FINANCIAL INSTRUMENTS

The fair values of financial instruments are determined and classified into three categories: Level I, II and III. Level I financial instruments are based on quoted market prices and are therefore subject to little estimation and judgment. Level II financial instruments have fair values that are determined using inputs other than quoted market prices that are readily observable for the specific asset or liability. These fair values are subject to estimates around determining the observable source to be used and the use of similar inputs for instruments that are not regularly traded. Level III financial instruments have fair values that are determined using inputs that are not readily observable. These fair values are subject to estimates embedded in the valuation technique used.

Further discussion of the impact of estimates on the fair values of financial instruments can be found in Note 4 in the Notes to the Consolidated Financial Statements.

INTEREST DURING CONSTRUCTION (IDC)

IDC is capitalized on a monthly basis on qualifying assets by applying a borrowing rate to the carrying amount of the asset. Qualifying assets are those assets that take a substantial period of time to complete (greater than or equal to six months, or that are less than six months but would incur significant borrowing).

RISK MANAGEMENT AND UNCERTAINTIES

Our approach to risk management addresses risk exposures across all of the Corporation's business activities and risk types. We utilize an Enterprise Risk Management (ERM) program to identify, analyze, evaluate, treat and communicate the Corporation's risk exposures in a manner consistent with ENMAX's business objectives and risk tolerance.

Risk exposures are managed within levels approved by the Board and senior management and monitored by personnel in the business units, the risk management department and by the senior management team. At a management level, each accountability area is responsible for assessing its risk exposures and implementing risk treatment plans. Our planning and risk management department coordinates an enterprise risk assessment process and provides risk reporting and related monitoring. Risk oversight is delivered through the Board and the Risk Management Committee (RMC), which is comprised of senior management members. Together, the RMC and Board oversee identified risk exposures and risk management programs, including the ERM program.

Our overall risk control environment includes:

- clearly articulated corporate values, principles of business ethics and a code of conduct, which employees are required to review annually;
- published enterprise-wide policies in key risk areas such as delegation of authority;
- documented commodity trading and position limits;
- an internal audit function to test compliance with internal controls and policies;
- regular reporting of risk exposures and mitigations, including insurance programs, to the RMC and Board;
- the use of industry-accepted tools and methodologies for tracking risk exposures; and
- a Safety and Ethics HelpLine for employees to anonymously report suspected illegal or unethical behaviour without fear of retaliation if the employee does not feel comfortable reporting this information directly to his or her manager.

These risk management programs and governance structures are designed to manage and mitigate a number of risk factors affecting our business.

It is not possible to accurately quantify or assess the financial risk of many future events. As such, we use the following financial impact bands in quantifying risks.

Indicative Impact	Potential Financial Impact on 1 Year Budget
Low	< $5 million
Moderate-Low	$5 to 10 million
Moderate-High	$10 to 20 million
High	>$20 million

The following discussion does not consider the result of any interrelationship among the factors. These impacts are hypothetical and not necessarily indicative of actual future results and should be used with caution. All risks described below are residual risks, meaning they are the remaining risk exposures after mitigations have been applied.

MARKET RISK

We have inherent risk in positions in electricity and natural gas commodities arising from owned and controlled supply assets and demand obligations. We also purchase and sell these commodities in wholesale markets to manage such positions. While our business model is designed to achieve a balanced portfolio, in the near term, our electricity and natural gas positions may experience periodic imbalances and result in exposures to price volatility from spot or short-term contract markets. In the longer term, where we have fewer fixed price retail contracts, there is greater exposure to market price risk. The outlook section of this report includes management's current view of the near-term risk to power prices.

ENMAX Energy utilizes numerous tools to forecast electricity consumption and generation, as well as the pattern of consumption and generation between peak and off-peak hours (load shape). However, it is not possible to hedge all positions every hour. As such, there is exposure to volume and load shape risk. ENMAX Energy may purchase blocks of electricity in advance of consumption in order to minimize exposure to extreme price fluctuations between off-peak and peak hours. We actively manage assets to match generation to consumption volumes and have peaking facilities that allow quick reaction to unexpected supply and demand factors. To oversee these risks, we have implemented an ERM program based on leading industry practices to analyze, control and report on commodity price risk exposures. This program includes risk metrics and associated limits, such as open commodity positions and Value at Risk, approved by the Board and senior management. Stress testing is performed regularly to provide additional information on the potential impact of extreme events on ENMAX Energy's portfolio. The ERM program is operated by a middle office controls group that is independent of the front office trading floor and the back office accounting and settlement group.

We have seen and could have future earnings variability with a moderate-low impact as it relates to the sustainability and diversification of our portfolio. Furthermore, a valuation modelling error could produce earnings variability, which could also have a low impact. Overall commodity price levels have a potential earnings variability, which could have a high financial impact. Moderate-low impact earnings variability could also be seen as a result of retail residential and small business and industrial, commercial and institutional customer demand volatility reducing retail margins or a decrease in renewal and acquisition rates.

ENMAX Energy uses derivative instruments, such as swaps and forwards, to manage exposure to commodity price risk. Financial gains and losses could be recognized as a result of volatility in the market values of these contracts. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these derivative instruments may involve management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts. The inability or failure to effectively hedge our energy portfolio and prevent financial losses from derivative instruments could adversely affect the business, results of operations, financial condition or prospects of the Corporation. Our hedging strategies control and mitigate these commodity price risks. Occasionally, hedging is ineffective as it is based upon predictions about future market conditions and may require a minimum level of market liquidity to actively manage positions.

We have foreign exchange rate exposures arising from certain procurement and energy commodity business activity. We hedge the majority of our foreign exchange risk exposures as such exposures arise. However, such hedges may not be sufficient to cover foreign exchange exposure in the event of timing mismatches or extreme foreign exchange rate movements.

Changes in interest rates can impact borrowing costs and certain revenue streams from business activities. Substantially all of our long-term debt is currently either fixed-rate amortizing debt or fixed-rate bullet debt. This structure effectively mitigates exposure to interest rate fluctuations in the near term. Short-term debt is generally variable rate, and long-term debt will need to be replaced at maturity leading to longer-term exposure.

Overall, market risk is considered high in the one-year time frame.

For additional details on our market risk exposures and sensitivities, refer to Note 4 in the Notes to the Consolidated Financial Statements.

OPERATIONAL RISK

ENMAX owns, controls or operates a number of electricity generation, transmission and distribution assets and facilities. The operation of such assets and facilities involves many risks, including public safety incidents; start-up risks; breakdown or failure of generation, transmission or distribution facilities or pipelines; use of new technology; dependence on a specific fuel source, including the transportation of fuel; impact of unusual or adverse weather conditions (including natural disasters); and performance below expected or contracted levels of output or efficiency. Natural resource operating facilities are subject to weather-driven risks such as water and wind availability. There is risk of inadequate or failed internal processes, people and systems within the competitive and regulated businesses, shared services departments and certain outsource service organizations.

Breakdown or failure of a facility may prevent the facility from performing as expected under applicable agreements, which, in certain situations, could result in terminating the agreements or incurring a liability for damages. Unanticipated transmission and distribution outages can cause interruptions in service. Unanticipated generation facility outages and de-rates can cause periodic imbalances in our electricity and natural gas positions. Weather conditions can materially affect the level of demand for electricity and natural gas, the prices for these commodities and the generation of electricity at certain facilities. In addition, our demand obligations may fluctuate based on commodity prices, season, day and time of use and specific customer requirements.

Events that could result from physical or cyber war, terrorism, civil unrest or vandalism may cause damage to ENMAX and our assets and have an impact on our generation, transmission and distribution operations or administrative functions in unpredictable ways.

These operational risks may affect our ability to execute on our strategy in an effective and efficient manner, affect the quality of customer service and result in lost revenues and/or increased costs. These risks are actively managed using incentives, site planning, controls, safety, security and insurance programs, in addition to a number of other measures within certain critical areas. We have implemented security measures and emergency response plans within certain critical areas.

We have obtained property, business interruption and other insurance coverage to mitigate some of these risk exposures, although such programs and measures may not prevent or cover the occurrence of any or all of these events and the adverse effects they may generate. There can be no assurance that we will be able to obtain or maintain adequate insurance in the future at rates the Corporation considers reasonable, that insurance will continue to be available on terms as favourable as our existing arrangements or that insurance companies will meet their obligation to pay claims. Further, there can be no assurance that available insurance will cover all losses or liabilities that may arise in the conduct of our business.

Earnings could be affected by a regulated transmission blackout/brownout, failure of metering equipment or loss of communication services. Fuel supply shortages, failure of third-party services or infrastructure, human error, labour disruption, hazards to facilities and regulatory decisions could cause earnings variability. There has been and could be future exposure to moderate-high impact earnings variability due to a significant failure at a PPA plant (defined as a failure causing an outage of six months or longer) or due to the variation in the annual incentive payments to PPA operators. A low impact in earnings variability could also be seen as a result of the non-performance of contracted physical electricity or natural gas by counterparties. Overall, the operational risk facing ENMAX is classified as high in the one-year horizon.

ENVIRONMENTAL RISK

ENMAX is subject to regulation by federal, provincial and local authorities with regard to air, land and water quality and other environmental matters. The generation, transmission and distribution of electricity results in and requires disposal of certain hazardous materials, which are subject to these laws and regulations. In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for non-compliance, including fines, injunctive relief and other sanctions. New environmental laws and regulations affecting our operations may be adopted and new interpretations of existing laws and regulations could be invoked or become applicable, which may substantially increase environmental expenditures in the future. New facilities or modifications of existing facilities may require new environmental permits or amendments to existing permits. Delays in the environmental permitting process, denials of permit applications and conditions imposed in permits may materially affect the cost and timing of projects. Non-compliance with environmental laws and regulations or incurrence of new costs or liabilities could adversely affect the business, results of operations, financial condition or prospects of the Corporation. We have implemented various programs to manage environmental risk exposures, many of which focus on prevention of and preparedness for adverse events.

In 2007, the Government of Alberta passed the Climate Change and Emissions Management Act and Alberta's Specified Gas Emitters Regulation to address the regulation of GHG emissions from certain facilities located in the province. Effective July 1, 2007, facilities emitting more than 100,000 tonnes of GHG per year are required to reduce their emissions intensity from an emissions intensity baseline. The companies responsible for these facilities have been given a number of options to allow them to comply with this requirement, including making operational improvements to the facilities, buying eligible offsets to apply against their emissions and contributing to a fund established for the purpose of investing in technology to reduce GHG emissions in the province. We have taken steps to substantially mitigate these impacts, including acquiring qualified credits from both wind generation assets and purchases on the wholesale market. We continue to assess and monitor the implications that these changes in legislation may have on our business.

The federal GHG regulations received Gazette II publication in September 2012. The regulations require coal generation facilities to reduce GHG emissions to the level of a combined cycle natural gas generation facility upon reaching the age of 45 to 50 years depending on the unit's commissioning date. In addition to the GHG regulation, Environment Canada is continuing to develop a National Air Quality Management System that could include Base Level Industrial Emissions Requirements (BLIERs) for existing coal-fired generation units that could set new limits for nitrogen oxide (NOx) and sulfur oxide (SOx) emissions. Environment Canada is in the process of assessing on NOx and SOx limits that may apply to existing coal generation. ENMAX has and continues to advocate that the combination of the federal GHG regulation and existing Alberta criteria air contaminant regulation will result in similar emissions reductions so that BLIERs does not need to be implemented in Alberta.

We mitigate our exposure to environmental regulations by building and acquiring new generation capacity emitting fewer GHGs, purchasing emission reductions offsets, investing in environmentally improved technologies in its supply from PPAs and developing workplace conservation programs. Overall, moderate earnings variability exposure is possible if we fail to comply with our Environmental Management System (EMS). Exposure to further moderate volatility is possible due to potential of spills, releases and fire from hazardous materials, or as a result of GHG emissions policy changes.

REGULATORY RISK

We operate in competitive and regulated sectors of the electricity and natural gas industries and are subject to regulation by federal, provincial and municipal governmental regulatory and market authorities. Oversight of industry regulations is provided by the Alberta Department of Energy, AUC, MSA, AESO, National Energy Board, North American Electric Reliability Corporation, U.S. Federal Energy Regulatory Commission and other agencies.

Regulations and regulatory decisions affect our regulated business in a number of areas, including allowed rates of return; capital structure; industry and rate structure; development and operation of transmission and distribution assets; acquisition, disposal, depreciation and amortization; and recovery of certain operating costs. Our competitive and regulated businesses are subject to a number of specific regulations established to help ensure Alberta's wholesale and retail electricity, and natural gas markets operate in a fair, efficient and openly competitive manner. ENMAX Power is a transmission and distribution system owner, and an electrical utility that is regulated by the AUC. It is also subject to AUC regulatory oversight for the provision of the RRO, with ENMAX Energy being the exclusive RRO provider within the City. ENMAX Energy is an affiliated retailer of ENMAX Power and, along with ENMAX Power, must comply with Code of Conduct regulation, which preserves a level playing field for all retailers, as well as general energy marketing regulations.

We cannot predict the future municipal, provincial or federal governments or their policies that may impact the development of regulation over our business or the ultimate effect that any changes to the regulatory environment may have on our business. The regulatory process or specific decisions by a regulator may restrict our ability to grow earnings, recover costs or achieve a targeted ROE in certain parts of our competitive and regulated businesses, or cause delays in or impact business planning and transactions and increase costs. Non-compliance with laws or regulations or changes to the regulatory environment could adversely impact the business, results of operations, financial condition or prospects of the Corporation.

We actively participate in the various regulatory processes that influence our business environment and operations. We actively monitor business activity that is subject to regulation and have implemented compliance programs to mitigate regulatory and political risk exposures. We are potentially exposed to financial impact as it relates to changes to existing as well as new or upcoming policies, protocols, standards, administrative orders or regulations that can have an impact on our activities and operations. We are also potentially exposed to financial impact in regard to regulatory decisions and matters related to generation operations. Overall exposure to regulatory risk is considered to be moderate in the one-year time frame.

HUMAN RESOURCES RISK

ENMAX is subject to workforce factors, including loss or retirement of key executives or other employees; availability of and ability to attract, develop and retain qualified personnel; collective bargaining agreements with union employees and performance of key suppliers and service providers. A number of personnel with highly specialized knowledge, skills and experience are required to lead and operate competitive and regulated businesses and shared services departments. Failure to manage human resources risk could adversely affect the business, results of operations, financial condition or prospects of the Corporation. We have mitigated this risk by implementing a number of programs to attract, develop and retain personnel, including recruitment, career development, recognition and competitive compensation and benefits programs.

We believe we have an effective relationship with the Corporation's unions. There are risks that successful negotiations will not be completed with collective bargaining units on mutually agreeable terms. Difficulties in negotiating these agreements or continuing these programs could lead to higher employee costs, a work stoppage or strike and attraction or retention rates below expectations. We have two collective bargaining agreements covering our workforce. The Canadian Union of Public Employees (CUPE) collective bargaining agreement has a three-year term that expires on December 31, 2016. The International Brotherhood of Electrical Workers (IBEW) collective bargaining agreement was renegotiated at the end of December 2014 for a three-year term set to expire on December 31, 2017. Exposure in relation to a breakdown in labour relations with either of the two unions is possible. Earnings variability could result from workforce attraction and retention issues, the aging workforce and changing values of employees. The Corporation also could be impacted by security breaches and property theft at its facilities and workplaces. Considering the mitigations and current conditions, the human resources risk in the one-year period is considered to be low.

TECHNOLOGICAL RISK

We utilize complex technologies in all aspects of the business, from generation through to information technology. Improvements in current technologies and development of new technologies could render certain existing technologies obsolete. Alternative energy technologies such as fuel cells, micro-wind turbines, cogeneration and solar photovoltaic cells have become more accessible and cost competitive. As research and development continues on these alternative technologies, they become more economically viable energy sources. As well, newly constructed facilities are able to incorporate more efficient technologies. New laws and environmental regulations can require upgrades to current facilities' technologies. Our ability to interface with customers is managed through extensive billing and customer care information technology systems. New developments in information systems could render these billing and customer care systems obsolete. We actively monitor regulatory changes and the potential technological impacts of these changes. We are also investing in the development of advanced alternative technologies in generating and information systems. An information management failure, an overall operational system failure, failure of aging applications and infrastructure are all events that individually could result in a low impact in earnings variability but combined could result in moderate earnings volatility. As well, unauthorized access to confidential information and leakage of sensitive data could result in earnings variability. Finally, a loss of the data centre could result in earnings variability. Overall, the technological risk within the one-year time frame is considered low.

