Annual Report 2014

TransAlta

Unlocking Value

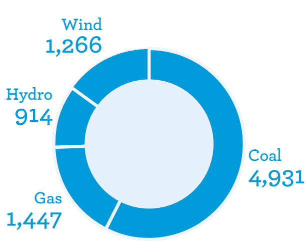
TransAlta Corporation is one of Canada's largest publicly traded power generators and marketers. In 2014, we focused on positioning our company for a future where growth is **steady, profitable** and **sustainable.**

At TransAlta,
Value is...

64
Power Generating Facilities
in Canada, the Western U.S. and Australia

Headquartered in Calgary – in North America's
Fastest Growing Deregulated
Power Market

Over 8,500
MW Generating Portfolio



Includes 100% of TransAlta Renewables Assets

100+
Years of Experience

90.5%
Facility Availability in 2014

2,700
Employees

$
Investment Grade

Sustainable Dividend

Go Forward Growth Target

$40-60 million EBITDA/year

Low Cost Structure

Listed on

TSX

NYSE

70% Owner of TransAlta Renewables

Preparing for a Post-PPA World

$10 billion

of Opportunities Under Review (Greenfield & Acquisitions)

$4.7 billion

Invested Over 10 Years

Generating Value

Gas

TransAlta is an experienced generator of gas-fired electricity with a portfolio of 12 facilities in Alberta, Ontario and Australia. With a total generating capacity of 1,447 MW, our gas fleet earned $309 million of comparable earnings before interest, taxes, depreciation and amortization (comparable EBITDA) in 2014. Gas will play an increasingly prominent role in our fuel mix; we are currently building the new 150 MW South Hedland Power Station in Western Australia and are also advancing development plans for the 856 MW Sundance 7 combined-cycle gas facility in Alberta.


Solomon Power Station, Western Australia

Hydro

TransAlta's first power generation assets were hydroelectric facilities built in Alberta. Many continue to operate today, delivering renewable power generation, ancillary services and start-up flexibility. Our Alberta-based hydro facilities have a net capacity of 822 MW and comprise 96 per cent of the province's hydro assets, our B.C.-based hydro facilities are capable of delivering 77 MW of clean power generation, and our Ontario facilities have a net capacity of 14 MW. In aggregate, these renewable assets contributed $85 million of comparable EBITDA in 2014.


Kananaskis Hydro Facility, Alberta

Wind

TransAlta is Canada's largest publicly traded wind generator with 1,122 MW of wind capacity across Alberta, Ontario, Quebec and New Brunswick. In 2013, we entered the U.S. wind market, acquiring our 144 MW Wyoming Wind facility. Our growing wind portfolio now represents about 15 per cent of our total generating capacity, further increasing our renewables portfolio to approximately 25 per cent. In addition to generating clean power, these assets deliver increased environmental value through renewable energy certificates and offsets. In 2014, our wind power assets generated $177 million of comparable EBITDA.


Castle River Wind Farm, Alberta

Coal

TransAlta has ownership in six coal-fired generating plants that deliver reliable, low-cost baseload power to our customers. Our Canadian coal fleet includes five facilities that are based in Alberta: Sundance, Keephills, Keephills 3, Genesee 3 and Sheerness. They have a combined capacity of 3,591 MW. TransAlta also owns and operates the Highvale Mine in Alberta and the 1,340 MW Centralia coal-fired power plant in Washington State. Our combined Canadian and U.S. coal fleet contributed $448 million of comparable EBITDA in 2014.

Sundance Power Plant, Alberta

Energy Marketing

TransAlta's Energy Marketing team employs some of the most advanced tools and systems in the industry to capture value for our generating assets, while managing our marketplace risk. This team of approximately 140 professionals markets our production to a growing base of commercial, industrial and wholesale consumers, secures competitive fuels for our plants and serves our customers' own marketing needs. Energy Marketing is focused on building our long-term customer base to replace the Alberta Power Purchase Arrangements (PPAs) that start to roll off at the end of 2017 and to drive growth in our business.

Calgary Skyline, Alberta

Corporate

TransAlta's Generation and Energy Marketing segments are supported by a Corporate group that provides finance, tax, treasury, legal, regulatory, environmental, procurement, health and safety, sustainable development, corporate communications, government and investor relations, information technology, risk management, human resources, aboriginal relations, internal audit and other administrative support. These focused teams are dedicated to generating value across our company, conducting business in a responsible, transparent and sustainable manner.

Terry Kwas, *Manager, Environment, Health and Safety – Wind*

Message from the Chair

The past year was a busy one for TransAlta. We placed emphasis on operational excellence, strengthening our balance sheet and growing the company for the future. In addition, we continued our strategic planning for the upcoming period where the power purchase arrangements (PPAs) mandated by the deregulation regime begin to expire, along with the onset of the federal coal regulations.

While low power prices in Alberta and the Pacific Northwest dampened our financial results, TransAlta made progress in 2014 against each of these goals, setting the stage for the future.

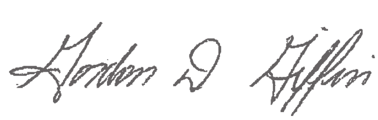
I will leave the specifics of company performance to our President and Chief Executive Officer Dawn Farrell to discuss. On behalf of the Board, however, I would like to make note of a few highlights. In 2014, our Alberta coal plants exceeded their availability targets; we added talent to our top managementin Donald Tremblay as Chief Financial Officer and Wayne Collins as Executive Vice-President, Coal and Mining Operations; we made a material addition to our Western Australian assets with a successful bid to build a significant new power facility in South Hedland; we reduced debt; and we continued to plan for the market evolution in Alberta due to public policy mandates.

At the Board, we were able to attract two new very talented Directors in John Dielwart and Tom Jenkins, as we continue our agenda to bring fresh experience and insight to our governance. We have also proposed Bev Park, a talented new director with extensive financial experience, for election. Once again, our overall governance practices were recognized by *The Globe and Mail's* annual survey as being among Canada's top ten public companies.

We believe that real progress was made in 2014 towards laying a firm foundation for solid performance in the future, both operational and financial. There is no doubt that challenges remain to be addressed, but we have confidence that TransAlta has the strategic plan and the management team to succeed in the years ahead.

I look forward to discussing 2014 and the future with our shareholders at our annual meeting.

Sincerely,



Ambassador Gordon D. Giffin
Chair of the Board of Directors
February 18, 2015

Letter to Shareholders

Our priorities in 2014 were to: 1) continue to unlock value from our base business through operational excellence; 2) strengthen our financial position; and 3) grow our portfolio of assets by delivering an average of $40 to $60 million dollars of additional EBITDA from growth. I'm pleased to report we have made significant progress in all three areas. The actions we have taken over the past year have enabled us to leverage our low-cost strategic positioning ahead of the expiration of Alberta's Power Purchase Arrangements (PPAs) set to begin in 2018.

These contracts, which took effect January 1, 2001, reflect government legislation that required us to sell power from our facilities to PPA buyers. The expiration of these contracts will allow us to re-contract the power currently committed to our PPA buyers, changing the make-up of our contract profile and restoring a direct relationship with our industrial, commercial and wholesale customers.

Dawn L. Farrell
President and CEO

Financial and Operating Results

In 2014, we delivered on our financial expectations. Funds from operations (FFO) and comparable earnings before interest, taxes, depreciation and amortization (comparable EBITDA) for the year totaled $762 million and $1,036 million respectively, versus $729 million and $1,023 million in 2013. This improvement over 2013 was due to better availability in our Canadian Coal business and strong performance from our Energy Marketing platform. Canadian Coal achieved a $16 million reduction in operations, maintenance and administration costs over 2013 levels and reduced contractor costs by $14 million.

Our Energy Marketing platform's successes included growth in customer origination across all markets, where we sought business with stable margins or fees using our asset-based marketing capabilities. This contributed to near-record proprietary results this year. Our Commercial & Industrial business in Alberta saw a 12 per cent increase in delivered volumes year over year.

These two factors more than offset the impact of lower power prices on our Alberta hydro business. We were expecting lower prices at the beginning of 2014, and we were not surprised by the price environment as the year drew to a close.

Our attention to costs and plant operations, the diversity of our assets and markets, as well as our contracting strategy, mitigated the impact of lower prices. Our sustaining capital expenditures were slightly below our plan due to good planning and execution of all our major projects. We believe TransAlta's diverse, low-cost generating fleet will allow the company to excel in the Alberta market environment by attracting new and maintaining existing customers. We intend to remain highly contracted and build our customer business by pursuing long-term contracts. This creates the potential to unlock considerable value for our shareholders.

Our ability to sign contracts in competitive markets will require a strong balance sheet to offset market volatility. This will allow us to be responsive to both customers and investors. We have factored this into our 2015 financing plan, which is designed to strengthen our capital structure and support growth.

Strengthening Our Balance Sheet

In 2014, we took significant action to improve our credit metrics, including selling some of our less strategic assets, reducing our ownership in TransAlta Renewables and issuing more preferred shares. We used the proceeds from these actions to reduce our net debt by approximately $500 million during the year. We also announced a change in our dividend from $1.16 annually to $0.72, to free up cash flow and support our strategy.

To strengthen our financial position, maintain our investment grade rating and ensure we have the financial capability to grow, we expect to further reduce our debt level by $300 million to $500 million in 2015. We believe maintaining an investment grade balance sheet is key to our business model. It allows us to access capital in both Canada and the U.S. and will demonstrate the soundness of our business to our partners and customers. Balance sheet strength gives us financial flexibility so we can be positioned for the right growth at the right time.

TransAlta Renewables

TransAlta Renewables (RNW) was launched in June 2013 as a sponsored vehicle and includes a fully contracted portfolio of renewable power generation facilities. It has performed well, with a total shareholder return of approximately 29 per cent since its inception. In November, we hosted an Investor Day conference in Stoney Plain, Alberta, where we reiterated our commitment to maintain at least a 70 per cent share of TransAlta Renewables. We also discussed opportunities for further drop-downs of assets into RNW to advance that company's strategy of owning contracted assets.

> We believe TransAlta's diverse, low-cost generating fleet will allow the company to excel in the Alberta market environment by attracting new and maintaining existing customers.

A "drop-down" is the sale of an asset or economic interest to a subsidiary that is majority-owned by the parent company and with public shareholders owning the minority position. As the majority sponsor of RNW, TransAlta still retains a high level of ownership of any assets that are dropped down or vended into that subsidiary. TransAlta's proceeds from these offerings will be used to reduce corporate debt and provide growth capital.

Growing Our Cash Flow

To continue to build value for TransAlta shareholders, our management team remains focused on aggressively growing the company. As we pursue our goal of continuing to grow our portfolio of assets by adding $40 to $60 million dollars of new EBITDA growth every year, we are searching for profitable opportunities to grow our wind and gas portfolios and to add and expand existing cogeneration projects. We are seeing some behind-the-fence opportunities emerging in Alberta and a need for new generation in Saskatchewan. We plan to use the benefit of our significant tax pools in the United States to maximize our competitive advantage in that market. To further enhance our ability to grow, in early 2014 we appointed Donald Tremblay Chief Financial Officer, and moved Brett Gellner to the role of Chief Investment Officer, where he is now solely focused on leading all growth aspects of the company.

In 2014, we began construction in Western Australia of the 270-kilometre Fortescue River Gas Pipeline to supply natural gas to our Solomon Power Station. On completion in March 2015, we will have invested approximately $90 million in this fully contracted project, in partnership with DBP Development Group.

Last year, we also delivered on our commitment to reinvest the cash flow we freed up by resizing our dividend to grow our business by contracting, designing and permitting the construction of a new AUD $570 million 150 megawatt (MW) gas-fired generation station in South Hedland, Australia. In January 2015, we started construction on the power station. Between May and July 2014, our team fully negotiated agreements with both counterparties and finalized the project design. We successfully negotiated construction agreements and customer contracts, and also obtained all necessary permits. The plant is fully contracted under 25-year agreements with Horizon Power and Fortescue Metals Group, and could be expanded to accommodate additional customers at a later date. The project will be commissioned in the first half of 2017. TransAlta has operated for more than 20 years in Western Australia and we expect more investment opportunities, thanks to TransAlta's experienced project development team and the company's reputation for reliable operations and fair dealings in the country.

At the end of 2014, with the pipeline in the final stage of construction and South Hedland, we had approximately $650 million of committed capital projects. We expect this investment to contribute $90 million of annualized EBITDA by 2017. Looking ahead, we see the potential to support

> We bring the best generation resources together with the best marketing and trading capability so our large commercial, large industrial and utility customers get the power they need, where and when they need it.

new load growth in Alberta and Saskatchewan, as well as in British Columbia, assuming the current economic environment supports progress in developing liquefied natural gas (LNG) projects in that province.

Development of our proposed 856 MW state-of-the-art Sundance 7 plant advanced in 2014. We continued discussions with potential customers, held open houses with stakeholders and entered the early stages of preparation for public hearings on the development. Be assured that Sundance 7 will be built only when the market signals the need for new profitably priced capacity and we have signed a sufficient number of contracts to backstop the capital investment. All of our new investments in the Alberta market must meet, support and maintain our lowest-cost power provider status.

Gaining Further Competitive Advantage in Our Alberta Coal Fleet

TransAlta's mission is to use our natural resources to generate safe, reliable, affordable and environmentally responsible power. Our coal assets continue to have strong revenue-generating potential. In past years, however, we did not meet our high operating standards and performance. This is changing thanks to new operating practices and lessons learned from the past and the leadership of our recently appointed Executive Vice-President, Coal and Mining Operations Wayne Collins. Our operations teams are focused on continuing to reduce operating costs and increase productivity to meet our reliability targets.

In November 2014, we signed a three-year maintenance agreement with Alstom, a global engineering firm whose services include maintaining power plants. Alstom has the experience, technology and solutions to deliver improvements in reliability and availability, and they will be responsible for the next 10 turnarounds over three years at the 1,253 MW Keephills and the 2,141 MW Sundance plants. This agreement is part of a broader initiative that includes investment in state-of-the-art diagnostic technologies.

In 2014, we achieved an Equivalent Availability Factor (EAF) of 88.6 per cent compared to 80.9 per cent in 2013. EAF measures a generating unit's ability to generate electricity on demand 24 hours a day, 365 days a year. Our Sundance Unit 4 was able to achieve a new record of 354 days online without interruption, breaking the previous record of 348 days online. As well, the Sundance Units 1 and 2 teams completed the equivalent of two planned outages in one operation on May 31 that lasted less than 90 minutes. Our teams are commended for their excellent planning and pre-execution preparation.

In early 2015, we announced additional steps to increase operational effectiveness with fewer resources. After completing a detailed review and analysis of the structure and staff complement required to run a more competitive coal business, we announced workforce reductions in our Canadian Coal operations. Under the new structure, and with the assistance of Alstom, we expect to see ongoing improvements in availability, while further controlling costs.

Power Price Outlook for TransAlta and Alberta

Every day, we work side-by-side with Alberta's oil and gas industry to support its continued growth in the short and longer term. Oil and gas markets were in flux at the end of 2014, while the electricity sector faced continued low power prices. Due to the long lead time for major oil and gas capital projects, however, the sharp downturn in energy markets will not have an immediate material impact on energy demand through 2015 and 2016. Projects already underway are continuing and will come on stream as planned, generating two to three per cent growth. Longer term, the pace of oil price recovery will be the major driver of demand growth. Despite the inherent uncertainty as companies adapt and reposition, we expect demand will be created for competitive financing solutions for new power, more opportunities for cogeneration, and new and more flexible combinations of product offerings that can be scaled up or down as required by our customers.

By maintaining our customer focus, TransAlta will be well positioned through the downturn in this economic cycle, whether we face an extended period of energy price uncertainty or a rebound driven by broader economic growth across Canada and the U.S. Even under continued and persistent low oil prices, additional generation will be needed in Alberta at the end of this decade. Depending on the pace of oil price recovery, over the next 10 to 15 years industrial load growth is estimated at about 8,000 MW. Of this, 3,000 to 4,000 MW will be needed by companies that currently expect to self-generate power. As they get closer to committing capital, we intend to offer to build and operate these plants for them. The current environment may also create other opportunities for TransAlta, in terms of acquiring assets or leveraging our experience and capacity to create partnerships.

We have a tradition of putting customers at the centre of our value proposition. We bring the best generation resources together with the best marketing and trading capability so our large commercial, large industrial and utility customers get the power they need, where and when they need it. This is evident in our cogeneration facility for steam and power at Poplar Creek for Suncor's oil sands operations near Fort McMurray. All excess generation at Poplar Creek can be sold to the province's electricity grid. Our South Hedland project also highlights our capabilities to provide on-site, customized generation.

Diversity and Optionality

TransAlta today has more than $2 billion in revenues and more than $9 billion in assets in five Canadian provinces, two U.S. states, and in Western Australia. Our overall portfolio, one of the most diversified in Canada, includes 19 wind facilities, 27 hydro facilities and 12 gas facilities in Canada, the U.S. and Australia, as well as six coal-fired generation plants in Alberta and Washington State. Our overall mix is changing, and today, gas and renewables power generation accounts for 50 per cent of TransAlta's EBITDA. Our energy marketing platform contracts with customers to provide a range of power and energy services. This strategic diversity and optionality provide the backdrop for our growth plan. It served us well in 2014 and will provide a competitive advantage for the years ahead.

Environmental Performance

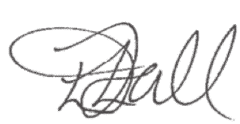
TransAlta has begun to transition our older coal plants to meet federal and provincial environmental regulations limiting the greenhouse gas (GHG) emission intensity of coal plants. The coal transition will continue through 2029, when all coal plants except our Sheerness, Genessee 3 and Keephills 3 operations are scheduled to close in their current capacity, as required under current regulations. Genessee 3 and Keephills 3 are two of Canada's largest and cleanest coal-fired facilities and among the most advanced of their kind worldwide.

Strategic options during this transition may require us to invest in plant life extensions and carbon capture and storage, or to convert baseload coal plants to low-cost peakers. We may also choose to shut down coal plants and replace them with other forms of generation. Our goal is to meet the federal and provincial regulations with investments that will reduce GHG emissions and maintain cost competitiveness. Our customers and investors want both.

We strongly believe our strategy of protecting our ability to both grow and maintain an investment grade balance sheet will create long-term value for our shareholders. The financial and operational performance of the company in 2014 was as we planned and expected and our ability to secure the South Hedland project for growth in 2017 was a clear win. Our three-year plan between now and the post-PPA environment is clear and transparent. Our team continues to be determined and committed to its delivery.

I would like to thank our Board of Directors for their sound judgment and continued support. Their commitment to ensuring we make the best decisions for the future of our company and our shareholders is uncompromising. I would also like to thank all of TransAlta's employees for their contributions to our company's success in 2014. I am proud of what they have accomplished in a very dynamic environment. They are focused and determined. Because of their efforts, TransAlta is generating a strong, stable cash flow that well supports its dividend to shareholders, payments to debt holders and funds our growth prospects.

Sincerely,



Dawn L. Farrell
President and CEO
February 18, 2015

Management's Discussion and Analysis

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*This Management's Discussion and Analysis ("MD&A") should be read in conjunction with our audited annual 2014 consolidated financial statements and our 2015 Annual Information Form for the year ended Dec. 31, 2014. Our consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") for Canadian publicly accountable enterprises as issued by the International Accounting Standards Boards ("IASB") and in effect at Dec. 31, 2014. All dollar amounts in the following discussion, including the tables, are in millions of Canadian dollars unless otherwise noted. This MD&A is dated Feb. 18, 2015. Additional information respecting TransAlta Corporation ("TransAlta", "we", "our", "us", or the "Corporation"), including our Annual Information Form, is available on SEDAR at **www.sedar.com**, on EDGAR at **www.sec.gov**, and on our website at **www.transalta.com**.*

Non-IFRS Measures

We evaluate our performance and the performance of our business segments using a variety of measures. Certain of the financial measures discussed in this MD&A are not defined under IFRS and, therefore, should not be considered in isolation or as an alternative to or to be more meaningful than net earnings attributable to common shareholders or cash flow from operating activities, as determined in accordance with IFRS, when assessing our financial performance or liquidity. These measures may not be comparable to similar measures presented by other issuers and should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. See the Comparable Funds from Operations and Comparable Free Cash Flow, and Earnings and Other Measures on a Comparable Basis sections of this MD&A for additional information.

Forward-Looking Statements

This MD&A, the documents incorporated herein by reference, and other reports and filings made with securities regulatory authorities include forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. All forward-looking statements are based on our beliefs as well as assumptions based on information available at the time the assumptions were made and on management's experience and perception of historical trends, current conditions, and expected future developments, as well as other factors deemed appropriate in the circumstances. Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "believe", "expect", "anticipate", "intend", "plan", "project", "foresee", "potential", "enable", "continue", or other comparable terminology. These statements are not guarantees of our future performance and are subject to risks, uncertainties, and other important factors that could cause our actual performance to be materially different from that projected.

In particular, this MD&A contains forward-looking statements pertaining to our business and anticipated future financial performance; our success in executing on our growth projects; the timing and the completion and commissioning of projects under development, including major projects such as the South Hedland Power Project, and their attendant costs; expectations regarding the Alberta Electric System Operator's ("AESO") plans for resolving regional constraints on Alberta's transmission system; spending on growth and sustaining capital and productivity projects; expectations in terms of the cost of operations, capital spend, and maintenance, and the variability of those costs, including expectations about the cost savings anticipated from the major maintenance agreement entered into with Alstom; the impact of certain hedges on future reported earnings and cash flows; expectations related to future earnings and cash flow from operating and contracting activities (including estimates of 2015 comparable earnings before interest, taxes, depreciation, and amortization ("EBITDA"), comparable funds from operations ("FFO"), and comparable free cash flow); estimates of fuel supply and demand conditions and the costs of procuring fuel; expectations for demand for electricity in both the short term and long term, and the resulting impact on electricity prices; the impact of load growth, increased capacity, and natural gas costs on power prices; expectations in respect of generation availability, capacity, and production; expectations regarding the role different energy sources will play in meeting future energy needs; expected financing of our capital expenditures; expected governmental regulatory regimes and legislation and their expected impact on us and the timing of the implementation of such regimes and regulations, as well as the cost of complying with resulting regulations and laws; our trading strategies and the risk involved in these strategies; estimates of future tax rates, future tax expense, and the adequacy of tax provisions; accounting estimates; anticipated growth rates in our markets; our expectations regarding proceedings before the Alberta Utilities Commission (the "AUC") as well as those relating to the outcome of existing or potential legal and contractual claims, regulatory investigations, and disputes; expectations regarding the renewal of collective bargaining agreements; expectations for the ability to access capital markets at reasonable terms; the estimated impact of changes in interest rates and the value of the Canadian dollar relative to the U.S. dollar and other currencies in locations where we do business; the monitoring of our exposure to liquidity risk; expectations in respect of the global economic environment and growing scrutiny by investors relating to sustainability performance; our credit practices; the estimated contribution of Energy Marketing activities to gross margin; and expectations relating to the performance of TransAlta Renewables Inc.'s ("TransAlta Renewables") assets and plans for the sale of contracted assets to TransAlta Renewables.

Factors that may adversely impact our forward-looking statements include risks relating to: fluctuations in market prices and the availability of fuel supplies required to generate electricity; our ability to contract our generation for prices that will provide expected returns; the regulatory and political environments in the jurisdictions in which we operate; environmental requirements and changes in, or liabilities under, these requirements; changes in general economic conditions including interest rates; operational risks involving our facilities, including unplanned outages at such facilities; disruptions in the transmission and distribution of electricity; the effects of weather; disruptions in the source of fuels, water, or wind required to operate our facilities; natural or man-made disasters; the threat of domestic terrorism and cyberattacks; equipment failure and our ability to carry out or have completed the repairs in a cost-effective manner or timely manner; commodity risk management; industry risk and competition; fluctuations in the value of foreign currencies and foreign political risks; the need for additional financing; structural subordination of securities; counterparty credit risk; insurance coverage; our provision for income taxes; legal, regulatory, and contractual proceedings involving the Corporation; outcomes of investigations and disputes; reliance on key personnel; labour relations matters; development projects and acquisitions, including delays in the permitting and construction of the South Hedland Power Project and the construction of the Australia Natural Gas Pipeline; failure to proceed with plans for the sale of contracted assets to TransAlta Renewables as a result of failure to agree to commercial terms with the independent directors of TransAlta Renewables, adverse market conditions or failure to obtain any required regulatory, shareholder or other third party approvals; and the satisfactory receipt of applicable regulatory approvals for existing and proposed operations and growth initiatives.

The foregoing risk factors, among others, are described in further detail in the Risk Management section of this MD&A and under the heading "Risk Factors" in our 2015 Annual Information Form.

Readers are urged to consider these factors carefully in evaluating the forward-looking statements and are cautioned not to place undue reliance on these forward-looking statements. The forward-looking statements included in this document are made only as of the date hereof and we do not undertake to publicly update these forward-looking statements to reflect new information, future events or otherwise, except as required by applicable laws. In light of these risks, uncertainties, and assumptions, the forward-looking events might occur to a different extent or at a different time than we have described, or might not occur. We cannot assure that projected results or events will be achieved.

Highlights

Consolidated Highlights

Year ended Dec. 31	2014	2013	2012
Revenues	**2,623**	2,292	2,210
Comparable EBITDA[1]	**1,036**	1,023	1,015
Net earnings (loss) attributable to common shareholders	**141**	(71)	(615)
Comparable net earnings attributable to common shareholders[1]	**68**	81	117
Comparable funds from operations[1]	**762**	729	788
Cash flow from operating activities	**796**	765	520
Comparable free cash flow[1]	**295**	295	258
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.52**	(0.27)	(2.62)
Comparable net earnings per share[1]	**0.25**	0.31	0.50
Comparable funds from operations per share[1]	**2.79**	2.76	3.35
Comparable free cash flow per share[1]	**1.08**	1.12	1.10
Dividends paid per common share	**0.83**	1.16	1.16

As at Dec. 31	2014	2013[2]
Total assets	**9,833**	9,624
Total long-term liabilities	**4,504**	5,337

Financial Highlights

- Comparable EBITDA totalled $1,036 million in 2014 compared to $1,023 million in 2013. Strong availability throughout our generation portfolio, improved operational performance at Canadian Coal, higher than planned margins delivered by our Energy Marketing Segment, and a robust hedging strategy offset the impact of much lower power prices in Alberta. Prices in Alberta averaged $49 per megawatt hour ("MWh") in 2014, compared to $80 per MWh in 2013. Our strategy of having a highly contracted portfolio limited the impact of price fluctuations.
- Comparable FFO for 2014 increased $33 million to $762 million as the FFO for 2013 excluded higher amounts of unrealized mark-to-market gains included in EBITDA.
- Comparable net earnings attributable to common shareholders was $68 million ($0.25 per share) in 2014 compared to $81 million ($0.31 per share) in 2013. The decrease in 2014 was primarily due to lower ownership interest in TransAlta Renewables following the public offerings of TransAlta Renewables common shares.
- Reported net earnings attributable to common shareholders was $141 million ($0.52 net earnings per share) in 2014, compared to a net loss of $71 million ($0.27 net loss per share) for 2013, and a net loss of $615 million ($2.62 net loss per share) in 2012. The increase in 2014 is attributable primarily to the change in value of certain de-designated and economic hedges in place at U.S. Coal, driven by decreases in future power prices at the end of the year, and the loss on assumption of pension obligations in 2013. The net earnings for 2013 also include a $56 million settlement of a claim relating to power trading activities in California in 2000 to 2001. Higher losses were recorded in 2012 due to the Sundance Units 1 and 2 return to service decision, as well as impairment at U.S. Coal.

1 *These items are not defined under IFRS. Presenting these items from period to period provides management and investors with the ability to evaluate earnings and cash flow trends more readily in comparison with prior periods' results. Refer to the Comparable Funds from Operations and Comparable Free Cash Flow, and Earnings and Other Measures on a Comparable Basis sections of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.*

2 *After giving effect to the reclassification described in the Current Accounting Changes section of this MD&A.*

Strategic Initiative Highlights

During the year we continued to make significant progress to grow our portfolio of highly contracted assets, improve our operating performance, and strengthen our financial condition through initiatives such as:

- Permitted and commenced construction in January 2015 on a 150 megawatt ("MW") combined cycle gas power station in South Hedland, Western Australia, which we will own and operate. The project is estimated to cost approximately AUD$570 million to build. The fully contracted power station is expected to be commissioned and delivering power to customers in the first half of 2017.
- Significantly advanced construction with a joint venture partner of an AUD$178 million natural gas pipeline to our Solomon power station. We hold a 43 per cent interest in the joint venture. The project is on schedule and within budget, with expected commencement of commercial operations in the first quarter of 2015.
- Strengthened our financial position by reducing our debt by approximately $500 million, before the effects of changes in foreign exchange rates, through the sale of non-strategic investments for proceeds of $205 million, an issuance of preferred shares for $165 million, and completion of a secondary offering of common shares of TransAlta Renewables for $136 million. We have also refinanced over $400 million of credit facilities and maturing long-term debt by way of a senior notes offering, due in 2017.
- Entered into an agreement with Alstom to provide major maintenance for 10 major maintenance projects over the next three years at our Keephills and Sundance plants. The new arrangement is expected to deliver an average 15 per cent cost reduction per turnaround and shorter turnaround times for major maintenance work, resulting in estimated direct cost savings of $34 million over the full term of the agreement.
- Resized the annualized common share dividend to $0.72 from $1.18 to align with our growth and financial objectives.
- Continued execution of our hydro life extension plan, sustaining our advantage as the first hydro power producer in Alberta.

Safety

Safety is our top priority with all of our staff, contractors, and visitors. Our objective is to maintain our Injury Frequency Rate ("IFR"), which includes employees and contractors, at less than 1.00 for 2014. Our ultimate goal is to achieve zero injury incidents. We achieved our best results ever for safety performance in 2014.

Year ended Dec. 31	2014	2013	2012
IFR	**0.86**	0.93	0.89

Operational Results

Year ended Dec. 31	**2014**	2013	2012
Availability *(%)*[1]	**89.7**	85.5	88.4
Adjusted availability *(%)*[1,2]	**90.5**	87.8	90.0
Production *(GWh)*[1]	**45,002**	42,482	38,750
Comparable EBITDA			
Generation Segment			
Canadian Coal	**386**	309	373
U.S. Coal	**62**	66	148
Gas	**309**	327	312
Wind	**177**	180	151
Hydro	**85**	147	127
Total Generation Segment	**1,019**	1,029	1,111
Energy Marketing Segment[3]	**76**	61	(13)
Corporate Segment	**(59)**	(67)	(83)
Total comparable EBITDA	**1,036**	1,023	1,015

- **Canadian Coal**: Comparable EBITDA increased by $77 million to $386 million in 2014 compared to $309 million in 2013 and $373 million in 2012. The improvement is primarily driven by increased availability, from 80.9 per cent in 2013 to 88.6 per cent in 2014 and the reduction of coal costs. After assuming operations of the Highvale mine in 2013, we have reduced our annual coal costs by over $30 million year-over-year in 2014 through greater efficiency and productivity, and a reduction in the transition costs. Our contract profile in Alberta and our hedging strategy significantly mitigated the impact of lower prices in Alberta. Sundance Units 1 and 2, which returned to service in the second half of 2013, have been performing well with availability in excess of 90 per cent.
- **U.S. Coal**: Comparable EBITDA decreased by $4 million to $62 million in 2014 as 2013 comparable EBITDA included favourable adjustments related to prior period costs and provisions. Margins otherwise increased as we further optimized real-time operations against the spot market, estimated marginal costs, and fixed-price contracts. The 2012 results included larger volumes of higher-priced hedges.
- **Gas**: Comparable EBITDA decreased by $18 million to $309 million in 2014 compared to $327 million in 2013 and $312 million in 2012, primarily due to lower Alberta prices impacting our Poplar Creek facility and the effects of the new contract in Ottawa. Compared to 2012, 2013 benefitted from a full year of income from the Solomon power station that was acquired in August 2012.
- **Wind**: Comparable EBITDA was $177 million in 2014 compared to $180 million in 2013 and $151 million in 2012. Increased production from our Wyoming wind facility acquired in December 2013 has mostly offset the effects of lower Alberta prices. In addition to higher prices, 2013 results also include incremental contribution from the New Richmond facility, which was commissioned in March 2013.
- **Hydro**: Comparable EBITDA decreased by $62 million to $85 million in 2014 compared to 2013 due to the reduced potential to use the flexibility of our portfolio during periods of lower volatility. Comparable EBITDA in 2013 was $20 million higher than 2012 due to high prices and market volatility in Alberta.
- **Energy Marketing Segment**: Comparable EBITDA in 2014 was $76 million, up $15 million from $61 million in 2013 due to our ability to capture arbitrage opportunities and optimize our energy marketing assets during extraordinarily volatile market conditions in the first and fourth quarters of 2014. The business has shifted its focus toward lower-risk revenue generation activities such as asset optimization, customer fee and margin-based growth, and arbitrage trading.
- **Corporate Segment**: Corporate overhead costs decreased by $8 million in 2014 compared to 2013 due to a change in the way allocations are made within the organization. Reductions in corporate costs from a restructuring in 2012 have been sustained.

1 *Availability includes assets under generation operations and finance leases and excludes Hydro assets and Equity Investments. Production includes all generating assets, irrespective of investment vehicle and fuel type.*
2 *Adjusted for economic dispatching at U.S. Coal.*
3 *The Segment changed its name from "Energy Trading" in 2014 following a shift in focus toward lower-risk revenue generation activities such as asset optimization, customer fee and margin-based growth, and arbitrage trading.*

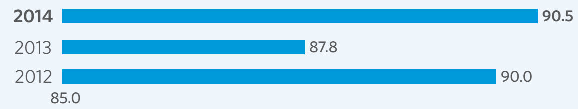
Availability and Production

Our availability in 2014, after adjusting for economic dispatching at U.S. Coal, was 90.5 per cent (2013 – 87.8 per cent; 2012 – 90.0 per cent), which is higher than our long-term target of 88 to 90 per cent. Improvement in our availability for the year ended Dec. 31, 2014 was due to lower unplanned outages at Canadian Coal.

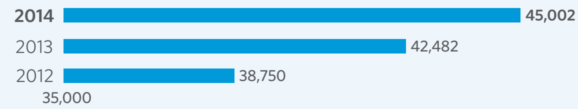
Availability in 2013 was impacted by the Keephills Unit 1 force majeure outage, which was partially offset by lower planned outages at the Alberta coal Power Purchase Arrangement ("PPA") facilities.

Production for the year ended Dec. 31, 2014 increased 2,520 gigawatt hours ("GWh") compared to 2013, primarily due to a full year of contribution from Sundance Units 1 and 2, which returned to service in the second half of 2013, as well as the return to service of Keephills Unit 1, which was unavailable for seven months in 2013.

Adjusted Availability *(%)*



Production *(GWh)*



For the year ended Dec. 31, 2013, production increased 3,732 GWh compared to 2012, primarily due to lower economic dispatching at U.S. Coal, Sundance Units 1 and 2 returning to service in the second half of 2013, lower planned outages at the Alberta coal PPA facilities, and higher PPA customer demand, partially offset by higher unplanned outages at the Alberta coal PPA facilities, primarily driven by the Keephills Unit 1 force majeure outage.

Comparable Funds from Operations and Comparable Free Cash Flow

Comparable funds from operations and comparable free cash flow provide investors with a proxy for the amount of cash generated from operating activities before changes in working capital, and provide the ability to evaluate cash flow trends more readily in comparison with results from prior periods. Comparable FFO per share and comparable free cash flow per share are calculated using the weighted average number of common shares outstanding during the year.

Year ended Dec. 31	**2014**	2013	2012
Cash flow from operating activities	**796**	765	520
Change in non-cash operating working capital balances	**(73)**	(74)	56
Cash flow from operations before changes in working capital	**723**	691	576
Settlement of 2000 to 2001 California claim	**33**	27	–
Impacts to working capital associated with Sundance Units 1 and 2 arbitration	**–**	–	204
TAMA Transmission bid costs	**5**	–	–
Other non-comparable items	**1**	11	8
Comparable FFO	**762**	729	788
Deduct:			
Sustaining capital	**(342)**	(341)	(439)
Dividends paid on preferred shares	**(41)**	(38)	(32)
Distributions paid to subsidiaries' non-controlling interests	**(84)**	(55)	(59)
Comparable free cash flow	**295**	295	258
Weighted average number of common shares outstanding in the year	**273**	264	235
Comparable FFO per share	**2.79**	2.76	3.35
Comparable free cash flow per share	**1.08**	1.12	1.10

A reconciliation of comparable EBITDA to comparable FFO is as follows:

Year ended Dec. 31	2014	2013	2012
Comparable EBITDA	**1,036**	1,023	1,015
Unrealized losses (gains) from risk management activities	**4**	(27)	27
Interest expense	**(236)**	(238)	(225)
Provisions	**-**	11	11
Current income tax expense	**(33)**	(39)	(13)
Realized foreign exchange gain (loss)	**11**	-	(4)
Decommissioning and restoration costs settled	**(16)**	(24)	(34)
Restructuring charges paid (incurred)	**-**	8	(8)
Impacts to revenue associated with Sundance Units 1 and 2	**-**	-	20
Impacts to working capital associated with Sundance Units 1 and 2 arbitration	**-**	-	204
Sundance Units 1 and 2 return to service	**-**	-	(211)
Gain on sale of collateral	**-**	-	15
Flood-related maintenance costs	**-**	5	-
Other non-cash items	**(4)**	10	(9)
Comparable FFO	**762**	729	788

For the year ended Dec. 31, 2014, comparable FFO increased $33 million to $762 million compared to 2013. The increase in FFO outpaced the increase in EBITDA, as last year's EBITDA included $27 million of unrealized risk management gains. The current year's FFO also includes $11 million in realized foreign exchange gains.

Comparable FFO for the year ended Dec. 31, 2013 decreased $59 million to $729 million compared to 2012, primarily due to higher cash interest and cash taxes as well as differences in timing of cash proceeds associated with power hedges.

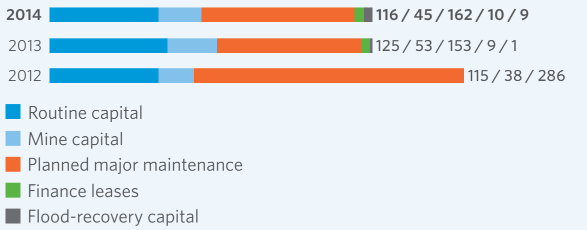
Comparable free cash flow for 2014 was $295 million, which was the same as 2013, as the increase in comparable FFO was offset by distributions paid to TransAlta Renewables' public shareholders and improved performance at TransAlta Cogeneration L.P. ("TA Cogen").

For the year ended Dec. 31, 2013, comparable free cash flow increased $37 million compared to 2012, to $295 million, due to lower sustaining capital, partially offset by lower comparable FFO.

Sustaining Capital

We are in a long-cycle, capital-intensive business that requires significant capital expenditures. Our goal is to undertake sustaining capital that ensures our facilities operate reliably and safely over a long period of time. Our sustaining capital is comprised of: (i) routine capital, (ii) mine capital, (iii) planned major maintenance, and (iv) finance lease. Sustaining capital also includes capital required following the 2013 flood in Alberta, most of which is recoverable from third parties.

Sustaining Capital *($ millions)*



Lost production as a result of planned major maintenance is as follows:

Year ended Dec. 31	2014	2013	2012
GWh lost[1]	**1,519**	1,154	2,387

In 2014, routine capital decreased compared to 2013 as a result of fewer unplanned outages during the year. The decrease in mine capital was primarily due to fewer mine support equipment purchases as mining intensity stabilized. Planned major maintenance costs increased primarily due to having five planned outages at Sundance Unit 5, Sundance Unit 6, Keephills Unit 2, U.S. Coal, and Genesee Unit 3 in 2014 compared to four in 2013 at Sundance Unit 4, Keephills Unit 3, U.S. Coal, and Sheerness.

The increase in routine capital in 2013 compared to 2012 was primarily due to the stator replacement at Keephills Unit 1. Mine capital and finance leases increased as a result of the purchase of pre-stripping trucks and other equipment in 2013 in anticipation of production increases associated with the return to service of Sundance Units 1 and 2. Planned major maintenance decreased, as we carried an unusually large number of outages in 2012 in order to sustain greater efficiency in the following years.

Financial Position

We seek to maintain financial flexibility by using multiple sources of capital to finance our business plans, while maintaining a sufficient level of available liquidity to support contracting and trading activities. We are focused on strengthening our financial position and cash flow coverage ratios to support stable investment grade credit ratings. Strengthening our financial position allows our commercial team to contract our portfolio with a variety of counterparties on terms and prices that are favourable to our financial results, and provides us with better access to capital markets through commodity and credit cycles.

During 2014, we took several steps to strengthen our financial position and reduce debt, raising over $900 million from divestitures, sale of non-controlling interests, sale of preferred shares, and debt refinancing.

The methodologies and ratios used by rating agencies to assess our credit rating are not publicly disclosed. We have developed our own definitions of ratios and targets to manage our capital. These metrics and ratios are not defined under IFRS, and may not be comparable to those used by other entities or by rating agencies. During the year, we revised the way in which we calculate our ratios in order to align more closely with how we understand some credit rating agencies calculate them. The prior year figures have been restated to conform with the current year's presentation.

Comparable Funds from Operations before Interest to Adjusted Interest Coverage

Year ended Dec. 31	2014	2013	2012
Comparable FFO	**762**	729	788
Add: Interest on debt net of interest income and capitalized interest	**236**	238	221
Comparable FFO before interest	**998**	967	1,009
Interest on debt net of interest income	**239**	240	225
Add: 50 per cent of dividends paid on preferred shares	**21**	19	16
Adjusted interest	**260**	259	241
Comparable FFO before interest to adjusted interest coverage *(times)*	**3.8**	3.7	4.2

1 *Lost production excludes periods of planned major maintenance at U.S. Coal, which occur during periods of economic dispatching.*

Comparable FFO before interest to adjusted interest coverage improved slightly compared to 2013 due to higher comparable FFO and lower debt levels. In 2013, comparable FFO before interest to adjusted interest coverage decreased compared to 2012, primarily due to lower comparable FFO and higher interest on debt. Our goal is to maintain this ratio in a range of four to five times.

Adjusted Comparable Funds from Operations to Adjusted Net Debt

Year ended Dec. 31	2014	2013	2012
Comparable FFO	**762**	729	788
Less: 50 per cent of dividends paid on preferred shares	**(21)**	(19)	(16)
Adjusted comparable FFO	**741**	710	772
Period-end long-term debt, including finance lease obligations	**4,056**	4,347	4,217
Add: 50 per cent of issued preferred shares	**471**	391	391
Less: Cash and cash equivalents (excluding restricted cash)	**(43)**	(42)	(25)
Fair value (asset) liability of hedging instruments on debt[1]	**(96)**	(16)	50
Adjusted net debt	**4,388**	4,680	4,633
Adjusted comparable FFO to adjusted net debt *(%)*	**16.9**	15.2	16.7

Adjusted comparable FFO to adjusted net debt increased in 2014 compared to 2013, due to lower debt levels in 2014 and an increase in comparable FFO. In 2013, adjusted comparable FFO to adjusted net debt decreased compared to 2012, due to higher debt levels in 2013 and a decrease in comparable FFO. Our goal is to maintain this ratio in a range of 20 to 25 per cent.

Adjusted Net Debt to Comparable EBITDA

Year ended Dec. 31	2014	2013	2012
Period-end long-term debt, including finance lease obligations	**4,056**	4,347	4,217
Less: cash and cash equivalents	**(43)**	(42)	(25)
Add: 50 per cent of issued preferred shares	**471**	391	391
Fair value (asset) liability of hedging instruments on debt[1]	**(96)**	(16)	50
Adjusted net debt	**4,388**	4,680	4,633
Comparable EBITDA	**1,036**	1,023	1,015
Adjusted net debt to comparable EBITDA *(times)*	**4.2**	4.6	4.6

Adjusted net debt to comparable EBITDA in 2014 improved compared to 2013, primarily due to a decrease in long-term debt. In 2013, adjusted net debt to comparable EBITDA was consistent with 2012. Our goal is to maintain this ratio in a range of three to four times.

1 *Refer to Note 14 of our 2014 Notes to the Annual Financial Statements.*

Business Environment

Overview of our Business

We are one of Canada's largest publicly traded power generators with over 100 years of operating experience. We own, operate, and manage a highly contracted and geographically diversified portfolio of assets and use a broad range of generation fuels comprised of coal, natural gas, water, and wind. Our energy marketing operations maximize margins by securing and optimizing high value products and markets for ourselves and our customers in dynamic market conditions.

The **Generation Segment** includes our power generation facilities and related mining operations in Canada, the U.S., and Australia. The full capacity of the facilities in which we have an ownership share is 9,898 MW[1]. At Dec. 31, 2014, our generating assets had 8,846 MW[1] of gross generating capacity in operation. Generation revenues and overall profitability are derived from the availability and production of electricity and steam as well as ancillary services such as system support. Our renewable energy facilities can also derive income from the sale of environmental attributes.

The majority of our capacity is located in Alberta and 66 per cent of it is subject to legislated Alberta PPAs, which were put in place in 2001 to facilitate the transition from regulated generation to the current energy market in the province. Alberta PPAs expire at the end of 2017 (Sundance Units 1 and 2) and the end of 2020 (Keephills Units 1 and 2, Sundance Units 3 to 6, Sheerness, and Hydro). We also provide power generation on a contract basis to regional utility and industrial customers in Ontario, Québec, New Brunswick, British Columbia, Alberta, Washington State, Wyoming State, and Western Australia.

Some of our capacity in Alberta and the U.S. Pacific Northwest is not contracted and we sell power into merchant electricity markets. Further, our Alberta PPA coal plants pay penalties or receive payments for production below or above, respectively, targeted availability based upon a rolling 30-day average of spot prices. We can also retain proceeds from the sale of energy and ancillary services in excess of obligations on our Hydro Alberta PPAs. Our contractual arrangements also provide a limited degree of participation in Ontario's electricity market.

Our results are seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are usually incurred in the spring and fall when electricity prices are expected to be lower, as electricity prices generally increase in the peak winter and summer months in our main markets due to increased heating and cooling loads. Margins are also typically impacted in the second quarter due to the volume of hydro production resulting from spring runoff and rainfall in the Pacific Northwest market, which impacts production at U.S. Coal. Typically, hydro facilities generate most of their electricity and revenues during the spring months when melting snow starts feeding watersheds and rivers. Inversely, wind speeds are historically greater during the cold winter months and lower in the warm summer months.

The **Energy Marketing Segment** derives revenue and earnings from the marketing and trading of electricity and other energy-related commodities and derivatives. Our energy marketing operations maximize margins by securing and optimizing high value products and markets for ourselves and our customers in dynamic market conditions.

Energy Marketing sells our production through short-term and long-term contracts, ensures cost-effective and reliable fuel supply, and seeks to improve margins by optimizing our portfolio as market conditions change throughout the year. In addition to serving our assets, our marketing team actively markets energy products and services to energy producers and consumers.

Our marketing commitments are backed by our own supply and through the acquisition of third-party supply and proprietary marketing assets, such as transmission, transportation, and storage rights. In the course of managing our portfolio, we actively seek to apply our knowledge of physical power and fuel markets to capture incremental arbitrage margins. All activities are managed within our core markets following strict compliance practices and we impose tight limits on our capital at risk and maintain strict position limits to ensure that our trading strategies meet our low risk tolerances.

Our marketing activities use a variety of instruments to manage risk, earn margins, and gain market information. Our marketing strategies employ shorter-term physical and financial derivative instruments including forwards, swaps, futures, and options in various commodities in regions where we have assets and the markets that directly or indirectly interconnect with those regions. These contracts meet the definition of trading activities and have been accounted for at fair value under IFRS. Changes in the fair value of the portfolio are recognized in earnings in the period they occur.

1 *We measure capacity as net maximum capacity (see Glossary of Key Terms for definition of this and other key terms), which is consistent with industry standards. Capacity figures represent capacity owned and in operation unless otherwise stated and reflects the basis of consolidation of underlying assets.*

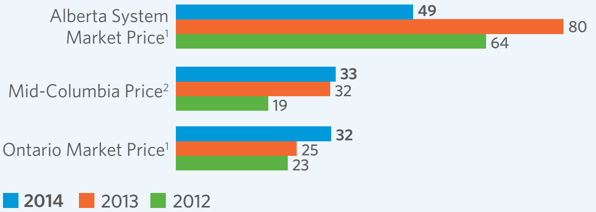
While our strategy is generally consistent between periods, positions held and resulting earnings impacts may vary due to current and forecasted external market conditions. Positions for each region are established based on the market conditions and the risk/reward ratio established for each trade at the time it is transacted. Results may therefore vary regionally or by strategy from one reported period to the next.

Direct marketing of our own generation is reported in the Generation Segment results. All activities indirectly related to our assets and all other marketing activities are reported in the Energy Marketing Segment.

Electricity Prices

Spot electricity prices in our markets are driven by customer demand, generator supply, natural gas prices, weather, renewable resource availability, and other business environment dynamics. We monitor these trends in prices, and schedule planned maintenance of our generation portfolio, where possible, during times of lower prices.

Average Spot Electricity Prices



1 Cdn$/MWh.
2 U.S.$/MWh.

Demand and supply balances are the fundamental drivers of prices for electricity. Underlying economic growth is the main driver of longer-term changes in the demand for electricity. Historically, demand for electricity in Alberta, the Pacific Northwest, and Ontario has grown at an average rate of one to three per cent per year. New supply will impact prices in the short term. We expect surplus supply in the Alberta market over the next three to five years to dampen prices.

Renewable generation growth has been strong in all regions for the past several years. New supply in the near term and intermediate term is expected to come primarily from investment in renewable energy and natural gas-fired generation across most North American markets. This expectation is driven by the relatively low prices in the natural gas market combined with a continued expectation that greenhouse gas ("GHG") legislation of some form is still expected in Canada and the U.S. While there are many new developments that will likely impact the future supply of electricity, the low cost of our baseload operations means that we expect that our plants will continue to be supported in the market.

Alberta

Alberta has seen annual average demand growth of about three per cent over the past three years. Investment in oil sands development is a key driver of electricity demand growth in the province. Recent weakness in oil prices is not expected to significantly reduce growth in the near term since many projects are already committed and under construction and will be increasing production despite lower market prices. Weaker oil prices may impact long-term growth prospects as many companies are reducing their capital programs.

During 2014, reserve margins[3] increased primarily as a result of coal capacity returning to service and increased capacity being commissioned. In 2014, Alberta added about 350 MW of wind capacity. Average spot prices decreased significantly compared to 2013, due to increased reserve margin. Electricity prices in 2013 were higher than 2012 due to tighter supply and demand conditions.

In Alberta we expect to see higher reserve margins in 2015 based on additional capacity that is coming online during the year. Combined cycle and cogeneration projects at large oil sands developments are expected to be key sources of new generation supply within Alberta. We believe that continued and growing demand for electricity, including demand for renewable energy, and the potential of increasing amounts of intermittent renewable generation to require additional capacity, may provide an opportunity to increase our generation capacity.

There are currently 1,434 MW of wind generation facilities in operation and projects totalling approximately 1,100 MW of capacity have received regulatory approval. In total, approximately 2,350 MW of wind generation is in the AESO interconnection queue. However, not all announced generation is expected to be built and some projects cannot be developed prior to transmission expansions.

3 Reserve margins measure available capacity in a market over and above the capacity needed to meet normal peak demand levels. Falling reserve margins indicate that generation capacity is becoming relatively scarce and results in increased power prices.

U.S. Pacific Northwest

As a result of economic conditions, demand growth has been weak in recent years and in 2014 demand growth was relatively flat. Electricity demand is expected to increase by approximately one per cent per year, with potentially stronger growth being partially offset by a large emphasis on energy efficiency across the region.

During 2014, reserve margins were relatively flat. The Pacific Northwest did not see large-scale wind additions in 2014. Average spot prices in 2014 were similar to 2013.

Capacity additions are expected in 2015 as developers seek to take advantage of the wind production tax credit before it expires. The wind production credit expiration is expected to drive stronger wind builds in 2015 and 2016 than was seen in 2014, which is expected to constrain price growth in the market.

Ontario

In recent years, demand growth has been weak due to economic conditions. In 2014, demand growth was relatively flat and is expected to remain weak at below one per cent.

During 2014, reserve margins were relatively flat, even though the increase in renewable capacity has increased supply in much of the year. Ontario added almost 1,500 MW of renewable capacity, including hydro and distributed solar.

Average spot prices for the year ended Dec. 31, 2014 increased compared to 2013 primarily due to extreme cold weather across the entire northeast during the first quarter, which led to higher natural gas prices and increased demand. Prices in 2013 were higher than in 2012 due to higher natural gas prices, partially offset by an increase in supply as a result of nuclear generating plants returning to service.

The reserve margin in the province is not expected to change materially until anticipated nuclear refurbishments take capacity offline around 2016. Ontario is expected to add renewable capacity in the next several years. There is currently 104 MW of wind in the commissioning stages and 479 MW of wind under construction. In addition, 1,651 MW of contracted wind is set to come online during the mid-2015 time frame, of which approximately 18 per cent has received notice to proceed approval from the Independent Electricity System Operator.

Transmission

Transmission refers to the bulk delivery system of power and energy between generating units and consumers. In the North American market, we believe investment in transmission capacity has not kept pace with the growth in demand for electricity. Lead times in new transmission infrastructure projects are significant, subject to extensive consultation processes with landowners, and subject to regulatory requirements that can change frequently. As a result, existing generation or additions of generating capacity may not have access to markets until key bulk transmission upgrades and additions are completed.

Transmission costs in Alberta are forecast to double between 2011 and 2020, and transmission and distribution costs are expected to outweigh energy costs for residential consumers by 2020. This is driving large consumers towards behind-the-fence supply to avoid paying transmission costs and this may constrain growth in the Alberta market. We continue to monitor risks and opportunities associated with transmission on an ongoing basis.

Environmental Legislation and Technologies

All energy sources used to generate electricity have some impact on the environment. While we are pursuing a business strategy that includes investing in low-impact renewable energy resources such as wind and hydro, we also believe that coal and natural gas as fuels will continue to play an important role in meeting future energy needs. Regardless of the fuel type, we place significant importance on environmental compliance and continued environmental impact mitigation, while seeking to deliver low-cost electricity.

In the jurisdictions in which we operate, legislators have proposed and enacted regulations to discontinue over time the use of the technologies that our coal-fueled plants currently utilize. Our thermal facilities can also incur costs in relation to their carbon emissions, depending on the jurisdiction in which the facility is located. Our contracted facilities can generally recover those costs from the customer. Conversely, our renewable generation facilities are generally able to realize value from their environmental attributes. We continue to closely monitor the progress and risks associated with environmental legislation changes on our future operations.

Refer to the Climate Change and the Environment section of this MD&A for additional information on these matters.

Strategy and Capability to Deliver Results

Our goals are to deliver shareholder value by delivering solid returns through a combination of dividend yield and disciplined growth in cash flow per share, while striving for a low to moderate risk profile over the long term, balancing capital allocation, and maintaining financial strength to allow for financial flexibility. Our comparable cash flow growth is driven by optimizing our existing assets and further expanding our overall portfolio and operations in Canada, the U.S., and Australia. We are focusing on these geographic areas as our expertise, scale, and diversified fuel mix allows us to create expansion opportunities in our core markets. Our strategy to achieve these goals has the following key elements:

Growth Strategy

Our growth strategy is to continue to diversify our asset base in our core markets with a focus on renewables and natural gas-fired generation. Our sponsored, majority-owned subsidiary, TransAlta Renewables, provides us with access to lower cost of capital for contracted asset opportunities. We believe that our significant U.S. tax attributes provide us with an advantage for acquisition opportunities in that country. Furthermore, we are focused on pursuing options for extending the life of our coal assets that are scheduled to retire in Alberta, investing in the Alberta power market, and ensuring that we replace our coal assets in the Pacific Northwest on their retirement. We maintain significant optionality within legislation to optimize cash flows across Canadian Coal units, convert coal units to gas fuel, or integrate newest carbon capture and storage technology in order to achieve these goals.

We continue to selectively grow our diversified generating fleet to increase production and meet future demand requirements, with growth projects that have the ability to meet or exceed our targeted rate of return. During 2014, construction began on an AUD$178 million natural gas pipeline to our Solomon power station and we entered into agreements to build and operate a 150 MW combined cycle gas power station in South Hedland, Western Australia. The project is estimated to cost approximately AUD$570 million. During 2013, commercial operations began at our 68 MW New Richmond wind farm and we also completed the acquisition of a 144 MW wind farm in Wyoming.

Partnerships are part of our growth strategy. We have developed a partnership, TAMA Power, with Berkshire Hathaway Energy to develop new gas-fired generation in Canada. In prior years, we have joined Capital Power Corporation in the development of Keephills Unit 3 and Genesee Unit 3, and we maintain a significant partnership with Cheung Kong Infrastructure for our subsidiary, TA Cogen.

Financial Strategy

We are focused on strengthening our financial position and maintaining our investment grade credit ratings to provide a solid foundation for our long-cycle, capital-intensive, and commodity-sensitive business. Strengthening our financial position and maintaining our investment grade credit ratings improve our competitiveness by providing greater access to capital markets, lowering our cost of capital, and enabling us to contract our assets with customers on more favourable commercial terms. We value financial flexibility, which allows us to selectively access the capital markets in either Canada or the U.S. when conditions are favourable.

We manage our financial position and cash flows to maintain financial strength and flexibility throughout all economic cycles. This financial discipline will continue to be important during 2015. We continue to maintain $2.1 billion in committed credit facilities, and as of Dec. 31, 2014, $1.6 billion was available to us.

Our financial strategy is focused on providing competitively priced capital to support growth while simultaneously strengthening our financial position in anticipation of the increased commodity exposure of the post-PPA period. In 2014, we took advantage of favourable capital markets by completing a secondary offering of TransAlta Renewables shares for gross proceeds of approximately $136 million, as well as an offering of U.S.$400 million of senior notes, due in June 2017, and an offering of preferred shares for gross proceeds of $165 million. We have also sold our investments in CE Generation LLC ("CE Gen"), Wailuku Holding Company, LLC ("Wailuku"), the Blackrock Development Project ("Blackrock"), and CalEnergy, LLC ("CalEnergy") for total net proceeds of U.S.$193.5 million to better allocate this capital within our business. Looking forward, we expect continued capital market support for projects that meet our return requirements and risk profile. We also plan to continue to execute our strategy through the sale of contracted assets to our majority-owned subsidiary, TransAlta Renewables, to access a lower cost source of equity, and by issuing additional preferred shares.

Our senior unsecured debt is rated as investment grade: BBB (stable), BBB- (stable), Baa3 (negative), and BBB- (stable); by DBRS, Standard and Poor's ("S&P"), Moody's Investors Services ("Moody's"), and Fitch Ratings ("Fitch"), respectively. Our preferred shares are rated P-3 and Pfd-3 with S&P and DBRS, respectively.[1]

1 *Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. The credit ratings accorded to our outstanding securities by DBRS, S&P, Moody's, and Fitch, as applicable, are not recommendations to purchase, hold, or sell such securities inasmuch as such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that the ratings will remain in effect for any given period or that a rating will not be revised or withdrawn entirely by DBRS, S&P, Moody's or Fitch in the future if, in its judgment, circumstances so warrant.*

Marketing Strategy

On an aggregated portfolio basis, depending on market conditions, we target contracting up to 90 per cent of our expected production for the upcoming year through a combination of Alberta PPAs, long-term contracts with regulated utilities or power authorities, and short- and long-term contracts with small commercial to large industrial customers, supplemented with financial contracts where necessary. This strategy helps protect our cash flow and our financial position through economic cycles. In addition, we are focused on re-contracting our Ontario and Australia facilities where some contracts are set to expire in the 2016 to 2019 period. During 2013, we re-contracted approximately 835 MW of our facilities and investments, in some cases extending the lives of the assets. Currently, approximately 88 per cent of 2015 and approximately 81 per cent of 2016 expected capacity across our fleet has been contracted.

In addition, we have started to leverage our marketing capability by offering products and services to third parties. We anticipate this activity can support sustainable gross margin growth for our Energy Marketing Segment in the coming years.

Operational Strategy

We manage our facilities to achieve stable and predictable operations that are comparatively low cost and balanced with our fleet availability target.

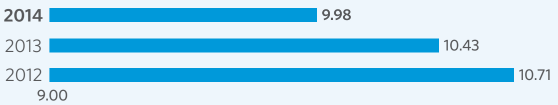
We strive to optimize the availability of our plants throughout the year to meet demand. Our operations and marketing teams work together, in compliance with regional market rules, to optimize production in response to market conditions. However, the ability to meet demand is limited by the requirement to shut down for planned maintenance and by unplanned outages, as well as by reduced production from derates. Our goal is to minimize these events through regular assessments of our equipment and an ongoing review of our maintenance plans in order to balance our maintenance costs with optimal availability targets.

Our long-term target is to increase productivity and maintain availability at 88 to 90 per cent. In 2014, our adjusted availability was 90.5 per cent, up from 87.8 in 2013 due to lower unplanned outages at Canadian Coal. Over the last three years, our average adjusted availability has been 89.4 per cent, which is in line with our corporate target.

Our operations, maintenance, and administration ("OM&A") costs reflect the cost of operating our facilities. These costs can fluctuate due to the timing and nature of planned and unplanned maintenance activities. The remainder of OM&A costs reflects the cost of day-to-day operations. Our target is to offset the impact of inflation in our recurring operating costs as much as possible through cost control and targeted productivity initiatives. In our Wind fleet, at some of our Gas facilities, and at the Canadian Coal plants we operate, we have established long-term service agreements with third-party suppliers to reduce these costs, as well as maintenance-related sustaining capital costs. We measure our ability to maintain productivity based on the Generation Segment's comparable OM&A costs per produced MWh.

Comparable generation OM&A costs per produced MWh have decreased by three per cent per year over the last three years due to greater efficiency following the return to service of Sundance Units 1 and 2. Further improvements were achieved as a result of reduced maintenance costs associated with lower unplanned outages and the implementation of initiatives to reduce contract labour, staff overtime work, and material usage.

Comparable Generation OM&A *($/produced MWh)*



People

Our experienced leadership team has a broad mix of skills in the electricity sector, including in relation to finance, law, government, regulation, engineering, operations, construction, risk management, and corporate governance. The leadership team's experience and expertise, our employees' knowledge and dedication to operational excellence, and our entire organization's knowledge of the energy business, in our opinion, has resulted in a long-term proven track record of financial stability.

Significant 2014 Events and Subsequent Events

South Hedland Power Project

On July 28, 2014, we agreed to build, own, and operate a 150 MW combined cycle gas power station in South Hedland, Western Australia. The project is estimated to cost approximately AUD$570 million to build, including the cost of acquiring existing equipment from Horizon Power. The development has been fully contracted under 25-year Power Purchase Agreements with Horizon Power, a state-owned utility company, and The Pilbara Infrastructure Pty Ltd., a wholly owned subsidiary of Fortescue Metals Group ("FMG"), a mining company. The project may be expanded to accommodate additional customers at later dates. The power station will supply Horizon Power's customers in the Pilbara region as well as FMG's port operations. IHI Engineering Australia has been selected as the contractor to construct the power station. Relevant work and environmental permits have been received and construction commenced in January 2015. The power station is expected to be commissioned and delivering power to customers in the first half of 2017.

Australia Natural Gas Pipeline

On Jan. 15, 2014, we formed the Fortescue River Gas Pipeline Joint Venture to build, own, and operate an AUD$178 million, 270-kilometre natural gas pipeline from the Dampier to Bunbury Natural Gas Pipeline to our Solomon power station. Usage of the pipeline has been contracted to FMG to supply gas for the Solomon gas-fired facilities under a 20-year agreement. We hold a 43 per cent interest in the joint venture through a wholly owned subsidiary. The project is on schedule and within budget. Construction is being finalized and commercial operations are expected to begin in March 2015. In addition to our portion of the pipeline cost, AUD$14 million in plant retrofitting costs were incurred to allow the Solomon power station to burn gas instead of diesel, which will provide a return over time through increased lease payments. Full commissioning of the Solomon plant is expected to align with the start of the pipeline operations.

Sundance Unit 7

During 2014, TAMA Power continued to develop plans to build an 856 MW, highly efficient gas-fired power plant, Sundance Unit 7, in an area adjacent to our Canadian Coal operations. TAMA Power has secured a contract for primary equipment and is in the final stage of negotiations for other equipment. TAMA Power is also finalizing an arrangement with an engineering, procurement, and construction contractor. On Dec. 11, 2014, the AUC announced a public hearing, to proceed in 2015, on the proposed facility. TAMA Power expects to receive approval from the AUC in the first half of 2015.

Sale of Preferred Shares

On Aug. 15, 2014, we completed a public offering of 6.6 million Series G 5.3 per cent Cumulative Redeemable Rate Reset First Preferred Shares, resulting in gross proceeds of $165 million. The net proceeds from the offering were used for general corporate purposes, including repaying borrowings under existing credit facilities and funding 2015 debt maturities.

Sale of CE Gen, Blackrock, CalEnergy, and Wailuku

We completed the sale of our 50 per cent interest in CE Gen, Blackrock, and CalEnergy on June 12, 2014, and the sale of our 50 per cent interest in the Wailuku facility on Nov. 25, 2014, for total gross proceeds of U.S.$205.5 million. The net proceeds were U.S.$193.5 million, after consideration of an equity contribution that we made to CE Gen in May 2014. No significant gains or losses resulted from the sales. Proceeds have been used to repay amounts outstanding on our credit facilities.

Secondary Offering of TransAlta Renewables Shares

On April 29, 2014, we completed a secondary offering of 11,950,000 common shares of TransAlta Renewables at a price of $11.40 per common share. As a result of the offering, we received gross proceeds of approximately $136 million (net proceeds of approximately $129 million after issuance costs). The net proceeds from the offering were used to reduce indebtedness. Following completion of the offering, we own approximately 70.3 per cent of the common shares of TransAlta Renewables.