LIQUIDITY RISK

A need to raise additional capital may occur if sources of cash and cash flow from operations are insufficient to fund activities. Such additional capital may not be available when it is needed or on favourable terms for a number of reasons, including changes in market conditions or perceptions of the investment community. We may be required to post collateral to support certain contracts that were executed to hedge commodity positions. Downgrades to credit ratings by credit rating agencies could affect our ability to access capital on favourable terms and within a desired time frame and could also increase the amount of collateral required to be provided to counterparties. We actively monitor our cash position and anticipated flows to achieve adequate funding levels. We communicate regularly with credit rating agencies and the investment community regarding our capital position.

ENMAX offers a DB pension plan for qualifying employees. Our contributions to the pension plan are based on periodic actuarial valuations, the next of which is being completed for December 31, 2016. For accounting purposes, as at December 31, 2014, the pension plan had an estimated deficit of $45.4 million ($32.0 million at December 31, 2013). The actual amount of contributions required in the future will depend on future investment returns, changes in benefits and actuarial assumptions. Failure to effectively manage financial resources and related exposures could adversely affect the business, results of operations, financial condition or prospects of the Corporation. To manage this risk, we engage expert pension managers and have investment policies and procedures in place to set out the investment framework of the funds, including permitted investments and various investment constraints. These policies and procedures are approved annually by the Human Resources and Governance Committee of the Board, which also actively monitors the performance of the pension plan.

Our company could be exposed to earnings variability if our credit ratings were to be downgraded covenants were breached on recourse debt or insufficient liquidity was experienced. We are also potentially exposed to earnings variability as a result of negative pension asset performance. Liquidity risk is considered low in the one-year period.

For additional details on our liquidity risk exposures, refer to Note 4 in the Notes to the Consolidated Financial Statements. For additional details on our pension plan, refer to Note 14 in the Notes to the Consolidated Financial Statements.

CREDIT RISK

We enter into agreements and engage in transactions with a number of external parties, including suppliers, service providers, retail customers and other counterparties. In such arrangements, exposure exists to counterparty credit risks and the risk that one or more counterparties may fail to fulfill their obligations, including paying for or delivery of commodities. These risks are often exacerbated during periods of sustained low commodity prices and tighter credit markets.

We have implemented a credit risk management program to mitigate our exposures to credit risk. While we seek to manage credit risk exposure by considering creditworthiness before and after entering into such agreements, monitoring business activity against pre-defined credit limits and obtaining collateral when it is prudent to do so, we may not be able to identify and avoid all counterparties that are not creditworthy. Defaults by suppliers, service providers, retail customers and other counterparties could adversely affect the business, results of operations, financial condition or prospects of the Corporation.

We have credit and collections activities to monitor credit risk exposures and have implemented available measures to protect against any future losses. In specific situations, this includes but is not limited to a reduction of credit limits, requests for additional collateral, requirements for performance bonds on significant projects or restriction of new transaction terms.

Financial results could be affected as a result of industrial, commercial or institutional customer default or as a result of default by residential, small commercial and wholesale customers. We consider credit risk to be low in the one-year period. For additional details on our credit risk exposures, refer to Note 4 in the Notes to the Consolidated Financial Statements.

DEVELOPMENT RISK

Our ability to successfully complete generation, transmission and distribution projects currently under construction, those projects yet to begin construction or capital improvements to existing assets in a timely manner and within established budgets is contingent upon many variables and subject to a variety of risks, some of which are beyond our control. Should any such risks come to bear, we could be subject to additional costs, delays to the in-service dates of these projects, termination payments under committed contracts and/or the write-off of the investment in the project or improvement. In addition, while our business model is designed to mitigate exposure to risks (as does our strategy to fix the development costs by contractually fixing the price with contractors), we may be required to purchase additional electricity or natural gas to fulfill demand obligations until these projects are completed.

Our ability to successfully identify, value, evaluate, complete and integrate new acquisition opportunities, organic growth opportunities and major capital projects is subject to risks, including increased competition for acquisition targets, capital and other resources resulting from consolidation of the industry and the performance of the Alberta economy. Such business development challenges could adversely affect the business, results of operations, financial condition or prospects of the Corporation.

We budget for capital programs and projects on an annual basis and funding for specific approved capital programs and projects on an ongoing basis. We perform risk assessments and develop risk treatment plans for major capital programs and projects. Project performance relative to expectations is regularly reported to senior management and the Board, and any corrective measures are taken as required. Delays and overspending in the development of capital projects could affect our financial results. Overall, in the one-year period, development risk is considered low.

LEGAL RISK

We are occasionally subject to costs and other effects of legal and administrative proceedings, settlements, investigations, claims and actions, in addition to the effect of new or revised tax laws, rates or policies, accounting standards, securities laws and corporate governance requirements. Non-compliance with existing laws, resolution of legal actions and changes to the legal environment could adversely impact the business, results of operations, financial condition or prospects of the Corporation.

We review and actively monitor business activity that could be subject to public or private legal actions, including changes to certain legislation, contracts with outside parties and incidents or claims allegedly involving our company, and we have implemented programs to mitigate our legal risk exposures. We could experience earnings variability as it relates to potential employment rights violations that results in union, legal or regulatory action; an incident of material unauthorized communication; a breach of material contract or litigation; litigation for any alleged negligence, defamation, nuisance or other matters; or a material breach of legislation or rules. Legal risk is assessed as being low in the one-year period.

CORPORATE STRUCTURE RISK

We conduct a significant amount of business through subsidiaries and joint ventures. The ability to meet and service debt obligations is dependent on the operational results of these investments and their ability to distribute funds to ENMAX. Any restrictions on the ability of these investments to distribute funds to ENMAX may affect our ability to service the corporate debt. A change in the corporate structure of ENMAX has been assessed as a low risk in the one-year period.

REPORTING/DISCLOSURE RISK

The application of critical accounting policies reflects complex judgments and estimates. These policies include industry-specific accounting applicable to regulated public utilities, accounting for pensions and derivative instruments. The adoption of new accounting standards or changes to current accounting policies or interpretations of such policies could adversely affect the business, results of operations, financial condition or prospects of the Corporation. We have implemented various programs to reinforce our ICFR, including periodic assessments of controls by internal and external auditors and review of certain disclosures by the Board. Transition to IFRS could also adversely affect the reported earnings of the business and impact the prospects of the Corporation. We are nearing completion of a comprehensive project to assess the impacts of IFRS transition and to ensure appropriate controls over financial reporting are maintained through the conversion period and beyond. The risk that errors in consolidated financial statements could cause a loss of credibility with creditors and increase risk of breach of covenants or a decrease in debt ratings is considered to be low in the one-year time frame.

TAX RISK

Prior to January 1, 2001, the legal entities comprising the ENMAX group of companies were not subject to federal or provincial income taxes based on an exemption for municipally owned corporations in the Canadian Income Tax Act (ITA). The exemption generally requires corporations be wholly owned by a municipality, and substantially all income must be derived from sources within the geographic boundaries of the municipality. Entities that do not meet these requirements are subject to income tax.

In 2001, the Government of Alberta introduced a payment in lieu of tax (PILOT) regulation in conjunction with the deregulation of the Alberta utilities industry. The purpose of this regulation was to level the playing field between municipally owned tax-exempt entities and non-tax-exempt organizations participating in the competitive part of the electricity market, by requiring tax-exempt organizations to make a payment in lieu of taxes equal to what they would have had to pay if they were not tax-exempt. This regulation required municipally owned retailers and municipally owned PPA holders to remit PILOT payments to the Balancing Pool, based on the retail and commodity components of their electricity operations. PILOT regulations do not apply to those entities subject to tax under the ITA.

With the introduction of PILOT regulations in 2001, certain ENMAX entities experienced a change in tax status. This resulted in all PILOT-related assets (primarily the PPA-owned assets at that time) being deemed to be disposed of and immediately reacquired at fair market value for tax purposes effective December 31, 2000. As a result, the tax base of these assets exceeds their net book value, resulting in a future income tax asset of $315.3 million being recorded in the Consolidated Financial Statements with a corresponding increase in retained earnings. As at December 31, 2014, the future income tax asset remaining related to this balance is $54.0 million. We have received reassessments and communications from Alberta Finance in respect of the taxation years 2001 through 2010 related to this tax base. We do not agree with the reassessments and have commenced the necessary steps to defend our positions through the formal appeals and litigation process. We expect this process to be successful and will evaluate all options should the appeals and litigation process result in an unfavourable outcome.

The Alberta Electric Utilities Act precludes municipally owned corporations competing in the electricity generation business from realizing a tax, subsidy or financing advantage as a result of their association with the municipality. Accordingly, we hold generation assets in entities that do not qualify for the income tax exemptions noted above.

The computation of our provision for income taxes involves tax interpretations, regulations and legislation that are continually changing. Tax filings are subject to audit by taxation authorities, and the outcome of such audits may increase tax liabilities. Any implementation of incremental taxes or changes to the current legislation could adversely affect the business, results of operations, financial condition or prospects of the Corporation. Earnings variability in relation to reassessments from Alberta Finance in regard to prior years' returns and other contingent tax liabilities is possible. Considering the above, tax risk is considered to be moderate to low to the Corporation in the one-year time frame.

STRATEGIC RISK

ENMAX Energy's business model and strategic direction are predicated on certain assumptions, including the long-term viability of the competitive and regulated businesses, benefits associated with holding each of these businesses, evolution of technology used in the industry and attractiveness of growth opportunities. While we believe these assumptions will remain valid in the future, significant changes to the overall business environment or other factors could cause us to re-evaluate our business model or strategic direction.

We have several competitors that operate in the electricity and natural gas markets where we serve customers. Competitors vary in size from small companies to large corporations, some of which have significantly greater financial, marketing and procurement resources than us. ENMAX Energy must also compete with the RRO service provided by various parties throughout Alberta in order to convince customers to select ENMAX Energy as their competitive retailer. Changes to the business environment and failure to attract and retain customers could adversely affect the business, results of operations, financial condition or prospects of the Corporation. We could potentially see earnings variability as it relates to constraints on our growth targets for market share.

FINANCIAL INSTRUMENTS

In conducting our operations, we use various instruments, including forwards, futures, swaps and options to reduce our market risks.

ENERGY TRADING DERIVATIVES

Energy trading derivatives are contracts-for-differences that are financial forwards and futures for electricity and gas positions. This does not include electricity and gas contracts that are not considered to be accounting derivatives (normal purchase and sale contracts). The fair value of ENMAX Energy's contracts-for-differences is determined by estimating the amounts that would have to be received or paid to counterparties to terminate the contracts at December 31, 2014, and December 31, 2013.

OUTSTANDING CONTRACTS-FOR-DIFFERENCES

As at December 31	2014	2013
Notional quantities:		
Electricity sales (GWh)	6,376	3,958
Natural gas sales (TJ)	6,553	670
Electricity purchases (GWh)	4,985	6,185
Natural gas purchases (TJ)	62,904	19,615

At December 31, 2014, on the basis of electricity and natural gas prices at that date, the fair market value of these contracts amounted to an unrealized negative mark-to-market adjustment of $52.7 million as compared to a negative mark-to-market adjustment of $3.2 million as at December 31, 2013. This amount does not reflect the fact that these contracts will settle at prices in effect in the future. The increase in the notional quantity of outstanding contracts for natural gas purchases is related to fuel requirements for our natural-gas-fuelled Shepard facility.

Refer to Note 2 in the Notes to the Consolidated Financial Statements for further information on financial instruments.

CLIMATE CHANGE AND THE ENVIRONMENT

ENVIRONMENTAL RISKS

Refer to the Risk Management and Uncertainties section for discussion regarding environmental risks.

TRENDS AND UNCERTAINTIES

Environmental matters cause certain trends and uncertainties to exist. Customers are becoming more attuned to the source of their energy. As a result, the need to offer energy from alternative production methods and renewable resources is increasing. Based on our asset portfolio, we are positioned to offer consumers choices and progressive technologies that will help increase revenues should this trend continue to develop. The Home Solar program launched in 2011 provides residential and commercial customers the opportunity to generate their own solar power using grid-tied solar photovoltaic technology.

ASSET RETIREMENT OBLIGATIONS

At December 31, 2014, asset retirement obligations exist relating to the following generating assets: McBride, Taber, Kettles, Crossfield, CEC, Cavalier and Balzac. The accretion expense on these assets is included in OM&A in the Consolidated Statements of Earnings and Comprehensive Income.

EXPECTED REMEDIATION LIABILITY AND TIMING FOR EACH ASSET

(millions of dollars)	Date	Amount
McBride	September 2057	47.8
Taber	December 2057	32.4
Kettles	May 2071	26.2
Crossfield	December 2048	10.4
CEC	March 2043	29.6
Cavalier	December 2039	8.7
Balzac	December 2039	4.3

ENVIRONMENTAL LIABILITIES

Environmental liabilities recorded in our financial statements include GHG liabilities. The GHG liabilities relate to electricity generated from both our PPAs and ENMAX-owned generation facilities. These items have been reflected as liabilities in the Consolidated Financial Statements as at December 31, 2014. We continue to actively monitor the EMS and will continue to abide with current and future environmental regulations.

We currently have no outstanding litigation for environmental matters. There are no other material environmental liabilities at this time.

Provincial legislation aimed at reducing emissions of high GHG-emitting facilities, including coal-fired plants, was passed a number of years ago and resulted in costs being incurred. Further expenditures are anticipated to be spent in future years to comply with this legislation, and there is an expectation that ongoing operating costs will increase as a result of these compliance matters.

MATERIAL CONTRACTS

With the exception of contracts entered into in the ordinary course of business, the Corporation has entered into a material contract in the year ended December 31, 2014. This is the second JVA with Capital Power to develop, construct, own and operate a natural-gas-fuelled facility, Genesee 4 and 5. ENMAX has a 50 per cent interest in the 1,050 MW facility.

INTEREST OF EXPERTS

INDEPENDENT AUDITOR

ENMAX's external auditor is Deloitte LLP, Chartered Accountants, Suite 700, 850 – 2 Street SW, Calgary, Alberta, T2P 0R8. Deloitte LLP is independent with respect to ENMAX within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

ACTUARY

ENMAX utilizes external professional services in relation to its employee benefits from Towers Watson, Suite 1600, 111 – 5 Avenue SW, Calgary, Alberta, T2P 3Y6. Towers Watson is independent with respect to ENMAX, as it has no equity interest in the Corporation and is compensated at a contracted fixed rate, regardless of the outcome of its reports.

LEGAL AND REGULATORY PROCEEDINGS

The Corporation is occasionally named as a party in various claims and legal proceedings that arise during the normal course of its business. The Corporation reviews each of these claims, including the nature of the claim and the amount in dispute. Although there is no assurance that each claim will be resolved in favour of the Corporation, the Corporation does not believe that the outcome of any claims or potential claims it is currently aware of will have a material adverse effect on the financial results or position of the Corporation, after taking into account amounts previously reserved by the Corporation. For further information, refer to Note 20 in the Notes to the Consolidated Financial Statements.

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

The President and Chief Executive Officer (CEO) and the Executive Vice President, Finance and Chief Financial Officer (CFO) of ENMAX, together with management, have established and maintain disclosure controls and procedures for the Corporation in order to provide reasonable assurance that material information relating to the Corporation is made known to them in a timely manner, particularly during the period in which the annual filings are being prepared. The CEO and CFO of ENMAX, together with management, have evaluated the design and operating effectiveness of the Corporation's disclosure controls and procedures as of December 31, 2014, and, based on that evaluation, have concluded that these controls and procedures are effective in providing such reasonable assurance.

The CEO and CFO of ENMAX, together with management, are also responsible for establishing and maintaining ICFR within the Corporation in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements for external purposes in accordance with GAAP. The CEO and CFO of ENMAX, together with management, have evaluated the design and operating effectiveness of the Corporation's ICFR as of December 31, 2014, and, based on that evaluation, have concluded that the controls are effective in providing such reasonable assurance. During 2014, there were no changes in the Corporation's ICFR that materially affected, or are reasonably likely to materially affect, the Corporation's ICFR.

OUTLOOK

The discussion in this section is qualified by the Caution to Readers at the beginning of the report. The financial results forecasted for 2015 are based on certain assumptions about factors that are outside of the control of the Corporation or management. Actual results that differ from these assumptions could have a significant impact on expected results. The key assumptions that could significantly impact forecast earnings are commodity prices, residential and small business volumes, unplanned outages at generating facilities, settlement of contingencies, regulatory changes and project execution on the Corporation's significant capital projects.

The market price outlook for electricity in 2015 is expected to be lower than 2014 as we enter into a few years that may be challenged with lower electricity prices as the Alberta market absorbs an increase in electricity supply. Timing of market absorption of new supply will be impacted by the recent decline in global oil prices and the uncertainty of its impact on the Alberta economy and its growth rate, which grew by 3.9 per cent in 2014. A decrease in Alberta's growth rate may lengthen the time the market takes to absorb new supply and for electricity prices to increase. Near-term sources of increased supply to market primarily include our Shepard (800 MW) facility, which started testing (commissioning) activities in the latter half of 2014 with full commercial operations announced on March 11, 2015. We have recently experienced a decrease in natural gas prices as we entered into 2015, and we expect them to remain at levels lower than 2014. Spark spreads are expected to be lower primarily due to lower anticipated electricity prices. The volume contracted in each of our customer segments will be a function of availability for contracting and profitability, including alignment with the supply portfolio. With respect to our regulated business, we are awaiting decisions from the AUC, which will have an impact on our 2015 earnings. Overall, profitability in 2015 is expected to decrease from 2014 as we anticipate lower electricity prices and the impact Shepard will have on earnings as we begin amortization and cease capitalization of interest costs associated with its construction.

CONSOLIDATED FINANCIAL STATEMENTS

CONTENTS

MANAGEMENT’S RESPONSIBILITY FOR FINANCIAL REPORTING

The preparation and presentation of the accompanying consolidated financial statements of ENMAX Corporation are the responsibility of management, and the consolidated financial statements have been approved by the Board of Directors (the Board). In management's opinion, the consolidated financial statements have been prepared within reasonable limits of materiality in accordance with Canadian Generally Accepted Accounting Principles (GAAP). The preparation of financial statements necessarily requires judgment and estimation when events affecting the current year depend on determinations to be made in the future. Management has exercised careful judgment where estimates were required, and these consolidated financial statements reflect all information available to March 19, 2015. Financial information presented elsewhere in this report is consistent with that in the consolidated financial statements.

To discharge its responsibility for financial reporting, management maintains systems of internal controls designed to provide reasonable assurance that the Corporation's assets are safeguarded, that transactions are properly authorized and that reliable financial information is relevant, accurate and available on a timely basis. The internal control systems are monitored by management and evaluated by an internal audit function that regularly reports its findings to management and the Audit, Finance and Risk Committee (AFRC) of the Board.

The consolidated financial statements have been examined by Deloitte LLP, the Corporation’s external auditor. The external auditor is responsible for examining the consolidated financial statements and expressing their opinion on the fairness of the financial statements in accordance with GAAP. The auditor’s report outlines the scope of their audit examination and states their opinion.

The Board, through the AFRC, is responsible for ensuring management fulfills its responsibilities for financial reporting and internal controls. The AFRC, which comprises independent directors, meets regularly with management, the internal auditors and the external auditor to verify that each group is discharging its responsibilities with respect to internal controls and financial reporting. The AFRC reviews the consolidated financial statements and annual financial report and recommends its approval to the Board. The external auditor has full and open access to the AFRC, with and without the presence of management. The AFRC is also responsible for reviewing and recommending the annual appointment of the external auditor and approving the annual external audit plan.

On behalf of management,

Gianna Manes
President and Chief Executive Officer

David Halford, CPA, CA
Executive Vice President, Finance and Planning,
Chief Financial Officer and Chief Risk Officer

March 19, 2015

INDEPENDENT AUDITOR'S REPORT

To the Shareholder of ENMAX Corporation:

We have audited the accompanying consolidated financial statements of ENMAX Corporation, which comprise the consolidated balance sheets as at December 31, 2014 and December 31, 2013, and the consolidated statements of earnings and comprehensive income, shareholder's equity, and cash flows for the years then ended, and the notes to the consolidated financial statements.

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

AUDITOR'S RESPONSIBILITY

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

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

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

OPINION

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of ENMAX Corporation as at December 31, 2014 and December 31, 2013, and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte LLP

Chartered Accountants
March 19, 2015
Calgary, Alberta

CONSOLIDATED BALANCE SHEETS

As at December 31 *(millions of dollars)*	2014	2013
ASSETS		
Cash and cash equivalents	$ 16.7	$ 80.6
Accounts receivable *(Notes 4 and 5)*	606.5	665.5
Income taxes receivable	96.8	96.9
Future income tax asset *(Note 6)*	16.6	8.7
Other current assets *(Notes 4 and 7)*	85.8	42.6
	822.4	894.3
Property, plant and equipment *(Note 11)*	3,483.7	3,022.6
Power purchase arrangements *(Note 12)*	316.7	369.5
Intangible assets *(Note 13)*	136.7	124.3
Goodwill *(Note 13)*	-	16.0
Employee future benefits *(Note 14)*	21.6	22.8
Future income tax asset *(Note 6)*	23.8	59.0
Other long-term assets *(Notes 4 and 7)*	36.7	57.0
TOTAL ASSETS	$ 4,841.6	$ 4,565.5
LIABILITIES		
Short-term debt *(Note 15)*	$ 27.3	$ -
Accounts payable and accrued liabilities *(Notes 4 and 5)*	422.3	436.8
Income taxes payable	0.6	–
Future income tax liability *(Note 6)*	0.9	0.5
Current portion of long-term debt *(Notes 4 and 16)*	62.6	63.7
Other current liabilities *(Notes 4 and 7)*	135.8	52.8
	649.5	553.8
Long-term debt *(Notes 4 and 16)*	1,547.7	1,375.3
Future income tax liability *(Note 6)*	61.4	100.1
Other long-term liabilities *(Notes 4 and 7)*	35.2	60.7
Asset retirement obligations *(Note 17)*	20.1	15.4
	2,313.9	2,105.3
SHAREHOLDER'S EQUITY		
Share capital *(Note 18)*	280.1	280.1
Retained earnings	2,281.4	2,186.4
Accumulated other comprehensive loss *(Note 19)*	(33.8)	(6.3)
	2,527.7	2,460.2
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 4,841.6	$ 4,565.5

Commitments and contingencies *(Note 20)*
See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME

Year Ended December 31 *(millions of dollars)*	2014	2013
REVENUE *(Note 23)*		
Electricity	$ 2,152.7	$ 2,423.9
Natural gas	541.6	397.9
Transmission and distribution	380.3	339.0
Local access fees	131.3	129.3
Contractual services	121.8	95.4
Other	20.6	31.1
TOTAL REVENUE	3,348.3	3,416.6
COST OF SERVICES PROVIDED *(Note 23)*		
Electricity	1,766.6	2,072.3
Natural gas	508.0	364.3
Transmission and distribution	106.8	97.8
Local access fees	131.3	129.3
Contractual services	82.0	61.1
Operations, maintenance and administration	355.5	325.8
Impairment loss *(Note 13)*	34.4	-
Foreign exchange gain	(11.9)	(6.6)
TOTAL COST OF SERVICES PROVIDED	2,972.7	3,044.0
	375.6	372.6
Amortization	174.2	168.1
Interest *(Note 22)*	44.3	33.1
Current income tax (recovery) expense *(Note 6)*	9.9	(10.0)
Future income tax (recovery) expense *(Note 6)*	(7.8)	8.0
NET EARNINGS FROM CONTINUING OPERATIONS	155.0	173.4
Net earnings from discontinued operations, net of tax *(Note 8)*	-	3.2
Gain on sale of subsidiary *(Note 8)*	-	175.9
NET EARNINGS	155.0	352.5
OTHER COMPREHENSIVE INCOME, NET OF TAX		
Unrealized gains (losses) on derivatives designated as cash flow hedges; includes future income tax expense of $2.7 (2013 – $9.7 tax expense)	(2.5)	24.1
Realized losses on derivatives designated as cash flow hedges in prior periods transferred to net earnings in current year; includes future income tax expense of $7.3 (2013 – $6.3 tax expense)	(25.0)	(10.8)
Other comprehensive income (loss), net of tax	(27.5)	13.3
COMPREHENSIVE INCOME	$ 127.5	$ 365.8

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDER'S EQUITY

(millions of dollars)	Share Capital	Retained Earnings	Accumulated Other Comprehensive Income	Total
BALANCE, JANUARY 1, 2013	$ 280.1	$ 1,901.4	$ (19.6)	$ 2,161.9
Net earnings	–	352.5	–	352.5
Dividends	–	(67.5)	–	(67.5)
Other comprehensive income including future tax expense of $3.4	–	–	13.3	13.3
BALANCE, DECEMBER 31, 2013	$ 280.1	$ 2,186.4	$ (6.3)	$ 2,460.2
Net earnings	–	155.0	–	155.0
Dividends	–	(60.0)	–	(60.0)
Other comprehensive income including future tax benefit of $4.6 *(Note 19)*	–	–	(27.5)	(27.5)
BALANCE, DECEMBER 31, 2014	**$ 280.1**	**$ 2,281.4**	**$ (33.8)**	**$ 2,527.7**

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31 *(millions of dollars)*		2014		2013
CASH PROVIDED BY (USED IN):				
OPERATING ACTIVITIES				
Net earnings	$	**155.0**	$	352.5
Net earnings from discontinued operations		**-**		(3.2)
Gain on sale of subsidiary		**-**		(175.9)
Impairment loss		**34.4**		-
Items not involving cash *(Note 24)*		**196.6**		186.3
		386.0		359.7
Change in non-cash working capital *(Note 25)*		**47.1**		(136.2)
Employee future benefits		**1.2**		(4.7)
Cash flow from continuing operating activities		**434.3**		218.8
Cash flow used in discontinued operations		**-**		(14.1)
		434.3		204.7
INVESTING ACTIVITIES				
Purchase of property, plant and equipment		**(406.4)**		(298.8)
Acquisition of generating assets *(Notes 11 and 26)*		**(225.1)**		-
Net proceeds from disposal of assets held for sale		**-**		802.2
Other assets		**8.8**		(14.0)
Contributions in aid of construction		**18.9**		15.7
Cash flow from (used in) continuing investing activities		**(603.8)**		505.1
Cash flow used in discontinued operations		**-**		(269.6)
		(603.8)		235.5
FINANCING ACTIVITIES				
Repayment of short-term debt		**(2,064.2)**		(1,588.5)
Proceeds of short-term debt		**2,091.5**		1,422.6
Proceeds of long-term debt *(Notes 4 and 16)*		**432.1**		140.6
Repayment of long-term debt and interest rate swaps *(Note 16)*		**(296.8)**		(311.1)
Dividend paid		**(60.0)**		(67.5)
Other long-term liabilities		**3.0**		(1.2)
		105.6		(405.1)
Increase (decrease) in cash and cash equivalents		**(63.9)**		35.1
Cash and cash equivalents, beginning of year		**80.6**		45.5
CASH AND CASH EQUIVALENTS, END OF YEAR	$	**16.7**	$	80.6
Supplementary information:				
Interest paid	$	**67.3**	$	89.1
Income taxes paid		**8.4**		6.8
Cash and cash equivalents consist of:				
Cash	$	**16.1**	$	79.9
Cash equivalents		**0.6**		0.7

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. DESCRIPTION OF THE BUSINESS

ENMAX Corporation (ENMAX or the Corporation), a wholly owned subsidiary of The City, was incorporated under the Business Corporations Act (Alberta) in July 1997. The Corporation was formed to carry on the electric utility transmission and distribution operations previously carried on by the Calgary Electric System (CES), a former department of The City, in contemplation of the emerging deregulated electric industry in Alberta. As such, operations of the Corporation began on January 1, 1998, with the transfer of substantially all of the assets and liabilities of the CES by The City into the Corporation at net book value for consideration of one common share issued to The City.

The Corporation operates in two segments representing separately managed business units, each of which offers different products and services.

ENMAX ENERGY

ENMAX Energy is an operating segment established to carry out all non-regulated energy supply and retail functions through various legal entities and affiliated companies.

ENMAX POWER

ENMAX Power is primarily a regulated segment established to carry out electricity transmission and distribution service functions and the regulated-rate option retail function through various legal entities and affiliated companies. ENMAX Power also provides non-regulated engineering, procurement, construction and maintenance services.

2. SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION

The consolidated financial statements have been prepared by management in accordance with Part V of the *CPA Canada Handbook* – Pre-changeover accounting standards (GAAP). The consolidated financial statements include the accounts of the Corporation and its subsidiaries, as well as its proportionate share of the accounts of its joint ventures.

The assets and liabilities, results of operations and cash flows of the subsidiaries and the proportionate share of its joint ventures are included in the consolidated financial statements of the Corporation.

All inter-company accounts and transactions have been eliminated, except as described in Note 5.

MEASUREMENT UNCERTAINTY

The preparation of the Corporation's consolidated financial statements, in accordance with GAAP, requires management to make estimates that affect the reported amounts of revenues, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities at the financial statement date. On January 1, 2001, the Alberta retail electricity marketplace opened to retail competition. The various systems and procedures used by third parties to provide load and settlement data to retailers across the province are required to capture, completely and accurately, all customer movement, load classification and consumption data. By regulation, wire service providers are not required to submit final load settlement data on customer electricity usage until four months after the month in which such electricity was consumed. The data and associated processes and systems are used by the Corporation to estimate electricity revenues and costs, including unbilled consumption. The Corporation's estimation procedures will not necessarily detect errors in underlying data provided by industry participants, including wire service providers and load settlement agents. Any changes to electricity revenues and costs arising from these estimation processes will be accounted for as a change in estimate in the period they occur.

For determining potential impairment, the Corporation is required to estimate the recoverable values of certain assets. Estimates of recoverable values are based on undiscounted cash flow techniques, which rely on a number of assumptions: the amount of future cash flows that will be generated from the asset, expected future prices for inputs and outputs and expected usage of the asset.

The allowance for doubtful accounts reflects an estimate of the accounts receivable that are ultimately expected to be uncollectible. It is based on a number of factors, including the aging of accounts receivable, historical write-offs, assessments of the collectability of amounts from individual customers and general economic conditions.

Amortization is an estimate to allocate the cost of an asset over its estimated useful life on a systematic and rational basis. Estimating the appropriate useful lives of assets requires significant judgment and is based on estimates of useful life characteristics of common assets.

Measurement of the Corporation's asset retirement obligations requires the use of estimates with respect to the amount and timing of asset retirements; the extent of site remediation required; and related future cash flows, inflation rates and discount rates.

Income taxes and amounts in lieu of income taxes are determined based upon estimates of the Corporation's current income taxes and estimates of future taxes resulting from temporary tax differences. Future income tax assets are assessed to determine the likelihood that they will be recovered from future taxable income. To the extent that recovery is not considered more likely than not, a valuation allowance will be recorded and charged against income in the period that the allowance is created or revised.

Certain estimates are necessary since the regulatory environment in which the Corporation operates often requires amounts to be recorded at estimated values until finalization and adjustment, pursuant to subsequent regulatory decisions or other regulatory proceedings.

Certain financial instruments are recorded at fair value. These fair values can be subject to estimates of inputs other than quoted market prices, future prices, expected cash flows and discount rates.

ENMAX has a defined benefits (DB) pension plan and post-retirement benefits that are provided to certain employees. The cost of these benefits recognized in the consolidated financial statements are subject to estimates around many factors, including, but not limited to, assumptions of future return on plan assets, retirement age, mortality rates, discount rates, future health care costs, salary escalation rates and claims experiences.

Adjustments to previous estimates, which will impact net earnings and could be material, are recorded in the period they become known.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents consist of cash-on-hand balances with banks and investments in money market instruments with maturities within three months from the date of acquisition.

PROPERTY, PLANT AND EQUIPMENT

Amortization of property, plant and equipment (PPE) is recorded on a straight-line basis over the estimated useful life of the asset class at the rates opposite:

PPE is recorded at cost, which includes direct labour, material, equipment charges, directly attributable overhead and interest during construction (IDC). IDC is capitalized on a monthly basis on qualifying assets by applying a borrowing rate to the carrying amount of the assets. Qualifying assets are those assets that take a substantial period of time to complete (greater than or equal to six months) or are of such substantial value they would incur significant borrowing costs over a shorter period of time.

PPE AMORTIZATION RATES

Transmission, distribution and substation equipment	0.00%	–	22.72%
Tools, systems and equipment	3.66%	–	25.00%
Buildings and site development	0.61%	–	4.60%
Generation facilities and equipment	2.00%	–	20.00%
Vehicles	2.36%	–	8.00%

The Corporation classifies all major components of its electricity transmission and distribution system infrastructure under construction as PPE. These items are not amortized until they are placed into service.

Construction in progress represents assets that are not yet available for use and therefore not subject to amortization.

Original costs of retired regulated depreciable assets are charged, and the related net disposal proceeds are credited, to accumulated amortization in a manner consistent with regulatory accounting. As a result, all gains and losses on the disposal of regulated depreciable assets are deferred and amortized over the estimated remaining service life of the related assets, as described in Note 5. Gains and losses on the disposal of non-regulated, non-depreciable assets are recognized in the year of disposal.

INTANGIBLE ASSETS

Intangible assets are recorded at cost and amortization is recorded on a straight-line basis over the estimated useful lives of the assets at the rates opposite:

Intangible assets with indefinite lives include some land easements, renewable energy certificates and water licenses, and are not subject to amortization. These assets are assessed annually for impairment or more frequently if events or changes in circumstances indicate that the asset may be impaired.