Senior Notes Offering

On June 3, 2014, we completed an offering of U.S.$400 million of senior notes, due in June 2017, that carry a coupon rate of 1.90 per cent, payable semi-annually, at an issue price equal to 99.887 per cent of the principal amount of the notes. The net proceeds from the offering were used for general corporate purposes, including repaying borrowings under existing credit facilities and funding 2015 debt maturities.

Issuance of Bonds

On Feb. 11, 2015, the Corporation and its partner issued bonds secured by their jointly owned Pingston facility. Our share of gross proceeds was $45 million. The bonds bear interest at the annual fixed interest rate of 2.95 per cent, payable semi-annually with no principal repayments until maturity in May 2023. Proceeds were used to repay the $35 million secured debenture bearing interest at 5.28 per cent. Excess proceeds, net of transaction costs, are to be used for general corporate purposes.

Major Maintenance Agreement

On Nov. 14, 2014, we entered into an agreement with Alstom to provide major maintenance for our Canadian Coal facilities. The agreement relates to 10 major maintenance projects over the next three years at our Keephills and Sundance plants. It also expands Alstom's current scope of work to service critical power assets, including boilers, steam turbines, generators, and other plant equipment. Alstom will be accountable for providing its services on budget and on time with a guarantee on performance.

The new arrangement is expected to deliver an average 15 per cent cost reduction per turnaround and shorter turnaround times for major maintenance work, resulting in estimated direct cost savings of $34 million over the full term of the agreement.

Restructuring of Canadian Coal

On Jan. 14, 2015, we initiated a significant cost reduction initiative at our Canadian Coal operations to run a stronger and more competitive business. The restructuring results in the elimination of positions, providing anticipated full year annual savings of approximately $12 million. Costs associated with the initiative are expected to total $10 million.

Board of Directors Appointments

During the third quarter of 2014, we announced that Mr. P. Thomas Jenkins, OC, CD and Mr. John. P. Dielwart had been appointed to our Board of Directors (the "Board"), effective Sept. 1 and Oct. 1, 2014, respectively. The appointments are the result of our ongoing process of evaluating the skills and composition of the Board, planning for succession, and aligning the skills of the Board with the strategic direction of the Corporation.

Executive Leadership Team Appointments

On March 18, 2014, we announced three senior leadership appointments that will enhance our objectives of operational excellence from the base business and growth. Brett Gellner was appointed to the role of Chief Investment Officer, responsible for leading all growth aspects of the Corporation. Donald Tremblay joined TransAlta as Chief Financial Officer, effective March 31, 2014, and on July 3, 2014, Wayne Collins joined TransAlta as Executive Vice President, Coal and Mining Operations.

California Claim

On May 30, 2014, we announced that our settlement with California utilities, the California Attorney General, and certain other parties (the "California Parties") to resolve claims related to the 2000-2001 power crisis in the State of California had been approved by the U.S. Federal Energy Regulatory Commission. The settlement provides for the payment by us of U.S.$52 million in two equal payments and a credit of approximately U.S.$97 million for monies owed to us from accounts receivable. The first payment of U.S.$26 million was paid in June 2014 and the second is expected to be made in 2015. During the fourth quarter of 2013, the Corporation accrued for the then expected settlement of these disputes with the California Parties, which resulted in a pre-tax charge to earnings of approximately $56 million. An additional pre-tax charge to 2014 second quarter earnings of $5 million arose as a result of the final settlement.

Proceedings before the Alberta Utilities Commission

On March 21, 2014, the Alberta Market Surveillance Administrator (the "MSA") filed an application with the AUC alleging, among other things, that TransAlta manipulated the price of electricity in the Province of Alberta when it took outages at certain of its coal-fired generating units in late 2010 and early 2011. TransAlta has denied the MSA's allegations in their entirety. An oral hearing before the AUC took place in December 2014. The next phase of the hearing, consisting of a written argument, is currently under way and will be completed by the end of February 2015. The AUC's decision on this matter is expected within 90 days after the written argument has completed. Presently, the outcome is not determinable.

Fort McMurray Transmission Project

During 2014, our strategic partnership with MidAmerican Transmission, TAMA Transmission LP ("TAMA Transmission"), qualified to bid to design, build, and operate the Fort McMurray West 500 kilovolt transmission project. In December 2014, after completing its review of all bid submissions, the AESO notified TAMA Transmission that the contract had been awarded to a competitor.

Discussion of Segmented Comparable Results

We have three business segments: Generation, Energy Marketing, and Corporate. Comparable figures are not defined under IFRS. Refer to the Earnings and Other Measures on a Comparable Basis section of this MD&A for further discussion of these items, including, where applicable, reconciliations to net earnings attributable to common shareholders.

Generation

For this MD&A, we have further split what is reported as our Generation business segment into the various fuel types to provide additional information to our readers.

Coal: **TransAlta owns and operates coal-fired facilities and related mining operations in Canada and the U.S. Coal revenues and overall profitability are derived from the plant availability and production of electricity. Electricity sales generated by our commercial and industrial group in Alberta are assumed to be sourced from our Canadian Coal production within the Generation Segment.**

Canadian Coal

Year ended Dec. 31	2014	2013	2012
Availability *(%)*	**88.6**	80.9	85.7
Contract production *(GWh)*	**21,748**	17,789	16,924
Merchant production *(GWh)*	**3,806**	3,779	3,341
Total production *(GWh)*	**25,554**	21,568	20,265
Gross installed capacity *(MW)*	**3,771**	3,771	3,211
Revenues	**1,023**	916	913
Fuel and purchased power	**436**	393	342
Comparable gross margin	**587**	523	571
Operations, maintenance, and administration	**199**	205	198
Taxes, other than income taxes	**12**	11	10
Gain on sale of assets	**(1)**	(2)	(10)
Net other operating income	**(9)**	–	–
Comparable EBITDA	**386**	309	373
Depreciation and amortization	**292**	292	268
Other[1]	**–**	–	(20)
Comparable operating income	**94**	17	125
Sustaining capital:			
Routine capital	**56**	69	59
Mining capital	**45**	65	38
Finance leases	**10**	9	–
Planned major maintenance	**100**	94	219
Total	**211**	237	316

1 *Impacts to revenue associated with Sundance Units 1 and 2.*

2014

Production for the year ended Dec. 31, 2014 increased 3,986 GWh compared to 2013. Production for 2013 was impacted by a seven-month outage at our Keephills Unit 1 facility and the return to service of Sundance Units 1 and 2 in September and October, respectively.

For the year ended Dec. 31, 2014, comparable gross margin increased by $64 million compared to 2013, primarily as a result of lower unplanned outages, lower unit coal costs, and contract price escalations. Lower prices in Alberta in 2014 compared to 2013 decreased incentive payments received for generation in excess of PPA targets, offsetting some of the gain in reliability. We were able to achieve the reduction in coal costs after we took over operations at the Highvale mine in 2013.

OM&A for the year ended Dec. 31, 2014 decreased despite much higher operating capacity with Sundance Units 1 and 2 returning to service. We achieved a reduction in OM&A as a result of reduced maintenance costs associated with lower unplanned outages and the implementation of initiatives to reduce contract labour, staff overtime work, and material usage.

Other operating income resulted from the settlement of a dispute with a supplier in relation to an equipment failure in prior years.

Depreciation and amortization for the year ended Dec. 31, 2014 was consistent compared to 2013. The increase in depreciation and amortization that resulted from an increased asset base, primarily related to Sundance Units 1 and 2 returning to service, was offset by fewer asset retirements during the year and the life extension of certain components.

For the year ended Dec. 31, 2014, sustaining capital returned to a more normal level and decreased $26 million compared to 2013. Sustaining capital in 2013 was higher as a result of the Keephills Unit 1 force majeure and investments to increase mining intensity.

2013

Production for the year ended Dec. 31, 2013 increased 1,303 GWh compared to 2012 due to Sundance Units 1 and 2 returning to service, lower planned outages at the Alberta coal PPA facilities, lower market curtailments, and higher PPA customer demand, partially offset by higher unplanned outages at the Alberta coal PPA facilities, primarily driven by the Keephills Unit 1 force majeure outage.

For the year ended Dec. 31, 2013, comparable EBITDA decreased by $64 million compared to 2012 due to lower realized prices, higher penalties, higher coal costs, and higher unplanned outages at the Alberta coal PPA facilities, partially offset by lower planned outages at the Alberta coal PPA facilities and lower market curtailments. Coal costs increased as a result of an increased asset base from the mine transition and the normal advancement of the mine.

Depreciation and amortization for the year ended Dec. 31, 2013 increased by $24 million compared to 2012 due to an increased asset base and an increase in mine depreciation, partially offset by a decrease in asset retirements and the effect of the change of the economic useful lives of certain plants during 2012.

For the year ended Dec. 31, 2013, the decrease in sustaining capital compared to 2012 is mainly due to the lower number of planned outages, offset by higher mining equipment purchases.

U.S. Coal

Year ended Dec. 31	2014	2013	2012
Availability *(%)*	**82.8**	78.3	81.8
Adjusted availability *(%)*[1]	**87.7**	91.9	90.8
Production *(GWh)*	**6,684**	6,711	3,736
Gross installed capacity *(MW)*	**1,340**	1,340	1,340
Revenues	**368**	346	368
Fuel and purchased power	**251**	227	169
Comparable gross margin	**117**	119	199
Operations, maintenance, and administration	**52**	49	46
Taxes, other than income taxes	**3**	4	6
Gain on sale of assets	**–**	–	(1)
Comparable EBITDA	**62**	66	148
Depreciation and amortization	**54**	56	66
Comparable operating income	**8**	10	82
Sustaining capital:			
Routine capital	**2**	6	10
Planned major maintenance	**10**	10	22
Total	**12**	16	32

2014

Production was stable in 2014 compared to 2013, as higher unplanned outages at U.S. Coal were offset by lower economic dispatching as certain months during the period had higher prices which made production more economic. In periods of low market prices, such as during spring runoff, it can be more economic for us to not produce power at U.S. Coal and purchase power in the market to satisfy our contractual obligations.

Comparable EBITDA decreased $4 million in 2014, as 2013 comparable EBITDA included the favourable effects of adjustments to commercial arrangements recognized in prior periods. The effect of prior year adjustments was partially offset by increased optimization margins earned, as we were able to capitalize on high market volatility early in the year. Our marketing and operations teams took advantage of this volatility by generating more power during periods of higher prices or reducing production and supplying from cheaper sources during periods of low prices to satisfy contracted sales.

In December 2014, we started supplying 280 MW under a long-term contract with Puget Sound Energy. The contract volumes escalate to 380 MW in December 2016. Hedge accounting was applied to this contract, with changes in value recorded in other comprehensive income ("OCI"). Hedge accounting could not be applied to certain other contracts, and accordingly, the mark-to-market on these contracts impacted reported earnings. The impacts of these mark-to-market fluctuations have been removed from revenues to arrive at comparable results, which reflect the economic nature of these contracts.

For the year ended Dec. 31, 2014, sustaining capital decreased by $4 million compared to 2013 primarily due to general equipment repair and replacement.

2013

Production for the year ended Dec. 31, 2013 increased 2,975 GWh compared to 2012 due to lower economic dispatching at U.S. Coal, driven by improving market conditions, partially offset by higher planned outages at U.S. Coal.

For the year ended Dec. 31, 2013, comparable EBITDA decreased by $82 million compared to 2012 due to contracts expiring and lower spot prices, partially offset by favourable coal pricing.

Depreciation and amortization for the year ended Dec. 31, 2013 decreased by $10 million compared to 2012 due to the impact of a lower asset base as a result of asset impairments.

For the year ended Dec. 31, 2013, the decrease in sustaining capital compared to 2012 is mainly due to the lower expenditures on planned outages.

1 *Adjusted for economic dispatching.*

Gas: **TransAlta owns and operates natural gas-fired facilities in Canada and Australia. Gas revenues and overall profitability are derived from the availability and production of electricity and steam. Comparable results, availability, production, and capacity include assets under finance leases.**

Year ended Dec. 31	**2014**	2013	2012
Availability *(%)*	**94.0**	94.5	93.6
Production *(GWh)*	**7,390**	7,854	8,230
Gross installed capacity *(MW)*	**1,531**	1,779	1,731
Revenues	**744**	683	626
Fuel and purchased power	**326**	252	226
Comparable gross margin	**418**	431	400
Operations, maintenance, and administration	**105**	102	87
Taxes, other than income taxes	**4**	3	4
Gain on sale of assets	**-**	-	(3)
Net other operating income	**-**	(1)	-
Comparable EBITDA	**309**	327	312
Depreciation and amortization	**114**	108	112
Comparable operating income	**195**	219	200
Sustaining capital:			
Routine capital	**24**	17	13
Planned major maintenance	**39**	41	36
Total	**63**	58	49

2014

Production for the year ended Dec. 31, 2014 decreased 464 GWh compared to 2013 due to the reduced requirement to run our Ottawa facility under the terms of its new capacity-based contract. The new contract is consistent with our contracting strategy and its 20-year duration supports continued investment in the facility.

Comparable EBITDA for the year ended Dec. 31, 2014 decreased by $18 million compared to 2013, primarily due to the impact of lower Alberta prices on our merchant capacity in the province and the reduced contribution from our Ottawa facility under the terms of the new contract. These decreases in comparable EBITDA were partially offset by the benefits achieved through resale of higher priced excess gas during unplanned outages in 2014. The current year results include an $8 million unrealized loss on forward purchase and physical gas volumes in Ontario, which is offset by unrealized gains of the same amount in the Energy Marketing Segment.

For the year ended Dec. 31, 2014, sustaining capital increased by $5 million compared to 2013 mainly due to compressor repairs at Mississauga.

2013

Production for the year ended Dec. 31, 2013 decreased 376 GWh compared to 2012 due to higher contract and market curtailments at our Ottawa and Sarnia facilities, partially offset by lower unplanned outages at our Sarnia facility.

For the year ended Dec. 31, 2013, comparable EBITDA increased by $15 million compared to 2012 due to a full year of income from the Solomon power station that was acquired in August 2012, partially offset by higher OM&A costs resulting from higher routine maintenance.

Depreciation and amortization for the year ended Dec. 31, 2013 decreased by $4 million compared to 2012 due to a decrease in asset retirements and favourable changes in foreign exchange rates.

Renewables: **TransAlta owns and operates hydro and wind facilities in Canada and the U.S. Renewables revenues and overall profitability are derived from the availability of water and wind resources and the production of electricity, sale of environmental attributes, as well as ancillary services such as system support.**

Wind

Year ended Dec. 31	2014	2013	2012
Availability *(%)*	**94.6**	93.8	95.6
Production *(GWh)*	**3,175**	2,709	2,583
Gross installed capacity *(MW)*	**1,291**	1,289	1,145
Revenues	**247**	237	207
Fuel and purchased power	**14**	13	12
Comparable gross margin	**233**	224	195
Operations, maintenance, and administration	**50**	39	39
Taxes, other than income taxes	**6**	5	5
Comparable EBITDA	**177**	180	151
Depreciation and amortization	**88**	79	72
Comparable operating income	**89**	101	79
Sustaining capital:			
Routine capital	**2**	3	2
Planned major maintenance	**10**	6	2
Total	**12**	9	4

2014

Production for the year ended Dec. 31, 2014 increased 466 GWh compared to 2013, primarily due to the contribution from a full year of operations at Wyoming wind and New Richmond and higher wind volumes in Eastern Canada.

For the year ended Dec. 31, 2014, comparable EBITDA decreased by $3 million compared to 2013. Lower prices in Alberta in 2014 compared to 2013 more than offset the contribution of new wind projects commissioned or acquired in 2013.

Depreciation and amortization for the year ended Dec. 31, 2014 increased by $9 million compared to 2013, primarily due to the higher asset base associated with recently added facilities.

For the year ended Dec. 31, 2014, sustaining capital increased by $3 million compared to 2013 mainly due to an increase in planned major maintenance activities as a result of an outage at Le Nordais. All units at Le Nordais are now in operation.

2013

Production for the year ended Dec. 31, 2013 increased 126 GWh compared to 2012 due to the commencement of commercial operations at New Richmond.

For the year ended Dec. 31, 2013, comparable EBITDA increased by $29 million compared to 2012 due to the commencement of commercial operations at New Richmond and higher Alberta merchant prices.

Depreciation and amortization for the year ended Dec. 31, 2013 increased by $7 million compared to 2012 due to the commencement of operations at New Richmond.

Hydro

Year ended Dec. 31	2014	2013	2012
Production *(GWh)*	**1,885**	2,085	2,356
Gross installed capacity *(MW)*	**913**	913	913
Revenues	**131**	181	164
Fuel and purchased power	**9**	5	7
Comparable gross margin	**122**	176	157
Operations, maintenance, and administration	**40**	32	28
Taxes, other than income taxes	**3**	3	2
Net other operating income	**(6)**	(6)	–
Comparable EBITDA	**85**	147	127
Depreciation and amortization	**24**	25	29
Comparable operating income	**61**	122	98
Sustaining capital:			
Routine capital	**9**	8	7
Planned major maintenance	**3**	5	7
Total before flood-recovery capital	**12**	13	14
Flood-recovery capital	**9**	1	–
Total	**21**	14	14

2014

Production for the year ended Dec. 31, 2014 decreased 200 GWh compared to 2013 due to lower water resource in Western Canada and optimization of storage capacity to capture highest prices.

Comparable EBITDA decreased by $62 million in 2014 compared to 2013, primarily as a result of lower prices and low price volatility in Alberta, which limited our ability to take advantage of our flexibility to produce electricity during higher priced hours.

Net other operating income relates to business interruption insurance proceeds paid in respect of prior period events.

For the year ended Dec. 31, 2014, sustaining capital increased by $7 million compared to 2013, mainly due to flood-recovery capital. These expenditures were mostly recovered through insurance proceeds recognized in net earnings in 2014, as non-comparable items.

2013

Production for the year ended Dec. 31, 2013 decreased 271 GWh compared to 2012 due to lower water resource.

For the year ended Dec. 31, 2013, comparable EBITDA increased by $20 million compared to 2012 due to favourable prices, partially offset by lower water resource.

Depreciation and amortization for the year ended Dec. 31, 2013 decreased by $4 million compared to 2012 due to a change in the useful lives of the Hydro assets during 2013.

Equity Investments

As outlined in the Significant 2014 Events and Subsequent Events section of this MD&A, we completed the sale of our interests in CE Gen and CalEnergy in June 2014 and Wailuku in November 2014.

The equity method was used to account for the results of the CE Gen, CalEnergy, and Wailuku joint ventures for the months of January and February 2014, but ceased effective March 1, 2014 with classification of these investments as assets held for sale in compliance with IFRS requirements. There were no earnings from Equity Investments during the two-month period (2013 annual – loss of $10 million, 2012 annual – loss of $15 million).

The table below summarizes key operational information adjusted to reflect our interest in these investments:

	Two months ended Feb. 28, 2014	Year ended Dec. 31, 2013	Year ended Dec. 31, 2012
Availability *(%)*	**97.1**	91.2	94.2
Production *(GWh)*:			
Gas	**127**	385	380
Renewables	**187**	1,170	1,200
Total production	**314**	1,555	1,580

Energy Marketing

The results of the Energy Marketing Segment, with all trading results presented on a net revenue basis, are as follows:

Year ended Dec. 31	**2014**	2013	2012
Revenues and comparable gross margin	**108**	79	3
Operations, maintenance, and administration	**32**	18	16
Comparable EBITDA	**76**	61	(13)
Depreciation and amortization	**–**	1	–
Comparable operating income (loss)	**76**	60	(13)

2014

For the year ended Dec. 31, 2014, Energy Marketing comparable EBITDA increased by $15 million compared to 2013 due to extreme weather events that caused unprecedented gas and power commodity price volatility in eastern markets during the first and fourth quarters of 2014, which positively impacted our ability to optimize our portfolio of generation, transportation, transmission, and storage assets. We also capitalized on low risk arbitrage opportunities brought about by the extreme market volatility. As noted in the Gas subsection earlier, an offsetting gain has also been recorded in this segment against Gas generation losses. The increase was partially offset by higher corporate cost allocations and higher performance-based compensation costs driven by the strong results.

2013

For the year ended Dec. 31, 2013, Energy Marketing comparable EBITDA increased by $74 million compared to 2012 due to strong trading performance across all markets and prudent management of risk. The increase is attributable to successful trading strategies involving regional power demand and price differentials across all markets.

Corporate

Our Generation and Energy Marketing segments are supported by a Corporate group that provides finance, tax, treasury, legal, regulatory, environmental, procurement, health and safety, sustainable development, corporate communications, government and investor relations, information technology, risk management, human resources, aboriginal relations, internal audit, and other administrative support.

The expenses incurred by the Corporate Segment are as follows:

Year ended Dec. 31	2014	2013	2012
Operations, maintenance, and administration and taxes other than income taxes	**(59)**	(67)	(83)
Depreciation and amortization	**26**	23	20
Comparable operating loss	**(85)**	(90)	(103)
Sustaining capital:			
Routine capital	**23**	22	24

2014

For the year ended Dec. 31, 2014, OM&A expense decreased by $8 million compared to 2013, primarily due to a change in the way in which certain overhead cost allocations are made within the organization, partially offset by higher incentive compensation.

2013

For the year ended Dec. 31, 2013, OM&A expense decreased by $16 million compared to 2012, primarily due to lower compensation costs as a result of restructuring in the fourth quarter of 2012, a continued focus on managing costs, and lower costs as a result of the way in which certain overhead cost allocations are made within the organization. These changes in methodologies primarily arose as a result of our 2012 realignment of resources and more clear focus between base operations and growth.

Other Consolidated Results

Asset Impairment Charges and Reversals

All impairment charges and reversals are reported in the Generation Segment. Impairment charges can be reversed in future periods if the forecasted cash flows of the impacted plants improve.

2014

U.S. Coal

As at Nov. 30, 2014, we identified the decrease in projected growth in Mid-Columbia power prices as an indicator that the U.S. Coal cash-generating unit ("CGU") could be impaired. The U.S. Coal CGU's carrying amount at that date, net of associated long-term liabilities, was $372 million. We estimated the fair value less costs of disposal of the CGU, utilizing our long-range forecast, and the following key assumptions:

Mid-Columbia annual average power prices	U.S.$31.00 to 52.00 per MWh
On-highway diesel fuel on coal shipments	U.S.$3.06 to 3.37 per gallon
Discount rates	5.1 to 6.2 per cent

The valuation is subject to measurement uncertainty based on those assumptions, and on inputs to our long-range forecast, including changes to fuel costs, operating costs, capital expenses and the level of contractedness under the Memorandum of Agreement ("MoA") for coal transition established with the State of Washington. The valuation period extended to the assumed decommissioning of the asset, after its projected cessation of operation in its current form in 2025.

Fair value less costs of disposal of the CGU was estimated to approximate its carrying amount, and accordingly, no impairment charge was recorded. Any adverse change in assumptions, in isolation, would have resulted in an impairment charge being recorded. We continue to manage risks associated with the CGU through optimization of our operating activities and capital plan.

Centralia Gas

During 2014, we sold to external counterparties and transferred to other owned facilities for productive use, assets of the Centralia gas facility, which had been fully impaired and had remained idled since 2010. As a result of the transactions, we recognized impairment reversals of $5 million, and the plant's generating capacity has been removed from total TransAlta owned capacity.

2013

Alberta Merchant

As part of the annual impairment review and assessment process in 2013, the Corporation's Alberta plants with significant merchant capacity were considered one cash-generating unit (the "Alberta Merchant CGU"). While no impairment losses were recognized in 2013 for the Alberta Merchant CGU, total pre-tax impairment losses of $23 million that were recognized previously on renewables plants that became part of the Alberta Merchant CGU were reversed. Please refer to Note 6 of our audited consolidated financial statements within this Annual Report for additional information.

Renewables

We recognized a total pre-tax impairment charge of $4 million related to three contracted Hydro assets. The assets were impaired primarily due to an increase in future capital and operating expenses that resulted from the completion of condition assessments.

Net Interest Expense

The components of net interest expense are shown below:

Year ended Dec. 31	2014	2013	2012
Interest on debt	238	240	227
Interest income	-	-	(2)
Capitalized interest	(3)	(2)	(4)
Ineffectiveness on hedges	-	-	4
Interest on finance lease obligations	1	-	-
Accretion of provisions	18	18	17
Net interest expense	**254**	256	242

For the year ended Dec. 31, 2014, net interest expense decreased compared to 2013, primarily due to the approximate $500 million reduction in debt during the year and lower interest rates on debt that was refinanced. Higher interest expense due to strengthening of the U.S. dollar has partially offset these decreases.

In 2013, net interest expense increased compared to 2012, primarily due to higher debt levels, unfavourable changes in foreign exchange rates, and higher interest rates, partially offset by lower ineffectiveness on hedges.

Income Taxes

Our income tax rates and tax expense are based on the earnings generated in each jurisdiction in which we operate and any permanent differences between how pre-tax income is calculated for accounting and tax purposes. If there is a timing difference between when an expense or revenue item is recognized for accounting and tax purposes, these differences result in deferred income tax assets or liabilities and are measured using the income tax rate expected to be in effect when these temporary differences reverse. The impact of any changes in future income tax rates on deferred income tax assets or liabilities is recognized in earnings in the period the new rates are enacted.

A reconciliation of income taxes and effective tax rates on earnings, excluding non-comparable items, is presented below:

Year ended Dec. 31	2014	2013	2012
Earnings (loss) before income taxes	**239**	(12)	(445)
Income attributable to non-controlling interests	**(49)**	(29)	(37)
Equity loss	**-**	10	15
Impacts associated with certain de-designated and economic hedges	**(54)**	103	72
Asset impairment charges (reversals)	**(6)**	(18)	324
Restructuring provision (reversal)	**-**	(3)	13
Gain on sale of assets	**(2)**	(12)	(3)
Gain on sale of collateral	**-**	-	(15)
Foreign exchange loss on California claim	**4**	-	-
Flood-related maintenance costs, net of insurance recovery	**1**	7	3
TAMA Transmission bid costs	**5**	-	-
Net other operating losses	**1**	109	254
Comparable earnings attributable to TransAlta shareholders subject to tax	**139**	155	181
Comparable income tax expense adjustments:			
Income tax (expense) recovery related to impacts associated with certain de-designated and economic hedges	**(19)**	36	25
Income tax expense related to asset impairment charges and reversals	**(1)**	(5)	(5)
Income tax (expense) recovery related to restructuring provision	**-**	(1)	3
Income tax (expense) recovery related to gain on sale of assets	**1**	(2)	(1)
Income tax recovery related to divestiture of investment	**35**	-	-
Income tax expense related to (gain on sale of) reserve on collateral	**-**	-	(4)
Income tax (expense) recovery related to writedown of deferred income tax assets	**5**	(28)	(169)
Income tax recovery related to the resolution of certain outstanding tax matters	**-**	-	9
Income tax (expense) recovery related to changes in corporate income tax rates	**-**	5	(8)
Income tax recovery related to foreign exchange loss on California claim	**1**	-	-
Income tax recovery related to flood-related maintenance costs, net of insurance recovery	**-**	2	1
Income tax recovery related to TAMA Transmission bid costs	**1**	-	-
Income tax recovery related to net other operating losses	**-**	27	65
Total comparable income tax expense adjustments	**23**	34	(84)
Income tax expense (recovery)	**7**	(8)	102
Comparable income tax expense	**30**	26	18
Comparable effective tax rate on earnings attributable to TransAlta shareholders *(%)*	**22**	22	(46)

The comparable income tax expense increased for the year ended Dec. 31, 2014 compared to 2013 due to changes in the amount of earnings between the jurisdictions in which pre-tax income is earned, offset by lower comparable earnings.

In 2013, the comparable income tax expense increased compared to 2012 due to the positive resolution of certain tax contingency matters in the prior period and changes in the amount of earnings between the jurisdictions in which pre-tax income is earned.

The comparable effective tax rate on earnings attributable to TransAlta shareholders increased for the year ended Dec. 31, 2014 compared to 2013 due to changes in the amount of earnings between the jurisdictions in which pre-tax income is earned and the effect of certain deductions that do not fluctuate with earnings.

In 2013, the comparable effective tax rate on earnings attributable to TransAlta shareholders increased compared to 2012 due to changes in the amount of earnings between the jurisdictions in which pre-tax income is earned, the effect of certain deductions that do not fluctuate with earnings, and the positive resolution of certain tax contingency matters in the prior period.

During the year ended Dec. 31, 2014, we reversed a previous writedown of deferred income tax assets of $5 million. The reversal was based on changes to taxable and deductible temporary differences during 2014 that impact the net U.S. deferred income tax assets and our assessment of recognition.

During the year ended Dec. 31, 2013, we recognized a writedown of deferred income tax assets of $28 million (2012 – $169 million). The deferred income tax assets related mainly to the tax benefits of losses associated with our directly owned U.S. operations. We wrote these assets off as it was no longer considered probable that sufficient future taxable income would be available from our directly owned U.S. operations to utilize the underlying tax losses, due to reduced price growth expectations.

Non-Controlling Interests

We own 50.01 per cent of TA Cogen, which owns, operates, or has an interest in four natural gas-fired facilities and one coal-fired generating facility. Canadian Power Holdings Inc. owns the minority interest in TA Cogen. We also own 70.3 per cent (80.6 per cent in 2013) of TransAlta Renewables. TransAlta Renewables is a publicly traded company listed on the Toronto Stock Exchange under the symbol "RNW". It has interests in 1,283 MW of renewable assets. Since we own a controlling interest in TA Cogen and TransAlta Renewables we consolidate the entire earnings, assets, and liabilities in relation to our ownership of those assets.

Non-controlling interests on the Consolidated Statements of Earnings (Loss) and Consolidated Statements of Financial Position relate to the earnings and net assets attributable to TA Cogen and TransAlta Renewables that we do not own. On the Consolidated Statements of Cash Flows, cash paid to the minority shareholders of TA Cogen and TransAlta Renewables is shown in the financing section as distributions paid to subsidiaries' non-controlling interests.

Earnings attributable to non-controlling interests for the year ended Dec. 31, 2014 increased $20 million to $49 million compared to 2013, primarily due to the formation of TransAlta Renewables and increased public ownership.

In 2013, earnings attributable to non-controlling interests decreased $8 million compared to 2012, due to lower earnings at TA Cogen.

Additional IFRS Measures

An additional IFRS measure is a line item, heading, or subtotal that is relevant to an understanding of the financial statements but is not a minimum line item mandated under IFRS, or the presentation of a financial measure that is relevant to an understanding of the financial statements but is not presented elsewhere in the financial statements. We have included line items entitled gross margin and operating income (loss) in our Consolidated Statements of Earnings (Loss) for the years ended Dec. 31, 2014, 2013, and 2012. Presenting these line items provides management and investors with a measurement of ongoing operating performance that is readily comparable from period to period.

Earnings and Other Measures on a Comparable Basis

We evaluate our performance and the performance of our business segments using a variety of measures. Those discussed below, and elsewhere in this MD&A, are not defined under IFRS and, therefore, should not be considered in isolation or as an alternative to or to be more meaningful than net earnings attributable to common shareholders or cash flow from operating activities, as determined in accordance with IFRS, when assessing our financial performance or liquidity. These measures are not necessarily comparable to a similarly titled measure of another company.

Each business unit assumes responsibility for its operating results measured to gross margin and operating income. Operating income and gross margin provides management and investors with a measurement of operating performance that is readily comparable from period to period.

In calculating these items, we exclude certain items as management believes these transactions are not representative of our business operations. Earnings on a comparable basis per share are calculated using the weighted average common shares outstanding during the period.

During 2014, prior period restatements were made to 2013 and 2012. Refer to the Current Accounting Changes section of this MD&A for a description of these items.

The adjustments made to calculate comparable earnings for the year ended Dec. 31, 2014, 2013, and 2012 are as follows. References are to reconciliations presented on the following pages.