INTANGIBLE AMORTIZATION RATES

Customer lists and contracts			10.00%
Computer systems	2.81%	–	25.00%
Land easements, rights and lease options	2.74%	–	25.86%

ASSET IMPAIRMENT

Long-lived assets subject to amortization are tested for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. Intangible assets with indefinite lives are tested for impairment annually or more frequently when events or changes in circumstances indicate the carrying amount may not be recoverable. An impairment loss would be recognized if the carrying amount exceeds the recoverable value of an asset, determined as the sum of the undiscounted cash flows expected to result from the asset's use and eventual disposition. The loss, if any, is measured as the amount by which the carrying amount exceeds the fair value of the asset.

The fair values are estimated using accepted valuation methodologies such as undiscounted future net cash flows, earnings multiples or prices for similar assets, whichever is most appropriate under the circumstances.

ASSET RETIREMENT OBLIGATION

The Corporation recognizes its obligation to retire certain tangible long-lived assets, whereby the fair value of an asset retirement obligation is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset and then amortized over its estimated useful life. In subsequent periods, the asset retirement obligation is adjusted for the passage of time, and any changes in the amount or timing of the underlying future cash flows are recognized as a change in the carrying amount of the liability for an asset retirement obligation; the related asset retirement cost is capitalized as part of the carrying amount of the related long-lived asset. A gain or loss may be incurred upon settlement of the liability.

CONTRIBUTIONS IN AID OF CONSTRUCTION

Under various statutory requirements and agreements with customers and developers, the Corporation receives Contributions in Aid of Construction (CIAC) in the form of cash contributions. Such contributions are recorded as a reduction of PPE and amortized on the same basis as, and offset the amortization charge for, the assets to which they relate.

GOVERNMENT GRANTS

Government grants are accounted for using the income approach. Under this method, amounts received have been deducted from the carrying amount of the related assets. Government grants are not recognized until there is reasonable assurance that the Corporation will comply with the conditions attached to them and that the grants will be received. Government grants have been received by the Corporation for the purchases of certain items of PPE.

POWER PURCHASE ARRANGEMENTS

The cost to acquire power purchase arrangements (PPAs) has been recorded on the consolidated balance sheet as a long-term asset. The cost is amortized on a straight-line basis to amortization expense over the useful life of the arrangements.

GOODWILL

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is annually assessed for impairment. Goodwill and all other assets and liabilities have been allocated to the Corporation's segments, referred to as reporting units. To assess impairment, the fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment.

The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount.

REVENUE RECOGNITION

Revenues are recognized on an accrual basis as services are provided and include an estimate of fees for services provided but not yet billed. For ENMAX Power's billable construction projects, revenue is recognized on the percentage of completion basis. All revenues are reviewed for collectability and recognized only when collection is reasonably assured.

INCOME TAX

The Corporation and its subsidiaries are municipally owned and are generally not subject to federal or provincial income taxes. Those subsidiaries that do not meet the criteria for municipal exemption are taxable under the Canadian Income Tax Act (ITA). The Corporation also records income tax expense based on a regulation to the Alberta Electric Utilities Act (EUA) that requires tax exempt, municipally owned entities to make payment in lieu of tax (PILOT) on certain portions of their operations. These PILOT payments are made to the Balancing Pool of Alberta.

ENMAX uses the liability method of accounting for income taxes and PILOT. Under this method, current income taxes are recognized for the estimated income taxes payable or recoverable for the current year. Future income tax assets and liabilities are recognized for the future tax consequences attributable to temporary (or timing) differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future income tax assets and liabilities are measured using substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on future tax assets and liabilities is recognized in income in the period that includes the date of substantive enactment.

FINANCIAL INSTRUMENTS

The financial instruments of the Corporation include held-for-trading instruments, loans and receivables, available-for-sale instruments and other financial liabilities.

Cash and cash equivalents are classified as held-for-trading instruments and are recorded at fair value. Accounts receivable are classified as loans and receivables and are recorded initially at fair value and subsequently carried at amortized cost with interest and other income earned from these financial assets recorded in other revenue. Short-term debt, long-term debt, customer guarantee deposits, dividends payable, accounts payable and accrued liabilities are classified as other financial liabilities and are recorded initially at fair value and subsequently carried at amortized cost using the effective interest method. Investments in equity instruments are classified as available-for-sale instruments and are carried at fair value with changes to fair value recorded through other comprehensive income (OCI). Investments in equity instruments that do not have a quoted market price in an active market are measured at cost. Derivatives such as swaps, futures, options and forwards are classified as held-for-trading instruments and are recorded at their fair value with changes in fair value recorded through earnings. If these derivatives are designated as hedging items, they are accounted for as described in the Hedges section of this note.

Held-for-trading items are required to be classified as such due to their nature as derivatives or are items held for the purpose of selling or repurchasing in the near term. Available-for-sale items are non-derivative financial assets that do not fit into any of the other classes of financial assets.

The Corporation uses an allowance for doubtful accounts to reduce the carrying amount of accounts receivables that are impaired. This allowance is based on a number of factors, including the aging of accounts receivable, historical write-offs within customer groups, assessments of the collectability of amounts from individual customers and general economic conditions. Write-offs are determined using similar techniques and by reviewing significant amounts on a case-by-case basis.

Other financial assets are reviewed for impairment by comparing their carrying value to fair value. An impairment loss is recorded in earnings during the period in which the fair value falls below the carrying value and such decline is other than temporary.

The Corporation had a procurement contract denominated in Japanese Yen. As this foreign currency is not a common transaction currency of the Corporation, the Corporation's policy is to account for this embedded foreign currency derivative separately from the underlying host contract.

Transaction costs that are directly attributable to the issuance of financial liabilities are netted against the fair value initially recognized. These costs are subsequently expensed to earnings using the effective interest rate method.

HEDGES

In conducting its business, the Corporation uses derivatives and other financial instruments, including forward contracts, swaps, options and contracts-for-differences, to manage its exposure to certain market risks. Certain derivatives are designated as hedging instruments for accounting purposes when meeting certain effectiveness and documentation requirements at inception of the hedging relationship and on an ongoing basis. Effectiveness is measured with reference to the risk management objective and strategy for the hedged item.

Cash flow hedges are used to manage the variability of cash flows resulting from the purchase and sale of electricity and natural gas and foreign exchange. For cash flow hedges, changes in the fair value of the effective portion of the hedging derivative are accumulated in OCI and recognized in net earnings during the periods when the cash flows of the hedged items are realized. Gains and losses on cash flow hedges are reclassified immediately to net earnings when the hedging item is sold or terminated early or when a hedged anticipated transaction is no longer probable. Changes in fair value due to ineffectiveness of hedges and changes in fair value of non-hedge derivatives are recorded in earnings under cost of services provided. Changes in fair value of de-designated or discontinued hedges are recorded in earnings under cost of services provided from the date of de-designation or discontinuation. The unrealized changes in fair value recorded prior to de-designation or discontinuation are reclassified from accumulated OCI to earnings when the related hedged item is recognized in earnings.

FOREIGN CURRENCY TRANSLATION

The Corporation's consolidated financial statements are presented in Canadian dollars, which is the functional currency of the Corporation and all of its subsidiaries.

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at year-end exchange rates of monetary items and liabilities denominated in foreign currencies are recognized in the statement of earnings, except when deferred in equity as qualifying cash flow hedges.

Foreign exchange gains and losses are presented on the consolidated statements of earnings and comprehensive income within costs of services provided.

EMPLOYEE BENEFIT PLANS

The Corporation sponsors pension plans that contain both DB and defined contribution (DC) provisions. The cost of DB pensions and other post-employment benefits earned by employees is actuarially determined using the projected benefit method pro-rated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. Pension plan assets are measured at fair market value. For the purpose of calculating the expected return on plan assets for the net benefit cost, a market-related value is used.

The market-related value of assets is calculated based on the average of the adjusted market value of assets for the current and three preceding years. The adjusted market values are determined from the preceding three year-end market values accumulated to the end of the fiscal year in question using net contributions less distributions and assumed investment return. Adjustments arising from plan amendments are amortized on a straight-line basis over the average remaining service lifetime of employees active at the date of amendment. The excess of the cumulative, unamortized net actuarial gain or loss over 10 per cent of the greater of the benefit obligation and the fair value of plan assets at the beginning of the year is amortized over the average remaining service lifetime of the active employees.

EMISSION CREDITS AND ALLOWANCES

Effective July 1, 2007, the Climate Change and Emissions Management Amendment (CCEMA) Act was enacted into law in Alberta. The CCEMA Act, and regulations made pursuant to it, establishes baseline emission intensity levels for each large generating facility, and emissions over this baseline are subject to a surcharge. Changes in law provisions in the Corporation's PPAs have the potential to expose the Corporation to significant portions of these compliance costs (see Note 20).

Purchased emission allowances are recorded on the consolidated balance sheets as part of intangible assets, at historical cost and are carried at the lower of weighted average cost and net realizable value. Allowances granted to the Corporation or internally generated from approved projects are accounted for as intangible assets.

The Corporation has recorded emissions liabilities on the consolidated balance sheets, as a component of accounts payable and accrued liabilities, using the best estimate of the amount required to settle the obligation in excess of government-established emission intensity levels. To the extent compliance costs are charged to the Corporation under the change in law provisions of the Corporation's PPAs, these amounts are recognized as cost of electricity services provided in the period they are charged.

JOINT VENTURE INVESTMENTS

The Corporation accounts for its interest in joint ventures using the proportionate consolidation method. Under this method, the Corporation records its share of the joint venture's assets, liabilities, revenues and expenses line-by-line on its financial statements.

BUSINESS COMBINATIONS

Business combinations are accounted for using the acquisition method. The acquired identifiable net assets are measured at their fair value at the date of acquisition. Any excess of the purchase price over the fair value of the net assets acquired is recognized as goodwill while any deficiency of the purchase price below the fair value of the net assets acquired is recorded as a gain in the period of acquisition. The associated transaction costs are expensed when incurred.

The Corporation allocates the purchase price of the acquisition to its identifiable assets acquired and liabilities assumed at their estimated fair values at the acquisition date. The allocation of purchase price involves uncertainty as assumptions are used to identify the acquired assets and liabilities assumed in the acquisition. Accepted valuation techniques are used to estimate purchase price allocation.

3. FUTURE ACCOUNTING CHANGES

INTERNATIONAL FINANCIAL REPORTING STANDARDS

On February 13, 2008, the Accounting Standards Board of Canada (AcSB) confirmed that the changeover from GAAP to International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB), would be effective for fiscal years beginning on or after January 1, 2011. Subsequent to February 13, 2008, AcSB issued amendments to this directive that allowed entities that have activities subject to rate regulation to delay adoption of IFRS until January 1, 2015.

On January 1, 2015, the Corporation will adopt IFRS for interim and annual consolidated statements, including comparative periods. While IFRS uses a conceptual framework similar to GAAP, there are still differences in accounting policies.

4. FINANCIAL INSTRUMENTS, HEDGES AND RISK MANAGEMENT

RISK ASSOCIATED WITH FINANCIAL INSTRUMENTS AND DERIVATIVES

	Measured Initially at Fair Value and Subsequently at Cost or Amortized Cost			Initially and Subsequently Measured at Fair Value		
As at December 31, 2014 and 2013	Accounts Receivable	Accounts Payable	Short- and Long-Term Debt	Cash and Cash Equivalents	Investments	Electricity and Natural Gas Derivatives
Market risk						
Commodity prices						√
Foreign exchange		√		√		√
Interest rate			√			
Equity price risk					√	
Credit risk	√			√	√	√
Liquidity risk		√	√			√

OVERVIEW OF RISK MANAGEMENT

ENMAX is exposed to market risk, credit risk and liquidity risk. The Corporation's strategy, policies and controls are designed to ensure that the risks it assumes comply with regulatory requirements, ENMAX's internal objectives and its risk tolerance. Risks are managed within limits approved by the Board and applied by senior management.

ENMAX builds and acquires energy infrastructure assets and enters into energy supply contracts to meet its demand obligations, purchases and sells commodities in North American markets both for resale and to manage market risk associated with generation output, enters transactions denominated in foreign currencies (U.S. dollars and Japanese Yen) and borrows funds over short- and long-term time horizons. These activities expose ENMAX to market risk from changes in commodity prices, foreign exchange rates and interest rates, which affect the Corporation's earnings and the value of associated financial instruments it holds.

MARKET RISK

ENMAX uses various contractual agreements and financial instruments to manage its energy portfolio and market risk exposures, including, but not limited to:

- Energy Services Agreements (ESA): the PPAs and tolling agreements convey the right to the buyer a level of capacity, electricity and ancillary services from a generating facility. ENMAX has entered into PPAs for electricity from units at the Keephills and Battle River coal-fired generation facilities. ENMAX has a tolling agreement for 100 per cent of the output of the McBride Lake Wind Farm (McBride).
- Swaps: contractual agreements between two parties to exchange streams of payments over time according to specified terms. ENMAX enters into commodity, cross-currency and interest rate swaps to mitigate the impact of changes in commodity prices, foreign exchange rates and interest rates.
- Forwards and futures: contractual agreements to purchase or sell a specific commodity or financial instrument at a specified price and date in the future. ENMAX enters into forwards and futures to mitigate the impact of volatility in commodity prices and foreign exchange rates.

- Options: contractual agreements to convey the right, but not the obligation, for the purchaser to buy or sell a specific amount of a commodity or financial instrument at a fixed price, either at a fixed date or at any time within a specified period. Occasionally, ENMAX enters into option agreements to mitigate the impact of changes in commodity prices, foreign exchange rates and interest rates.

COMMODITY PRICE RISK

ENMAX has inherent positions in electricity and natural gas commodities arising from its owned and controlled supply assets and its demand obligations. While ENMAX Energy's business model is designed to achieve a balanced portfolio, its electricity and natural gas positions experience periodic imbalances resulting in exposures to price volatility from spot or short-term contract markets. The Corporation purchases and sells electricity and natural gas commodities in the wholesale market to mitigate the risk exposures arising from such positions.

While the Corporation does not engage in speculative financial instrument trading, it uses various hedging strategies executed within a controlled environment to mitigate these commodity price risks, including the use of derivative instruments such as swaps and forwards. Hedging does not guard against all risks and is not always effective as it is based upon predictions about future market conditions. ENMAX could recognize financial losses as a result of volatility in the market values of these contracts.

RISK ANALYSIS AND CONTROL

ENMAX manages its exposure to market risk (interest rate risk, foreign currency exchange risk, commodity price risk and equity price risk) on a portfolio basis, which includes positions arising from its interests in generation facilities, liability positions arising from its commitments to its customers and transacting positions arising from its hedging activities.

SENSITIVITY ANALYSIS ON MARKET RISKS

The analysis below represents the effect of market risks on the Corporation's results as those risks apply to derivative financial instruments. Non-derivative financial instruments are recorded at cost. The carrying amounts of non-derivative financial instruments are not affected by changes in market variables whereas carrying amounts of derivative financial instruments are affected by market variables.

The following table reflects the sensitivity of the fair value of outstanding derivative instruments to reasonably possible changes in the markets of derivative financial instruments. Market interest rates impacted interest rate swaps for comparative periods. Interest rate swaps were settled on March 17, 2014. Foreign currency exchange rates impact commodity derivatives and foreign currency hedge contracts. Forward prices of natural gas and electricity impact commodity derivatives. The market value of equity investments impacts those instruments carried at fair value.

Certain assumptions have been made in arriving at the sensitivity analysis:

- The same fair value methodologies have been used as were used to obtain actual fair values in the fair values section of this note.
- Changes in the fair value of derivative instruments that are effective cash flow hedges are recorded in OCI.
- Changes in the fair value of derivative instruments that are not designated as hedges, that are fair value hedges or that are ineffective cash flow hedges are recorded in earnings.
- Foreign currency balances, principal and notional amounts are based on amounts as at December 31, 2014 and December 31, 2013.

- Interest rate sensitivities are based on Canadian dealer offered rates.
- Sensitivities are exclusive of any potential income tax impacts.

SENSITIVITIES OF MARKET RISKS

As at December 31
(millions of dollars)

	2014		2013	
	Earnings	OCI	Earnings	OCI
Interest rates increase 100 basis points (1% pure rate change)	–	–	+ 0.4	+ 11.2
Canadian dollar strengthens compared with the U.S. dollar by 10%	**-14.6**	**+0.5**	– 13.2	+ 0.6
Forward price of natural gas increases by 10%	**+1.9**	**+14.7**	–	+ 7.6
Forward price of electricity increases by 10%	–	**-5.5**	–	+ 14.8

These sensitivities are based on financial instruments carried at fair value, which include derivative contracts. The impact of a change in one factor may be compounded or offset by changes in other factors. This table does not consider the impact of any interrelationship among the factors or taxes. These sensitivities are not necessarily indicative of actual future results.

FOREIGN EXCHANGE AND INTEREST RATE RISK

Foreign exchange and interest rate risks are created by fluctuations in the fair values or cash flows of financial instruments due to changes in foreign exchange rates and/or changes in the market interest rates.

ENMAX is not exposed to significant interest rate risk or volatility as a result of the issuance of fixed-rate long-term debt and the use of interest rate hedging instruments. The fair value of ENMAX's long-term debt and any associated interest rate hedging instruments change as interest rates change, assuming all other variables remain constant. For example, a 1 per cent increase (decrease) in interest rates as at December 31, 2014, would have an effect on fair value of fixed interest rate debt of $130.1 million decrease (increase) (December 31, 2013—$92.4 million).

Changes in the value of the Canadian dollar relative to the U.S. dollar could impact the Canadian dollar cost of natural gas, which affects the input cost of the Corporation's natural-gas-fuelled generation capacity, as well as the cost to the Corporation of offering fixed price gas contracts to its customers. The foreign exchange impact on these gas purchases is offset, when possible, by foreign exchange contracts. Foreign exchange exposure resulting from procurement contracts has also been mitigated by foreign exchange contracts.

CREDIT RISK

ENMAX is exposed to credit risk primarily through its wholesale and retail energy sales business. Credit risk is the loss that may result from counterparties' non-performance. ENMAX evaluates the credit risk of wholesale and retail competitive supply activities separately as discussed below.

The Corporation's maximum financial statement exposure to credit risk is the carrying value of the financial assets, as set out in the table below. This maximum exposure does not necessarily reflect losses expected by management nor does it necessarily reflect losses experienced in the past.

FINANCIAL ASSETS

As at December 31 *(millions of dollars)*	2014	2013
Cash and cash equivalents (Note a)	**16.7**	80.6
Accounts receivable (Note b)	**606.5**	665.5
Other current assets (Note c)	**85.8**	42.6
Other long-term assets (Note c)	**36.7**	57.0

(a) Cash and Cash Equivalents

Credit risk associated with cash and cash equivalents is minimized substantially by ensuring these financial assets are placed with governments, well-capitalized financial institutions and other creditworthy counterparties. Continuous reviews are performed to evaluate changes in the creditworthiness of counterparties.

(b) Accounts Receivable

The majority of the Corporation's accounts receivable are exposed to credit risk. Exposure to credit risk occurs through competitive electricity and natural gas supply activities, which serve residential, commercial and industrial customers. The risk represents the loss that may be incurred due to the non-payment of a customer's accounts receivable balance, as well as the loss that may be incurred from the resale of energy previously allocated to serve the customer.

Charges to earnings as a result of credit losses for the Corporation for 2014 totalled $18.5 million (2013 – $6.8 million). Management monitors credit risk exposure and has implemented measures to mitigate losses. In specific situations, this includes, but is not limited to, a reduction of credit limits, requests for additional collateral or restrictions on new transaction terms.

AGING ANALYSIS OF TRADE RECEIVABLES PAST DUE BUT NOT IMPAIRED

As at December 31 *(millions of dollars)*	2014	2013
1–30 days past due	**16.7**	31.6
31–60 days past due	**4.7**	3.4
61 days or more past due	**13.1**	10.0
Total past due	**34.5**	45.0

CHANGES IN THE ALLOWANCE FOR DOUBTFUL ACCOUNTS

As at December 31 *(millions of dollars)*	2014	2013
Provision at the beginning of the year	**7.8**	6.7
Increase to allowance	**18.5**	6.8
Recoveries and write-offs	**(7.2)**	(5.7)
Provision at end of the year	**19.1**	7.8

The remainder of the accounts receivable balance outstanding at December 31, 2014, consists of unbilled revenue accruals. No provision has been recorded due to the minimal credit risk at the consolidated balance sheet date.

(c) Other Current and Long-Term Assets

ENMAX measures wholesale credit risk as the replacement cost for open energy commodity and derivative transactions (both mark-to-market and accrual), adjusted for amounts owed to or due from counterparties for settled transactions and all other amounts owing but not yet due. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where the Corporation has a legally enforceable right to offset and intends to settle on a net basis. ENMAX monitors and manages the credit risk of wholesale operations through credit policies and procedures that include an established credit approval process, daily monitoring of counterparty credit limits and the use of credit mitigation measures such as margin, collateral, letters of credit and/or prepayment arrangements.

Due to the possibility of extreme volatility in the prices of energy commodities and derivatives, the market value of contractual positions with individual counterparties could exceed established credit limits or collateral provided by those counterparties. If such a counterparty were to fail to perform its obligations under its contract (for example, fail to provide adequate assurances or credit support), ENMAX could incur a loss that could have a material impact on its financial results.

Additionally, if a counterparty were to default and the Corporation were to liquidate all contracts with that entity, the credit loss would include the loss in value of mark-to-market contracts, the amount owed for settled transactions and unbilled deliveries and additional payments, if any, that would have to be made to settle unrealized losses on accrual contracts.

The majority of counterparties enabled for wholesale transactions are rated investment grade (BBB- or higher) by recognized rating agencies.

LIQUIDITY RISK

Liquidity risk is that ENMAX will not be able to meet its financial obligations as they fall due. The Corporation's approach to managing liquidity risk is to ensure it always has sufficient cash and credit facilities to meet its obligations when due.

The following table details the remaining contractual maturities for ENMAX's current and long-term non-derivative financial liabilities, including both the principal and interest cash flows:

CONTRACTUAL MATURITIES OF NON-DERIVATIVE FINANCIAL LIABILITIES

As at December 31 *(millions of dollars)*	2014	2013
2015	**609.7**	123.9
2016	**143.7**	137.3
2017	**120.9**	116.2
2018	**409.9**	406.3
2019	**95.0**	93.5
Thereafter	**1,325.7**	1,009.8

The following table details the remaining contractual maturities for ENMAX's derivative financial liabilities:

CONTRACTUAL MATURITIES OF DERIVATIVE FINANCIAL LIABILITIES

As at December 31 *(millions of dollars)*	2014	2013
2015	**95.9**	21.5
2016	**11.3**	9.6
2017	**3.9**	6.4
2018	**2.8**	4.4
2019	**2.1**	3.5
Thereafter	**3.2**	2.5

VALUATION OF DERIVATIVE ASSETS AND LIABILITIES

Financial derivative instruments are recorded on the consolidated balance sheet at fair value. As at December 31, 2014, the mark-to-market adjustment based on the fair value of these hedge contracts resulted in unrealized gains or losses on derivative instruments, which are included in the consolidated balance sheets as per the table below:

As at December 31 *(millions of dollars)*	2014		2013	
	Hedge Instruments	Non-Hedge Derivatives	Hedge Instruments	Non-Hedge Derivatives
Assets				
Current	**44.1**	**14.9**	19.7	9.9
Non-current	**14.0**	**1.0**	18.3	8.1
Liabilities				
Current	**71.5**	**24.4**	19.6	9.4
Non-current	**23.3**	**-**	22.8	25.1

Cash flow hedges are used to manage the variability of cash flows resulting from the purchase and sale of electricity and natural gas, as well as foreign exchange exposure. For cash flow hedges, changes in the fair value of the effective portion of the hedging derivative are accumulated in OCI and recognized in net earnings during the periods when the variability in cash flows of the hedged item is realized. In 2014, there were losses of $9.1 million (2013—$7.8 million in losses) recognized in earnings as a reflection of the ineffectiveness of the relevant hedges. Gains and losses on cash flow hedges are reclassified immediately to net earnings when the hedged item is sold or terminated early, or when a hedged anticipated transaction is no longer likely to occur. During 2014, there was an $11.2 million impact to earnings (2013—nil), related to the interest rate swap hedge that was terminated, on March 17, 2014, upon repayment of the non-recourse term financing.

The Corporation estimates that of the $33.8 million of losses reported in accumulated OCI as at December 31, 2014, losses of $27.4 million are expected to be realized within the next 12 months, which will be offset by long-term losses at market prices in effect at the time of settlement.

Non-hedge derivatives are classified as held for trading and recognized at fair market value with changes in fair market value being recorded through earnings. During 2014, there were gains of $8.0 million (2013—$7.8 million loss) recorded in net earnings.

FAIR VALUE

Fair value of financial instruments and derivatives is determined by reference to quoted bid or asking price, as appropriate, in active markets at reporting dates. In the absence of an active market, the Corporation determines fair value by using valuation techniques that refer to observable market data or estimated market prices. Fair values determined using valuation models require the use of assumptions about the amount and timing of estimated future cash flows and discount rates. In making these assumptions, ENMAX gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level I) and the lowest priority to unobservable inputs (Level III), as applicable.

Level Determination and Classifications

The Level I, II and III classifications in the fair value hierarchy used by the Corporation are defined as follows:

Level I

Fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Corporation has the ability to access. In determining Level I, the Corporation uses quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange and the Natural Gas Exchange.

Level II

Fair values are determined using inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly.

Fair values are determined using inputs, including interest rate yield curves, forward market rates, quoted commodity prices or credit spreads that are readily observable and reliable or for which unobservable inputs are deemed to be insignificant to the fair values that are categorized as Level II.

Commodity contracts' fair values falling within the Level II category are determined through the use of quoted prices in active markets adjusted for factors specific to the asset or liability. Level II fair values include those determined using pricing applications for creating power curves where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets.

Interest rate swap contract fair values falling within the Level II fair values include those determined by using a benchmark index and applying that index to the notional debt outstanding.

Level III

The fair values are determined using significant unobservable data or inputs.

In rare circumstances, ENMAX enters into commodity transactions with non-standard features for which market-observable data are not available. In these cases, Level III fair values are determined using valuation techniques with inputs that are based on historical data.

FAIR VALUES OF THE CORPORATION'S FINANCIAL ASSETS AND LIABILITIES

As at December 31, 2014 *(millions of dollars)*	Quoted Prices in Active Markets (LEVEL I)	Significant Other Observable Inputs (1) (LEVEL II)	Significant Unobservable Inputs (2) (LEVEL III)	TOTAL
Financial assets measured at fair value:				
Energy trading forward contracts	7.3	50.0	9.2	66.5
Foreign currency forward contracts	–	7.5	–	7.5
Financial assets total	7.3	57.5	9.2	74.0
Financial liabilities measured at fair value:				
Energy trading forward contracts	(7.2)	(111.9)	–	(119.1)
Foreign currency forward contracts	–	(0.1)	–	(0.1)
Financial liabilities total	(7.2)	(112.0)	–	(119.2)
Net risk management assets (liabilities)	0.1	(54.5)	9.2	(45.2)

(1) Excludes financial assets and liabilities where carrying value approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities).

(2) Market-observable data are not available. Fair values are determined using valuation techniques.

FAIR VALUES OF THE CORPORATION'S FINANCIAL ASSETS AND LIABILITIES

As at December 31, 2013 *(millions of dollars)*	Quoted Prices in Active Markets (LEVEL I)	Significant Other Observable Inputs (1) (LEVEL II)	Significant Unobservable Inputs (2) (LEVEL III)	TOTAL
Financial assets measured at fair value:				
Energy trading forward contracts	–	27.1	11.1	38.2
Foreign currency forward contracts	–	6.9	–	6.9
Interest rate swap	–	10.9	–	10.9
Financial assets total	–	44.9	11.1	56.0
Financial liabilities measured at fair value:				
Energy trading forward contracts	–	(41.4)	–	(41.4)
Interest rate swap	–	(35.5)	–	(35.5)
Financial liabilities total	–	(76.9)	–	(76.9)
Net risk management assets (liabilities)	–	(32.0)	11.1	(20.9)

(1) Excludes financial assets and liabilities where carrying value approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities).

(2) Market-observable data are not available. Fair values are determined using valuation techniques.

The following table summarizes the key factors impacting the change in the fair value of the Corporation's Level III net risk management assets and liabilities separately by source of valuation during the year:

CHANGE IN FAIR VALUE OF LEVEL III RISK MANAGEMENT ASSETS AND LIABILITIES

(millions of dollars)	Hedges
Net risk management assets as at December 31, 2013	11.1
Changes attributable to:	
Commodity price changes	0.7
New contracts entered	0.1
Transfers in/out of Level III	(2.7)
Net risk management assets as at December 31, 2014	9.2
Total change in fair value included in OCI	(2.0)
Total change in fair value included in pre-tax earnings	–

VALUATION OF NON-DERIVATIVE FINANCIAL ASSETS AND LIABILITIES

Cash, cash equivalents and restricted cash are recorded at fair market value. Fair values for accounts receivable, short-term debt, accounts payable and accrued liabilities are not materially different from their carrying amounts due to their short-term nature.

The fair value of the Corporation's long-term debt was estimated based on quoted market prices for the same or similar debt instruments. When such information was not available, future payments of interest and principal were discounted at estimated interest rates that were made available to ENMAX for comparable credit-rated entities to the Corporation.

CARRYING AMOUNTS AND FAIR VALUES OF LONG-TERM DEBT

As at December 31 *(millions of dollars)*	2014		2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt [1], consisting of:				
Debentures, with remaining terms of				
Less than 5 years	**63.2**	**65.8**	34.0	35.4
6–10 years	**85.8**	**93.7**	122.4	132.4
11–15 years	**21.8**	**25.4**	14.4	16.1
16–20 years	**269.7**	**316.5**	187.1	205.6
21–25 years	**648.3**	**690.8**	557.6	571.6
Private debentures				
Series 1 (6.15%)	**298.5**	**339.8**	298.2	338.8
Series 3 (3.81%) [2]	**198.5**	**201.5**	-	-
Non-recourse Kettles Hill Wind Farm (Kettles) term financing (2013 amount includes CEC non-recourse debt [3])	**19.9**	**21.6**	220.5	207.2
Promissory note	**4.6**	**4.8**	4.8	4.9
	1,610.3	**1,759.9**	1,439.0	1,512.0

(1) Includes current portion of $62.6 million (December 31, 2013—$63.7 million). Maturity dates range from May 2015 to June 2039.
(2) On December 5, 2014, $200.0 million of Series 3 Private Debentures were issued for a 10-year term with a coupon rate of 3.81 per cent.
(3) On March 17, 2014, $200.6 million of non-recourse term financing related to Calgary Energy Centre (CEC) was repaid.

5. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

Under regulatory accounting, the timing of recognition of certain assets, liabilities, revenues and expenses may differ from what is otherwise expected under GAAP for non-regulated operations. ENMAX has recorded the following regulatory assets and liabilities:

REGULATORY ASSETS AND LIABILITIES

As at December 31 *(millions of dollars)*	2014	2013
Regulatory assets		
Accounts receivable (Note a)	**18.5**	41.5
Distribution and transmission assets: Inter-company profit on construction of regulated PPE (Note b)	**39.9**	38.4
Other regulatory assets (Note c)	**46.5**	42.2
Total regulatory assets	**104.9**	122.1
Regulatory liabilities		
Other regulatory liabilities (Note d)	**2.5**	1.9
Total regulatory liabilities	**2.5**	1.9

The following describes each of the circumstances in which rate regulation affects the accounting for a transaction or event. Regulatory assets represent future revenues associated with certain costs, incurred in the current period or in prior periods, which are expected to be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that are expected to be returned to customers as a result of the rate-setting process.

(a) Accounts Receivable

Accounts receivable represent a price-only deferral account for transmission charges from the Alberta Electric System Operator (AESO). In the absence of rate regulation, GAAP would require that actual costs be recognized as an expense when incurred. In this case, operating results for 2014 would have been $23.0 million higher (2013—$19.8 million lower). The regulatory assets are included in accounts receivable.

(b) Inter-Company Profit on Construction of Regulated Property, Plant and Equipment

Distribution assets for the regulated operations of ENMAX Power include intercompany profit relating to construction work performed by an ENMAX subsidiary. Such profit is deemed for regulatory purposes to be realized to the extent that the transfer price is recognized for rate-making purposes by the regulator and included in the capital cost. In the absence of rate regulation, GAAP would require that intercompany profits be eliminated upon consolidation. If these intercompany profits had been eliminated, the impact on earnings for 2014 would be a reduction of $1.5 million (2013—$1.1 million increase) representing the profit or loss on these services. The balances for PPE and retained earnings at December 31, 2014, would be further reduced by $39.9 million (December 31, 2013—$38.4 million reduction).

(c) Other Regulatory Assets

Other regulatory assets primarily relate to the Alberta Utilities Commission (AUC) flow-through items and other costs that will be collected from customers through future rates such as access service charges. Timing of the decision on collection of these items can result in significant fluctuation in balances from year to year.