Year ended Dec. 31			2014	2013	2012
Reference number	Adjustment	Segment and fuel type			
Reclassifications:					
1	Finance lease income used as a proxy for operating revenue	Generation (Gas)	**49**	46	16
2	Decrease in finance lease receivable used as a proxy for operating revenue and depreciation	Generation (Gas)	**3**	1	3
3	Reclassification of mine depreciation from fuel and purchased power	Generation (Canadian Coal)	**56**	58	41
4	Reclassification of comparable gain on sale of property, plant, and equipment that is included in depreciation	Generation (Canadian Coal)	**1**	2	10
		Generation (U.S. Coal)	**-**	-	1
		Generation (Gas)	**-**	-	3
5	Impacts to revenue associated with Sundance Units 1 and 2	Generation (Canadian Coal)	**-**	-	20
Adjustments (increasing (decreasing) earnings to arrive at comparable results):					
6	Impacts to revenue associated with certain de-designated and economic hedges	Generation (U.S. Coal)	**(54)**	103	72
7	Flood-related maintenance costs, net of insurance recoveries	Generation (Hydro)	**1**	7	-
8	Writeoff of Project Pioneer costs	Generation (Canadian Coal)	**-**	-	3
9	Costs related to TAMA Transmission bid	Corporate	**5**	-	-
10	Asset impairment charges (reversals)	Generation (Canadian Coal)	**-**	-	(41)
		Generation (U.S. Coal)	**-**	-	347
		Generation (Gas)	**(6)**	1	-
		Generation (Wind)	**-**	(23)	16
		Generation (Hydro)	**-**	4	2
11	Restructuring charges	Generation (Canadian Coal)	**-**	(2)	4
		Generation (Gas)	**-**	-	1
		Corporate	**-**	(1)	8
12	California claim	Energy Marketing	**5**	56	-
13	Non-comparable portion of insurance recovery received	Generation (Hydro)	**(4)**	(1)	-
14	Sundance Units 1 and 2 return to service	Generation (Canadian Coal)	**-**	25	254
15	Loss on assumption of pension obligation	Generation (Canadian Coal)	**-**	29	-
16	Foreign exchange on California claim	Unassigned	**4**	-	-
17	Non-comparable gain on sale of assets	Generation (Equity Investments)	**(2)**	-	-
		Corporate	**-**	(12)	-
		Generation (Wind)	**-**	-	(3)
18	Gain on sale of collateral	Energy Marketing	**-**	-	(15)
19	Writedown (reversal of writedown) of deferred income tax assets	Unassigned	**(5)**	28	169
20	Net tax effect of other comparable adjustments	Unassigned	**(18)**	(62)	(85)
21	Non-comparable item attributable to non-controlling interest	Unassigned	**1**	-	-

A reconciliation of comparable results to reported results for the year ended Dec. 31, 2014 and 2013 is as follows:

Year ended Dec. 31	2014				2013			
	Reported	Comparable reclassifications	Comparable adjustments	Comparable total	Reported	Comparable reclassifications	Comparable adjustments	Comparable total
Revenues	**2,623**	**52**[1,2]	**(54)**[6]	**2,621**	2,292	47[1,2]	103[6]	2,442
Fuel and purchased power	**1,092**	**(56)**[3]	**-**	**1,036**	948	(58)[3]	-	890
Gross margin	**1,531**	**108**	**(54)**	**1,585**	1,344	105	103	1,552
Operations, maintenance, and administration	**542**	**-**	**(6)**[7,9]	**536**	516	-	(5)[7]	511
Asset impairment charges	**(6)**	**-**	**6**[10]	**-**	(18)	-	18[10]	-
Restructuring provision	**-**	**-**	**-**	**-**	(3)	-	3[11]	-
Taxes, other than income taxes	**29**	**-**	**-**	**29**	27	-	-	27
Gain on sale of assets	**-**	**(1)**[4]	**-**	**(1)**	-	(2)[4]	-	(2)
Net other operating (income) losses	**(14)**	**-**	**(1)**[12,13]	**(15)**	102	-	(109)[12,13,14,15]	(7)
Earnings before interest, taxes, depreciation, and amortization	**980**	**109**	**(53)**	**1,036**	720	107	196	1,023
Depreciation and amortization	**538**	**60**[2,3,4]	**-**	**598**	525	61[2,3,4]	(2)[7]	584
Operating income	**442**	**49**	**(53)**	**438**	195	46	198	439
Finance lease income	**49**	**(49)**[1]	**-**	**-**	46	(46)[1]	-	-
Equity loss	**-**	**-**	**-**	**-**	(10)	-	-	(10)
Foreign exchange gain (loss)	**-**	**-**	**4**[16]	**4**	1	-	-	1
Gain on sale of assets	**2**	**-**	**(2)**[17]	**-**	12	-	(12)[17]	-
Other income	**-**	**-**	**-**	**-**	-	-	-	-
Earnings (loss) before interest and taxes	**493**	**-**	**(51)**	**442**	244	-	186	430
Net interest expense	**254**	**-**	**-**	**254**	256	-	-	256
Income tax expense (recovery)	**7**	**-**	**23**[19,20]	**30**	(8)	-	34[19,20]	26
Net earnings (loss)	**232**	**-**	**(74)**	**158**	(4)	-	152	148
Non-controlling interests	**50**	**-**	**(1)**[21]	**49**	29	-	-	29
Net earnings (loss) attributable to TransAlta shareholders	**182**	**-**	**(73)**	**109**	(33)	-	152	119
Preferred share dividends	**41**	**-**	**-**	**41**	38	-	-	38
Net earnings (loss) attributable to common shareholders	**141**	**-**	**(73)**	**68**	(71)	-	152	81
Weighted average number of common shares outstanding in the year	**273**			**273**	264			264
Net earnings (loss) per share attributable to common shareholders	**0.52**			**0.25**	(0.27)			0.31

A reconciliation of comparable results to reported results for the year ended Dec. 31, 2012 is as follows:

Year ended Dec. 31	2012			
	Reported	Comparable reclassifications	Comparable adjustments	Comparable total
Revenues	2,210	(1)[1,2,5]	72[6]	2,281
Fuel and purchased power	797	(41)[3]	–	756
Gross margin	1,413	40	72	1,525
Operations, maintenance, and administration	499	–	(3)[8]	496
Asset impairment charges	324	–	(324)[10]	–
Restructuring provision	13	–	(13)[11]	–
Taxes, other than income taxes	28	–	–	28
Gain on sale of assets	–	(14)[4]	–	(14)
Net other operating (income) losses	254	–	(254)[14]	–
Earnings before interest, taxes, depreciation, and amortization	295	54	666	1,015
Depreciation and amortization	509	58[2,3,4]	–	567
Other	–	(20)[5]	–	(20)
Operating income	(214)	16	666	468
Finance lease income	16	(16)[1]	–	–
Equity loss	(15)	–	–	(15)
Foreign exchange loss	(9)	–	–	(9)
Gain on sale of assets	3	–	(3)[17]	–
Gain on sale of collateral	15	–	(15)[18]	–
Other income	1	–	–	1
Earnings before interest and taxes	(203)	–	648	445
Net interest expense	242	–	–	242
Income tax expense	102	–	(84)[19,20]	18
Net earnings	(547)	–	732	185
Non-controlling interests	37	–	–	37
Net earnings attributable to TransAlta shareholders	(584)	–	732	148
Preferred share dividends	31	–	–	31
Net earnings attributable to common shareholders	(615)	–	732	117
Weighted average number of common shares outstanding in the year	235			235
Net earnings per share attributable to common shareholders	(2.62)			0.50

Financial Instruments

Financial instruments are used to manage our exposure to interest rates, commodity prices, and currency fluctuations, as well as other market risks. We currently use physical and financial swaps, forward sale and purchase contracts, futures contracts, foreign exchange contracts, interest rate swaps, and options to achieve our risk management objectives. Financial instruments are accounted for using the fair value method of accounting. The initial recognition of fair value and subsequent changes in fair value can affect reported earnings in the period the change occurs if hedge accounting is not elected. Otherwise, changes in fair value will generally not affect earnings until the financial instrument is settled.

We have two types of financial instruments: (i) those that are used in the Generation and Energy Marketing segments in relation to commodity risk management activities, commodity hedging activities, and other contracting activities and (ii) those used in the hedging of interest rate and foreign currency exposures on debt, foreign currency exposures on projects and other expenditures, and our net investment in foreign operations.

Some of our financial instruments and physical commodity contracts are recorded under own use accounting or qualify for, and are recorded under, hedge accounting rules. The accounting for those contracts for which we have elected to apply hedge accounting depends on the type of hedge. Our financial instruments are categorized as fair value hedges, cash flow hedges, net investment hedges, or non-hedges. These categories and their associated accounting treatments are explained in further detail below.

For all types of hedges, we test for effectiveness at the end of each reporting period to determine if the instruments are performing as intended and hedge accounting can still be applied. The financial instruments we enter into are designed to ensure that future cash inflows and outflows are predictable. In a hedging relationship, the effective portion of the change in the fair value of the hedging derivative does not impact net earnings, while any ineffective portion is recognized in net earnings.

As well, there are certain contracts in our portfolio that at their inception do not qualify for, or we have chosen not to elect to apply, hedge accounting. For these contracts, we recognize in net earnings mark-to-market gains and losses resulting from changes in forward prices compared to the price at which these contracts were transacted. These changes in price alter the timing of earnings recognition, but do not affect the final settlement amount received. The fair value of future contracts will continue to fluctuate as market prices change.

The fair value of derivatives traded by the Corporation that are not traded on an active exchange, or extend beyond the time period for which exchange-based quotes are available, are determined using valuation techniques or models.

Fair Value Hedges

Fair value hedges are used to offset the impact of changes in the fair value of fixed rate long-term debt caused by variations in market interest rates. We use interest rate swaps in our fair value hedges.

In a fair value hedge, changes in the fair value of the hedging instrument (an interest rate swap, for example) are recognized in risk management assets or liabilities, and the related gains or losses are recognized in net earnings. The carrying amount of long-term debt subject to the hedge is adjusted for losses or gains associated with the hedged risk, with the corresponding amounts recognized in net earnings. As a result, only the net ineffectiveness is recognized in net earnings.

Cash Flow Hedges

Cash flow hedges are categorized as project, foreign exchange, interest rate, or commodity hedges and are used to offset foreign exchange, interest rate, and commodity price exposures resulting from market fluctuations.

Project Hedges

Foreign currency forward contracts are used to hedge foreign exchange exposures resulting from anticipated contracts and firm commitments denominated in foreign currencies, primarily related to capital expenditures.

Foreign Exchange, Interest Rate, and Commodity Hedges

Physical and financial swaps, forward sale and purchase contracts, futures contracts, and options are used primarily to offset the variability in future cash flows caused by fluctuations in electricity and natural gas prices. Foreign exchange forward contracts and cross-currency swaps are used to offset the exposures resulting from foreign-denominated long-term debt. Forward start interest rate swaps are used to offset the variability in cash flows related to interest expense resulting from anticipated issuances of long-term debt.

In a cash flow hedge, changes in the fair value of the hedging instrument (a forward contract or financial swap, for example) are recognized in risk management assets or liabilities, and the related gains or losses are recognized in OCI. These gains or losses are subsequently reclassified from OCI to net earnings in the same period as the hedged forecast cash flows impact net earnings, and offset the losses or gains arising from the forecast transactions. For project hedges, the gains and losses reclassified from OCI are included in the carrying amount of the related property, plant, and equipment ("PP&E").

When we do not elect hedge accounting, or when the hedge is no longer effective and does not qualify for hedge accounting, the gains or losses as a result of changes in prices, interest, or exchange rates related to these financial instruments are recorded in net earnings in the period in which they arise.

Net Investment Hedges

Foreign currency forward contracts and foreign-denominated long-term debt are used to hedge exposure to changes in the carrying values of our net investments in foreign operations that have a functional currency other than the Canadian dollar. Gains or losses on these instruments are recognized and deferred in OCI and reclassified to net earnings on the disposal of the foreign operation. We attempt to manage our foreign exchange translation exposure by matching foreign-denominated expenses with revenues, such as offsetting revenues from our U.S. operations with interest payments on our U.S. dollar debt.

Following the divestiture of CE Gen, Blackrock, and CalEnergy, and the repatriation of proceeds into Canadian funds, we de-designated approximately U.S.$180 million of debt from hedging U.S. net investments. During the third quarter of 2014, we de-designated an additional U.S.$90 million of U.S.-denominated debt hedging other U.S. operations. Prospectively, these tranches of U.S.-denominated debt are being hedged with foreign currency derivative instruments.

Non-Hedges

Financial instruments not designated as hedges are used to reduce commodity price, foreign exchange, and interest rate risks. Changes in the fair value of financial instruments not designated as hedges are recognized in risk management assets or liabilities, and the related gains or losses are recognized in net earnings in the period in which the change occurs.

Fair Values

The majority of fair values for our project, foreign exchange, interest rate, commodity hedges, and non-hedge derivatives are calculated using adjusted quoted prices from an active market or inputs validated by broker quotes. We may enter into commodity transactions involving non-standard features for which market-observable data is not available. These transactions are defined under IFRS as Level III instruments. Level III instruments incorporate inputs that are not observable from the market, and fair value is therefore determined using valuation techniques. Fair values are validated by using reasonably possible alternative assumptions as inputs to valuation techniques, and any material differences are disclosed in the notes to the financial statements. At Dec. 31, 2014, Level III instruments had a net asset carrying value of $217 million. Refer to the Critical Accounting Policies and Estimates section of this MD&A for further details regarding valuation techniques. Our risk management profile and practices have not changed materially from Dec. 31, 2013.

Liquidity and Capital Resources

Liquidity risk arises from our ability to meet general funding needs, engage in trading and hedging activities, and manage the assets, liabilities, and capital structure of the Corporation. Liquidity risk is managed by maintaining sufficient liquid financial resources to fund obligations as they come due in the most cost-effective manner. Liquidity risk related to commodity risk management activities is managed by maintaining sufficient reserves and monitoring our counterparties and the markets in which we transact.

Our liquidity needs are met through a variety of sources, including cash generated from operations, availability under our long-term credit facilities, and long-term debt or equity issued under our Canadian and U.S. shelf registrations. Our primary uses of funds are operational expenses, capital expenditures, dividends, distributions to non-controlling interests, and interest and principal payments on debt securities.

On Dec. 17, 2014, we filed a U.S. base shelf prospectus that allows for the issuance of up to U.S.$2.0 billion aggregate principal amount (or its equivalent in other currencies) of common shares, first preferred shares, warrants, subscription receipts, or debt securities from time to time. The specific terms of any offering of securities is to be determined at the date of issue.

Debt

Long-term debt totalled $4.0 billion as at Dec. 31, 2014 compared to $4.3 billion as at Dec. 31, 2013. Long-term debt decreased from Dec. 31, 2013 primarily due to the use of proceeds from the sale of CE Gen, Blackrock, and CalEnergy, the secondary offering of TransAlta Renewables common shares, and the issuance of preferred shares to pay down our credit facility borrowings. In May we repaid a $200 million maturing debenture by issuing a U.S.$400 million senior note. Excess proceeds were used to further reduce borrowings under our credit facilities.

During the year, strengthening of the U.S. dollar increased our long-term debt balances by $174 million. Almost all of our U.S.-denominated debt is hedged either through financial contracts or net investments in our U.S. operations. For 2014, the changes in our U.S.-denominated debt were offset as follows:

For the year ended Dec. 31	2014
Effects of foreign exchange on carrying amounts of U.S. operations (net investment hedge)	55
Foreign currency cash flow hedges on debt	79
Effects of foreign exchange on value of U.S.-denominated Solomon finance lease	29
Other economic hedges	11
Total	**174**

Credit Facilities

At Dec. 31, 2014, we had a total of $2.1 billion (2013 – $2.1 billion) of committed credit facilities, of which $1.6 billion (2013 – $0.9 billion) was not drawn and is available, subject to customary borrowing conditions. At Dec. 31, 2014, the $0.5 billion (2013 – $1.2 billion) of credit utilized under these facilities was comprised of actual drawings of $0.1 billion (2013 – $0.8 billion) and letters of credit of $0.4 billion (2013 – $0.4 billion). These facilities are comprised of a $1.5 billion committed syndicated bank facility that matures in 2018, with the remainder comprised of bilateral credit facilities, of which $0.3 billion matures in 2017 and $0.2 billion matures in the fourth quarter of 2016. We anticipate renewing these facilities, based on reasonable commercial terms, prior to their maturities.

In addition to the $1.6 billion available under the credit facilities, we have $43 million of available cash.

Share Capital

On Feb. 18, 2015, we had 277.0 million common shares outstanding, 12.0 million Series A, 11.0 million Series C, 9.0 million Series E, and 6.6 million Series G preferred shares outstanding. At Dec. 31, 2014, we had 275.0 million (2013 – 268.2 million) common shares issued and outstanding. At Dec. 31, 2014, we had 38.6 million (2013 – 32.0 million) first preferred shares issued and outstanding.

During the year ended Dec. 31, 2014, 6.8 million (2013 – 13.5 million) common shares were issued to shareholders that elected dividend reinvestment, for a total of $85 million (2013 – $186 million).

As noted in the Significant 2014 Events and Subsequent Events section of this MD&A, on Aug. 15, 2014, we completed a public offering of 6.6 million Series G Cumulative Redeemable Rate Reset First Preferred Shares for gross proceeds of $165 million. The holders of the preferred shares are entitled to receive fixed cumulative cash dividends at an annual rate of $1.325 per share as approved by the Board, payable quarterly, yielding 5.30 per cent per annum, for the initial period ending Sept. 30, 2019. The dividend rate will reset on Sept. 30, 2019 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield plus 3.80 per cent. The preferred shares are redeemable at the option of TransAlta on or after Sept. 30, 2019 and on Sept. 30 of every fifth year thereafter at a price of $25.00 per share plus all accrued and unpaid dividends.

The Series G preferred shareholders have the right at their option to convert their shares into Series H Cumulative Redeemable Rate Reset First Preferred Shares on Sept. 30, 2019 and on Sept. 30 of every fifth year thereafter. The holders of Series H preferred shares will be entitled to receive quarterly floating rate cumulative dividends as approved by the Board at a yield per annum equal to the sum of the then three-month Government of Canada Treasury Bill yield plus 3.80 per cent.

On Jan. 23, 2015, we declared a quarterly dividend of $0.18 per share on common shares, payable on April 1, 2015. This dividend is in line with the resized dividend that was announced in February 2014 of $0.72 per common share on an annualized basis. Declaration of dividends is at the discretion of the Board.

On Jan. 23, 2015, we declared a quarterly dividend of $0.2875 per share on the Series A and Series C preferred shares, $0.3125 per share on the Series E preferred shares, and $0.33125 per share on the Series G preferred shares, all payable on March 31, 2015.

Guarantee Contracts

We have obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, commodity risk management and hedging activities, construction projects, and purchase obligations. At Dec. 31, 2014, we provided letters of credit totalling $396 million (2013 – $370 million) and cash collateral of $25 million (2013 – $21 million). These letters of credit and cash collateral secure certain amounts included on our Consolidated Statements of Financial Position under risk management liabilities and decommissioning and other provisions.

Working Capital

As at Dec. 31, 2014, the excess of current liabilities over current assets was $597 million (2013 – $116 million). The excess of current liabilities over current assets increased $481 million compared to 2013, primarily due to a U.S.$500 million senior note due in January 2015. The note was repaid using liquidity.

Capital Structure

Our capital structure consisted of the following components as shown below:

	2014		2013	
As at Dec. 31	**Amount**	**%**	Amount	%
Net debt[1]	**3,917**	**50**	4,289	55
Non-controlling interests	**594**	**8**	517	7
Equity attributable to shareholders	**3,284**	**42**	2,906	38
Total capital	**7,795**	**100**	7,712	100

Commitments

Contractual commitments are as follows:

	Natural gas, transportation, and other purchase contracts	Transmission and power purchase agreements	Non-cancellable operating leases	Coal supply and mining agreements	Long-term service agreements	Long-term debt[2]	Interest on long-term debt[3]	Growth	Total
2015	43	12	11	159	119	738	178	207	1,467
2016	29	9	10	137	120	29	171	50	555
2017	13	3	8	44	105	466	166	175	980
2018	12	4	8	45	33	878	129	8	1,117
2019	7	2	8	46	31	402	104	–	600
2020 and thereafter	101	6	54	605	172	1,472	723	–	3,133
Total	**205**	**36**	**99**	**1,036**	**580**	**3,985**	**1,471**	**440**	**7,852**

In November 2014, we entered into an agreement with Alstom to provide major maintenance for our operated Canadian Coal facilities. Please refer to the Significant 2014 Events and Subsequent Events section of this MD&A for more information.

As part of the TransAlta Energy Bill signed into law in the State of Washington and the subsequent MoA, we have committed to fund U.S.$55 million over the remaining life of the U.S. Coal plant to support economic and community development, promote energy efficiency, and develop energy technologies related to the improvement of the environment. The MoA contains certain provisions for termination and in the event of the termination and certain circumstances, this funding or part thereof would no longer be required.

1 *Total debt and finance lease obligations net of cash and cash equivalents and fair value of related hedging instruments. Refer to Note 14 of our 2014 Notes to the Annual Financial Statements.*
2 *Repayments of long-term debt include amounts related to our credit facilities that are currently scheduled to mature in 2016, 2017, and 2018.*
3 *Interest on long-term debt is based on debt currently in place with no assumption as to re-financing an instrument on maturity.*

Financial Position

The following chart outlines significant changes in the Consolidated Statements of Financial Position from Dec. 31, 2013 to Dec. 31, 2014:

	Increase/ (decrease)	Primary factors explaining change
Trade and other receivables	**(54)**	Timing of customer receipts
Investments	**(192)**	Sale of CE Gen
Finance lease receivables (long-term)	**26**	Favourable changes in foreign exchange rates
Property, plant, and equipment, net	**45**	Additions and favourable changes in foreign exchange rates, partially offset by depreciation for the period
Deferred income tax assets	**(73)**	Changes in temporary differences
Risk management assets (current and long-term)[1]	**446**	Gains on long-term power sale contract and U.S. foreign currency hedges
Accounts payable and accrued liabilities	**34**	Higher capital accruals, partially offset by timing of payments and accruals
Dividends payable	**(30)**	Reduction of quarterly dividend
Long-term debt and finance lease obligations (including current portion)	**(291)**	Reduction of borrowings under credit facility and payout on maturity of medium-term notes, partially offset by the issuance of senior notes
Decommissioning and other provisions (current and long-term)	**24**	Fluctuations in period-end discount rates
Deferred income tax liabilities	**(25)**	Changes in temporary differences
Risk management liabilities (current and long-term)[1]	**34**	Price movements and changes in underlying positions and settlements
Equity attributable to shareholders	**378**	Net earnings for the period, gains on cash flow hedges recognized in other comprehensive income, and preferred shares issued, partially offset by declared dividends
Non-controlling interests	**77**	Sale of additional non-controlling interest in TransAlta Renewables, partially offset by non-controlling interests' portion of net earnings net of distributions

Statements of Cash Flows

The following charts highlight significant changes in the Consolidated Statements of Cash Flows for the years ended Dec. 31, 2014 and 2013:

Year ended Dec. 31	**2014**	2013	**Explanation of change**
Cash and cash equivalents, beginning of year	**42**	27	
Provided by (used in):			
Operating activities	**796**	765	Increase in cash earnings of $32 million. Refer to our discussion of funds from operations
Investing activities	**(292)**	(703)	Increase in proceeds on sale of investments of $224 million, a decrease in cash paid on the acquisition of Wyoming wind of $109 million, a decrease in additions to PP&E and intangibles of $72 million, and a decrease in investing non-cash working capital balances of $31 million, partially offset by a decrease in realized gains on financial instruments of $16 million and a decrease in proceeds on disposal of PP&E of $8 million
Financing activities	**(503)**	(47)	An increase in repayments of borrowings under credit facilities and in repayments (net of issuances) of long-term debt of $504 million, a decrease in proceeds on sale of non-controlling interest in subsidiary of $78 million, an increase in distributions paid to subsidiaries' non-controlling interests of $29 million, and an increase in common share cash dividends of $24 million, partially offset by an increase in proceeds on issuance of preferred shares of $161 million and an increase in realized gains on financial instruments of $20 million
Cash and cash equivalents, end of year	**43**	42	

1 After giving effect to the reclassification described in the Current Accounting Changes section of this MD&A.

Year ended Dec. 31	2013	2012	Explanation of change
Cash and cash equivalents, beginning of year	27	49	
Provided by (used in):			
Operating activities	765	520	Favourable changes in working capital of $307 million, net of a $27 million impact associated with the California claim in 2013 and a $204 million impact associated with the Sundance Units 1 and 2 arbitration in 2012, partially offset by lower cash earnings of $62 million
Investing activities	(703)	(1,048)	Decrease in acquisition of finance lease of $312 million, a decrease in additions to PP&E and intangibles of $149 million, an increase in realized gains on financial instruments of $26 million, and an increase in proceeds on sale of PP&E of $11 million, partially offset by the acquisition of the Wyoming wind farm for $109 million, an increase in equity investments of $17 million, a net negative impact of $12 million related to changes in collateral received from or paid to counterparties, and a decrease in investing non-cash working capital balances of $27 million
Financing activities	(47)	504	Decrease in proceeds on issuance of common shares of $293 million, a decrease in borrowings under credit facilities of $271 million partially due to the use of net proceeds received from the sale of the non-controlling interest in TransAlta Renewables to pay down borrowings on our credit facility, a decrease in proceeds on issuance of preferred shares of $217 million, an increase in common share cash dividends of $12 million, partially offset by an increase in proceeds on sale of non-controlling interest in subsidiary of $207 million, an increase in realized gains on financial instruments of $46 million, a decrease in long-term debt payments of $14 million, and an increase in proceeds on the issuance of long-term debt of $10 million
Translation of foreign currency cash	–	2	
Cash and cash equivalents, end of year	42	27	

Employee Future Benefits

We have registered pension plans in Canada and the U.S. covering substantially all employees of the Corporation, its domestic subsidiaries, and specific named employees working internationally. These plans have defined benefit and defined contribution options, and in Canada there is an additional supplemental defined benefit plan for members whose annual earnings exceed the Canadian income tax limit. Except for the Highvale pension plans acquired in 2013, the Canadian and U.S. defined benefit pension plans are closed to new entrants. The U.S. defined benefit pension plan was frozen effective Dec. 31, 2010, resulting in no future benefits being earned. The most recent actuarial valuation for accounting purposes of the registered and supplemental pension plans was conducted as at Dec. 31, 2014 for the Canadian pension plan, Jan. 1, 2014 for the U.S. pension plan, and Dec. 31, 2013 for the Highvale plan.

We provide other health and dental benefits for disabled members and retired members, typically up to the age of 65 (other post-employment benefits). The most recent actuarial valuation of these plans for accounting purposes was conducted as at Dec. 31, 2013 for the Canadian plan and Jan. 1, 2014 for the U.S. plan.

The supplemental pension plan is an obligation of the Corporation. We are not obligated to fund the supplemental plan but are obligated to pay benefits under the terms of the plan as they come due. We have posted a letter of credit in the amount of $64 million to secure the obligations under the supplemental plan.

Unconsolidated Structured Entities or Arrangements

Disclosure is required of all unconsolidated structured entities or arrangements such as transactions, agreements, or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities, or variable interest entities that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources. We currently have no such unconsolidated structured entities or arrangements.

Climate Change and the Environment

Environmental issues and related legislation have, and will continue to have, an impact upon our business. We are committed to complying with legislative and regulatory requirements and to minimizing the environmental impact of our operations. We work with governments and the public to develop appropriate frameworks to protect the environment and to promote sustainable development.

Recent changes to environmental regulations may materially adversely affect us. As indicated under "Risk Factors" in our Annual Information Form and within the Risk Management section of this MD&A, many of our activities and properties are subject to environmental requirements, as well as changes in our liabilities under these requirements, which may have a material adverse effect upon our consolidated financial results.

Ongoing and Recently Passed Environmental Legislation

Changes in current environmental legislation do have, and will continue to have, an impact upon our operations and our business.

Canadian Coal

In Alberta there are requirements for coal-fired generation units to implement additional air emission controls for oxides of nitrogen ("NOx") and sulphur dioxide ("SO_2") once they reach the end of their respective PPAs, in most cases at 2020. These regulatory requirements were developed by the province in 2004 as a result of multi-stakeholder discussions under Alberta's Clean Air Strategic Alliance ("CASA").

On Sept. 11, 2012, the Canadian federal government published the final regulations governing GHG emissions from coal-fired power plants, to become effective on July 1, 2015. The regulations provide for up to 50 years of life for coal units, at which point units must meet an emissions performance standard of approximately 420 tonnes per GWh. There are some exceptions that require older units commissioned before 1975 to reach end of life by Dec. 31, 2019, and units commissioned between 1975 and 1986 to reach end of life by Dec. 31, 2029. We believe the regulations provide additional operating time and increased flexibility for our Canadian Coal units, allowing those units to comply in a more cost-effective manner.

The release of the federal regulations creates a potential misalignment between the CASA air pollutant requirements and schedules, and the GHG retirement schedules for older coal plants, which in themselves will result in significant reductions of NOx, SO_2, and particulates. We are in discussions with the provincial government in an effort to ensure coordination between GHG and air pollutant regulations, such that emission reduction objectives are achieved in the most effective manner while taking into consideration the reliability and cost of Alberta's generation supply.

Other Canadian Developments

Since 2007, we have incurred costs as a result of GHG legislation in Alberta. On Dec. 19, 2014, the Alberta Government announced it was extending its current climate change legislation (the Specified Gas Emitters Regulation) until June 2015, with the stated intention of re-instituting a new program at that time. Our exposure to increased costs as a result of environmental legislation in Alberta is mitigated to some extent through change-in-law provisions in our PPAs that allow us the opportunity to recover capital and operating compliance costs from our PPA customers. The value realized from our environmental attributes generated in the province may also be impacted by the program's terms.

On Jan. 13, 2015, the Ontario Government announced its plan to put a price on carbon emissions in 2015, as part of its climate change program and stated objective of reducing GHG emissions by 15 per cent by 2020. No details are available yet. Our contracts at Gas facilities in the province generally include provisions protecting us from the adverse effects of changes in laws.

U.S. Coal

On June 2, 2014, the U.S. Environmental Protection Agency ("EPA") released draft regulations for managing GHG emissions from the power sector. These draft regulations target GHG emissions from all existing fossil-fired generation in the U.S.: coal, natural gas, and other hydrocarbon fuels. The draft regulations are designed to achieve a 30 per cent reduction from 2005 emission levels by 2030, for that sector. The proposed framework would establish 2030 emission rate goals, measured in pounds of carbon dioxide per MWh, for each state's electricity sector.

The draft regulations require interim goals to be achieved between 2020 and 2030 and a final goal to be achieved by 2030, and maintained beyond. The goals are state-specific depending on circumstances. States are to be given broad freedom to achieve the goals in a variety of ways, ranging from single- or multi-state cap and trade programs, heat rate improvements, and fuel switching initiatives, to more prescriptive approaches, such as, renewable energy and conservation programs. States will develop their individual approaches or State Implementation Plans, which will subsequently have to be reviewed and approved by the EPA. The draft regulations are expected to be finalized by the EPA by June 2015, with State Implementation Plans submitted by June 2016.

On Dec. 17, 2014, Washington State Governor Jay Inslee released a carbon-emissions reduction program for the State, where our U.S. Coal plant is located. Included in this program are a cap-and-trade plan and a low-carbon fuels standard. The proposed emissions cap will become more stringent over time, providing emitters time to transition their operations.

The recently proposed EPA GHG regulations for existing power plants are not expected to significantly affect our U.S. operations. TransAlta has agreed with Washington State to retire units in 2020 and 2025. This agreement is formally part of the State's climate change program. We believe that there will be no additional GHG regulatory burden on U.S. Coal given these commitments. The related TransAlta Energy Bill was signed into law in 2011 and provides a framework to transition from coal to other forms of generation.

Other U.S. Developments

Effective January 2013, direct deliveries of power to the California Independent System Operator are subject to Cap and Trade Regulations established by the California Air Resources Board. We continue to monitor our GHG inventory into California.

Australia

In Australia, the Government repealed the nation's carbon tax on July 17, 2014. This will eliminate the previous emission charges on our Australian gas-fired generation, although the impact is expected to be minimal as these emission charges were generally passed through to contracted customers. The Liberal Government has not yet implemented an alternative climate change program.

TransAlta Activities

Reducing the environmental impact of our activities has a benefit not only to our operations and financial results, but also to the communities in which we operate. We expect that increased scrutiny will be placed on environmental emissions and compliance, and we therefore have a proactive approach to minimizing risks to our results. Our Board provides oversight to our environmental management programs and emission reduction initiatives to ensure continued compliance with environmental regulations.

In 2014, we estimate that 35.1 million tonnes of GHGs with an intensity of 0.91 tonnes per MWh (2013 – 27.5 million tonnes of GHGs with an intensity of 0.801 tonnes per MWh) were emitted as a result of normal operating activities.[1] The increased volume and intensity of GHG emissions in 2014 compared to 2013 is primarily due to higher Canadian Coal production, driven by reduced outages and Sundance Units 1 and 2 returning to service in the second half of 2013.

Our environmental management programs encompass the following elements:

Renewable Power

We continue to invest in and build renewable power resources. Commercial operations began at our 68 MW New Richmond wind facility during the first quarter of 2013 and on Dec. 20, 2013 we completed the acquisition of a 144 MW wind farm in Wyoming. A larger renewable portfolio provides increased flexibility in generation and creates incremental environmental value through renewable energy certificates or through offsets.

Environmental Controls and Efficiency

We continue to make operational improvements and investments to our existing generating facilities to reduce the environmental impact of generating electricity. We installed mercury control equipment at our Canadian Coal operations in 2010 in order to meet Alberta's 70 per cent reduction objectives, and voluntarily at our U.S. coal-fired plant in 2012. Our Keephills Unit 3 plant began operations in September 2011 using supercritical combustion technology to maximize thermal efficiency, as well as SO_2 capture and low NOx combustion technology, which is consistent with the technology that is currently in use at Genesee Unit 3. Uprate projects completed at our Keephills and Sundance plants have improved the energy and emissions efficiency of those units.