(d) Other Regulatory Liabilities

Other regulatory liabilities primarily relate to items that will be refunded to customers through future rates.

For certain regulatory items identified above, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the regulator in determining the item's treatment for rate-setting purposes. For example, ENMAX's treatment of purchased power costs is dependent on the continued use of an automatic adjustment mechanism for regulatory purposes and would require reconsideration if the regulator decided to discontinue the use of this mechanism or to require ENMAX Power to absorb cost variances in a particular year. Similarly, there is a risk the regulator may disallow a portion of certain costs incurred in the current period for recovery through future rates or disagree with the proposed recovery period.

OTHER ITEMS AFFECTED BY RATE REGULATION

Current regulations exclude the Corporation's transmission, distribution and regulated rate electricity sales earnings from corporate income taxes, although regulated rate electricity sales are subject to PILOT. Accordingly, ENMAX Power has not recognized current or future corporate income taxes on tax-exempt earnings. In the event regulations change, it would be expected that when these amounts became payable, they would be recovered through future rate revenues.

Gains and losses on the disposal and retirement of regulated depreciable assets are deferred and amortized over the estimated remaining service life of similar assets, through a charge to accumulated amortization equal to the net book value of the disposed or retired asset. In the absence of rate regulation, under GAAP the difference between the proceeds and net book value would be charged or credited to earnings in the period the asset is disposed of or retired. The amount deferred from current period earnings for the year ended December 31, 2014, was a $1.0 million loss (2013—$11.5 million loss) representing the gains and losses on disposals and retirements of regulated assets.

6. INCOME TAXES

RECONCILIATION OF INCOME TAX EXPENSE

Year ended December 31 *(millions of dollars)*	2014	2013
Earnings before income taxes from continuing operations	157.1	171.4
Income not subject to taxes	(261.4)	(201.6)
	(104.3)	(30.2)
Federal and provincial tax rate	25.0%	25.0%
Expected income tax expense	(26.0)	(7.5)
Non-deductible expenses	6.9	3.2
Adjustment for future tax reversal and other estimate revisions	21.2	2.3
Income taxes on continuing operations	2.1	(2.0)

The tax effects of temporary differences and loss carry-forwards that give rise to significant portions of the Corporation's future income tax asset and future income tax liability are presented below:

FUTURE INCOME TAX ASSET AND LIABILITY

As at December 31 *(millions of dollars)*	2014	2013
Future income tax asset:		
PPAs [(1)]	**(12.0)**	11.3
PPE-differences in net book value and undepreciated capital	**5.0**	4.8
Cumulative eligible capital	**6.1**	6.1
Other	**-**	0.1
Non-capital loss carry-forwards	**34.5**	45.9
Unrealized derivative	**3.9**	4.0
OCI	**2.9**	(4.5)
	40.4	67.7
Less current portion	**(16.6)**	(8.7)
	23.8	59.0
Future income tax liability:		
PPE-difference in net book value and undepreciated capital cost	**92.0**	103.0
PPAs	**17.6**	20.7
Non-capital loss carry-forwards	**(40.5)**	(12.6)
OCI	**-**	(2.8)
Mark-to-market liability	**0.8**	(1.1)
Other	**(7.6)**	(6.6)
	62.3	100.6
Less current portion	**(0.9)**	(0.5)
	61.4	100.1
Net future income tax liability	**(21.9)**	(32.9)

(1) Under PILOT, certain assets of the Corporation were deemed to be disposed of and reacquired at fair market value for tax purposes on December 31, 2000. This resulted in tax values in excess of book value for these assets.

As at December 31, 2014, the Corporation has non-capital loss carry-forwards that will be used to offset taxes in future years. These non-capital loss carry-forwards expire as follows:

NON-CAPITAL LOSS CARRY FORWARD

(millions of dollars)	2014
2027	**1.8**
2028	**19.6**
2029	**22.5**
2030	**22.0**
2031	**2.2**
2032	**7.3**
2033	**46.2**
2034	**52.7**
	174.3

7. OTHER ASSETS AND LIABILITIES

As at December 31 *(millions of dollars)*	2014	2013
Other current assets		
Hedge instruments	44.1	19.7
Non-hedge derivatives	14.9	9.9
Prepaid expenses	26.3	12.3
Inventory	0.5	0.7
	85.8	42.6
Other long-term assets		
Hedge instruments	14.0	18.3
Non-hedge derivatives	1.0	8.1
Restricted cash	–	8.4
Shares in other companies	0.1	0.1
Prepaid expenses	4.8	3.6
Long-term accounts receivable	7.3	9.2
Other	9.5	9.3
	36.7	57.0
Other current liabilities		
Hedge instruments	71.5	19.6
Non-hedge derivative	24.4	9.4
Deposits	27.9	18.6
Deferred revenue	12.0	5.2
	135.8	52.8
Other long-term liabilities		
Hedge instruments	23.3	22.8
Non-hedge derivative	-	25.1
Long-term payables	6.7	8.0
Deferred revenue	5.2	4.8
	35.2	60.7

8. ASSETS HELD FOR SALE

On February 28, 2013, the Corporation sold a 25 per cent interest in Shepard Energy Center (Shepard) to Capital Power (Alberta) LP (CPLP). This was the first of a two-part purchase and sale arrangement entered into on December 5, 2012. On September 30, 2013, CPLP completed the second and final part of the arrangement and purchased an additional 25 per cent interest in Shepard.

On April 8, 2013, ENMAX entered into an agreement to sell ENMAX Envision Inc. (Envision), its high-speed data communications subsidiary, which operates a fibre-optic network that provides large bandwidth solutions to Calgary businesses. On April 30, 2013, ENMAX sold Envision to Shaw Communications Inc. for net cash consideration of $221.9 million. Transaction costs related to the sale totalled $5.7 million. The net gain on sale of Envision was $175.9 million. The net assets of Envision sold consisted of cash of $0.4 million, total assets other than cash of $47.5 million and total liabilities of $7.6 million. From December 31, 2012, until April 30, 2013, the assets and liabilities of Envision were reclassified to assets and liabilities held for sale on the consolidated balance sheets, and its operating results are included in net earnings from discontinued operations on the consolidated statements of earnings and comprehensive income.

NET EARNINGS FROM DISCONTINUED OPERATIONS

Year ended December 31 *(millions of dollars)*	2014	2013
REVENUE		
Contractual services	-	8.7
Other	-	0.2
TOTAL REVENUE	-	8.9
COST OF SERVICES PROVIDED		
Contractual services	-	1.5
OM&A	-	2.3
COST OF SERVICES PROVIDED	-	3.8
Gain on sale	-	175.9
Amortization	-	1.8
Interest	-	0.1
NET EARNINGS FROM DISCONTINUED OPERATIONS (1)	-	179.1

(1) Net earnings from discontinued operations related to Envision.

9. RESTRICTED CASH

Cash and cash equivalents includes restricted cash of $0.1 million (2013–$0.5 million) relating to margin posted with a financial institution. This margin is required as a result of the Corporation's commodity trading activity.

Other long-term assets include restricted cash and cash equivalents of nil (2013—$8.4 million), relating to a debt servicing obligation on a non-recourse financing arrangement. The non-recourse financing was repaid during 2014; there is no further requirement to retain restricted cash (see Note 16).

10. BUSINESS COMBINATIONS

Cavalier Power Station

On September 16, 2014, the Corporation acquired Encana Power and Processing ULC's 100 per cent interest in the assets of the Cavalier Power Station (Cavalier) for $169.2 million. The Corporation acquired Cavalier to increase its generation capacity. Cavalier is a natural-gas-fuelled generation plant located southeast of Strathmore, Alberta. The results of operations for these assets have been included in the consolidated financial statements since that date.

ASSETS ACQUIRED AND LIABILITIES RECOGNIZED AT THE DATE OF ACQUISITION

(millions of dollars)	
Property, plant and equipment	171.8
Asset retirement obligation	(2.6)
Fair value of net assets acquired	169.2

PURCHASE CONSIDERATION:

(millions of dollars)	
Cash	169.2
Other consideration	-
	169.2

The purchase price adjustments for the acquisition are not finalized but have been provisionally determined as at December 31, 2014. If new information—obtained within one year of the acquisition date—identifies additional items or adjustments, then the acquisition accounting will be revised.

The acquisition of Cavalier has resulted in revenues of $5.0 million and overall net loss of $2.9 million for the period subsequent to September 16, 2014. Acquisition related costs amounting to $1.9 million have been expensed in the current year within operations, maintenance and administration (OM&A).

Had the acquisition occurred on January 1, 2014, management estimates that consolidated 2014 revenues would have increased by an additional $30.2 million, and consolidated 2014 earnings would have increased by $6.9 million.

11. PROPERTY, PLANT AND EQUIPMENT

As at December 31, 2014 *(millions of dollars)*	Cost	Accumulated Amortization	Net Book Value
Transmission, distribution and substation equipment	2,214.9	(634.7)	1,580.2
Generation facilities and equipment (1) (2)	1,267.8	(275.8)	992.0
Construction in progress (3)	1,073.3	–	1,073.3
Buildings and site development	266.5	(73.0)	193.5
Tools, systems and equipment	103.9	(70.5)	33.4
Land	36.9	–	36.9
Capital spares and other	39.3	–	39.3
Vehicles	33.6	(13.1)	20.5
	5,036.2	(1,067.1)	3,969.1
Government grants	(20.0)	3.0	(17.0)
Contributions in aid of construction	(580.8)	112.4	(468.4)
	4,435.4	(951.7)	3,483.7

(1) Includes acquisition of Cavalier generating asset in the amount of $171.8 million and Balzac Power Station (Balzac) generating asset in the amount of $57.2 million.

(2) Kettles assets were impaired in the amount of $17.8 million.

(3) Includes construction costs in the amount of $867.2 million related to ENMAX's 50 per cent interest in Shepard.

As at December 31, 2013 *(millions of dollars)*	Cost	Accumulated Amortization	Net Book Value
Transmission, distribution and substation equipment	2,024.7	(577.6)	1,447.1
Generation facilities and equipment	1,040.1	(218.6)	821.5
Construction in progress (1)	922.5	–	922.5
Buildings and site development	208.9	(65.9)	143.0
Tools, systems and equipment	93.9	(65.4)	28.5
Land	34.5	–	34.5
Capital spares and other	33.6	–	33.6
Vehicles	32.8	(12.7)	20.1
	4,391.0	(940.2)	3,450.8
Government grants	(20.0)	2.3	(17.7)
Contributions in aid of construction	(509.4)	98.9	(410.5)
	3,861.6	(839.0)	3,022.6

(1) Includes construction costs in the amount of $745.0 million related to ENMAX's 50 per cent interest in SEC.

12. POWER PURCHASE ARRANGEMENTS

Under the Keephills PPA, which was acquired in 2000 and expires December 2020, the Corporation owns the rights to the physical output of two electrical generating units. Under the Battle River PPA, which was acquired in stages from 2006 to 2010, Battle River 3 and 4 expired at the end of 2013 and Battle River 5 expires in 2020.

As at December 31, 2014 *(millions of dollars)*	Cost	Accumulated Amortization	Net Book Value
Battle River	**572.0**	**(320.5)**	**251.5**
Keephills	**256.5**	**(191.3)**	**65.2**
	828.5	**(511.8)**	**316.7**

As at December 31, 2013 *(millions of dollars)*	Cost	Accumulated Amortization	Net Book Value
Battle River	572.0	(278.6)	293.4
Keephills	256.5	(180.4)	76.1
	828.5	(459.0)	369.5

13. INTANGIBLE ASSETS AND GOODWILL

As at December 31, 2014 *(millions of dollars)*	Cost	Accumulated Amortization	Net Book Value
Computer systems	**251.0**	**(177.4)**	**73.6**
Renewable energy certificates and water licenses (1)	**12.4**	**(9.4)**	**3.0**
Customer lists and contracts	**20.0**	**(20.0)**	**-**
Land easements, rights and lease options	**3.1**	**(2.7)**	**0.4**
Work in progress	**59.7**	**–**	**59.7**
	346.2	**(209.5)**	**136.7**

(1) Kettles intangible assets were impaired in the amount of $0.6 million.

As at December 31, 2013 *(millions of dollars)*	Cost	Accumulated Amortization	Net Book Value
Computer systems	272.9	(191.6)	81.3
Renewable energy certificates and water licenses	12.4	(7.5)	4.9
Customer lists and contracts	20.0	(17.9)	2.1
Land easements, rights and lease options	3.1	(2.7)	0.4
Work in progress	35.6	–	35.6
	344.0	(219.7)	124.3

In accordance with GAAP, the carrying value of goodwill is tested for impairment on an annual basis or when events or circumstances indicate that the related carrying value may not be recoverable. As at December 31, 2014, the Corporation tested Kettles goodwill for impairment as a result of the current market conditions. Kettles wind farm assets carrying value was assessed, including PPE and intangible asset and goodwill, via estimated after-tax discounted future cash flows of the assets to determine the estimated fair value.

Kettles was impaired by $34.4 million. Goodwill had a carrying value of $16.0 million of which $16.0 million was impaired. PPE was impaired by $17.8 million and intangible assets was impaired by $0.6 million. Kettles assets are a component of ENMAX Energy.

14. EMPLOYEE FUTURE BENEFITS

The Corporation has a registered pension plan that substantially covers all employees and includes both DB and DC provisions. The DB provisions provide a pension based on years of service and highest average earnings over five consecutive years of employment. DB pension benefits under the registered plan will increase annually by at least 60 per cent of the consumer price index for Alberta. Under the DC provisions, employer contributions are based on the participating members' pensionable earnings and contribution levels.

The Corporation also sponsors a supplemental pension plan providing an additional DB pension based on years of service and highest average earnings (including incentive pay) to both DB and DC members whose benefits are limited by maximum pension rules under the ITA. The supplemental pension plan benefits do not automatically increase. In addition, the Corporation provides employees with post-retirement benefits other than pensions, including extended health and dental benefits beyond those provided by government-sponsored plans, life insurance and a lump-sum allowance payable at retirement, up to age 65.

Total cash payments for employee future benefits for 2014, consisting of cash contributed by the Corporation under the DB and DC provisions of the registered pension plan and cash payments directly to beneficiaries of the Corporation's unfunded other-benefit plans, were $21.4 million (2013 – $29.1 million).

For the year ended December 31, 2014, the total expense for the DC provisions of the plan is $8.9 million (2013— $8.5 million).

Information about the DB provisions of the plan, including the supplemental pension plan and the post-retirement non-pension benefit plan, is as follows:

DB PROVISION, INCLUDING SUPPLEMENTAL PENSION PLAN AND POST-RETIREMENT NON-PENSION BENEFIT PLAN

Years ended December 31 *(millions of dollars)*	2014		2013	
	Pension Benefit Plan	Other Benefit Plan	Pension Benefit Plan	Other Benefit Plan
Change in benefit obligation:				
Benefit obligation, beginning of year	268.1	11.2	273.7	11.1
Current service cost	8.8	0.9	8.7	1.0
Employee contributions	3.1	–	2.8	–
Benefits paid	(15.5)	(0.7)	(16.1)	(0.6)
Interest cost	12.0	0.5	11.0	0.4
Non-investment	(0.4)	–	(0.5)	–
Experience gain (loss)	34.9	(0.6)	(11.5)	(0.7)
Benefit obligation, end of year	311.0	11.3	268.1	11.2
Change in plan assets:				
Plan assets at market-related value, beginning of year	223.8	–	202.1	–
Employer contributions	11.5	0.7	19.4	0.6
Employee contributions	3.1	–	2.8	–
Benefits paid	(15.5)	(0.7)	(16.1)	(0.6)
Non-investment expenses	(0.4)	–	(0.5)	–
Return on plan assets	14.5	–	13.5	–
Acquisitions and divestitures	–	–	–	–
Experience loss	6.8	–	2.6	–
Plan assets at market-related value, end of year	243.8	–	223.8	–
Deferred investment gain	22.2	–	12.3	–
Plan assets at fair value, end of year	266.0	–	236.1	–
Funded status-plan deficit	(45.0)	(11.3)	(32.0)	(11.2)
Unamortized past service cost	–	(0.5)	–	(0.6)
Unamortized experience losses	77.0	1.4	64.5	2.1
Accrued benefit asset (liability)	32.0	(10.4)	32.5	(9.7)

Plan assets at December 31, 2014, consist of Canadian equity securities of 28 per cent (2013—30 per cent), foreign equity securities of 32 per cent (2013—31 per cent), long-term fixed-income securities of 40 per cent (2013—37 per cent) and cash and short-term securities of 2 per cent (2013—2 per cent).

NET BENEFIT COST

Years ended December 31	2014		2013	
(millions of dollars)	Pension Benefit Plan	Other Benefit Plan	Pension Benefit Plan	Other Benefit Plan
Current service costs	8.8	0.9	8.7	0.9
Interest cost	12.0	0.5	11.0	0.4
Actual return on assets	(31.2)	–	(24.4)	–
Actuarial gains	34.9	(0.6)	(11.5)	(0.7)
Difference between expected and actual return	16.7	–	10.9	–
Difference between recognized and actual actuarial gains	(29.2)	0.7	19.5	0.8
Difference between amortization of past service costs and actual plan	–	–	–	–
Net benefit plan expense	12.0	1.4	14.2	1.4

The significant weighted-average actuarial assumptions adopted in measuring the Corporation's accrued benefit obligations and net benefit plan expense are as follows:

SIGNIFICANT WEIGHTED-AVERAGE ACTUARIAL ASSUMPTIONS

Years ended December 31	2014		2013	
(%)	Pension Benefit Plan	Other Benefit Plan	Pension Benefit Plan	Other Benefit Plan
Accrued benefit obligation:				
Discount rate	**3.75**	**3.50**	4.50	4.50
Rate of compensation increase	**3.25**	**3.25**	3.25	3.25
Health care cost trend rate for next year	**n/a**	**7.00**	n/a	8.00
Decreasing gradually to 5% in the year	**n/a**	**2021**	n/a	2020
Benefit cost:				
Discount rate	**4.50**	**4.25**	4.00	3.75
Expected long-term rate of return on plan assets	**6.50**	**n/a**	6.50	n/a
Rate of compensation increase	**3.25**	**3.25**	3.25	3.50
Health care cost trend rate for next year	**n/a**	**8.00**	n/a	8.00
Decreasing gradually to 5% in the year	**n/a**	**2020**	n/a	2020

The per capita cost of covered dental benefits was assumed to increase by 4.5 per cent per year (2013—4.5 per cent).

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plan. A one-percentage-point change in the assumed health care cost trend rate would have the following effect for 2014:

ONE-PERCENTAGE-POINT CHANGE IN ASSUMED HEALTH CARE COST TREND RATE

(millions of dollars)	1% increase	1% decrease
Increase (decrease) in service cost for year ended December 31	–	–
Increase (decrease) in interest cost for year ended December 31	–	–
Increase (decrease) in accrued benefit obligation at December 31	0.3	(0.3)

15. SHORT-TERM DEBT

The Corporation has unsecured credit facilities amounting to $1,150.0 million (December 31, 2013—$1,150.0 million) to fund general operating requirements and to provide liquidity support for commercial paper and commodity marketing programs. Combined, all of the facilities encompass $900.0 million in bilateral credit facilities and $250.0 million of syndicated credit facilities. As at December 31, 2014, $219.0 million (2013—$273.9 million) of operating facilities and $30.0 million (2013—$30.0 million) of syndicated facilities were used in support of outstanding letters of credit.

Short-term debt is comprised of commercial paper and bank overdrafts, which is backed by the Corporation's credit facilities. At December 31, 2014, the Corporation had $27.3 million in bank overdrafts at a weighted average interest rate of 3.0% (December 31, 2013—nil).

16. LONG-TERM DEBT

As at December 31 *(millions of dollars)*	2014	Weighted Average Interest Rates	2013	Weighted Average Interest Rates
City debentures [(1)], with remaining terms of:				
Less than 5 years	**63.2**	**3.41%**	34.0	4.20%
5 – 10 years	**85.8**	**4.30%**	122.4	4.39%
10 – 15 years	**21.8**	**4.85%**	14.4	4.85%
15 – 20 years	**269.7**	**4.61%**	187.1	4.57%
20 – 25 years	**648.3**	**3.68%**	557.6	3.93%
Private debenture [(1)]	**497.0**	**5.21%**	298.2	6.15%
Non-recourse financing	**19.9**	**5.86%**	220.5	6.45%
Promissory note	**4.6**	**5.00%**	4.8	5.00%
	1,610.3		1,439.0	
Less: current portion	**62.6**		63.7	
	1,547.7		1,375.3	

(1) Unsecured debentures.

CITY DEBENTURES

Debentures were initially issued by The City on behalf of the CES pursuant to City bylaw authorizations prior to January 1, 1998. Pursuant to the master agreement between the Corporation and The City, the debentures were included in the assumed liabilities upon transfer of substantially all of the assets and liabilities of the CES from The City to the Corporation at January 1, 1998. In accordance with a debt management service level agreement between the Corporation and The City, The City continues to administer the new and existing debentures on behalf of the Corporation.

On June 15, 2014, the Corporation obtained $232.1 million of 5-, 10-, 20- and 25-year unsecured debentures from The City through arrangements with the Alberta Capital Finance Authority (ACFA) (June 2013–$140.6 million in 5-, 10-, 20- and 25-year debentures). Interest on the debentures is compounded semi-annually as follows: $21.8 million, which matures in June 2019, at 1.72 per cent; $3.7 million, maturing in June 2024, at 2.51 per cent; $15.7 million, maturing in June 2034, at 3.24 per cent; and the remaining $190.9 million of the debt, which matures in June 2039, at 3.51 per cent. The funds were used for capital expenditures in ENMAX Power.

The Corporation is required to reimburse The City for all principal repayments and interest payments with respect to the debentures on the same day as The City disburses the payments to ACFA. In addition, the Corporation is required to pay a loan guarantee and administration fee to The City of 0.25 per cent on the average monthly outstanding ACFA debenture balance held by The City on behalf of the Corporation.

PRIVATE DEBENTURES

On December 5, 2014, a Series 3 Private Debenture of $200.0 million at 3.81 per cent was issued. No private debentures were issued in 2013. The outstanding unsecured private debentures of $300.0 million and $200.0 million at December 31, 2014, bear interest at rate of 6.15 per cent and 3.81 per cent, respectively, payable semi-annually and mature on June 19, 2018, and December 5, 2024, respectively.

NON-RECOURSE FINANCING

The non-recourse financing represents the Corporation's loans, through subsidiaries, for the Kettles and CEC projects. The balance outstanding on the Kettles debt at December 31, 2014, was $19.9 million (December 31, 2013—$19.9 million), which bears interest at a fixed rate of 5.86 per cent, payable monthly, maturing in December 2016. There was no balance outstanding on the CEC debt at December 31, 2014 (December 31, 2013—$200.6 million).

On March 17, 2014, $200.6 million of non-recourse term financing and $35.6 million of a fixed-for-floating interest rate swap related to CEC was repaid prior to maturity on September 2026. In addition, ENMAX settled back-to-back swaps that were initially executed as a hedging relationship in relation to the fixed-for-floating swap. The settlement of the back-to-back swaps was $0.4 million. Settlement costs of $20.7 million associated with the termination of the interest rate swaps were recorded as interest expense.

PROMISSORY NOTE

The promissory note was issued in the fourth quarter of 2006 and represents an amortizing loan from the Board of Trustees of Westwind School Division No. 74, acting as agent for the Wind Participation Consortium (WPC), which is comprised of three school divisions. The 20-year note, in the amount of $6.3 million, bears interest at a fixed rate of 5 per cent and is repayable in monthly instalments. The Corporation provided a fixed charge over two wind turbines located at Taber, Alberta, as security for the loan. Concurrent with execution of the loan, WPC executed a 20-year electricity services agreement with ENMAX Energy.

PRINCIPAL REPAYMENTS

The required repayments of principal on the long-term debt at December 31, 2014, are as follows:

REQUIRED REPAYMENTS OF PRINCIPAL

As at December 31 *(millions of dollars)*	2014
2015	**62.0**
2016	**76.2**
2017	**56.8**
2018	**357.2**
2019	**53.9**
Thereafter	**1,004.2**

As at December 31, 2014, the Corporation is non-compliant with a financial covenants for Kettles related to non-recourse financing classified as long-term debt on the Consolidated Balance Sheet. The carrying amount of the debt as at December 31, 2014, is $19.9 million.

17. ASSET RETIREMENT OBLIGATION

The Corporation recognizes its obligation to retire certain tangible long-lived assets, whereby the fair value of an asset retirement obligation is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset and then amortized over its estimated useful life. In subsequent periods, the asset retirement obligation is adjusted for the passage of time, any changes in the amount or timing of the underlying future cash flows are recognized as a change in the carrying amount of the liability for an asset retirement obligation, and the related asset retirement cost is capitalized as part of the carrying amount of the related long-lived asset. A gain or loss may be incurred upon settlement of the liability.

At December 31, 2014, the Corporation has asset retirement obligations relating to the following project generating assets: McBride, Taber Wind Farm (Taber), Kettles, Crossfield Energy Centre (Crossfield), CEC, Cavalier and Balzac. The accretion expense on these assets is included in the amortization line item on the consolidated statement of earnings. The change in the carrying amount of the asset retirement obligations is disclosed in the table below:

CHANGE IN CARRYING AMOUNT OF ASSET RETIREMENT OBLIGATIONS

(millions of dollars)	2014	2013
Balance, beginning of year	15.4	14.4
Liabilities incurred in the current period	3.9	–
Accretion expense	0.8	1.0
Balance, end of year	20.1	15.4

The expected remediation liability and timing for each undiscounted asset is disclosed in the table below, based on a credit adjusted risk-free discount rate of 4.9 and 6.0 per cent and a rate of inflation of 2.1 per cent:

EXPECTED REMEDIATION AND TIMING

(millions of dollars)	Amount	Date
McBride	47.8	September 2057
Taber	32.4	December 2057
Kettles	26.2	May 2071
Crossfield	10.4	December 2048
CEC	29.6	March 2043
Cavalier	8.7	December 2039
Balzac	4.3	December 2039

18. SHARE CAPITAL

(millions of dollars, except share amounts)	Number of Shares	Amount
Authorized:		
Unlimited number of common shares		
Issued and outstanding:		
Balance, December 31, 2013 and 2014:		
Issued on incorporation	1	–
Issued on transfer of net assets from CES *(Note 1)*	1	278.2
Issued on transfer of billing and customer care assets from The City in 2001	1	1.9
Balance, December 31, 2013 and 2014	3	280.1

19. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

As at December 31 *(millions of dollars)*	2014	2013
Unrealized losses on available-for-sale financial assets	-	(0.1)
Unrealized losses on derivatives designated as cash flow hedges	(33.8)	(6.2)
Accumulated other comprehensive loss, including a future income tax recovery of $2.9 million (2013—expense of $1.7 million)	(33.8)	(6.3)

20. COMMITMENTS AND CONTINGENCIES

PROPERTY, PLANT AND EQUIPMENT

The Corporation is committed to major capital expenditures over the next five years and thereafter, with minimum annual payments (including cancellation costs) as follows:

MAJOR CAPITAL COMMITMENTS OVER THE NEXT FIVE YEARS

(millions of dollars)	
2015	14.3
2016	0.9
2017	0.9
2018	0.9
2019	0.9
Thereafter	19.8

OBLIGATIONS UNDER OTHER AGREEMENTS

The Corporation rents premises, vehicles and equipment under multiple lease contracts with varying expiration dates.

The Corporation is obligated to make monthly payments in return for the output from PPAs and other tolling arrangements, based on normal operating conditions adjusted for inflation, other than in the event of a forced outage.

The Corporation commits to the purchase of renewable energy certificates and carbon offset credits. The Corporation commits to long-term service arrangements on certain generating assets.

The aggregated minimum payments under these arrangements over the next five years are as follows:

AGGREGATE PAYMENTS UNDER OTHER AGREEMENTS

(millions of dollars)	
2015	26.1
2016	19.0
2017	15.7
2018	10.0
2019	5.2
Thereafter	12.1

REGULATORY

The Corporation, along with other electrical transmission and distribution utilities in the province of Alberta, is subject to regulatory reviews and decisions. The impact of the reviews and decisions is reflected in the consolidated financial statements when the amount can be reasonably estimated.

LEGAL CLAIMS

In the normal course of business, the Corporation is named as a defendant in lawsuits related to various matters. The Corporation believes the outcome of these lawsuits will not have a material impact on the operating results or financial position of the Corporation.

POWER PURCHASE ARRANGEMENTS

The facilities covered under PPAs were subject to outages and operational issues during the year. The PPA owners and ENMAX often differ in opinion as to who should bear the costs arising from these events. Although there can be no assurance that these disputes will be resolved in the Corporation's favour, the Corporation does not believe that the outcome of these disputes will have a material adverse effect on its financial position.

INCOME TAX

Alberta Finance, Tax and Revenue Administration is responsible for assessing the income tax returns filed under the PILOT regulation of the EUA, which became effective January 1, 2001.

The Corporation regularly reviews the potential for adverse outcomes in respect of tax matters and believes it has adequate provisions for these tax matters. Tax provisions are adjusted, positively or negatively, for changes in estimates and assessments by tax authorities in the period in which they are more likely than not to have an impact on the financial results. Although there can be no assurance that these disputes will be resolved in the Corporation's favour, the Corporation does not believe that the outcome of these disputes will have a material adverse effect on its financial position.

ENVIRONMENTAL

Provincial regulations aimed at reducing the levels of greenhouse gas (GHG) emissions took effect July 2007. Due to the change of law provisions in ENMAX Energy's PPAs and tolling agreements, ENMAX Energy is exposed to the associated compliance costs.

For the year ended December 31, 2014, the consolidated financial statements include a charge to earnings in the amount of $20.2 million (2013—$4.1 million) included in costs of electricity services provided, relating to estimated compliance costs under the provincial GHG regulations for ENMAX Energy's interests in coal and natural-gas-fuelled generation facilities through its PPAs and owned assets. Compliance payments are due to the Province of Alberta, directly or via plant owners, by June 30 of the year following the compliance year. ENMAX Energy has taken steps, including acquiring qualified offset credits from both its wind-generation assets and purchases on the wholesale market, to mitigate impacts of the GHG regulations.

LETTERS OF CREDIT

In the normal course of operations, letters of credit are issued to facilitate the extension of sufficient credit for counterparties having credit exposure to the Corporation or its subsidiaries. As at December 31, 2014, the Corporation had issued letters of credit amounting to $249.0 million (December 31, 2013—$303.9 million).

DIRECTOR/OFFICER INDEMNIFICATIONS

Under its bylaws, the Corporation indemnifies individuals who have acted at the Corporation's request to be a director and/or officer of the Corporation and/or one or more of its direct and indirect subsidiaries, to the extent permitted by law, against any and all damages, liabilities, costs, charges or expenses suffered or incurred by the individuals as a result of their service. The claims covered by such indemnifications are subject to statutory or other legal restrictions and limitation periods. The nature of the indemnification agreements prevents the Corporation from making a reasonable estimate of the maximum potential amount it could be required to pay to beneficiaries of such indemnification agreements. The Corporation has purchased various insurance policies to reduce the risks associated with the indemnification.

OTHER INDEMNIFICATIONS

In the ordinary course of business, the Corporation and its subsidiaries enter into contracts that contain indemnification provisions, such as purchase and sale contracts, service agreements, intellectual property licensing agreements, purchases and sales of assets and equipment, joint venture agreements (JVAs), operating agreements and leasing and land use arrangements. In such contracts, the Corporation may indemnify counterparties to the contracts if certain events occur, such as undisclosed liabilities, changes in financial condition and loss caused by the actions of third parties or as a result of litigation or other claims by third parties. These indemnification provisions will vary based upon the contract. In most cases, there are no pre-determined amounts or limits included in these indemnification provisions, and the occurrence of contingent events that will trigger payment under them is difficult to predict. Therefore, the maximum potential future amount the Corporation could be required to pay cannot be estimated.

21. CAPITAL MANAGEMENT

The Corporation's objectives when managing capital are threefold: (i) to maintain a flexible capital structure that optimizes corporate liquidity as well as the cost of capital at acceptable risk; (ii) to manage capital in a manner that balances the interests of stakeholders; and (iii) to meet regulatory requirements for certain operations subject to rate regulation.

The Corporation's capital structure consists of net debt and shareholder's equity. Net debt is comprised of long-term debt, including current portions, less cash and cash equivalents.

CAPITAL STRUCTURE

As at December 31 *(millions of dollars)*	2014	2013
Long-term debt (1)	**1,610.3**	1,439.0
Less: cash and cash equivalents	**16.7**	80.6
Net debt	**1,593.6**	1,358.4
Shareholder's equity	**2,527.7**	2,460.2
Total capital	**4,121.3**	3,818.6

(1) Includes current portion of $62.6 million (2013—$63.7 million). Maturity dates range from May 2015 to June 2039.