Policy Participation

We are active in policy discussions at a variety of levels of government. These discussions have allowed us to engage in proactive discussions with governments and industry participants to meet environmental requirements over the longer term.

Clean Combustion Technologies

We look to advance clean energy technologies through organizations such as the Canadian Clean Power Coalition, which examines emerging clean combustion technologies such as gasification, oxygen combustion, biomass co-firing, and coal beneficiation.

Offsets Portfolio

TransAlta maintains an emissions offsets portfolio with a variety of instruments that can be used for compliance purposes or otherwise banked or sold. We continue to examine additional emissions offset opportunities that will allow us to meet emission targets at a competitive cost. Any investments in offsets will meet certification criteria in the market in which they are to be used.

1 *2014 data are estimates based on best available data at the time of report production. GHGs include water vapour, carbon dioxide ("CO_2"), methane, nitrous oxide, sulphur hexafluoride, hydrofluorocarbons, and perfluorocarbons. The majority of our estimated GHG emissions are comprised of CO_2 emissions from stationary combustion.*

2015 Financial Outlook

We expect comparable EBITDA for 2015 to be in the range of $1,000 million and $1,040 million based on the current outlook for power prices in Alberta and the Pacific Northwest. Comparable FFO is anticipated to be in the range of $720 to $770 million. Comparable free cash flow, excluding the effects of flood-recovery capital, is expected to be in the range of $265 million and $270 million, or $0.95 and $0.96 per share, based on sustaining capital, excluding the effects of flood-recovery capital, of approximately $310 million to $340 million. We anticipate that lower cash interest will be offset by higher distributions to non-controlling interest and preferred share dividends. Our expected dividend is 75 per cent to 76 per cent of comparable free cash flow.

Market

Power Prices

For 2015, power prices in Alberta are expected to be lower than 2014 as a result of increased supply, lower natural gas prices, and a risk to demand growth. However, prices can vary based on supply and weather conditions. In the Pacific Northwest and Ontario, we expect prices to settle lower than in 2014 due to lower natural gas prices.

Economic Environment

We expect growth to decelerate in Western Canada in 2015. The slowdown in the oil and gas sector is expected to reduce economic growth as a result of investment slowdown and lower consumer spending. After several years of weak growth, economic growth in the Pacific Northwest is expected to accelerate as the overall economic recovery in the U.S. gains strength. Growth in Ontario is expected to improve to moderate rates in 2015, driven largely by exports supported by U.S. recovery and the strengthening U.S. dollar.

We had no material counterparty losses in 2014. We continue to monitor counterparty credit risk and have established risk management policies to mitigate counterparty risk. We do not anticipate any material change to our existing credit practices and continue to deal primarily with investment grade counterparties.

Operations

Capacity, Production, and Availability

Excluding the effects of economic dispatching, production is expected to increase in 2015 primarily due to lower planned and unplanned outages. Overall adjusted availability is expected to be in the range of 89 to 91 per cent in 2015, which is at the higher end of our long-term target availability.

We also expect to commission our gas pipeline to supply our Solomon facility in the first quarter of 2015.

Contracted Cash Flows

As a result of Alberta PPAs, long-term contracts, and other short-term physical and financial contracts, on average, approximately 70 per cent of our capacity is contracted over the next seven years. On an aggregated portfolio basis, depending on market conditions, we target being up to 90 per cent contracted for the upcoming calendar year. As at the end of 2014, approximately 88 per cent of our 2015 capacity was contracted. The average prices of our short-term physical and financial contracts for 2015 are approximately $55 per MWh in Alberta and approximately U.S.$40 per MWh in the Pacific Northwest.

Fuel Costs

Mining coal in Alberta is subject to cost increases due to greater overburden removal, inflation, capital investments, and commodity prices. Seasonal variations in coal costs at our Alberta mine are minimized through the application of standard costing. Coal costs for 2015, on a standard cost per tonne basis, are expected to be similar to 2014 unit costs.

In the Pacific Northwest, our Centralia coal mine, adjacent to our power plant, is in the reclamation stage. Fuel at U.S. Coal is purchased primarily from external suppliers in the Powder River Basin and delivered by rail. The delivered cost of fuel per MWh for 2015 is expected to increase by approximately one to two per cent as a result of inflation.

The value of coal inventories is assessed for impairment at the end of each reporting period. If the inventory is impaired, further charges are recognized in net earnings.

We purchase natural gas from outside companies coincident with production or have it supplied by our customers, thereby minimizing our risk to changes in prices. The continued success of unconventional gas production in North America could reduce the year-to-year volatility of prices in the near term.

We closely monitor the risks associated with changes in electricity and input fuel prices on our future operations and, where we consider it appropriate, use various physical and financial instruments to hedge our assets and operations from such price risks.

Energy Marketing
Earnings from our Energy Marketing Segment are affected by prices and volatility in the market, overall strategies adopted, and changes in legislation. We continuously monitor both the market and our exposure to maximize earnings while still maintaining an acceptable risk profile. Our 2015 objective for Energy Marketing is to contribute between $50 million to $70 million in gross margin for the year.

Exposure to Fluctuations in Foreign Currencies
Our strategy is to minimize the impact of fluctuations in the Canadian dollar against the U.S. dollar, euro, and Australian dollar by offsetting foreign-denominated assets with foreign-denominated liabilities and by entering into foreign exchange contracts. We also have foreign-denominated expenses, including interest charges, which largely offset our foreign-denominated revenues.

Net Interest Expense
Net interest expense for 2015 is expected to be lower than in 2014 due to lower debt levels and higher capitalized interest. However, changes in interest rates and in the value of the Canadian dollar relative to the U.S. dollar can affect the amount of net interest expense incurred.

Liquidity and Capital Resources
We expect to maintain adequate available liquidity under our committed credit facilities.

Income Taxes
The effective tax rate on earnings, excluding non-comparable items for 2015, is expected to be approximately 17 to 22 per cent, which is lower than the statutory tax rate of 25 per cent, due to changes in the amount of earnings between the jurisdictions in which pre-tax income is earned and the effect of certain deductions that do not fluctuate with earnings.

Capital
Our major projects are focused on sustaining our current operations and supporting our growth strategy.

Growth and Major Project Capital
A summary of the significant growth and major projects that are in progress is outlined below:

	Total Project		2015		
	Estimated spend	Spent to date[1]	Estimated spend	Target completion date	Details
Project					
South Hedland Power Station[2]	562	69	183	Q2 2017	150 MW combined cycle power plant
Australia natural gas pipeline[3]	100	77	23	Q1 2015	270 kilometre pipeline to supply natural gas to our Solomon power station in Western Australia
Transmission	13	2	11	Q2 2015	Regulated transmission that receives a return on investment
Hydro life extension	19	19	–	Q4 2014	Generator replacement and turbine runner improvements to extend the life of selected plants
Total	**694**	**167**	**217**		

Based on an assessment of the nature of prospective hydro life extension projects, beginning in 2015, the costs incurred for the hydro life extension are classified as sustaining capital.

1 *Represents amounts spent as of Dec. 31, 2014.*
2 *Estimated project spend is AUD$570 million. Total estimated project spend is stated in CAD$ and includes estimated capitalized interest costs. The total estimated project spend may change due to fluctuations in foreign exchange rates.*
3 *Includes certain natural gas conversion costs at the Solomon power station that will be recognized as a finance lease receivable. The total estimated project spend may change due to fluctuations in foreign exchange rates.*

Sustaining and Productivity Capital

A significant portion of our sustaining and productivity capital is planned major maintenance, which includes inspection, repair and maintenance of existing components, and the replacement of existing components. Planned major maintenance costs are capitalized as part of PP&E and are amortized on a straight-line basis over the term until the next major maintenance event. It excludes amounts for day-to-day routine maintenance, unplanned maintenance activities, and minor inspections and overhauls, which are expensed as incurred.

Our estimate for total sustaining and productivity capital is allocated among the following:

Category	**Description**	**Spent in 2014**	**Expected spend in 2015**
Routine capital[1]	Capital required to maintain our existing generating capacity	116	100-110
Planned major maintenance	Regularly scheduled major maintenance	162	180-190
Mining capital	Capital related to mining equipment and land purchases	45	20-25
Finance leases	Payments related to mining equipment under finance leases	10	10-15
Total sustaining capital excluding flood-recovery capital		**333**	**310-340**
Flood-recovery capital	Capital arising from the 2013 Alberta flood	9	25-30
Total sustaining capital		**342**	**335-370**
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	14	5-10
Total sustaining and productivity capital		**356**	**340-380**

We continue to anticipate that most flood-recovery capital expenditures will be recovered from third parties.

Lost production as a result of planned major maintenance, excluding U.S. Coal planned major maintenance which is scheduled during a period of economic dispatching, is estimated as follows for 2015:

	Coal	**Gas and Renewables**	**Total**
GWh lost	1,094-1,104	220-230	1,314-1,334

Financing

Financing for these capital expenditures is expected to be provided by cash flow from operating activities, existing borrowing capacity, dividends reinvested, asset sales to TransAlta Renewables, and capital markets. The funds required for committed growth, sustaining capital, and productivity projects are not expected to be significantly impacted by the current economic environment due to the highly contracted nature of our cash flows, our financial position, and the amount of capital available to us under existing committed credit facilities.

1 *Does not include hydro life extension costs of $19 million in 2014. In 2015, includes estimated hydro life extension costs of $17 million.*

Risk Management

Our business activities expose us to a variety of risks including, but not limited to, increased regulatory changes, rapidly changing market dynamics, and increased volatility in our key commodity markets. Our goal is to manage these risks so that we are reasonably protected from an unacceptable level of risk or financial exposure while still enabling business development. We use a multilevel risk management oversight structure to manage the risks arising from our business activities, the markets in which we operate, and the political environments and structures with which we interface.

The responsibilities of various stakeholders of our risk management oversight structure are described below:

The Board of Directors provides stewardship of the Corporation; ensures that the Corporation establishes policies and procedures for the identification, assessment, and management of principal risks and risk appetite; and receives an annual comprehensive Enterprise Risk Management ("ERM") review. The ERM review consists of a holistic view of the Corporation's inherent risks, how we mitigate these risks, and residual risks. It defines our risks, discusses who is responsible to manage each risk, examines how the risks are interrelated with each other, and identifies the applicable risk metrics.

The Audit and Risk Committee ("ARC"), established by the Board of Directors, provides assistance to the Board of Directors in fulfilling its oversight responsibility relating to the integrity of our financial statements and the financial reporting process; the systems of internal accounting and financial controls; the internal audit function; the external auditors' qualifications and terms and conditions of appointment, including remuneration; independence; performance and reports; and the legal and risk compliance programs as established by management and the Board of Directors. The ARC approves our Commodity and Financial Exposure Management policies and reviews quarterly ERM reporting.

The Chief Executive Officer and the Executive Vice-Presidents review key risks at least quarterly. Weekly or monthly specific Trading Risk Management meetings are held by the Vice-President Risk, Vice-President Trading, Executive Vice-President Energy Marketing, and Chief Financial Officer.

The Technical Risk and Commercial Team ("TRACT") is a committee chaired by the Vice-President, Engineering, Environment, and Construction Services, and is comprised of our financial and operations directors. It reviews major projects and commercial agreements at various stages through development, prior to submission for approval by the Investment Committee and the Board of Directors.

The Investment Committee is chaired by our Chief Financial Officer and is comprised of the Chief Executive Officer, Chief Financial Officer, Chief Legal and Compliance Officer, Chief Investment Officer, and Executive Vice-President Corporate Services. It reviews and approves all major capital expenditures including growth, productivity, life extensions, and major coal outages. Projects that are approved by the committee will then be put forward for approval by the Board of Directors.

Risk Controls

Our risk controls have several key components:

Enterprise Tone

We strive to foster beliefs and actions that are true to and respectful of our many stakeholders. We do this by investing in communities where we live and work, operating and growing sustainably, putting safety first, and being responsible to the many groups and individuals with whom we work.

Policies

We maintain a comprehensive set of enterprise-wide policies. These policies establish delegated authorities and limits for business transactions, as well as allow for an exception approval process. Periodic reviews and audits are performed to ensure compliance with these policies. All employees and directors are required to sign a corporate code of conduct on an annual basis.

Reporting

On a regular basis, residual risk exposures are reported to key decision makers including the Board of Directors, senior management, and the Risk Management Committee ("RMC"). Reporting to the RMC includes analysis of new risks, monitoring of status to risk limits, review of events that can affect these risks, and discussion and status of actions to minimize risks. This quarterly reporting provides for effective and timely risk management and oversight.

Whistleblower System

We have a system in place where employees, shareholders, or other stakeholders may anonymously report any potential ethical concerns. These concerns can be submitted anonymously, either directly to the ARC or to the Director, Internal Audit, who engages Corporate Security, Legal, and Human Resources in determining the appropriate course of action. These concerns and any actions taken are discussed with the chair of the ARC.

Value at Risk and Trading Positions

Value at risk ("VaR") is one of the primary measures used to manage our exposure to market risk resulting from commodity risk management activities. VaR is calculated and reported on a daily basis. This metric describes the potential change in the value of our trading portfolio over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations.

VaR is a commonly used metric that is employed by industry to track the risk in commodity risk management positions and portfolios. Two common methodologies for estimating VaR are the historical variance/covariance and Monte Carlo approaches. We estimate VaR using the historical variance/covariance approach. An inherent limitation of historical variance/covariance VaR is that historical information used in the estimate may not be indicative of future market risk. Stress tests are performed periodically to measure the financial impact to the trading portfolio resulting from potential market events, including fluctuations in market prices, volatilities of those prices, and the relationships between those prices. We also employ additional risk mitigation measures. VaR at Dec. 31, 2014 associated with our proprietary commodity risk management activities was $5 million (2013 – $2 million). The increase is attributable to higher volatility levels around Dec. 31, 2014 than Dec. 31, 2013. Refer to the Commodity Price Risk section of this MD&A for further discussion.

Risk Factors

Risk is an inherent factor of doing business. The following section addresses some, but not all, risk factors that could affect our future results and our activities in mitigating those risks. These risks do not occur in isolation, but must be considered in conjunction with each other.

For some risk factors we show the after-tax effect on net earnings of changes in certain key variables. The analysis is based on business conditions and production volumes in 2014. Each item in the sensitivity analysis assumes all other potential variables are held constant. While these sensitivities are applicable to the period and the magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances, or for a greater magnitude of changes. The changes in rates should also not be assumed to be proportionate to earnings in all instances.

Volume Risk

Volume risk relates to the variances from our expected production. For example, the financial performance of our Hydro and Wind operations are partially dependent upon the availability of their input resources in a given year. Where we are unable to produce sufficient quantities of output in relation to contractually specified volumes, we may be required to pay penalties or purchase replacement power in the market.

We manage volume risk by:

- actively managing our assets and their condition through the Generation Segment and Capital and Asset Reporting group in order to be proactive in plant maintenance so that our plants are available to produce when required,
- monitoring water resources throughout Alberta to the best of our ability and optimizing this resource against real-time electricity market opportunities,
- placing our wind facilities in locations that we believe to have adequate resources to generate electricity to meet the requirements of our contracts. However, we cannot guarantee that these resources will be available when we need them or in the quantities that we require, and
- diversifying our fuels and geography as one way of mitigating regional or fuel-specific events.

The sensitivities of volumes to our net earnings are shown below:

Factor	Increase or decrease (%)	Approximate impact on net earnings
Availability/production	1	22

Generation Equipment and Technology Risk

There is a risk of equipment failure due to wear and tear, latent defect, design error or operator error, among other things, which could have a material adverse effect on the Corporation. Although our generation facilities have generally operated in accordance with expectations, there can be no assurance that they will continue to do so. Our plants are exposed to operational risks such as failures due to cyclic, thermal, and corrosion damage in boilers, generators, and turbines, and other issues that can lead to outages and increased volume risk. If plants do not meet availability or production targets specified in their PPA or other long-term contracts, we may be required to compensate the purchaser for the loss in the availability of production or record reduced energy or capacity payments. For merchant facilities, an outage can result in lost merchant opportunities. Therefore, an extended outage could have a material adverse effect on our business, financial condition, results of operations, or our cash flows.

As well, we are exposed to procurement risk for specialized parts that may have long lead times. If we are unable to procure these parts when they are needed for maintenance activities, we could face an extended period where our equipment is unavailable to produce electricity.

During 2013, the original equipment manufacturer for the generators at Sundance Units 3 to 6 revised the operating criteria for the units such that they would no longer be able to produce the same amount of leading reactive power ("MVAR") at current active power output levels. Reactive power refers to the voltage support that is required to make electrical systems like the Alberta Interconnected Electric System function and deliver power through transmission lines. More recently, equipment studies have been completed which have led to the original equipment manufacturer revising the capability curves such that the constraint for operations at high leading power factors has been relaxed. We are in the process of adjusting our plant settings to reflect the revised curves. We are also assessing compliance of uprated units with the AESO's proposed new MVAR standards.

We manage our generation equipment and technology risk by:

- operating our generating facilities within defined and proven operating standards that are designed to maximize the availability of our generating facilities for the longest period of time,
- performing preventative maintenance on a regular basis,
- adhering to a comprehensive plant maintenance program and regular turnaround schedules,
- adjusting maintenance plans by facility to reflect the equipment type and age,
- having sufficient business interruption coverage in place in the event of an extended outage,
- having force majeure clauses in our thermal and other PPAs and other long-term contracts,
- using technology in our generating facilities that is selected and maintained with the goal of maximizing the return on those assets,
- monitoring technological advances and evaluating their impact upon our existing generating fleet and related maintenance programs,
- negotiating strategic supply agreements with selected vendors to ensure key components are available in the event of a significant outage,
- entering into long-term arrangements with our strategic supply partners to ensure availability of critical spare parts, and
- developing a long-term asset management strategy with the objective of maximizing the life cycles of our existing facilities and/or replacement of selected generating assets.

Commodity Price Risk

We have exposure to movements in certain commodity prices, including the market price of electricity and fuels used to produce electricity in both our electricity generation and proprietary trading businesses.

We manage the financial exposure associated with fluctuations in electricity price risk by:

- entering into long-term contracts that specify the price at which electricity, steam, and other services are provided,
- maintaining a portfolio of short-, medium-, and long-term contracts to mitigate our exposure to short-term fluctuations in commodity prices,
- purchasing natural gas coincident with production for merchant plants so spot market spark spreads are adequate to produce and sell electricity at a profit, and
- ensuring limits and controls are in place for our proprietary trading activities.

In 2014, we had approximately 90 per cent (2013 – 90 per cent) of production under short-term and long-term contracts and hedges. In the event of a planned or unplanned plant outage or other similar event, however, we are exposed to changes in electricity prices on purchases of electricity from the market to fulfill our supply obligations under these short- and long-term contracts.

We manage the financial exposure to fluctuations in the costs of fuels used in production by:

- entering into long-term contracts that specify the price at which fuel is to be supplied to our plants,
- hedging emissions costs by entering into various emission trading arrangements, and
- selectively using hedges, where available, to set prices for fuel.

In 2014, 68 per cent (2013 – 64 per cent) of our cost of gas used in generating electricity was contractually fixed or passed through to our customers and 100 per cent (2013 – 100 per cent) of our purchased coal costs were contractually fixed.

The sensitivities of price changes to our net earnings, assuming production consistent with 2014 and applying the contractual profile in place at Dec. 31, 2014 for 2015, are shown below:

Factor	Increase or decrease	Approximate impact on net earnings and cash flow
Electricity price – Canada	$1.00/MWh	3
Electricity price – U.S.	U.S.$1.00/MWh	2
Natural gas price	$0.10/GJ	1

Actual variations in net earnings can vary from calculated sensitivities and may not be linear due to optimization opportunities, co-dependencies and cost mitigations, production, availability, and other factors.

Fuel Supply Risk

We buy natural gas and some of our coal to supply the fuel needed to operate our facilities. Having sufficient fuel available when required for generation is essential to maintaining our ability to produce electricity under contracts and for merchant sale opportunities.

At our coal-fired plants, input costs, such as diesel, tires, the price and availability of mining equipment, the volume of overburden removed to access coal reserves, rail rates, and the location of mining operations relative to the power plants are some of the exposures in our mining operations. Additionally, the ability of the mines to deliver coal to the power plants can be impacted by weather conditions and labour relations. At U.S. Coal, interruptions at our suppliers' mines and the availability of trains to deliver coal could affect our ability to generate electricity.

We manage coal supply risk by:

- ensuring that the majority of the coal used in electrical generation is from reserves permitted through coal rights we have purchased or for which have long-term supply contracts, thereby limiting our exposure to fluctuations in the supply of coal from third parties. All of the coal used in generating activities in Alberta is from reserves permitted through coal rights we have purchased. The coal used in generating activities in U.S. Coal is secured through long-term supply contracts,
- using longer-term mining plans to ensure the optimal supply of coal from our mines,
- sourcing the majority of the coal used at U.S. Coal under a mix of short-, medium-, and long-term contracts and from multiple mine sources to ensure sufficient coal is available at a competitive cost,
- contracting sufficient trains to deliver the coal requirements at U.S. Coal,
- ensuring coal inventories on hand at Canadian Coal and U.S. Coal are at appropriate levels for usage requirements,
- ensuring efficient coal handling and storage facilities are in place so that the coal being delivered can be processed in a timely and efficient manner,
- monitoring and maintaining coal specifications, carefully matching the specifications mined with the requirements of our plants, and
- hedging diesel exposure in mining and transportation costs.

We believe adequate supplies of natural gas at reasonable prices will be available for plants when existing supply contracts expire.

Environmental Risk

Environmental risks are risks to our business associated with existing and/or changes in environmental regulations. New emission reduction objectives for the power sector are being established by governments in Canada and the U.S. We anticipate continued and growing scrutiny by investors relating to sustainability performance. These changes to regulations may affect our earnings by imposing additional costs on the generation of electricity, such as emission caps, requiring additional capital investments in emission capture technology, or requiring us to invest in offset credits. It is anticipated that these compliance costs will increase due to increased political and public attention to environmental concerns.

We manage environmental risk by:

- seeking continuous improvement in numerous performance metrics such as emissions, safety, land and water impacts, and environmental incidents,
- having an International Organization for Standardization and Occupational Health and Safety Assessment Series-based environmental health and safety management system in place that is designed to continuously improve performance,
- committing significant experienced resources to work with regulators in Canada and the U.S. to advocate that regulatory changes are well designed and cost effective,
- developing compliance plans that address how to meet or exceed emission standards for GHGs, mercury, SO_2, and NOx, which will be adjusted as regulations are finalized,
- purchasing emission reduction offsets,
- investing in renewable energy projects, such as wind and hydro generation,
- investing in clean coal technology development, which potentially provides long-term promise for large emission reductions from fossil-fuel-fired generation, and
- incorporating change in law provisions in contracts that allow recovery of certain compliance costs from our customers.

We strive to be in compliance with all environmental regulations relating to operations and facilities. Compliance with both regulatory requirements and management system standards is regularly audited through our performance assurance policy and results are reported quarterly to the Governance and Environment Committee.

We are a founder of the Canadian Clean Power Coalition dedicated to developing clean combustion technologies, which in turn will mitigate the environmental and financial risks associated with continued fossil fuel use for power generation.

Credit Risk

Credit risk is the risk to our business associated with changes in the creditworthiness of entities with which we have commercial exposures. This risk results from the ability of a counterparty to either fulfill its financial or performance obligations to us or where we have made a payment in advance of the delivery of a product or service. The inability to collect cash due to us or to receive products or services may have an adverse impact upon our net earnings and cash flows.

We manage our exposure to credit risk by:

- establishing and adhering to policies that define credit limits based on the creditworthiness of counterparties, contract term limits, and the credit concentration with any specific counterparty,
- requiring formal sign-off on contracts that include commercial, financial, legal, and operational reviews,
- requiring security instruments, such as parental guarantees, letters of credit, and cash collateral that can be collected if a counterparty fails to fulfill its obligation or goes over its limits, and
- reporting our exposure using a variety of methods that allow key decision makers to assess credit exposure by counterparty. This reporting allows us to assess credit limits for counterparties and the mix of counterparties based on their credit ratings.

If established credit exposure limits are exceeded, we take steps to reduce this exposure, such as requesting collateral, if applicable, or by halting commercial activities with the affected counterparty. However, there can be no assurances that we will be successful in avoiding losses as a result of a contract counterparty not meeting its obligations.

Our credit risk management profile and practices have not changed materially from Dec. 31, 2013. We had no material counterparty losses in 2014, and we are exposed to minimal credit risk for Alberta PPAs because under the terms of these arrangements, receivables are substantially all secured by letters of credit. We continue to keep a close watch on changes and trends in the market and the impact these changes could have on our commodity risk management and hedging activities, and will take appropriate actions as required, although no assurance can be given that we will always be successful.

A summary of our credit exposure for our commodity risk management and hedging activities at Dec. 31, 2014 is provided below:

Counterparty credit rating	Net exposure amount
Investment grade	718
Non-investment grade	2
No external rating, internally rated as investment grade	23
No external rating, internally rated as non-investment grade	4

The maximum credit exposure to any one customer for commodity trading operations, including the fair value of open trading positions, is $29 million (2013 – $23 million).

Currency Rate Risk

We have exposure to various currencies as a result of our investments and operations in foreign jurisdictions, the earnings from those operations, the acquisition of equipment and services and foreign-denominated commodities from foreign suppliers, and our U.S.-denominated debt. Our exposures are primarily to the U.S. and Australian currencies. Changes in the values of these currencies in relation to the Canadian dollar may affect our earnings or the value of our foreign investments to the extent that these positions or cash flows are not hedged or the hedges are ineffective.

We manage our currency rate risk by establishing and adhering to policies that include:

- hedging our net investments in foreign operations using a combination of foreign-denominated debt and financial instruments. Our strategy is to offset 90 to 100 per cent of all such foreign currency exposures. At Dec. 31, 2014, we have hedged approximately 95 per cent (2013 – 99 per cent) of our foreign currency net investment exposure, which we define to exclude net U.S. risk management assets,
- offsetting earnings from our foreign operations as much as possible by using expenditures denominated in the same foreign currencies and financial instruments to hedge the balance of this exposure, and
- entering into forward foreign exchange contracts to hedge future foreign-denominated receipts and expenditures, and all U.S.-denominated debt outside of our net investment portfolio.

The sensitivity of our net earnings to changes in foreign exchange rates has been prepared using management's assessment that an average four cent increase or decrease in the U.S. or Australian currencies relative to the Canadian dollar is a reasonable potential change over the next quarter, and is shown below:

Factor	Increase or decrease	Approximate impact on net earnings
Exchange rate	$0.04	2

Creditworthiness and Liquidity Risk

Liquidity risk relates to our ability to access capital to be used for commodity risk management activities, commodity hedging, capital projects, debt refinancing, and general corporate purposes. Investment grade credit ratings support these activities and provide a more reliable and cost-effective means to access capital markets through commodity and credit cycles. We are focused on strengthening our financial position and maintaining stable investment grade credit ratings as our ability to efficiently access capital markets funding on a cost-effective basis is partially dependent upon the maintenance of satisfactory credit ratings. There can be no assurance that TransAlta's credit ratings and the corresponding outlook will not be changed, potentially resulting in adverse consequences for funding capacity, liquidity and access to capital markets. Changes in credit ratings may also affect the ability and/or the cost of establishing normal course derivative or hedging transactions undertaken by our Energy Marketing Segment. Credit ratings do not consider market price or address the suitability of any financial instrument for a particular investor and are not recommendations to purchase, sell or hold securities. Credit ratings are subject to revision or withdrawal at any time by the rating organization. Credit ratings issued for TransAlta, as well as the corresponding rating agency outlook, are set out in the Strategy and Capability to Deliver Results – Financial Strategy section of this MD&A.

Counterparties enter into certain electricity and natural gas purchase and sale contracts for the purposes of asset-backed sales and proprietary trading. The terms and conditions of these contracts require the counterparties to provide collateral when the fair value of the obligation pursuant to these contracts is in excess of any credit limits granted. Downgrades in creditworthiness by certain credit rating agencies may decrease the credit limits granted and accordingly increase the amount of collateral that may have to be provided.

We manage liquidity risk by:

- monitoring liquidity on trading positions,
- preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital,
- reporting liquidity risk exposure for commodity risk management activities on a regular basis to the RMC, senior management, and the ARC,
- maintaining investment grade credit ratings, and
- maintaining sufficient undrawn committed credit lines to support potential liquidity requirements.

Interest Rate Risk

Changes in interest rates can impact our borrowing costs while the opposite impact will be seen on the capacity revenues we receive from our Alberta PPA plants. Changes in our cost of capital may also affect the feasibility of new growth initiatives.

We manage interest rate risk by establishing and adhering to policies that include:

- employing a combination of fixed and floating rate debt instruments, and
- monitoring the mixture of floating and fixed rate debt and adjusting where necessary to ensure a continued efficient mixture of these types of debt.

At Dec. 31, 2014, approximately four per cent (2013 – 21 per cent) of our total debt portfolio was subject to changes in floating interest rates through a combination of floating rate debt and interest rate swaps.

The sensitivity of changes in interest rates upon our net earnings is shown below:

Factor	Increase or decrease (%)	Approximate impact on net earnings[1]
Interest rate	0.25	–

Project Management Risk

On capital projects, we face risks associated with cost overruns, delays, and performance.

We manage project risks by:

- ensuring all projects are vetted by the TRACT Committee so that projects have been highly scrutinized to see that established processes and policies are followed, risks have been properly identified and quantified, input assumptions are reasonable, and returns are realistically forecasted prior to senior management and Board of Directors approvals,
- using consistent and disciplined project management methodology and processes,
- performing detailed analysis of project economics prior to construction or acquisition and by determining our asset contracting strategy to ensure the right mix of contracted and merchant capacity prior to commencement of construction,
- partnering with those who have previously been able to deliver projects economically and on budget,
- developing and following through with comprehensive plans that include critical paths identified, key delivery points, and backup plans,
- managing project closeouts so that any learnings from the project are incorporated into the next significant project,
- fixing the price and availability of the equipment, foreign currency rates, warranties, and source agreements as much as is economically feasible prior to proceeding with the project, and
- entering into labour agreements to provide security around cost and productivity.

1 *A 0.25 per cent change in interest rates applied to our variable rate debt would not result in a material impact on net earnings. Based on our variable rate debt at Dec. 31, 2014, a 0.75 per cent change in interest rates would be required to have a $1 million impact on net earnings.*

Human Resource Risk

Human resource risk relates to the potential impact upon our business as a result of changes in the workplace. Human resource risk can occur in several ways:

- potential disruption as a result of labour action at our generating facilities,
- reduced productivity due to turnover in positions,
- inability to complete critical work due to vacant positions,
- failure to maintain fair compensation with respect to market rate changes, and
- reduced competencies due to insufficient training, failure to transfer knowledge from existing employees, or insufficient expertise within current employees.

We manage this risk by:

- monitoring industry compensation and aligning salaries with those benchmarks,
- using incentive pay to align employee goals with corporate goals,
- monitoring and managing target levels of employee turnover, and
- ensuring new employees have the appropriate training and qualifications to perform their jobs.

In 2014, 54 per cent (2013 – 54 per cent) of our labour force was covered by 12 (2013 – 12) collective bargaining agreements. In 2014, four (2013 – five) agreements were renegotiated. We anticipate the successful negotiation of three collective agreements in 2015.

Regulatory and Political Risk

Regulatory and political risk describes the risk to our business associated with potential changes to the existing regulatory structures and the political influence upon those structures. This risk can come from market re-regulation, increased oversight and control, structural or design changes in markets, or other unforeseen influences. Market rules are often dynamic and we are not able to predict whether there will be any material changes in the regulatory environment or the ultimate effect of changes in the regulatory environment on our business.

We manage these risks systematically through our Legal and Regulatory Compliance programs, which are reviewed periodically to ensure its effectiveness, as well as through our Government Relations team. We work with governments, regulators, electric system operators, and other stakeholders to resolve issues as they arise. We are actively monitoring changes to market rules and market design, and we engage in market-sponsored stakeholder engagement processes. Through these and other avenues, we engage in advocacy and policy discussions at a variety of levels. These stakeholder negotiations have allowed us to engage in proactive discussions with governments over the longer term.

International investments are subject to unique risks and uncertainties relating to the political, social, and economic structures of the respective country and such country's regulatory regime. We mitigate this risk through the use of non-recourse financing and insurance.

Transmission Risk

Access to transmission lines and transmission capacity for existing and new generation are key in our ability to deliver energy produced at our power plants to our customers. The risks associated with the aging existing transmission infrastructure in Alberta, Ontario, and the Pacific Northwest continue to increase because new connections to the power system are consuming transmission capacity quicker than it is being added by new transmission developments.

Reputation Risk

Our reputation is one of our most valued assets. Reputation risk relates to the risk associated with our business because of changes in opinion from the general public, private stakeholders, governments, and other entities.

We manage reputation risk by:

- striving as a neighbour and business partner in the regions where we operate to build viable relationships based on mutual understanding leading to workable solutions with our neighbours and other community stakeholders,
- clearly communicating our business objectives and priorities to a variety of stakeholders on a routine basis,
- maintaining positive relationships with various levels of government,
- pursuing sustainable development as a longer-term corporate strategy,
- ensuring that each business decision is made with integrity and in line with our corporate values,
- communicating the impact and rationale of business decisions to stakeholders in a timely manner, and
- maintaining strong corporate values that support reputation risk management initiatives.

Corporate Structure Risk

We conduct a significant amount of business through subsidiaries and partnerships. Our ability to meet and service debt obligations is dependent upon the results of operations of our subsidiaries and the payment of funds by our subsidiaries in the form of distributions, loans, dividends, or otherwise. In addition, our subsidiaries may be subject to statutory or contractual restrictions that limit their ability to distribute cash to us.

General Economic Conditions

Changes in general economic conditions impact product demand, revenue, operating costs, the timing and extent of capital expenditures, the net recoverable value of PP&E, financing costs, credit and liquidity risk, and counterparty risk.

Income Taxes

Our operations are complex and located in several countries. The computation of the provision for income taxes involves tax interpretations, regulations, and legislation that are continually changing. Our tax filings are subject to audit by taxation authorities. Management believes that it has adequately provided for income taxes as required by IFRS, based on all information currently available.

The sensitivity of changes in income tax rates upon our net earnings is shown below:

Factor	Increase or decrease (%)	Approximate impact on net earnings
Tax rate	1	2

The effective tax rate on comparable earnings before income taxes, equity income, and other items for 2014 was 21 per cent. The effective income tax rate can change depending on the mix of earnings from various countries and certain deductions that do not fluctuate with earnings.

Legal Contingencies

We are occasionally named as a party in various claims and legal proceedings that arise during the normal course of our business. We review each of these claims, including the nature of the claim, the amount in dispute or claimed, and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in our favour or that such claims may not have a material adverse effect on us.

Other Contingencies

We maintain a level of insurance coverage deemed appropriate by management. There were no significant changes to our insurance coverage during renewal of the insurance policies on December 31. Our insurance coverage may not be available in the future on commercially reasonable terms. There can be no assurance that our insurance coverage will be fully adequate to compensate for potential losses incurred. In the event of a significant economic event, the insurers may not be capable of fully paying all claims.

Critical Accounting Policies and Estimates

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as accounting rules and guidance have changed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules and the use of judgment relative to the circumstances existing in the business. Every effort is made to comply with all applicable rules on or before the effective date, and we believe the proper implementation and consistent application of accounting rules is critical.

However, not all situations are specifically addressed in the accounting literature. In these cases, our best judgment is used to adopt a policy for accounting for these situations. We draw analogies to similar situations and the accounting guidelines governing them, consider foreign accounting standards, and consult with our independent auditors about the appropriate interpretation and application of these policies. Each of the critical accounting policies involves complex situations and a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our consolidated financial statements.

Our significant accounting policies are described in Note 2 to our audited consolidated financial statements within this Annual Report. The most critical of these policies are those related to revenue recognition, financial instruments, valuation of PP&E and associated contracts, project development costs, useful life of PP&E, valuation of goodwill, leases, income taxes, employee future benefits, decommissioning and restoration provisions, and other provisions. Each policy involves a number of estimates and assumptions to be made about matters that are uncertain at the time the estimate is made. Different estimates, with respect to key variables used for the calculations, or changes to estimates, could potentially have a material impact on our financial position or results of operations.

We have discussed the development and selection of these critical accounting estimates with our ARC and our independent auditors. The ARC has reviewed and approved our disclosure relating to critical accounting estimates in this MD&A.

These critical accounting estimates are described as follows:

Revenue Recognition

The majority of our revenues are derived from the sale of physical power, leasing of power facilities, and from commodity risk management activities.

Revenues under long-term electricity and thermal sales contracts generally include one or more of the following components: fixed capacity payments for availability, energy payments for generation of electricity, incentives or penalties for exceeding or not meeting availability targets, excess energy payments for power generation above committed capacity, and ancillary services. Each of these components is recognized upon output, delivery, or satisfaction of contractually specific targets. Revenues from non-contracted capacity are comprised of energy payments, at market prices, for each MWh produced and are recognized upon delivery.

In certain situations, a long-term electricity or thermal sales contract may contain, or be considered, a lease. Where the terms and conditions of the contract result in the customer assuming the principal risks and rewards of ownership of the underlying asset, the contractual arrangement is considered a finance lease, which results in the recognition of finance lease income. Where we retain the principal risks and rewards, the contractual arrangement is an operating lease. Rental income, including contingent rents where applicable, is recognized over the term of the contract. Revenues associated with non-lease elements are recognized as goods or services revenues as outlined above.

Commodity risk management activities involve the use of derivatives such as physical and financial swaps, forward sales contracts, and futures contracts and options, to earn trading revenues and to gain market information. These derivatives are accounted for using fair value accounting when hedge accounting is not applied. The initial recognition of fair value and subsequent changes in fair value affect reported earnings in the period the change occurs. The fair values of instruments that remain open at the end of a reporting period represent unrealized gains or losses and are presented on the Consolidated Statements of Financial Position as risk management assets or liabilities.

The determination of the fair value of commodity risk management contracts and derivative instruments is complex and relies on judgments concerning future prices, volatility, and liquidity, among other factors. Some of our derivatives are not traded on an active exchange or extend beyond the time period for which exchange-based quotes are available, requiring us to use internal valuation techniques or models.

Financial Instruments

The fair value of a financial instrument is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair values can be determined by reference to prices for instruments in active markets to which we have access. In the absence of an active market, we determine fair values based on valuation models or by reference to other similar products in active markets.

Fair values determined using valuation models require the use of assumptions. In determining those assumptions, we look primarily to external readily observable market inputs. However, if not available, we use inputs that are not based on observable market data.

Level Determinations and Classifications

The Level I, II, and III classifications in the fair value hierarchy utilized by the Corporation are defined below. The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based on the lowest level input that is significant to the derivation of the fair value.

Level I

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

Level II

Fair values are determined, directly or indirectly, using inputs that are observable for the asset or liability.

Fair values falling within the Level II category are determined through the use of quoted prices in active markets, which in some cases are adjusted for factors specific to the asset or liability, such as basis, credit valuation, and location differentials. Our commodity risk management Level II financial instruments include over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models and regression or extrapolation formulas, where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets, and implied volatilities for options.

In determining Level II fair values of other risk management assets and liabilities, we use observable inputs other than unadjusted quoted prices that are observable for the asset or liability, such as interest rate yield curves and currency rates. For certain financial instruments where insufficient trading volume or lack of recent trades exists, we rely on similar interest or currency rate inputs and other third-party information such as credit spreads.

Level III

Fair values are determined using inputs for the asset or liability that are not readily observable.

We may enter into commodity transactions for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques such as the Black-Scholes, mark-to-forecast, and historical bootstrap models with inputs that are based on historical data such as unit availability, transmission congestion, demand profiles for individual non-standard deals and structured products, and/or volatilities and correlations between products derived from historical prices. We also have various contracts with terms that extend beyond a liquid trading period. As forward market prices are not available for the full period of these contracts, the value of these contracts is derived by reference to a forecast that is based on a combination of external and internal fundamental modelling, including discounting. As a result, these contracts are classified in Level III.

We have a Commodity Exposure Management Policy (the "Policy"), which governs both the commodity transactions undertaken in our proprietary trading business and those undertaken to manage commodity price exposures in our generation business. The Policy defines and specifies the controls and management responsibilities associated with commodity trading activities, as well as the nature and frequency of required reporting of such activities.

Methodologies and procedures regarding commodity risk management Level III fair value measurements are determined by our risk management department. Level III fair values are calculated within our energy trading risk management system based on underlying contractual data as well as observable and non-observable inputs. Development of non-observable inputs requires the use of judgment. To ensure reasonability, system-generated Level III fair value measurements are reviewed and validated by the risk management and finance departments. Review occurs formally on a quarterly basis or more frequently if daily review and monitoring procedures identify unexpected changes to fair value or changes to key parameters.

The effect of using reasonably possible alternative assumptions as inputs to valuation techniques from which the Level III commodity risk management fair values are determined at Dec. 31, 2014 is estimated to be a +/- $120 million (2013 +/- $105 million) impact to the carrying value of the financial instruments. Fair values are stressed for volumes and prices. An amount of +/- $92 million (2013 +/- $87 million) in the stress value stems from a long-dated power sale contract that is designated as a cash flow hedge, while the remaining +/- $28 million (2013 +/- $18 million) accounts for the rest of the portfolio. The variable volumes are stressed up and down one standard deviation from historically available production data. Prices are stressed for longer-term deals where there are no liquid market quotes using various internal and external forecasting sources to establish a high and a low price range.

Valuation of PP&E and Associated Contracts

As at Dec. 31, 2014, PP&E makes up 74 per cent of our assets, of which 99 per cent relates to the Generation Segment. At the end of each reporting period, we assess whether there is any indication that a PP&E asset is impaired. Impairment exists when the carrying amount of the asset or CGU to which it belongs exceeds its recoverable amount, which is the higher of fair value less costs of disposal and value in use.

Factors that could indicate that an impairment exists include: significant underperformance relative to historical or projected operating results; significant changes in the manner in which an asset is used or in our overall business strategy; or significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. This can be further complicated in situations where we are not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

Our operations, the market, and business environment are routinely monitored, and judgments and assessments are made to determine whether an event has occurred that indicates a possible impairment. If such an event has occurred, an estimate is made of the recoverable amount of the PP&E or CGU to which it belongs. Recoverable amount is the higher of an asset's fair value less costs of disposal and its value in use. Fair value is the price that would be received to sell an asset in an orderly transaction between market participants at the measurement date. In determining fair value less costs of disposal, information about third-party transactions for similar assets is used and if none is available, other valuation techniques, such as discounted cash flows, are used. Value in use is computed using the present value of management's best estimates of future cash flows based on the current use and present condition of the asset. In estimating either fair value less costs of disposal or value in use using discounted cash flow methods, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, retirement costs, and other related cash inflows and outflows over the life of the facilities, which can range from 30 to 60 years. In developing these assumptions, management uses estimates of contracted and future market prices based on expected market supply and demand in the region in which the plant operates, anticipated production levels, planned and unplanned outages, and transmission capacity or constraints for the remaining life of the facilities. Appropriate discount rates reflecting the risks specific to the asset under review are used in the assessments. These estimates and assumptions are susceptible to change from period to period and actual results can, and often do, differ from the estimates, and can have either a positive or negative impact on the estimate of the impairment charge, and may be material.

As a result of our review in 2014 and other specific events, net pre-tax asset impairment reversals of $6 million (2013 – reversals of $18 million) were recorded related to certain facilities. Also, an impairment indicator was identified at our U.S. Coal CGU, but the estimated recoverable amount approximated its carrying amount. Refer to the Asset Impairment Charges and Reversals section of this MD&A for further details.

Impairment charges can be reversed in future periods if circumstances improve. No assurances can be given if any reversal will occur or the amount or timing of any such reversal.

Project Development Costs

Deferred project development costs include external, direct, and incremental costs that are necessary for completing an acquisition or construction project. These costs are recognized in operating expenses until construction of a plant or acquisition of an investment is likely to occur, there is reason to believe that future costs are recoverable, and that efforts will result in future value to us, at which time the costs incurred subsequently are included in PP&E or investments. The appropriateness of capitalization of these costs is evaluated each reporting period, and amounts capitalized for projects no longer probable of occurring are charged to net earnings.

Useful Life of PP&E

Each significant component of an item of PP&E is depreciated over its estimated useful life. A component is a tangible asset that can be separately identified as an asset and is expected to provide a benefit of greater than one year. Estimated useful lives are determined based on current facts and past experience, and take into consideration the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecasted demand, the potential for technological obsolescence, and regulations. The useful lives of PP&E and depreciation rates used are reviewed at least annually to ensure they continue to be appropriate.

In 2014, depreciation and amortization expense per the Consolidated Statements of Cash Flows was $595 million (2013 – $585 million), of which $56 million (2013 – $58 million) relates to mining equipment and is included in fuel and purchased power.

Valuation of Goodwill

We evaluate goodwill for impairment at least annually, or more frequently if indicators of impairment exist. If the carrying amount of a CGU or group of CGUs, including goodwill, exceeds the unit's fair value, the excess represents a goodwill impairment loss. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets.

Goodwill arose on the acquisitions of the Wyoming wind farm, Canadian Hydro Developers, Inc., Merchant Energy Group of the Americas, Inc., and Vision Quest Windelectric Inc. As at Dec. 31, 2014, this goodwill had a total carrying amount of $462 million (2013 – $460 million).

We reviewed the carrying amount of goodwill prior to year-end and determined that the fair values of the related CGUs or groups of CGUs to which goodwill relates, based on estimates of future cash flows, exceeded their carrying amounts, and no goodwill impairments existed.

Determining the fair value of the CGUs or group of CGUs is susceptible to changes from period to period as management is required to make assumptions about future cash flows, production and trading volumes, margins, and fuel and operating costs. Had assumptions been made that resulted in fair values of the CGUs or groups of CGUs declining by ten per cent from current levels, there would not have been any impairment of goodwill.

Leases

In determining whether the Corporation's PPAs and other long-term electricity and thermal sales contracts contain, or are, leases, management must use judgment in assessing whether the fulfillment of the arrangement is dependent on the use of a specific asset and the arrangement conveys the right to use the asset. For those agreements considered to contain, or be, leases, further judgment is required to determine whether substantially all of the significant risks and rewards of ownership are transferred to the customer or remain with TransAlta, to appropriately account for the agreement as either a finance or operating lease. These judgments can be significant to how we classify amounts related to the arrangement as either PP&E or as a finance lease receivable on the Consolidated Statements of Financial Position, and therefore the value of certain items of revenue and expense is dependent upon such classifications.

Income Taxes

In accordance with IFRS, we use the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are recognized on the differences between the carrying amounts of assets and liabilities and their respective income tax basis.

Preparation of the consolidated financial statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which we operate. The process also involves making an estimate of taxes currently payable and taxes expected to be payable or recoverable in future periods, referred to as deferred income taxes. Deferred income taxes result from the effects of temporary differences due to items that are treated differently for tax and accounting purposes. The tax effects of these differences are reflected in the Consolidated Statements of Financial Position as deferred income tax assets and liabilities. An assessment must also be made to determine the likelihood that our future taxable income will be sufficient to permit the recovery of deferred income tax assets. To the extent that such recovery is not probable, deferred income tax assets must be reduced. The reduction of the deferred income tax asset can be reversed if the estimated future taxable income improves. No assurances can be given if any reversal will occur or the amount or timing of any such reversal. Management must exercise judgment in its assessment of continually changing tax interpretations, regulations, and legislation to ensure deferred income tax assets and liabilities are complete and fairly presented. Differing assessments and applications than our estimates could materially impact the amount recognized for deferred income tax assets and liabilities. Our tax filings are subject to audit by taxation authorities. The outcome of some audits may change our tax liability, although we believe that we have adequately provided for income taxes in accordance with IFRS based on all information currently available. The outcome of pending audits is not known nor is the potential impact on the consolidated financial statements determinable.

Deferred income tax assets of $45 million (2013 – $118 million) have been recorded on the Consolidated Statements of Financial Position as at Dec. 31, 2014. These assets primarily relate to net operating loss carryforwards. We believe there will be sufficient taxable income that will permit the use of these loss carryforwards in the tax jurisdictions where they exist.

Deferred income tax liabilities of $434 million (2013 – $459 million) have been recorded on the Consolidated Statements of Financial Position as at Dec. 31, 2014. These liabilities are comprised primarily of taxes on unrealized gains from risk management transactions and income tax deductions in excess of related depreciation of PP&E.

Employee Future Benefits

We provide selected pension and post-employment benefits to employees. The cost of providing these benefits is dependent upon many factors that result from actual plan experience and assumptions of future experience.

The liabilities for future benefits and associated pension costs included in annual compensation expenses are impacted by employee demographics, including age, compensation levels, employment periods, the level of contributions made to the plans, and earnings on plan assets.

Changes to the provisions of the plans may also affect current and future pension costs. Pension costs may also be significantly impacted by changes in key actuarial assumptions, including, for example, the discount rates used in determining the defined benefit obligation and the net interest cost on the net defined benefit liability. The discount rate used to estimate our obligation reflects high-quality corporate fixed income securities currently available and expected to be available during the period to maturity of the pension benefits.

The plan assets are comprised primarily of equity and fixed income investments. Fluctuations in the return on plan assets as a result of actual equity market returns and changes in interest rates may result in increased or decreased pension costs in future periods.

Decommissioning and Restoration Provisions

We recognize decommissioning and restoration provisions for PP&E in the period in which they are incurred if there is a legal or constructive obligation to reclaim the plant or site. The amount recognized as a provision is the best estimate of the expenditures required to settle the provision. Expected values are probability weighted to deal with the risks and uncertainties inherent in the timing and amount of settlement of many decommissioning and restoration provisions. Expected values are discounted at the risk-free interest rate adjusted to reflect the market's evaluation of our credit standing.

As at Dec. 31, 2014, the decommissioning and restoration provisions recorded on the Consolidated Statements of Financial Position were $305 million (2013 – $270 million). We estimate the undiscounted amount of cash flow required to settle the decommissioning and restoration provisions is approximately $1.0 billion, which will be incurred between 2015 and 2072. The majority of these costs will be incurred between 2020 and 2050. Some of the facilities that are co-located with mining operations do not currently have any decommissioning obligations recorded as the obligations associated with the facilities are indeterminate at this time.

Sensitivities for the major assumptions are as follows:

Factor	Increase or decrease (%)	Approximate impact on net earnings
Discount rate	1	3
Undiscounted decommissioning and restoration provision	10	2

Other Provisions

Where necessary, we recognize provisions arising from ongoing business activities, such as interpretation and application of contract terms and force majeure claims. These provisions, and subsequent changes thereto, are determined using our best estimate of the outcome of the underlying event and can also be impacted by determinations made by third parties, in compliance with contractual requirements. The actual amount of the provisions that may be required could differ materially from the amount recognized.

Current Accounting Changes

Inception Gains and Losses

We restated the Consolidated Statement of Financial Position as at Dec. 31, 2013 to reclassify the inception gains or losses arising from differences between the fair value of a financial instrument at initial recognition (the transaction price) and the amount calculated through a valuation model. These amounts were previously reported as gross contra-risk management assets or liabilities. The adjustment reclassifies them as direct offsets to the value of the derivative contract to which they relate. As a result of the adjustment, long-term risk management assets and long-term risk management liabilities were reduced by $160 million at Dec. 31, 2013. Corresponding adjustments to the Dec. 31, 2012 Consolidated Statement of Financial Position were immaterial. Refer to Note 13(C) in our audited consolidated financial statements as at and for the year ended Dec. 31, 2014 for further information on inception gains and losses.

Inventory Writedown

During the third quarter of 2014, we restated the Consolidated Statements of Earnings (Loss) for the years ended Dec. 31, 2013 and 2012 to reclassify inventory writedown as a component of fuel and purchased power. These amounts were previously reported as stand-alone components of operating income. The adjustment is intended to better capture within gross margin the generally offsetting effects that changes in future power prices have on mark-to-market gains or losses from economic forward power sale hedges, included in revenue, and on inventory writedown or reversals. As a result of the adjustment, fuel and purchased power for the years ended Dec. 31, 2013 and 2012 increased by $22 million and $44 million, respectively. The inventory writedown for the year ended Dec. 31, 2014 was $19 million.

Other Net Operating Income and Losses

We restated the Consolidated Statements of Earnings (Loss) for the years ended Dec. 31, 2013 and 2012 to reclassify the losses associated with the California claim, the Sundance Units 1 and 2 return to service, and the assumption of pension obligations, as well as gains from insurance recoveries, as a net other operating income and losses group within operating income. Previously, each item was presented in earnings outside of operating income. We initiated the change as part of our ongoing monitoring of additional IFRS measures. As a result of the change, operating income (loss) for the years ended Dec. 31, 2013 and 2012 decreased by $102 million and $254 million, respectively.

Energy Marketing Intersegment Cost Allocation

A portion of OM&A costs incurred in the Energy Marketing Segment and the Corporate Segment are allocated to other segments based on an estimate of operating expenses and a percentage of resources dedicated to providing support and services. Segment OM&A costs are comprised of expenses net of intersegment allocations. In prior years, the Energy Marketing intersegment charge and recovery was presented as a distinct line item as a component of operating income (loss). Comparative figures have been reclassified to conform to the current year's presentation.

IAS 32 Financial Instruments: Presentation

On Jan. 1, 2014, we adopted the amendments to IAS 32 *Financial Instruments: Presentation* regarding offsetting financial assets and financial liabilities. There was no impact of adopting the IAS 32 amendments on the audited consolidated financial statements.

IAS 36 Impairment of Assets

On Jan. 1, 2014, we adopted the amended disclosure requirements of IAS 36 *Impairment of Assets*. The amended disclosure requirements did not have an impact on the audited consolidated financial statements.

Comparative Figures

Certain comparative figures have been reclassified to conform to current period's presentation. These reclassifications did not impact previously reported net earnings.

Future Accounting Changes

Accounting standards that have been previously issued by the IASB but are not yet effective, and have not been applied by the Corporation include:

IFRS 9 Financial Instruments

In July 2014, on completion of the impairment phase of the project to reform accounting for financial instruments and replace IAS 39 *Financial Instruments: Recognition and Measurement*, the IASB issued the final version of IFRS 9 *Financial Instruments*. IFRS 9 includes guidance on the classification and measurement of financial assets and financial liabilities, impairment of financial assets (i.e. recognition of credit losses), and a new hedge accounting model.

Under the classification and measurement requirements for financial assets, financials assets must be classified and measured at either amortized cost or at fair value through profit or loss or through OCI, depending on the basis of the entity's business model for managing the financial asset and the contractual cash flow characteristics of the financial asset.

The classification requirements for financial liabilities are unchanged from IAS 39. IFRS 9 requirements address the problem of volatility in net earnings arising from an issuer choosing to measure certain liabilities at fair value and require that the portion of the change in fair value due to changes in the entity's own credit risk be presented in OCI, rather than within net earnings.

The new general hedge accounting model is intended to be simpler and more closely focus on how an entity manages its risks, replaces the IAS 39 effectiveness testing requirements with the principle of an economic relationship, and eliminates the requirement for retrospective assessment of hedge effectiveness.

The new requirements for impairment of financial assets introduce an expected loss impairment model that requires more timely recognition of expected credit losses. IAS 39 impairment requirements are based on an incurred loss model where credit losses are not recognized until there is evidence of a trigger event.

IFRS 9 is effective for annual periods beginning on or after Jan. 1, 2018 with early application permitted. We are assessing the impact of adopting this standard on our consolidated financial statements.

IFRS 15 Revenue from Contracts with Customers

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers*, which replaces existing revenue recognition guidance with a single comprehensive accounting model. The model specifies that an entity recognizes revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. IFRS 15 is effective for annual reporting periods beginning on or after Jan. 1, 2017 with early application permitted. We are assessing the impact of adopting this standard on our consolidated financial statements.

Fourth Quarter

Consolidated Highlights

Three months ended Dec. 31	2014	2013
Revenues	**718**	587
Comparable EBITDA[1]	**301**	242
Net earnings (loss) attributable to common shareholders	**148**	(66)
Comparable net earnings attributable to common shareholders[1]	**46**	1
Comparable funds from operations[1]	**225**	179
Cash flow from operating activities	**250**	165
Comparable free cash flow[1]	**104**	61
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.54**	(0.25)
Comparable net earnings per share[1]	**0.17**	0.00
Comparable funds from operations per share[1]	**0.82**	0.67
Comparable free cash flow per share[1]	**0.38**	0.23
Dividends paid per common share	**0.18**	0.29

Financial Highlights

- Comparable EBITDA for the fourth quarter of 2014 increased by $59 million to $301 million compared to the same period in 2013, primarily due to strong availability throughout our generation portfolio, continued improved operational performance at Canadian Coal, lower coal cost at Canadian Coal, and improved year-over-year margins. Lower prices in Alberta negatively impacted revenue from generation in excess of targets at coal PPA facilities as well as revenue from our Wind portfolio in the province. Prices in Alberta averaged $30 per MWh during the fourth quarter of 2014, compared to $49 per MWh in the same period in 2013. Our strategy of being highly contracted and high availability in Canadian Coal generally limited the impacts of lower prices in Alberta.
- Higher comparable EBITDA translated into higher comparable FFO for the three months ended Dec. 31, 2014 of $225 million, exceeding comparable FFO for the same period last year by $46 million.
- Fourth quarter comparable net earnings attributable to common shareholders was $46 million ($0.17 net earnings per share), up from comparable net earnings of $1 million (nil net earnings per share), due to the increase in comparable EBITDA, partially offset by higher income tax expense.
- Reported net earnings attributable to common shareholders was $148 million for the fourth quarter ($0.54 net earnings per share) compared to a net loss of $66 million ($0.25 net loss per share) for the same period in 2013. The differences between comparable and reported net earnings are mainly due to increases in the fair value of de-designated and economic hedges at U.S. Coal and the effects of the California claim in 2013.

1 *These items are not defined under IFRS. Presenting these items from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Comparable Funds from Operations and Comparable Free Cash Flow and Earnings and Other Measures on a Comparable Basis sections of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.*

Operational Results

Three months ended Dec. 31	2014	2013
Availability (%)[1]	93.2	91.8
Adjusted availability (%)[1]	93.2	91.8
Production (GWh)[1]	12,207	12,640
Comparable EBITDA		
Generation Segment		
Canadian Coal	118	68
U.S. Coal	19	14
Gas	81	82
Wind	56	58
Hydro	20	21
Total Generation Segment	294	243
Energy Marketing Segment	26	20
Corporate Segment	(19)	(21)
Total comparable EBITDA	301	242

- **Canadian Coal**: Comparable EBITDA increased $50 million to $118 million in the fourth quarter of 2014 compared to the same period in 2013, primarily as a result of lower coal costs following integration of the Highvale mine in 2013 and continued improved operational performance. Lower market-based incentive rates in connection with lower prices have offset some of the improvement. The 2014 comparable EBITDA also includes a gain on settlement of a dispute with a supplier in relation to an equipment failure in prior years.
- **U.S. Coal**: Comparable EBITDA was $19 million in the fourth quarter compared to $14 million for the same period in 2013. The increase in comparable EBITDA is primarily due to increased margins as we further optimized real-time operations against the spot market and fixed-price contracts. We have also started delivering power to Puget Sound Energy under a long-term fixed price contract in December 2014.
- **Gas**: Comparable EBITDA was consistent in the fourth quarter with the same period in 2013, despite lower Alberta prices, as gains from lower outages and contract adjustments were offset by a mark-to-market loss on gas.
- **Wind**: Comparable EBITDA decreased slightly in the fourth quarter to $56 million compared to $58 million for the same period in 2013. Production from our Wyoming facility has offset the effects of lower Alberta prices.
- **Hydro**: Comparable EBITDA was consistent in the fourth quarter with the same period in 2013, as most production was contract-based in both periods, and both periods included an insurance recovery for prior business interruption claims in similar amounts.
- **Energy Marketing Segment**: Energy Marketing generated income of $26 million in the fourth quarter, up $6 million compared to the fourth quarter of 2013 due to customer margin growth, our ability to capture arbitrage opportunities stemming from high volatility, particularly in Eastern markets, and offsetting intersegment gains to the Gas generation positions. The increase was partially offset by higher corporate cost allocations and higher performance-based compensation costs driven by the strong trading results.
- **Corporate Segment**: Our Corporate Segment incurred similar costs in the fourth quarter of 2014 of $19 million compared to $21 million in 2013. The lower costs resulted from reductions to external costs partially offset by higher incentive-based compensation and increased development costs.

1 *Availability includes assets under generation operations and finance leases and excludes Hydro assets and Equity Investments. Production includes all generating assets, irrespective of investment vehicle and fuel type.*

Availability and Production

Availability for the three months ended Dec. 31, 2014 increased compared to the same period in 2013, primarily due to lower unplanned outages at Canadian Coal.

Lower production for the three months ended Dec. 31, 2014 compared to the same period in 2013 is primarily due to market curtailments at Centralia, partially offset by lower unplanned outages at Canadian Coal.

Comparable Funds from Operations and Comparable Free Cash Flow

Comparable FFO per share and comparable free cash flow per share are calculated as follows using the weighted average number of common shares outstanding during the period.

Three months ended Dec. 31	**2014**	2013
Cash flow from operating activities	**250**	165
Change in non-cash operating working capital balances	**(23)**	(13)
Cash flow from operations before changes in working capital	**227**	152
Impacts associated with California claim	**-**	27
TAMA Transmission bid costs	**5**	-
Other non-comparable items	**(7)**	-
Comparable FFO	**225**	179
Deduct:		
Sustaining capital	**(87)**	(96)
Dividends paid on preferred shares	**(13)**	(10)
Distributions paid to subsidiaries' non-controlling interests	**(21)**	(12)
Comparable free cash flow	**104**	61
Weighted average number of common shares outstanding in the period	**275**	268
Comparable FFO per share	**0.82**	0.67
Comparable free cash flow per share	**0.38**	0.23

A reconciliation of comparable EBITDA to comparable FFO is as follows:

Three months ended Dec. 31	**2014**	2013
Comparable EBITDA	**301**	242
Unrealized (losses) gains from risk management activities	**(12)**	(11)
Interest expense	**(58)**	(61)
Provisions	**-**	1
Current income tax expense	**(9)**	(3)
Realized foreign exchange gain (loss)	**14**	(3)
Decommissioning and restoration costs settled	**(5)**	(5)
Gain on sale of assets	**-**	2
Other non-cash items	**(6)**	17
Comparable FFO	**225**	179

Comparable FFO for the three months ended Dec. 31, 2014 increased $46 million to $225 million, compared to the same period in 2013, primarily due to higher comparable EBITDA.

Comparable free cash flow for the three months ended Dec. 31, 2014 increased $43 million to $104 million compared to the same period in 2013, primarily due to the increase in comparable FFO and a decrease in sustaining capital, partially offset by higher distributions paid to our subsidiaries' non-controlling interests as a result of the reduction of our interest in TransAlta Renewables and improved performance at TA Cogen.

Earnings on a Comparable Basis

During 2014, prior period restatements were made to 2013. Refer to the Current Accounting Changes section of this MD&A for a description of these items.

The adjustments made to calculate comparable earnings for the three months ended Dec. 31, 2014 and 2013 are as follows. References are to the subsequent reconciliation table.