The calculation of earnings before interest, income taxes and depreciation (EBITDA) is a measure whose nearest GAAP measure is net earnings with the reconciliation between the two measures set out in the following schedule:

EBITDA

As at December 31 *(millions of dollars)*	2014	2013
Adjusted EBITDA	**410.0**	377.7
Less: Impairment loss	**34.4**	-
Less: EBITDA from discontinued operations	**-**	5.1
Standardized EBITDA	**375.6**	372.6
Deduct: Amortization	**174.2**	168.1
EBIT	**201.4**	204.5
Deduct: Interest expense	**44.3**	33.1
Deduct: Income taxes	**2.1**	(2.0)
Net earnings from continuing operations	**155.0**	173.4

In addition, the Corporation monitors its capital using various ratios, including (i) long-term debt-to-total capitalization, and (ii) EBITDA to interest expense.

Debt-to-total capitalization is calculated as long-term debt, including the current portion of long-term debt, divided by total capital and is also a calculation used in certain of the Corporation's debt covenants.

The calculation obtained by using interest expense and standardized EBITDA from the above table is substantially the same as the interest coverage ratio covenant set out in the Corporation's credit facilities.

The Corporation manages its consolidated capital structure through prudent levels of borrowing, cash flow forecasting and working capital management. These capital management policies, which remain unchanged from prior periods, provide access to capital at a reasonable cost while maintaining investment-grade credit ratings. Dominion Bond Rating Service (DBRS) and Standard & Poor's corporate credit ratings for the Corporation are A (low) (stable trend) and BBB+ (stable), respectively.

As at December 31, 2014, the Corporation is in compliance with its financial maintenance covenants on its outstanding long-term debt with the exception of covenants related to a $19.9 million non-recourse financing as described in Note 16.

22. INTEREST

As at December 31 *(millions of dollars)*	2014	2013
Interest on long-term debt	**67.2**	88.8
Short-term interest and other financing charges	**5.8**	2.2
Interest rate swaps settlement	**20.7**	-
Less: capitalized interest	**(49.4)**	(57.9)
	44.3	33.1

23. SEGMENTED INFORMATION

Year Ended December 31 (millions of dollars)	ENMAX Energy 2014	ENMAX Energy 2013	ENMAX Power 2014	ENMAX Power 2013	Corporate & Intersegment Eliminations 2014	Corporate & Intersegment Eliminations 2013	Consolidated Totals 2014	Consolidated Totals 2013
REVENUE								
Electricity	**2,389.4**	2,632.7	**139.3**	167.3	**(376.0)**	(376.1)	**2,152.7**	2,423.9
Natural gas	**542.6**	398.6	**–**	–	**(1.0)**	(0.7)	**541.6**	397.9
Transmission and distribution	**–**	–	**380.3**	339.0	**–**	–	**380.3**	339.0
Local access fees	**–**	–	**131.3**	129.3	**–**	–	**131.3**	129.3
Contractual services	**4.6**	2.9	**104.0**	82.2	**13.2**	10.3	**121.8**	95.4
Other	**19.0**	29.1	**9.1**	7.6	**(7.5)**	(5.6)	**20.6**	31.1
TOTAL REVENUE	**2,955.6**	3,063.3	**764.0**	725.4	**(371.3)**	(372.1)	**3,348.3**	3,416.6
COST OF SERVICES PROVIDED								
Electricity	**2,023.9**	2,303.4	**117.0**	143.7	**(374.3)**	(374.8)	**1,766.6**	2,072.3
Natural gas	**508.0**	364.3	**–**	–	**–**	–	**508.0**	364.3
Transmission and distribution	**–**	–	**106.8**	97.8	**–**	–	**106.8**	97.8
Local access fees	**–**	–	**131.3**	129.3	**–**	–	**131.3**	129.3
Contractual services	**3.0**	1.2	**79.0**	60.1	**–**	(0.2)	**82.0**	61.1
Operations, maintenance and administration (OM&A)	**213.4**	177.6	**172.1**	156.3	**(30.0)**	(8.1)	**355.5**	325.8
Impairment loss	34.4	–	–	–	–	–	34.4	–
Foreign exchange loss (gain)	**(11.9)**	(6.6)	**–**	–	**–**	–	**(11.9)**	(6.6)
TOTAL COSTS OF SERVICES PROVIDED	**2,770.8**	2,839.9	**606.2**	587.2	**(404.3)**	(383.1)	**2,972.7**	3,044.0
	184.8	223.4	**157.8**	138.2	**33.0**	11.0	**375.6**	372.6
Amortization	**109.4**	106.6	**59.9**	56.8	**4.9**	4.7	**174.2**	168.1
EARNINGS BEFORE INTEREST AND INCOME TAXES (EBIT)	**75.4**	116.8	**97.9**	81.4	**28.1**	6.3	**201.4**	204.5
Interest							**44.3**	33.1
Income tax expense (recovery)							**2.1**	(2.0)
NET EARNINGS FROM CONTINUING OPERATIONS							**155.0**	173.4
Net earnings from discontinued operations *(Note 9)*							-	3.2
Gain on sale of subsidiary *(Note 9)*							-	175.9
NET EARNINGS							**155.0**	352.5
GOODWILL	-	16.0	–	–	–	–	-	16.0
CAPITAL ADDITIONS	**391.8**	285.6	**200.3**	190.3	**24.1**	26.4	**616.2**	502.3

SEGMENTED TOTAL ASSETS

As at December 31 (millions of dollars)	2014	2013
ENMAX Energy	**3,050.8**	2,881.8
ENMAX Power	**1,675.4**	1,540.0
Corporate and eliminations	**115.4**	143.7
	4,841.6	4,565.5

24. ITEMS NOT INVOLVING CASH

For the year ended December 31 *(millions of dollars)*	2014	2013
Amortization	174.2	168.1
Future income taxes	(7.8)	8.0
Change in unrealized market value of financial contracts	28.1	7.7
Other	2.1	2.5
	196.6	186.3

25. CHANGE IN NON-CASH WORKING CAPITAL

As at December 31 *(millions of dollars)*	2014	2013
Accounts receivable	59.0	(1.6)
Income tax receivable	0.1	(6.3)
Other current assets	(13.8)	4.6
Accounts payable and accrued liabilities	(14.4)	(126.4)
Other current liabilities	16.2	(6.5)
	47.1	(136.2)

26. JOINT VENTURE INVESTMENTS

In 2002, the Corporation entered into a JVA with Vision Quest Windelectric Inc. to build and operate 114 wind turbines in southern Alberta (McBride). The turbines began generating electricity in 2003, and the Corporation has a 50 per cent ownership interest. The Corporation has also agreed to purchase 100 per cent of the output from the wind farm under a 20-year PPA.

In 2010, the Corporation entered into a JVA with SNC-Lavalin Constructions Inc. (SNC-Lavalin) to design and construct certain portions of the West LRT in Calgary. Construction was completed, and the West LRT was operational as of December 10, 2012.

In 2012, CPLP agreed to purchase a 50 per cent interest in Shepard and enter into a JVA to construct and operate the facility. The sale of the 50 per cent interest in Shepard was completed September 30, 2013.

In 2014, the Corporation acquired a 50 per cent interest in the Balzac joint venture with Nexen Inc. to operate the natural-gas-fuelled facility for $55.9 million. The acquisition was completed September 16, 2014, and has been accounted for using the acquisition method. The results of the joint venture have been included in the consolidated financial statements since the acquisition date using proportionate consolidation.

As at December 31
(millions of dollars)

	2014			
	Shepard	Balzac (1)	McBride	Total
Cash and cash equivalents	6.9	–	–	6.9
Accounts receivable	2.7	–	–	2.7
Other current assets	8.4	–	–	8.4
PPE	869.5	57.6	31.1	958.2
Other long-term assets	6.3	–	–	6.3
Accounts payable	(21.5)	(2.8)	(0.3)	(24.6)
Other current liabilities	(0.1)	–	–	(0.1)
Other long-term liabilities	–	(1.3)	(4.3)	(5.6)
Proportionate share in net assets of joint ventures	872.2	53.5	26.5	952.2

(1) Acquired on September 16, 2014

As at December 31
(millions of dollars)

	2013			
	Shepard	Balzac (1)	McBride	Total
Cash and cash equivalents	7.4	–	–	7.4
Accounts receivable	6.8	–	0.2	7.0
Other current assets	6.2	–	–	6.2
PPE	745.0	–	33.4	778.4
Other long-term assets	5.0	–	–	5.0
Accounts payable	(25.8)	–	(0.3)	(26.1)
Other current liabilities	–	–	–	–
Other long-term liabilities	–	–	(4.3)	(4.3)
Proportionate share in net assets of joint ventures	744.6	–	29.0	773.6

(1) Acquired on September 16, 2014.

PROPORTIONATE SHARE OF THE JOINT VENTURES' CASHFLOWS

As at December 31
(millions of dollars)

	2014			
	Shepard	Balzac (1)	McBride	Total
Operating Activities	–	1.8	(2.9)	(1.1)
Investing Activities	(124.8)	(57.6)	2.3	(180.1)
Financing Activities	124.3	55.8	0.6	180.7
Proportionate share in the increase/(decrease) in cash and cash equivalents of joint venture	(0.5)	–	–	(0.5)

(1) Acquired on September 16, 2014

As at December 31
(millions of dollars)

	2013			
	Shepard	Balzac (1)	McBride	Total
Operating Activities	–	–	4.5	4.5
Investing Activities	273.5	–	–	273.5
Financing Activities	(266.1)	–	(4.5)	(270.6)
Proportionate share in the increase/(decrease) in cash and cash equivalents of joint venture	7.4	–	–	7.4

(1) Acquired on September 16, 2014.

PROPORTIONATE SHARE OF THE JOINT VENTURES' NET EARNINGS

As at December 31
(millions of dollars)

	2014			
	Shepard	Balzac (1)	McBride	Total
Revenue	–	0.9	6.1	7.0
Cost and expenses	–	(0.9)	(6.7)	(7.6)
Amortization	–	(0.8)	(2.3)	(3.1)
Interest	–	(0.2)	(0.2)	(0.4)
Proportionate share in net earnings of joint ventures	–	(1.0)	(3.1)	(4.1)

(1) Acquired on September 16, 2014.

As at December 31
(millions of dollars)

	2013			
	Shepard	Balzac (1)	McBride	Total
Revenue	–	–	7.2	7.2
Cost and expenses	–	–	(3.1)	(3.1)
Amortization	–	–	(2.3)	(2.3)
Interest	–	–	(0.2)	(0.2)
Proportionate share in net earnings of joint ventures	–	–	1.6	1.6

(1) Acquired on September 16, 2014.

27. RELATED PARTY TRANSACTIONS

ENMAX's related party transactions are comprised of both revenues from and expenditures to The City. The City is the sole shareholder of the Corporation. Total revenues received from The City for the year ended December 31, 2014, were $127.2 million (2013—$121.1 million). The significant components include contract sales of electricity, construction of infrastructure, provision of non-regulated power distribution services and billing and customer care services relating to The City's utilities departments. ENMAX has committed to a water supply agreement with The City, to commence upon completion of Shepard, whereby The City will supply a specified amount of water annually to facilitate Shepard operations.

As at December 31, 2014, amounts owing to the Corporation from The City for services provided were $35.7 million (December 31, 2013—$31.2 million).

Total expenditures for goods and services received from The City for the year ended December 31, 2014, were $137.9 million (2013—$137.1 million). Most of these expenditures were for local access fees for use of The City's rights-of-way, the cost of which is passed through ENMAX directly to transmission and distribution customers. The measurement basis used in determining the above values is the contract amount that is considered fair market value; that is, the measurement basis that would be used for a third-party arm's-length transaction.

In 2009, the Corporation entered into a capital lease agreement with The City for the use of its land and buildings. As at December 31, 2014, the assets under the capital lease were $4.1 million (December 31, 2013—$4.3 million), and the capital lease obligation was $4.6 million (December 31, 2013—$4.6 million).

On June 15, 2014, the Corporation obtained $232.1 million from The City through arrangements with the ACFA to fund ongoing investment relating to the regulated transmission and distribution network in Calgary and the surrounding area. This brings the total amount of debt owed to The City to $1,088.8 million at December 31, 2014 (December 31, 2013—$915.5 million). Interest paid for the year ended December 31, 2014, was $41.3 million (2013—$37.6 million). Principal payments of $58.8 million were made during the year ended December 31, 2014 (2013—$52.9 million). In addition, ENMAX is required to pay a management fee to The City of 0.25 per cent on the average monthly outstanding debenture balance held by The City on behalf of ENMAX. The administration fee paid for the year ended December 31, 2014, was $2.6 million (2013—$2.2 million).

Transactions between the Corporation and The City have been recorded at the exchange amounts. Exchange amounts are the amounts as outlined by the contracts in effect between the Corporation and The City.

28. GOVERNMENT GRANTS

On October 7, 2008, the Corporation and The City entered into an infrastructure funding agreement for the construction of the Downtown District Energy Centre (DDEC). Funding of $10.0 million was received by the Corporation from the Government of Alberta, and an additional $10.0 million was received from the Government of Canada. The DDEC began operations in 2010, and the grants have been deducted from the carrying amount of the assets in PPE. The grants are being amortized over the life of the asset. For the year ended December 31, 2014, amortization of $0.7 million was recognized on the grants (2013—$0.7 million).

The Corporation offers renewable energy micro-generation products for residential and commercial customers in Alberta focused on grid-tied solar photovoltaic technology. The Corporation has entered into a contribution agreement with Climate Change and Emissions Management Corporation to aid with the costs related to this project. For the year ended December 31, 2014, $0.9 million of assistance has been recorded (2013—$0.2 million).

29. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current period's presentation.

At January 1, 2014, there was a reporting presentation change. Billing recoveries related to electricity, natural gas and penalty revenues were previously netted against OM&A expense. Based on the nature of the recoveries and revenues, it was management's decision that it was appropriate to attribute billing recoveries to the margins of electricity, natural gas and contractual services and other, respectively. The reclassification for the year ended December 31, 2014, was an increase in electricity revenue of $35.2 million, natural gas revenue of $8.6 million, other revenue of $8.7 million, electricity costs of $0.3 million and OM&A of $52.2 million.

30. SUBSEQUENT EVENTS

On March 11, 2015, ENMAX announced that Shepard has successfully completed the testing/commissioning period and is fully operational.

On March 12, 2015, ENMAX unsecured credit facilities were amended. The total unsecured credit facilities were reduced by $300.0 million to $850.0 million, with $600.0 million in bilateral credit faciliites and $250.0 million of syndicated credit facilities.

On March 19, 2015, the Corporation declared a dividend of $56.0 million payable to The City in quarterly instalments in 2015.

GLOSSARY OF TERMS

ACFA	Alberta Capital Finance Authority
AcSB	Accounting Standards Board of Canada
AESO	Alberta Electric System Operator
AFRC	Audit Finance and Risk Committee
AUC	Alberta Utilities Commission
Board	ENMAX's Board of Directors
CEC	Calgary Energy Centre
Corporation	ENMAX Corporation and its subsidiaries
CPLP	Capital Power LP
CES	Calgary Electric System
CCEMA	Change and Emissions Management Amendment
CIAC	Contributions in aid of construction
Crossfield	Crossfield Energy Centre
DB	Defined benefit
DBRS	Dominion Bond Rating Services
DC	Defined contribution
DDEC	Downtown District Energy Centre
EBIT	Earnings before interest and income taxes
EBITDA	Earnings before interest, income tax and depreciation
EPSP	Energy price setting plan
EMS	Environmental management system
ENMAX	ENMAX Corporation and its subsidiaries
Envision	ENMAX Envision Inc.
ERM	Enterprise risk management
ESA	Energy services agreements
EUA	Alberta Electric Utilities Act
FBR	Formula-based rates
GAAP	Generally Accepted Accounting Principles
GHG	Greenhouse gas
GJ	Gigajoule
GWh	Gigawatt hour
IASB	International Accounting Standards Board
ICFR	Internal control over financial reporting
IDC	Interest during construction
IFRS	International Financial Reporting Standard
ITA	Income Tax Act (Canada)
JVA	Joint venture agreement
Kettles	Kettles Hill Wind Farm
LTSA	Long-Term service agreement
McBride	McBride Lake Wind Farm
MD&A	Management's Discussion and Analysis
MSA	Market surveillance administrator
MW	Megawatt
MWh	Megawatt hour
OCI	Other comprehensive income
OM&A	Operations, maintenance and administration
PBR	Performance based rates
PILOT	Payment in lieu of tax
PPA	Power purchase arrangement
PPE	Property, plant and equipment
RMC	Risk Management Committee
ROE	Return on equity
RRO	Regulated rate option
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
Shepard	Shepard Energy Centre
Taber	Taber Wind Farm
The City	The City of Calgary
TJ	Terajoule
TransAlta	TransAlta Corporation
URD	Underground residential development

ADDITIONAL INFORMATION

ENMAX welcomes questions from stakeholders. Additional information relating to ENMAX can be found at enmax.com.

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ENMAX

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