Three months ended Dec. 31			**2014**	2013
Reference number	**Adjustment**	**Segment and fuel type**		
Reclassifications:				
1	Finance lease income used as a proxy for operating revenue	Generation (Gas)	**13**	12
2	Decrease in finance lease receivable used as a proxy for operating revenue and depreciation	Generation (Gas)	**1**	–
3	Reclassification of mine depreciation from fuel and purchased power	Generation (Canadian Coal)	**15**	16
4	Reclassification of comparable gain on sale of property, plant, and equipment that is included in depreciation	Generation (Canadian Coal)	**1**	1
Adjustments (increasing (decreasing) earnings to arrive at comparable results):				
5	Impacts to revenue associated with certain de-designated and economic hedges	Generation (U.S. Coal)	**(47)**	43
6	Flood-related maintenance costs, net of insurance recoveries	Generation (Hydro)	**(5)**	2
7	Costs related to TAMA Transmission bid	Corporate	**5**	–
8	Asset impairment charges (reversals)	Generation (Gas)	**(5)**	–
9	Non-comparable portion of insurance recovery received	Generation (Hydro)	**(3)**	(1)
10	California claim	Energy Marketing	**-**	56
11	Sundance Units 1 and 2 return to service	Generation (Canadian Coal)	**-**	10
12	Foreign exchange on California claim	Unassigned	**2**	–
13	Non-comparable gain on sale of assets	Generation (Equity Investments)	**(1)**	–
		Corporate	**-**	(2)
14	Writedown (reversal) of deferred income tax assets	Unassigned	**(68)**	(12)
15	Net tax effect of all comparable adjustments	Unassigned	**20**	(29)

A reconciliation of comparable results to reported results for the three months ended Dec. 31, 2014 and 2013 is as follows:

	Three months ended Dec. 31, 2014				Three months ended Dec. 31, 2013			
	Reported	**Comparable reclassifications**	**Comparable adjustments**	**Comparable total**	Reported	Comparable reclassifications	Comparable adjustments	Comparable total
Revenues	**718**	**14**[1,2]	**(47)**[5]	**685**	587	12[1]	43[5]	642
Fuel and purchased power	**268**	**(15)**[3]	**-**	**253**	279	(16)[3]	-	263
Gross margin	**450**	**29**	**(47)**	**432**	308	28	43	379
Operations, maintenance, and administration	**138**	**-**	**-**[6,7]	**138**	140	-	-	140
Asset impairment charges (reversals)	**(5)**	**-**	**5**[8]	**-**	-	-	-	-
Taxes, other than income taxes	**8**	**-**	**-**	**8**	5	-	-	5
Gain on sale of assets	**-**	**(1)**[4]	**-**	**(1)**	-	(1)[4]	-	(1)
Net other operating (income) losses	**(17)**	**-**	**3**[9]	**(14)**	58	-	(65)[9,10,11]	(7)
EBITDA	**326**	**30**	**(55)**	**301**	105	29	108	242
Depreciation and amortization	**136**	**17**[2,34]	**-**	**153**	143	17[3,4]	(2)[6]	158
Operating income	**190**	**13**	**(55)**	**148**	(38)	12	110	84
Finance lease income	**13**	**(13)**[1]	**-**	**-**	12	(12)[1]	-	-
Equity income	**-**	**-**	**-**	**-**	(5)	-	-	(5)
Foreign exchange gain (loss)	**7**	**-**	**2**[12]	**9**	3	-	-	3
Gain on sale of assets	**1**	**-**	**(1)**[13]	**-**	2	-	(2)[13]	-
Earnings before interest and taxes	**211**	**-**	**(54)**	**157**	(26)	-	108	82
Net interest expense	**62**	**-**	**-**	**62**	66	-	-	66
Income tax expense (recovery)	**(26)**	**-**	**48**[14,15]	**22**	(49)	-	41[14,15]	(8)
Net earnings (loss)	**175**	**-**	**(102)**	**73**	(43)	-	67	24
Non-controlling interests	**14**	**-**	**-**	**14**	13	-	-	13
Net earnings (loss) attributable to TransAlta shareholders	**161**	**-**	**(102)**	**59**	(56)	-	67	11
Preferred share dividends	**13**	**-**	**-**	**13**	10	-	-	10
Net earnings (loss) attributable to common shareholders	**148**	**-**	**(102)**	**46**	(66)	-	67	1
Weighted average number of common shares outstanding in the period	**275**			**275**	268			268
Net earnings (loss) per share attributable to common shareholders	**0.54**			**0.17**	(0.25)			0.00

Selected Quarterly Information

	Q1 2014	Q2 2014	Q3 2014	Q4 2014
Revenue	775	491	639	718
Comparable EBITDA	310	213	212	301
Comparable FFO	238	154	145	225
Comparable net earnings (loss) attributable to common shareholders	47	(12)	(13)	46
Net earnings (loss) attributable to common shareholders	49	(50)	(6)	148
Net earnings (loss) per share attributable to common shareholders, basic and diluted	0.18	(0.18)	(0.03)	0.54
Comparable net earnings (loss) per share, basic and diluted	0.17	(0.04)	(0.05)	0.17

	Q1 2013	Q2 2013	Q3 2013	Q4 2013
Revenue	540	542	623	587
Comparable EBITDA	268	247	266	242
Comparable FFO	193	184	174	179
Comparable net earnings attributable to common shareholders	32	9	39	1
Net earnings (loss) attributable to common shareholders	(11)	15	(9)	(66)
Net earnings (loss) per share attributable to common shareholders, basic and diluted	(0.04)	0.06	(0.03)	(0.25)
Comparable net earnings per share, basic and diluted	0.12	0.03	0.15	0.00

Basic and diluted earnings per share attributable to common shareholders and comparable earnings per share are calculated each period using the weighted average common shares outstanding during the period. As a result, the sum of the earnings per share for the four quarters making up the calendar year may sometimes differ from the annual earnings per share.

Comparable net earnings is generally higher in the first and fourth quarters due to higher demand associated with winter cold in the markets in which we operate. The second and third quarters of 2013 benefitted from high Alberta prices, offsetting some of the impacts of unplanned outages at Canadian Coal during the periods. In 2014, Canadian Coal improved its operational performance, with the third and fourth quarters also including reductions in coal costs. Some of these gains compared to the same periods in the previous year were offset by a downward trend in Alberta prices, starting from the second quarter of 2013. Market volatility can also impact quarterly contributions from our Energy Marketing Segment, as the first quarter of 2014 benefitted from exceptional weather conditions in northeastern North America, with the subsequent two quarters seeing muted volatility and reduced contribution from the Segment. Following public offerings of TransAlta Renewables common shares in the third quarter of 2013 and the second quarter of 2014, an increasing portion of earnings is attributable to non-controlling interests.

Revenue is impacted by market and operational factors listed above, and by changes in future power prices in the Pacific Northwest, which cause de-designated and economic hedges in the region to fluctuate in value. These hedges significantly depreciated in the first and fourth quarters of 2013, as well as the second quarter of 2014 and significantly increased in value over the second half of 2014.

Net earnings attributable to common shareholders have also been impacted by the following events:

- loss on assumption of pension obligation, in the first quarter of 2013;
- writedown of deferred tax assets, in the third quarter of 2013;
- loss associated with the California claim, in the fourth quarter of 2013.

Amounts per share reflect these fluctuations, with limited increases in the number of shares outstanding over the last eight quarters.

Disclosure Controls and Procedures

Management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Disclosure controls and procedures refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under the *Securities Exchange Act of 1934*, as amended ("Exchange Act") are recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in our reports that we file or submit under the Exchange Act is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding our required disclosure. In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management is required to apply its judgment in evaluating and implementing possible controls and procedures.

There has been no change in the internal control over financial reporting during the period covered by this report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of Dec. 31, 2014, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

Consolidated Financial Statements

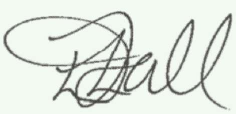
Management's Report

To the Shareholders of TransAlta Corporation

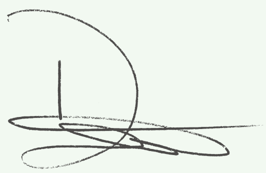
The consolidated financial statements and other financial information included in this annual report have been prepared by management. It is management's responsibility to ensure that sound judgment, appropriate accounting principles and methods, and reasonable estimates have been used to prepare this information. They also ensure that all information presented is consistent.

Management is also responsible for establishing and maintaining internal controls and procedures over the financial reporting process. The internal control system includes an internal audit function and an established business conduct policy that applies to all employees. In addition, TransAlta Corporation has a code of conduct that applies to all employees and is signed annually. The code of conduct can be viewed on TransAlta's website (www.transalta.com). Management believes the system of internal controls, review procedures, and established policies provide reasonable assurance as to the reliability and relevance of financial reports. Management also believes that TransAlta's operations are conducted in conformity with the law and with a high standard of business conduct.

The Board of Directors (the "Board") is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board carries out its responsibilities principally through its Audit and Risk Committee (the "Committee"). The Committee, which consists solely of independent directors, reviews the financial statements and annual report and recommends them to the Board for approval. The Committee meets with management, internal auditors, and external auditors to discuss internal controls, auditing matters, and financial reporting issues. Internal and external auditors have full and unrestricted access to the Committee. The Committee also recommends the firm of external auditors to be appointed by the shareholders.



Dawn L. Farrell
President and Chief Executive Officer



Donald Tremblay
Chief Financial Officer

February 18, 2015

Management's Annual Report on Internal Control over Financial Reporting

To the Shareholders of TransAlta Corporation

The following report is provided by management in respect of TransAlta Corporation's internal control over financial reporting (as defined in Rules 13a-15f and 15d-15f under the United States *Securities Exchange Act of 1934*).

TransAlta's management is responsible for establishing and maintaining adequate internal control over financial reporting for TransAlta Corporation.

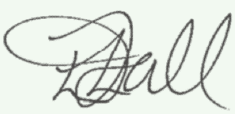
Management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") 2013 framework to evaluate the effectiveness of TransAlta Corporation's internal control over financial reporting. Management believes that the COSO 2013 framework is a suitable framework for its evaluation of TransAlta Corporation's internal control over financial reporting because it is free from bias, permits reasonably consistent qualitative and quantitative measurements of TransAlta Corporation's internal controls, is sufficiently complete so that those relevant factors that would alter a conclusion about the effectiveness of TransAlta Corporation's internal controls are not omitted, and is relevant to an evaluation of internal control over financial reporting.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper overrides. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process, and it is possible to design safeguards into the process to reduce, though not eliminate, this risk.

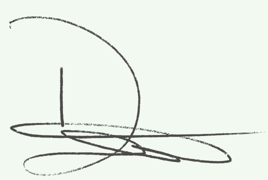
TransAlta Corporation proportionately consolidates the accounts of the Sheerness and Genesee Unit 3 joint operations in accordance with International Financial Reporting Standards ("IFRS"). Management does not have the contractual ability to assess the internal controls of these joint arrangements. Once the financial information is obtained from these joint arrangements it falls within the scope of TransAlta Corporation's internal controls framework. Management's conclusion regarding the effectiveness of internal controls does not extend to the internal controls at the transactional level of these joint arrangements. The 2014 consolidated financial statements of TransAlta Corporation included $678 million and $643 million of total and net assets, respectively, as of December 31, 2014, and $215 million and $73 million of revenues and net earnings, respectively, for the year then ended related to these joint arrangements.

Management has assessed the effectiveness of TransAlta Corporation's internal control over financial reporting, as at December 31, 2014, and has concluded that such internal control over financial reporting is effective.

Ernst & Young LLP, who has audited the consolidated financial statements of TransAlta Corporation for the year ended December 31, 2014, has also issued a report on internal control over financial reporting under Auditing Standard No. 5 of the Public Company Accounting Oversight Board (United States). This report is located on the following page of this Annual Report.



Dawn L. Farrell
President and Chief Executive Officer



Donald Tremblay
Chief Financial Officer

February 18, 2015

Report of Independent Registered Public Accounting Firm

To the Shareholders of TransAlta Corporation

We have audited TransAlta Corporation's internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), (the COSO criteria). TransAlta Corporation's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the corporation's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A corporation's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A corporation's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the corporation; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the corporation are being made only in accordance with authorizations of management and directors of the corporation; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the corporation's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As indicated in the accompanying Management's Annual Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of the Sheerness and Genesee Unit 3 joint arrangements, which are included in the 2014 consolidated financial statements of the Corporation and constituted $678 million and $643 million of total and net assets, respectively, as of December 31, 2014, and $215 million and $73 million of revenues and net earnings, respectively, for the year then ended. Our audit of internal control over financial reporting of the Corporation did not include an evaluation of the internal control over financial reporting of the Sheerness and Genesee Unit 3 joint arrangements.

In our opinion, TransAlta Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated statements of financial position as at December 31, 2014 and 2013, and the related consolidated statements of earnings (loss), comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2014 of TransAlta Corporation and our report dated February 18, 2015 expressed an unqualified opinion thereon.

Ernst & Young LLP

Chartered Accountants
Calgary, Canada

February 18, 2015

Independent Auditors' Report of Registered Public Accounting Firm

To the Shareholders of TransAlta Corporation

We have audited the accompanying consolidated financial statements of TransAlta Corporation, which comprise the consolidated statements of financial position as at December 31, 2014 and 2013, and the consolidated statements of earnings (loss), comprehensive income (loss), changes in equity and cash flows for each of the years in the three-year period ended December 31, 2014, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, 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.

Auditors' 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 and the standards of the Public Company Accounting Oversight Board (United States). 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 auditors' 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 auditors consider 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. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements, 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 TransAlta Corporation as at December 31, 2014 and 2013, and its financial performance and its cash flows for each of the years in the three-year period ended December 31, 2014 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Other Matter

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), TransAlta Corporation's internal control over financial reporting as of December 31, 2014, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 18, 2015 expressed an unqualified opinion on TransAlta Corporation's internal control over financial reporting.

Ernst & Young LLP

Chartered Accountants
Calgary, Canada

February 18, 2015

Consolidated Statements of Earnings (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars except where noted)*	**2014**	2013 *(Restated)**	2012 *(Restated)**
Revenues *(Note 35)*	**2,623**	2,292	2,210
Fuel and purchased power *(Note 5)*	**1,092**	948	797
Gross margin	**1,531**	1,344	1,413
Operations, maintenance, and administration *(Note 5)*	**542**	516	499
Depreciation and amortization	**538**	525	509
Asset impairment charges (reversals) *(Note 6)*	**(6)**	(18)	324
Restructuring provision *(Note 21)*	**-**	(3)	13
Taxes, other than income taxes	**29**	27	28
Net other operating (income) losses *(Note 8)*	**(14)**	102	254
Operating income (loss)	**442**	195	(214)
Finance lease income *(Note 7)*	**49**	46	16
Equity loss *(Note 16)*	**-**	(10)	(15)
Net interest expense *(Note 9)*	**(254)**	(256)	(242)
Foreign exchange gain (loss)	**-**	1	(9)
Gain on sale of assets *(Note 4)*	**2**	12	3
Gain on sale of collateral *(Note 14)*	**-**	-	15
Other income	**-**	-	1
Earnings (loss) before income taxes	**239**	(12)	(445)
Income tax expense (recovery) *(Note 10)*	**7**	(8)	102
Net earnings (loss)	**232**	(4)	(547)
Net earnings (loss) attributable to:			
TransAlta shareholders	**182**	(33)	(584)
Non-controlling interests *(Note 11)*	**50**	29	37
	232	(4)	(547)
Net earnings (loss) attributable to TransAlta shareholders	**182**	(33)	(584)
Preferred share dividends *(Note 25)*	**41**	38	31
Net earnings (loss) attributable to common shareholders	**141**	(71)	(615)
Weighted average number of common shares outstanding in the year *(millions)*	**273**	264	235

Net earnings (loss) per share attributable to common shareholders, basic and diluted *(Note 24)*	**0.52**	(0.27)	(2.62)

* *See Note 3(B) for prior period restatements.*

See accompanying notes.

Consolidated Statements of Comprehensive Income (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2014**	2013	2012
Net earnings (loss)	**232**	(4)	(547)
Other comprehensive income (loss)			
Net actuarial gains (losses) on defined benefit plans, net of tax[1]	**(20)**	31	(23)
Losses on derivatives designated as cash flow hedges, net of tax[2]	**(1)**	–	(2)
Reclassification of (gains) losses on derivatives designated as cash flow hedges to non-financial assets, net of tax[3]	**–**	1	5
Total items that will not be reclassified subsequently to net earnings	**(21)**	32	(20)
Gains (losses) on translating net assets of foreign operations	**75**	37	(23)
Reclassification of translation gains on net assets of divested foreign operations *(Note 4)*	**(7)**	–	–
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax[4]	**(58)**	(35)	13
Reclassification of losses on financial instruments designated as hedges of divested foreign operations, net of tax[5] *(Note 4)*	**7**	–	–
Gains (losses) on derivatives designated as cash flow hedges, net of tax[6]	**215**	76	(12)
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax[7]	**(45)**	(24)	(6)
Total items that will be reclassified subsequently to net earnings	**187**	54	(28)
Other comprehensive income (loss)	**166**	86	(48)
Total comprehensive income (loss)	**398**	82	(595)
Total comprehensive income (loss) attributable to:			
TransAlta shareholders	**348**	41	(626)
Non-controlling interests	**50**	41	31
	398	82	(595)

1 Net of income tax recovery of 7 for the year ended Dec. 31, 2014 (2013 – 11 expense, 2012 – 8 recovery).
2 Net of income tax of nil for the year ended Dec. 31, 2014 (2013 – nil, 2012 – 1 recovery).
3 Net of income tax of nil for the year ended Dec. 31, 2014 (2013 – 1 recovery, 2012 – 2 recovery).
4 Net of income tax recovery of 7 for the year ended Dec. 31, 2014 (2013 – 5 recovery, 2012 – 2 expense).
5 Net of income tax recovery of 1 for the year ended Dec. 31, 2014 (2013 – nil, 2012 – nil).
6 Net of income tax expense of 91 for the year ended Dec. 31, 2014 (2013 – 12 expense, 2012 – 4 expense).
7 Net of income tax expense of 3 for the year ended Dec. 31, 2014 (2013 – 1 expense, 2012 – 20 expense).

See accompanying notes.

Consolidated Statements of Financial Position

As at Dec. 31 *(in millions of Canadian dollars)*	**2014**	2013 *(Restated)**
Cash and cash equivalents	**43**	42
Trade and other receivables *(Note 12)*	**450**	504
Prepaid expenses	**17**	12
Risk management assets *(Notes 13 and 14)*	**273**	113
Inventory *(Note 15)*	**71**	77
	854	748
Investments *(Note 16)*	**-**	192
Long-term portion of finance lease receivables *(Note 7)*	**403**	377
Property, plant, and equipment *(Notes 17 and 35)*		
Cost	**12,532**	12,024
Accumulated depreciation	**(5,294)**	(4,831)
	7,238	7,193
Goodwill *(Notes 18 and 35)*	**462**	460
Intangible assets *(Notes 19 and 35)*	**331**	323
Deferred income tax assets *(Note 10)*	**45**	118
Risk management assets *(Notes 13 and 14)*	**402**	116
Other assets *(Notes 20 and 35)*	**98**	97
Total assets	**9,833**	9,624
Accounts payable and accrued liabilities	**481**	447
Current portion of decommissioning and other provisions *(Note 21)*	**34**	27
Risk management liabilities *(Notes 13 and 14)*	**128**	85
Income taxes payable	**2**	3
Dividends payable *(Note 24)*	**55**	85
Current portion of long-term debt and finance lease obligations *(Note 22)*	**751**	217
	1,451	864
Long-term debt and finance lease obligations *(Note 22)*	**3,305**	4,130
Decommissioning and other provisions *(Note 21)*	**322**	305
Deferred income tax liabilities *(Note 10)*	**434**	459
Risk management liabilities *(Notes 13 and 14)*	**94**	103
Defined benefit obligation and other long-term liabilities *(Notes 23 and 28)*	**349**	340
Equity		
Common shares *(Note 24)*	**2,999**	2,913
Preferred shares *(Note 25)*	**942**	781
Contributed surplus	**9**	9
Deficit	**(770)**	(735)
Accumulated other comprehensive income (loss) *(Note 26)*	**104**	(62)
Equity attributable to shareholders	**3,284**	2,906
Non-controlling interests *(Note 11)*	**594**	517
Total equity	**3,878**	3,423
Total liabilities and equity	**9,833**	9,624

* *See Note 3(B) for prior period restatements.*

Commitments *(Note 33)*

Contingencies *(Note 34)*

Subsequent events *(Note 36)*

See accompanying notes.

Gordon D Giffin   Karen E Maidment

On behalf of the Board:

Gordon D. Giffin
Director

Karen E. Maidment
Director

Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income (loss)[1]	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2012	2,726	781	9	(362)	(136)	3,018	330	3,348
Net earnings (loss)	–	–	–	(33)	–	(33)	29	(4)
Other comprehensive income:								
Net gains on translating net assets of foreign operations, net of hedges and of tax	–	–	–	–	2	2	–	2
Net gains on derivatives designated as cash flow hedges, net of tax	–	–	–	–	41	41	12	53
Net actuarial gains on defined benefits plans, net of tax	–	–	–	–	31	31	–	31
Total comprehensive income				(33)	74	41	41	82
Common share dividends	–	–	–	(306)	–	(306)	–	(306)
Preferred share dividends	–	–	–	(38)	–	(38)	–	(38)
Formation of TransAlta Renewables Inc. *(Note 11)*	–	–	–	4	–	4	206	210
Distributions paid, and payable, to non-controlling interests	–	–	–	–	–	–	(60)	(60)
Common shares issued	187	–	–	–	–	187	–	187
Balance, Dec. 31, 2013	2,913	781	9	(735)	(62)	2,906	517	3,423
Net earnings	**–**	**–**	**–**	**182**	**–**	**182**	**50**	**232**
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and of tax	**–**	**–**	**–**	**–**	**17**	**17**	**–**	**17**
Net gains on derivatives designated as cash flow hedges, net of tax	**–**	**–**	**–**	**–**	**169**	**169**	**–**	**169**
Net actuarial losses on defined benefits plans, net of tax	**–**	**–**	**–**	**–**	**(20)**	**(20)**	**–**	**(20)**
Total comprehensive income				**182**	**166**	**348**	**50**	**398**
Common share dividends	**–**	**–**	**–**	**(196)**	**–**	**(196)**	**–**	**(196)**
Preferred share dividends	**–**	**–**	**–**	**(41)**	**–**	**(41)**	**–**	**(41)**
Secondary offering of TransAlta Renewables Inc. shares *(Note 11)*	**–**	**–**	**–**	**20**	**–**	**20**	**109**	**129**
Distributions paid, and payable, to non-controlling interests	**–**	**–**	**–**	**–**	**–**	**–**	**(82)**	**(82)**
Common shares issued	**86**	**–**	**–**	**–**	**–**	**86**	**–**	**86**
Preferred shares issued	**–**	**161**	**–**	**–**	**–**	**161**	**–**	**161**
Balance, Dec. 31, 2014	**2,999**	**942**	**9**	**(770)**	**104**	**3,284**	**594**	**3,878**

1 Refer to Note 26 for details on components of, and changes in, Accumulated other comprehensive income (loss).

See accompanying notes.

Consolidated Statements of Cash Flows

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2014**	2013	2012
Operating activities			
Net earnings (loss)	**232**	(4)	(547)
Depreciation and amortization *(Note 35)*	**595**	585	564
Gain on sale of assets *(Note 4)*	**(2)**	(12)	(3)
California claim *(Note 8)*	**(28)**	28	–
Accretion of provisions *(Note 21)*	**18**	18	17
Decommissioning and restoration costs settled *(Note 21)*	**(16)**	(24)	(34)
Deferred income tax expense (recovery) *(Note 10)*	**(26)**	(47)	89
Unrealized (gain) loss from risk management activities	**(50)**	76	99
Unrealized foreign exchange (gain) loss	**11**	(1)	5
Provisions	**–**	11	11
Asset impairment charges (reversals) *(Note 6)*	**(6)**	(18)	324
Sundance Units 1 and 2 return to service *(Note 8)*	**–**	25	43
Equity loss, net of distributions received *(Note 16)*	**–**	10	14
Other non-cash items	**(5)**	44	(6)
Cash flow from operations before changes in working capital	**723**	691	576
Change in non-cash operating working capital balances *(Note 30)*	**73**	74	(56)
Cash flow from operating activities	**796**	765	520
Investing activities			
Additions to property, plant, and equipment *(Notes 17 and 35)*	**(487)**	(561)	(703)
Additions to intangibles *(Notes 19 and 35)*	**(34)**	(32)	(39)
Acquisition of finance lease *(Note 4)*	**–**	–	(312)
Addition to assets held for sale	**(13)**	(17)	–
Proceeds on sale of property, plant, and equipment	**6**	14	3
Proceeds on sale of investments and development projects *(Note 4)*	**224**	–	3
Resolution of certain outstanding tax matters *(Note 10)*	**–**	2	9
Realized gains (losses) on financial instruments	**(2)**	14	(13)
Net decrease in collateral received from counterparties	**(1)**	(1)	(13)
Net (increase) decrease in collateral paid to counterparties	**(3)**	–	24
Decrease in finance lease receivable	**3**	1	3
Acquisition of Wyoming wind farm *(Note 4)*	**–**	(109)	–
Other	**13**	15	(8)
Change in non-cash investing working capital balances	**2**	(29)	(2)
Cash flow used in investing activities	**(292)**	(703)	(1,048)
Financing activities			
Net increase (decrease) in borrowings under credit facilities *(Note 22)*	**(436)**	(119)	152
Repayment of long-term debt *(Note 22)*	**(551)**	(328)	(314)
Issuance of long-term debt *(Note 22)*	**434**	398	388
Dividends paid on common shares *(Note 24)*	**(140)**	(116)	(104)
Dividends paid on preferred shares *(Note 25)*	**(41)**	(38)	(32)
Net proceeds on issuance of common shares *(Note 24)*	**–**	–	293
Net proceeds on issuance of preferred shares *(Note 25)*	**161**	–	217
Net proceeds on sale of non-controlling interest in subsidiary *(Note 11)*	**129**	207	–
Realized gains (losses) on financial instruments	**35**	15	(31)
Distributions paid to subsidiaries' non-controlling interests *(Note 11)*	**(84)**	(55)	(59)
Decrease in finance lease obligations *(Note 22)*	**(10)**	(9)	–
Other	**–**	(2)	(6)
Cash flow from (used in) financing activities	**(503)**	(47)	504
Cash flow from (used in) operating, investing, and financing activities	**1**	15	(24)
Effect of translation on foreign currency cash	**–**	–	2
Increase (decrease) in cash and cash equivalents	**1**	15	(22)
Cash and cash equivalents, beginning of year	**42**	27	49
Cash and cash equivalents, end of year	**43**	42	27
Cash income taxes paid	**31**	46	30
Cash interest paid	**230**	240	234

See accompanying notes.

Notes to Consolidated Financial Statements

(Tabular amounts in millions of Canadian dollars, except as otherwise noted)

1. Corporate Information

A. Description of the Business

TransAlta Corporation ("TransAlta" or the "Corporation") was incorporated under the *Canada Business Corporations Act* in March 1985. The Corporation became a public company in December 1992. Its head office is located in Calgary, Alberta.

The three reportable segments of the Corporation are as follows:

I. Generation

The Generation Segment owns and operates hydro, wind, natural gas- and coal-fired facilities, and related mining operations in Canada, the United States ("U.S."), and Australia. Generation's revenues are derived from the availability and production of electricity and steam as well as ancillary services such as system support. Starting in 2013, electricity sales made by the Corporation's commercial and industrial group are assumed to be sourced from the Corporation's production and have been included in the Generation Segment.

II. Energy Marketing

The Segment changed its name from "Energy Trading" in 2014 following a shift in focus toward lower risk revenue generation activities such as asset optimization, customer fee and margin-based growth, and arbitrage trading.

The Energy Marketing Segment derives revenue and earnings from the wholesale trading of electricity and other energy-related commodities and derivatives.

Energy Marketing manages available generating capacity as well as the fuel and transmission needs of the Generation Segment by utilizing contracts of various durations for the forward sales of electricity and for the purchase of natural gas and transmission capacity. Energy Marketing is also responsible for recommending portfolio optimization decisions. The results of these other activities are included in the Generation Segment.

III. Corporate

The Corporate Segment provides finance, tax, treasury, legal, regulatory, environmental, health and safety, sustainable development, corporate communications, government and investor relations, information technology, risk management, human resources, aboriginal relations, internal audit, and other administrative support to the Generation and Energy Marketing segments. Charges directly or reasonably attributable to other segments are allocated thereto.

B. Basis of Preparation

These consolidated financial statements have been prepared by management in compliance with IFRS as issued by the International Accounting Standards Board ("IASB").

The consolidated financial statements have been prepared on a historical cost basis except for financial instruments that are measured at fair value, as explained in the following accounting policies.

These consolidated financial statements were authorized for issue by the Board on Feb. 18, 2015.

C. Basis of Consolidation

The consolidated financial statements include the accounts of the Corporation and the subsidiaries that it controls. Control exists when the Corporation is exposed, or has rights, to variable returns from its involvement with the subsidiary and has the ability to affect the returns through its power over the subsidiary. The financial statements of the subsidiaries are prepared for the same reporting period and apply consistent accounting policies as the parent company.

2. Significant Accounting Policies

A. Revenue Recognition

The majority of the Corporation's revenues are derived from the sale of physical power, leasing of power facilities, and from energy marketing and trading activities.

Revenues are measured at the fair value of the consideration received or receivable.

Revenues under long-term electricity and thermal sales contracts generally include one or more of the following components: fixed capacity payments for availability, energy payments for generation of electricity, incentives or penalties for exceeding or not meeting availability targets, excess energy payments for power generation above committed capacity, and ancillary services. Each component is recognized when: i) output, delivery, or satisfaction of specific targets is achieved, all as governed by contractual terms; ii) the amount of revenue can be measured reliably; iii) it is probable that the economic benefits will flow to the Corporation; and iv) the costs incurred or to be incurred in respect of the transaction can be measured reliably. Revenue from the rendering of services is recognized when criteria ii), iii), and iv) above are met and when the stage of completion of the transaction at the end of the reporting period can be measured reliably.

Revenues from non-contracted capacity are comprised of energy payments, at market prices, for each megawatt hour ("MWh") produced, and are recognized upon delivery.

In certain situations, a long-term electricity or thermal sales contract may contain, or be considered, a lease. Revenues associated with non-lease elements are recognized as goods or services revenues as outlined above. Revenues associated with leases are recognized as outlined in *Note 2(R)*.

Commodity risk management activities involve the use of derivatives such as physical and financial swaps, forward sales contracts, futures contracts, and options, which are used to earn revenues and to gain market information. These derivatives are accounted for using fair value accounting. The initial recognition and subsequent changes in fair value affect reported net earnings in the period the change occurs and are presented on a net basis in revenue. The fair values of instruments that remain open at the end of the reporting period represent unrealized gains or losses and are presented on the Consolidated Statements of Financial Position as risk management assets or liabilities. Some of the derivatives used by the Corporation in trading activities are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using internal valuation techniques or models.

B. Foreign Currency Translation

The Corporation, its subsidiary companies, and joint arrangements each determine their functional currency based on the currency of the primary economic environment in which they operate. The Corporation's functional currency is the Canadian dollar while the functional currencies of the subsidiary companies and joint arrangements are either the Canadian, U.S., or Australian dollar. Transactions denominated in a currency other than the functional currency of an entity are translated at the exchange rate in effect on the transaction date. The resulting exchange gains and losses are included in each entity's net earnings in the period in which they arise.

The Corporation's foreign operations are translated to the Corporation's presentation currency, which is the Canadian dollar, for inclusion in the consolidated financial statements. Foreign-denominated monetary and non-monetary assets and liabilities of foreign operations are translated at exchange rates in effect at the end of the reporting period and revenue and expenses are translated at exchange rates in effect on the transaction date. The resulting translation gains and losses are included in Other Comprehensive Income (Loss) ("OCI") with the cumulative gain or loss reported in Accumulated Other Comprehensive Income (Loss) ("AOCI"). Amounts previously recognized in AOCI are recognized in net earnings when there is a reduction in a foreign net investment as a result of a disposal, partial disposal, or loss of control.

C. Financial Instruments and Hedges

I. Financial Instruments

Financial assets and financial liabilities, including derivatives and certain non-financial derivatives, are recognized on the Consolidated Statements of Financial Position when the Corporation becomes a party to the contract. All financial instruments, except for certain non-financial derivative contracts that meet the Corporation's own use requirements, are measured at fair value upon initial recognition. Measurement in subsequent periods depends on whether the financial instrument has been classified as: at fair value through profit or loss, available-for-sale, held-to-maturity, loans and receivables, or other financial liabilities. Classification of the financial instrument is determined at inception depending on the nature and purpose of the financial instrument.

Financial assets and financial liabilities classified or designated as at fair value through profit or loss are measured at fair value with changes in fair values recognized in net earnings. Financial assets classified as either held-to-maturity or as loans and receivables, and other financial liabilities, are measured at amortized cost using the effective interest method of amortization.

Financial assets are assessed for impairment on an ongoing basis and at reporting dates. An impairment may exist if an incurred loss event has arisen that has an impact on the recoverability of the financial asset. Factors that may indicate an incurred loss event and related impairment may exist include, for example: a debtor is experiencing significant financial difficulty, or a debtor has or it is probable that they will enter bankruptcy or other financial reorganization. The carrying amount of financial assets, such as receivables, is reduced for impairment losses through the use of an allowance account, and the loss is recognized in net earnings.

Financial assets are derecognized when the contractual rights to receive cash flows expire. Financial liabilities are derecognized when the obligation is discharged, cancelled, or expired.

Financial assets and financial liabilities are offset and the net amount is reported in the Consolidated Statements of Financial Position if there is a currently enforceable legal right to offset the recognized amounts and there is an intention to settle on a net basis or to realize the assets and settle the liabilities simultaneously.

Derivative instruments that are embedded in financial or non-financial contracts that are not already required to be recognized at fair value are treated and recognized as separate derivatives if their risks and characteristics are not closely related to their host contracts and the contract is not measured at fair value. Changes in the fair values of these and other derivative instruments are recognized in net earnings with the exception of the effective portion of i) derivatives designated as cash flow hedges and ii) hedges of foreign currency exposure of a net investment in a foreign operation, each of which is recognized in OCI. Derivatives used in commodity risk management activities are described in more detail in *Note 2(A)*.

Transaction costs are expensed as incurred for financial instruments classified or designated as at fair value through profit or loss. For other financial instruments, such as debt instruments, transaction costs are recognized as part of the carrying amount of the financial instrument. The Corporation uses the effective interest method of amortization for any transaction costs or fees, premiums, or discounts earned or incurred for financial instruments measured at amortized cost.

II. Hedges

Where hedge accounting can be applied and the Corporation chooses to seek hedge accounting treatment, a hedge relationship is designated as a fair value hedge, a cash flow hedge, or a hedge of foreign currency exposures of a net investment in a foreign operation. A hedging relationship qualifies for hedge accounting if, at inception, it is formally designated and documented as a hedge, and the hedge is expected to be highly effective at inception and on an ongoing basis. The documentation includes identification of the hedging instrument and hedged item or transaction, the nature of the risk being hedged, the Corporation's risk management objectives and strategy for undertaking the hedge, and how hedge effectiveness will be assessed. The process of hedge accounting includes linking derivatives to specific recognized assets and liabilities or to specific firm commitments or highly probable anticipated transactions.

The Corporation formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives used are highly effective in offsetting changes in fair values or cash flows of hedged items. If hedge criteria are not met or the Corporation does not apply hedge accounting, the derivative is accounted for on the Consolidated Statements of Financial Position at fair value, with subsequent changes in fair value recorded in net earnings in the period of change.

a. Fair Value Hedges

In a fair value hedging relationship, the carrying amount of the hedged item is adjusted for changes in fair value attributable to the hedged risk, with the changes being recognized in net earnings. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging derivative, which is also recorded in net earnings. Hedge effectiveness for fair value hedges is achieved if changes in the fair value of the derivative are highly effective at offsetting changes in the fair value of the item hedged. If hedge accounting is discontinued, the carrying amount of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying amount of the hedged item are amortized to net earnings over the remaining term of the original hedging relationship.

The Corporation primarily uses interest rate swaps as fair value hedges to manage the ratio of floating rate versus fixed rate debt. Interest rate swaps require the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. Interest expense on the debt is adjusted to include the payments made or received under the interest rate swaps.

b. Cash Flow Hedges

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in OCI while any ineffective portion is recognized in net earnings. Hedge effectiveness is achieved if the derivative's cash flows are highly effective at offsetting the cash flows of the hedged item and the timing of the cash flows is similar. All components of each derivative's change in fair value are included in the assessment of cash flow hedge effectiveness. If hedge accounting is discontinued, the amounts previously recognized in AOCI are reclassified to net earnings during the periods when the variability in the cash flows of the hedged item affects net earnings. Gains and losses on derivatives are reclassified to net earnings from AOCI immediately when the forecasted transaction is no longer expected to occur within the time period specified in the hedge documentation.

The Corporation primarily uses physical and financial swaps, forward sales contracts, futures contracts, and options as cash flow hedges to hedge the Corporation's exposure to fluctuations in electricity and natural gas prices. If hedging criteria are met, the fair values of the hedges are recorded in risk management assets or liabilities with changes in value being reported in OCI. Gains and losses on these derivatives are recognized, on settlement, in net earnings in the same period and financial statement caption as the hedged exposure.

The Corporation also uses foreign currency forward contracts as cash flow hedges to hedge the foreign exchange exposures resulting from highly probable forecasted project-related transactions denominated in foreign currencies. If the hedging criteria are met, changes in fair value are reported in OCI with the fair value being reported in risk management assets or liabilities, as appropriate. Upon settlement of the derivative, any gain or loss on the forward contracts is included in the cost of the asset acquired or liability incurred.

The Corporation uses forward starting interest rate swaps as cash flow hedges to hedge exposures to anticipated changes in interest rates for forecasted issuances of debt. If the hedging criteria are met, changes in fair value are reported in OCI with the fair value being reported in risk management assets or liabilities, as appropriate. When the swaps are closed out on issuance of the debt, the resulting gains or losses recorded in AOCI are amortized to net earnings over the term of the swap. If no debt is issued, the gains or losses are recognized in net earnings immediately.

c. Hedges of Foreign Currency Exposures of a Net Investment in a Foreign Operation

In hedging a foreign currency exposure of a net investment in a foreign operation, the effective portion of foreign exchange gains and losses on the hedging instrument is recognized in OCI and the ineffective portion is recognized in net earnings. The related fair values are recorded in risk management assets or liabilities, as appropriate. The amounts previously recognized in AOCI are recognized in net earnings when there is a reduction in the hedged net investment as a result of a disposal, partial disposal, or loss of control. The Corporation primarily uses foreign currency forward contracts and foreign-denominated debt to hedge exposure to changes in the carrying values of the Corporation's net investments in foreign operations that result from changes in foreign exchange rates.

D. Cash and Cash Equivalents

Cash and cash equivalents are comprised of cash and highly liquid investments with original maturities of three months or less.

E. Collateral Paid and Received

The terms and conditions of certain contracts may require the Corporation or its counterparties to provide collateral when the fair value of the obligation pursuant to these contracts is in excess of any credit limits granted. Downgrades in creditworthiness by certain credit rating agencies may decrease the credit limits granted and accordingly increase the amount of collateral that may have to be provided.

F. Inventory

I. Fuel

The Corporation's inventory balance is comprised of coal and natural gas used as fuel, which is measured at the lower of weighted average cost and net realizable value.

The cost of internally produced coal inventory is determined using absorption costing, which is defined as the sum of all applicable expenditures and charges directly incurred in bringing inventory to its existing condition and location. Available coal inventory tends to increase during the second and third quarters as a result of favourable weather conditions and lower electricity production as maintenance is performed. Due to the limited number of processing steps incurred in mining coal and preparing it for consumption and the relatively low value on a per-unit basis, management does not distinguish between work in process and coal available for consumption. The cost of natural gas and purchased coal inventory includes all applicable expenditures and charges incurred in bringing the inventory to its existing condition and location.

II. Energy Marketing

Commodity inventories held in the Energy Marketing Segment for trading purposes are measured at fair value less costs to sell. Changes in fair value less costs to sell are recognized in net earnings in the period of change.

G. Property, Plant, and Equipment

The Corporation's investment in property, plant, and equipment ("PP&E") is initially measured at the original cost of each component at the time of construction, purchase, or acquisition. A component is a tangible portion of an asset that can be separately identified and depreciated over its own expected useful life, and is expected to provide a benefit for a period in excess of one year. Original cost includes items such as materials, labour, borrowing costs, and other directly attributable costs, including the initial estimate of the cost of decommissioning and restoration. Costs are recognized as PP&E assets if it is probable that future economic benefits will be realized and the cost of the item can be measured reliably.

The cost of major spare parts is capitalized and classified as PP&E, as these items can only be used in connection with an item of PP&E.

Planned maintenance is performed at regular intervals. Planned major maintenance includes inspection, repair, and maintenance of existing components, and the replacement of existing components. Costs incurred for planned major maintenance activities are capitalized in the period maintenance activities occur and are amortized on a straight-line basis over the term until the next major maintenance event. Expenditures incurred for the replacement of components during major maintenance are capitalized and amortized over the estimated useful life of such components.

The cost of routine repairs and maintenance and the replacement of minor parts are charged to net earnings as incurred.

Subsequent to initial recognition and measurement at cost, all classes of PP&E continue to be measured using the cost model and are reported at cost less accumulated depreciation and impairment losses, if any.

An item of PP&E or a component is derecognized upon disposal or when no future economic benefits are expected from its use or disposal. Any gain or loss arising on derecognition is included in net earnings when the asset is derecognized.

The estimate of the useful lives of each component of PP&E is based on current facts and past experience, and takes into consideration existing long-term sales agreements and contracts, current and forecasted demand, and the potential for technological obsolescence. The useful life is used to estimate the rate at which the component of PP&E is depreciated. PP&E assets are subject to depreciation when the asset is considered to be available for use, which is typically upon commencement of commercial operations. Each significant component of an item of PP&E is depreciated to its residual value over its estimated useful life, using straight-line or unit-of-production methods. Estimated useful lives, residual values, and depreciation methods are reviewed annually and are subject to revision based on new or additional information. The effect of a change in useful life, residual value, or depreciation method is accounted for prospectively.

Estimated useful lives of the components of depreciable assets, categorized by asset class, are as follows:

Coal generation	3-50 years
Gas generation	2-30 years
Renewable generation	3-60 years
Mining property and equipment	4-50 years
Capital spares and other	2-50 years

TransAlta capitalizes borrowing costs on capital invested in projects under construction *(see Note 2(S))*. Upon commencement of commercial operations, capitalized borrowing costs, as a portion of the total cost of the asset, are depreciated over the estimated useful life of the related asset.

H. Intangible Assets

Intangible assets acquired in a business combination are recognized separately from goodwill at their fair value at the date of acquisition. Intangible assets acquired separately are recognized at cost. Internally generated intangible assets arising from development projects are recognized when certain criteria related to the feasibility of internal use or sale, and probable future economic benefits of the intangible asset, are demonstrated. Intangible assets are initially recognized at cost, which is comprised of all directly attributable costs necessary to create, produce, and prepare the intangible asset to be capable of operating in the manner intended by management.

Subsequent to initial recognition, intangible assets continue to be measured using the cost model, and are reported at cost less accumulated amortization and impairment losses, if any. Amortization is included in depreciation and amortization and fuel and purchased power in the Consolidated Statements of Earnings (Loss).

Amortization commences when the intangible asset is available for use, and is computed on a straight-line basis over the intangible asset's estimated useful life, except for coal rights, which are amortized using a unit-of-production basis, based on the estimated mine reserves. Estimated useful lives of intangible assets may be determined, for example, with reference to the term of the related contract or licence agreement. The estimated useful lives and amortization methods are reviewed annually with the effect of any changes being accounted for prospectively.

Intangible assets consist of power sale contracts with fixed prices higher than market prices at the date of acquisition, coal rights, software, and intangibles under development. Estimated useful lives of intangible assets are as follows:

Software	2-7 years
Power contracts	1-30 years

I. Impairment of Tangible and Intangible Assets Excluding Goodwill

At the end of each reporting period, the Corporation assesses whether there is any indication that PP&E and finite life intangible assets are impaired.

Factors that could indicate that an impairment exists include: significant underperformance relative to historical or projected operating results; significant changes in the manner in which an asset is used, or in the Corporation's overall business strategy; or significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occurs over a period of time leading to an indication that an asset may be impaired. This can be further complicated in situations where the Corporation is not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

The Corporation's operations, the market, and business environment are routinely monitored, and judgments and assessments are made to determine whether an event has occurred that indicates a possible impairment. If such an event has occurred, an estimate is made of the recoverable amount of the asset or cash-generating unit ("CGU") to which the asset belongs. Recoverable amount is the higher of an asset's fair value less costs of disposal and its value in use. Fair value is the price that would be received to sell an asset in an orderly transaction between market participants at the measurement date. In determining fair value, recent market transactions are taken into account. If no such transactions can be identified an appropriate valuation model such as discounted cash flows is used. Value in use is the present value of the estimated future cash flows expected to be derived from the asset from its continued use and ultimate disposal by the Corporation. If the recoverable amount is less than the carrying amount of the asset or CGU, an asset impairment loss is recognized in net earnings, and the asset's carrying amount is reduced to its recoverable amount.

At each reporting date, an assessment is made whether there is any indication that an impairment loss previously recognized may no longer exist or may have decreased. If such indication exists, the recoverable amount of the asset or CGU to which the asset belongs is estimated and the impairment loss previously recognized is reversed if there has been an increase in the recoverable amount. Where an impairment loss is subsequently reversed, the carrying amount of the asset is increased to the lesser of the revised estimate of its recoverable amount or the carrying amount that would have been determined (net of depreciation) had no impairment loss been recognized previously. A reversal of an impairment loss is recognized in net earnings.

J. Goodwill

Goodwill arising in a business combination is recognized as an asset at the date control is acquired. Goodwill is measured as the cost of an acquisition plus the amount of any non-controlling interest in the acquiree (if applicable) less the fair value of the related identifiable assets acquired and liabilities assumed.

Goodwill is not subject to amortization, but is tested for impairment at least annually, or more frequently, if an analysis of events and circumstances indicate that a possible impairment may exist. These events could include a significant change in financial position of the CGUs or groups of CGUs to which the goodwill relates or significant negative industry or economic trends. For impairment purposes, goodwill is allocated to each of the Corporation's CGUs or groups of CGUs that are expected to benefit from the synergies of the business combination in which the goodwill arose. To test for impairment, the recoverable amount of the CGUs or groups of CGUs to which the goodwill relates is compared to its carrying amount. If the recoverable amount is less than the carrying amount, an impairment loss is recognized in net earnings immediately, by first reducing the carrying amount of the goodwill, and then by reducing the carrying amount of the other assets in the unit. An impairment loss recognized for goodwill is not reversed in subsequent periods.

K. Project Development Costs

Project development costs include external, direct, and incremental costs that are necessary for completing an acquisition or construction project. These costs are recognized as operating expenses until construction of a plant or acquisition of an investment is likely to occur, there is reason to believe that future costs are recoverable, and that efforts will result in future value to the Corporation, at which time the costs incurred subsequently are included in other assets. The appropriateness of capitalization of these costs is evaluated each reporting period, and amounts capitalized for projects no longer probable of occurring are charged to net earnings.

L. Income Taxes

The Corporation uses the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are recognized on the differences between the carrying amounts of assets and liabilities and their respective income tax basis (temporary differences). A deferred income tax asset may also be recognized for the benefit expected from unused tax credits and losses available for carryforward, to the extent that it is probable that future taxable earnings will be available against which the tax credits and losses can be applied. Deferred income tax assets and liabilities are measured based on income tax rates and tax laws that are enacted or substantively enacted by the end of the reporting period and that are expected to apply in the years in which temporary differences are expected to be realized or settled. Deferred income tax is charged or credited to net earnings, except when related to items charged or credited to either OCI or directly to equity. The carrying amount of deferred income tax assets is evaluated at the end of each reporting period and is reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow all or part of the asset to be realized.

Deferred income tax liabilities are recognized for taxable temporary differences arising on investments in subsidiaries, except where the Corporation is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future.

M. Employee Future Benefits

The Corporation has defined benefit pension and other post-employment benefit plans. The current service cost of providing benefits under the defined benefit plans is determined using the projected unit credit method pro-rated based on service. The net interest cost is determined by applying the discount rate to the net defined benefit liability. The discount rate used to determine the present value of the defined benefit obligation, and the net interest cost, is determined by reference to market yields at the end of the reporting period on high-quality corporate bonds with terms and currencies that match the estimated terms and currencies of the benefit obligations. Re-measurements, which include actuarial gains and losses and the return on plan assets (excluding net interest), are recognized through OCI in the period in which they occur. Actuarial gains and losses arise from experience adjustments and changes in actuarial assumptions. Re-measurements are not reclassified to profit or loss, from OCI, in subsequent periods.

Gains or losses arising from either a curtailment or settlement of a defined benefit plan are recognized when the curtailment or settlement occurs. When the restructuring of a benefit plan gives rise to a curtailment and a settlement of obligations, the curtailment is accounted for prior to the settlement.

In determining whether statutory minimum funding requirements of the Corporation's defined benefit pension plans give rise to recording an additional liability, letters of credit provided by the Corporation as security are considered to alleviate the funding requirements. No additional liability results in these circumstances.

Contributions payable under defined contribution pension plans are recognized as a liability and an expense in the period in which the services are rendered.

N. Provisions

Provisions are recognized when the Corporation has a present obligation (legal or constructive) as a result of a past event, it is probable that the Corporation will be required to settle the obligation, and a reliable estimate can be made of the amount of the obligation. A legal obligation can arise through a contract, legislation, or other operation of law. A constructive obligation arises from an entity's actions whereby through an established pattern of past practice, published policies, or a sufficiently specific current statement, the entity has indicated it will accept certain responsibilities and has thus created a valid expectation that it will discharge those responsibilities. The amount recognized as a provision is the best estimate, remeasured at each period-end, of the expenditures required to settle the present obligation, considering the risks and uncertainties associated with the obligation. Where expenditures are expected to be incurred in the future, the obligation is measured at its present value using a current market-based, risk-adjusted interest rate.

The Corporation records a decommissioning and restoration provision for all generating facilities and mine sites for which it is legally or constructively required to remove the facilities at the end of their useful lives and restore the plant or mine sites. For some hydro facilities, the Corporation is required to remove the generating equipment, but is not required to remove the structures. Initial decommissioning provisions are recognized at their present value when incurred. Each reporting date, the Corporation determines the present value of the provision using the current discount rates that reflect the time value of money and associated risks. The Corporation recognizes the initial decommissioning and restoration provisions, as well as changes resulting from revisions to cost estimates and period-end revisions to the market-based, risk-adjusted discount rate, as a cost of the related PP&E *(see Note 2(G))*. The accretion of the net present value discount is charged to net earnings each period and is included in net interest expense. Where the Corporation expects to receive reimbursement from a third party for a portion of future decommissioning costs, the reimbursement is recognized as a separate asset when it is virtually certain that the reimbursement will be received. Decommissioning and restoration obligations for coal mines are incurred over time, as new areas are mined, and a portion of the provision is settled over time as areas are reclaimed prior to final pit reclamation. Reclamation costs for mining assets are recognized on a unit-of-production basis.

Changes in other provisions resulting from revisions to estimates of expenditures required to settle the obligation or period-end revisions to the market-based, risk-adjusted discount rate are recognized in net earnings. The accretion of the net present value discount is charged to net earnings each period and is included in net interest expense.

O. Share-Based Payments

The Corporation measures share-based awards compensation expense at grant date fair value and recognizes the expense over the vesting period based on the Corporation's estimate of the number of units that will eventually vest. Any award that vests in instalments is accounted for as a separate award with its own distinct fair value measurement.

Compensation expense associated with equity-settled and cash-settled awards are recognized within equity and liability, respectively. The liability associated with cash-settled awards is remeasured to fair value at each reporting date up to, and including, the settlement date, with changes in fair value recognized within compensation expense.

P. Emission Credits and Allowances

Emission credits and allowances are recorded as inventory at cost. Those purchased for use by the Corporation are recorded at cost and are carried at the lower of weighted average cost and net realizable value. Credits granted to, or internally generated by, TransAlta are recorded at nil. Emission liabilities are recorded using the best estimate of the amount required by the Corporation to settle its obligation in excess of government-established caps and targets. To the extent compliance costs are recoverable under the terms of contracts with third parties the amounts are recognized as revenue in the period of recovery.

Emission credits and allowances that are held for trading and that meet the definition of a derivative are accounted for using the fair value method of accounting. Allowances that do not satisfy the criteria of a derivative are accounted for using the accrual method.

Q. Assets Held for Sale

Assets are classified as held for sale if their carrying amount will be recovered primarily through a sale as opposed to continued use by the Corporation. Assets classified as held for sale are measured at the lower of their carrying amount and fair value less costs of disposal. Any impairment is recognized in net earnings. Depreciation and equity accounting ceases when an asset or equity investment, respectively, is classified as held for sale. Assets classified as held for sale are reported as current assets in the Consolidated Statements of Financial Position.

R. Leases

A lease is an arrangement whereby the lessor conveys to the lessee, in return for a payment or series of payments, the right to use an asset for an agreed period of time.

Power purchase arrangements ("PPA") and other long-term contracts may contain, or may be considered, leases where the fulfillment of the arrangement is dependent on the use of a specific asset (e.g. a generating unit) and the arrangement conveys to the customer the right to use that asset.

Where the Corporation determines that the contractual provisions of a contract contain, or are, a lease and result in the customer assuming the principal risks and rewards of ownership of the asset, the arrangement is a finance lease. Assets subject to finance leases are not reflected as PP&E and the net investment in the lease, represented by the present value of the amounts due from the lessee, is recorded in the Consolidated Statements of Financial Position as a financial asset, classified as a finance lease receivable. The payments considered to be part of the leasing arrangement are apportioned between a reduction in the lease receivable and finance lease income. The finance lease income element of the payments is recognized using a method that results in a constant rate of return on the net investment in each period and is reflected in finance lease income on the Consolidated Statements of Earnings (Loss).

Where the Corporation determines that the contractual provisions of a contract contain, or are, a lease and result in the Corporation retaining the principal risks and rewards of ownership of the asset, the arrangement is an operating lease. For operating leases, the asset is, or continues to be, capitalized as PP&E and depreciated over its useful life. Rental income, including contingent rent, from operating leases is recognized over the term of the arrangement and is reflected in revenue on the Consolidated Statements of Earnings (Loss). Contingent rent may arise when payments due under the contract are not fixed in amount but vary based on a future factor such as the amount of use or production.

Leasing or other contractual arrangements that transfer substantially all of the risks and rewards of ownership to the Corporation are considered finance leases. A leased asset and lease obligation are recognized at the lower of the fair value or the present value of the minimum lease payments. Lease payments are apportioned between interest expense and a reduction of the lease liability. Contingent rents are charged as expenses in the periods incurred. The leased asset is depreciated over the shorter of the estimated useful life of the asset and the lease term.

S. Borrowing Costs

TransAlta capitalizes borrowing costs that are directly attributable to, or relate to general borrowings used for, the construction of qualifying assets. Qualifying assets are assets that take a substantial period of time to prepare for their intended use and typically include generating facilities or other assets that are constructed over periods of time exceeding 12 months. Borrowing costs are considered to be directly attributable if they could have been avoided if the expenditure on the qualifying asset had not been made. Borrowing costs that are capitalized are included in the cost of the related PP&E component. Capitalization of borrowing costs ceases when substantially all the activities necessary to prepare the asset for its intended use are complete.

All other borrowing costs are expensed in the period in which they are incurred.

T. Non-Controlling Interests

Non-controlling interests arise from business combinations in which the Corporation acquires less than a 100 per cent interest. Non-controlling interests are initially measured at either fair value or at the non-controlling interest's proportionate share of the acquiree's identifiable net assets. The Corporation determines on a transaction by transaction basis which measurement method is used.

Non-controlling interests also arise from other contractual arrangements between the Corporation and other parties, whereby the other party has acquired an interest in a specified asset or operation, and the Corporation retains control.

Subsequent to acquisition, the carrying amount of non-controlling interests is increased or decreased by the non-controlling interest's share of subsequent changes in equity and payments to the non-controlling interest. Total comprehensive income is attributed to the non-controlling interests even if this results in the non-controlling interests having a negative balance.

U. Joint Arrangements

A joint arrangement is a contractual arrangement that establishes the terms by which two or more parties agree to undertake and jointly control an economic activity. TransAlta's joint arrangements are generally classified as two types: joint operations and joint ventures.

A joint operation arises when the parties that have joint control have rights to the assets, and obligations for the liabilities, relating to the arrangement. Generally, each party takes a share of the output from the asset and each bears an agreed upon share of the costs incurred in respect of the joint operation. The Corporation reports its interests in joint operations in its consolidated financial statements using the proportionate consolidation method by recognizing its share of the assets, liabilities, revenues, and expenses in respect of its interest in the joint operation.

In a joint venture, the venturers do not have rights to individual assets or obligations of the venture. Rather, each venturer has rights to the net assets of the arrangement. The Corporation reports its interests in joint ventures using the equity method. Under the equity method, the investment is initially recognized at cost and the carrying amount is increased or decreased to recognize the Corporation's share of the joint venture's net earnings or loss after the date of acquisition. The impact of transactions between the Corporation and joint ventures is eliminated based on the Corporation's ownership interest. Distributions received from joint ventures reduce the carrying amount of the investment. Any excess of the cost of an acquisition less the fair value of the recognized identifiable assets, liabilities, and contingent liabilities of an acquired joint venture is recognized as goodwill and is included in the carrying amount of the investment and is assessed for impairment as part of the investment.

Investments in joint ventures are evaluated for impairment at each reporting date by first assessing whether there is objective evidence that the investment is impaired. If such objective evidence is present, an impairment loss is recognized if the investment's recoverable amount is less than its carrying amount. The investment's recoverable amount is determined as the higher of value in use and fair value less costs of disposal.

V. Government Incentives

Government incentives are recognized when the Corporation has reasonable assurance that it will comply with the conditions associated with the incentive and that the incentive will be received. When the incentive relates to an expense item, it is recognized in net earnings over the same period in which the related costs or revenues are recognized. When the incentive relates to an asset, it is recognized as a reduction of the carrying amount of PP&E and released to earnings as a reduction in depreciation over the expected useful life of the related asset.

W. Earnings per Share

Basic earnings per share is calculated by dividing net earnings attributable to common shareholders by the weighted average number of common shares outstanding in the year.

Diluted earnings per share is calculated by dividing net earnings attributable to common shareholders, adjusted for the after-tax effects of dividends, interest or other changes in net earnings that would result from potential dilutive instruments, by the weighted average number of common shares outstanding in the year, adjusted for additional common shares that would have been issued on the conversion of all potential dilutive instruments.

X. Business Combinations

Transactions in which the acquisition constitutes a business are accounted for using the acquisition method. Identifiable assets acquired and liabilities assumed are measured at their acquisition-date fair values. Goodwill is measured as the excess of the fair value of consideration transferred less the fair value of the identifiable assets acquired and liabilities assumed.

Acquisition-related costs to effect the business combination, with the exception of costs to issue debt or equity securities, are recognized in net earnings as incurred.

Y. Stripping Costs

A mine stripping activity asset is recognized when all of the following are met: i) it is probable that the future benefit associated with improved access to the coal reserves associated with the stripping activity will be realized; ii) the component of the coal reserve to which access has been improved can be identified; and iii) the costs related to the stripping activity associated with that component can be measured reliably. Costs include those directly incurred to perform the stripping activity as well as an allocation of directly attributable overheads. The resulting stripping activity asset is amortized on a unit-of-production basis over the expected useful life of the identified component that it relates to. The amortization is recognized as a component of the standard cost of coal inventory.

Z. Significant Accounting Judgments and Key Sources of Estimation Uncertainty

The preparation of financial statements requires management to make judgments, estimates and assumptions that could affect the reported amounts of assets, liabilities, revenues, expenses, and disclosures of contingent assets and liabilities during the period. These estimates are subject to uncertainty. Actual results could differ from those estimates due to factors such as fluctuations in interest rates, foreign exchange rates, inflation and commodity prices, and changes in economic conditions, legislation, and regulations.

In the process of applying the Corporation's accounting policies, management has to make judgments and estimates about matters that are highly uncertain at the time the estimate is made and that could significantly affect the amounts recognized in the consolidated financial statements. Different estimates with respect to key variables used in the calculations, or changes to estimates, could potentially have a material impact on the Corporation's financial position or performance. The key judgments and sources of estimation uncertainty are described below:

I. Impairment of PP&E and Goodwill

Impairment exists when the carrying amount of an asset, CGU or group of CGUs to which goodwill relates exceeds its recoverable amount, which is the higher of its fair value less costs of disposal and its value in use. An assessment is made at each reporting date as to whether there is any indication that an impairment loss may exist or that a previously recognized impairment loss may no longer exist or may have decreased. In determining fair value less costs of disposal, information about third-party transactions for similar assets is used and if none is available, other valuation techniques, such as discounted cash flows, are used. Value in use is computed using the present value of management's best estimates of future cash flows based on the current use and present condition of the asset. In estimating either fair value less costs of disposal or value in use using discounted cash flow methods, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, capital expenditures, retirement costs, and other related cash inflows and outflows over the life of the facilities, which can range from 30 to 60 years. In developing these assumptions, management uses estimates of contracted and future market prices based on expected market supply and demand in the region in which the plant operates, anticipated production levels, planned and unplanned outages, changes to regulations, and transmission capacity or constraints for the remaining life of the facilities. Discount rates are determined by employing a weighted average cost of capital methodology that is based on capital structure, cost of equity, and cost of debt assumptions based on comparable companies with similar risk characteristics and market data as the asset, CGU or group of CGUs subject to the test. These estimates and assumptions are susceptible to change from period to period and actual results can, and often do, differ from the estimates, and can have either a positive or negative impact on the estimate of the impairment charge, and may be material. Information regarding determinations of CGUs for asset and goodwill impairment testing can be found in *Notes 6 and 18*. Key assumptions used in determining the 2014 and 2012 recoverable amount of the Centralia coal plant and the 2012 recoverable amount of Sundance Units 1 and 2 are further explained in *Note 6*.

II. Leases

In determining whether the Corporation's PPAs and other long-term electricity and thermal contracts contain, or are, leases, management must use judgment in assessing whether the fulfillment of the arrangement is dependent on the use of a specific asset and the arrangement conveys the right to use the asset. For those agreements considered to contain, or be, leases, further judgment is required to determine whether substantially all of the significant risks and rewards of ownership are transferred to the customer or remain with the Corporation, to appropriately account for the agreement as either a finance or operating lease. These judgments can be significant and impact how the Corporation classifies amounts related to the arrangement as either PP&E or as a finance lease receivable on the Consolidated Statements of Financial Position, and therefore the amount of certain items of revenue and expense is dependent upon such classifications.

III. Income Taxes

Preparation of the consolidated financial statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which the Corporation operates. The process also involves making an estimate of income taxes currently payable and income taxes expected to be payable or recoverable in future periods, referred to as deferred income taxes. Deferred income taxes result from the effects of temporary differences due to items that are treated differently for tax and accounting purposes. The tax effects of these differences are reflected in the Consolidated Statements of Financial Position as deferred income tax assets and liabilities. An assessment must also be made to determine the likelihood that the Corporation's future taxable income will be sufficient to permit the recovery of deferred income tax assets. To the extent that such recovery is not probable, deferred income tax assets must be reduced. Management uses the Corporation's long-range forecasts as a basis for evaluation of recovery of deferred income tax assets. Management must exercise judgment in its assessment of continually changing tax interpretations, regulations, and legislation to ensure deferred income tax assets and liabilities are complete and fairly presented. Differing assessments and applications than the Corporation's estimates could materially impact the amounts recognized for deferred income tax assets and liabilities.

IV. Financial Instruments and Derivatives

The Corporation's financial instruments and derivatives are accounted for at fair value, with the initial and subsequent changes in fair value affecting earnings in the period the change occurs. The fair values of financial instruments and derivatives are classified within three levels, with Level III fair values determined using inputs for the asset or liability that are not readily observable. These fair value levels are outlined and discussed in more detail in *Note 13*. Some of the Corporation's fair values are included in Level III because they are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available and require the use of internal valuation techniques or models to determine fair value. The determination of the fair value of these contracts and derivative instruments can be complex and relies on judgments and estimates concerning future prices, volatility, and liquidity, among other factors. These fair value estimates may not necessarily be indicative of the amounts that could be realized or settled, and changes in these assumptions could affect the reported fair value of financial instruments. Fair values can fluctuate significantly and can be favourable or unfavourable depending on current market conditions. Judgment is also used in determining whether a highly probable forecasted transaction designated in a cash flow hedge is expected to occur based on the Corporation's estimates of pricing and production to allow the future transaction to be fulfilled.

V. Joint Control

In January 2014, the Corporation, through a wholly owned subsidiary, formed an unincorporated joint venture named Fortescue River Gas Pipeline, of which it has a 43 per cent interest. Management, using judgment, assessed whether the Corporation's sole partner had control over the joint venture, or whether joint control existed. The contractual terms of the joint venture agreement and the management agreement were reviewed and management concluded that joint control exists as decisions regarding the relevant activities of the joint venture require a special majority vote (at least 70 per cent in favour). Accordingly, the business is accounted for as a joint operation.

VI. Project Development Costs

Project development costs are capitalized in accordance with the accounting policy in *Note 2(K)*. Management is required to use judgment to determine if there is reason to believe that future costs are recoverable, and that efforts will result in future value to the Corporation, in determining the amount to be capitalized.

VII. Provisions for Decommissioning and Restoration Activities

TransAlta recognizes provisions for decommissioning and restoration obligations as outlined in *Note 2(N)* and *Note 21*. Initial decommissioning provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the required cash expenditures, adjusted to reflect the risks and uncertainties inherent in the timing and amount of settlement. The estimated cash expenditures are present valued using a current, risk-adjusted, market-based, pre-tax discount rate. A change in estimated cash flows, market interest rates, or timing could have a material impact on the carrying amount of the provision.

VIII. Useful Life of PP&E

Each significant component of an item of PP&E is depreciated over its estimated useful life. Estimated useful lives are determined based on current facts and past experience, and take into consideration the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecasted demand, the potential for technological obsolescence, and regulations. The useful lives of PP&E are reviewed at least annually to ensure they continue to be appropriate.

IX. Employee Future Benefits

The Corporation provides pension and other post-employment benefits, such as health and dental benefits, to employees. The cost of providing these benefits is dependent upon many factors, including actual plan experience and estimates and assumptions about future experience.

The liability for pension and post-employment benefits and associated costs included in annual compensation expenses are impacted by estimates related to:

- employee demographics, including age, compensation levels, employment periods, the level of contributions made to the plans, and earnings on plan assets;
- the effects of changes to the provisions of the plans; and
- changes in key actuarial assumptions, including rates of compensation and health-care cost increases, and discount rates.

Due to the complexity of the valuation of pension and post-employment benefits, a change in the estimate of any one of these factors could have a material effect on the carrying amount of the liability for pension and other post-employment benefits or the related expense. These assumptions are reviewed annually to ensure they continue to be appropriate.

X. Other Provisions

Where necessary, TransAlta recognizes provisions arising from ongoing business activities, such as interpretation and application of contract terms, ongoing litigation, and force majeure claims. These provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the outcome of the underlying event and can also be impacted by determinations made by third parties, in compliance with contractual requirements. The actual amount of the provisions that may be required could differ materially from the amount recognized.

3. Accounting Changes

A. Adoption of New or Amended IFRS

On Jan. 1, 2014, the Corporation adopted the following new or amended accounting standards and interpretations that were previously issued by the IASB. There was no impact of adopting these on the consolidated financial statements.

I. Offsetting Financial Assets and Financial Liabilities – IAS 32 *Financial Instruments: Presentation*

The amendments clarify the existing guidance on offsetting financial assets and financial liabilities due to the diversity in application of the requirements.

II. Recoverable Amount Disclosures for Non-Financial Assets – IAS 36 *Impairment of Assets*

The amendments remove the unintended consequences that IFRS 13 *Fair Value Measurement* had on the disclosures required under IAS 36 and require disclosure of the recoverable amounts for assets or CGUs for which a significant impairment loss has been recognized or reversed. The amendment was evaluated for application retrospectively from the date of initial application of IFRS 13 *Fair Value Measurement*, Jan. 1, 2013.

B. Other Current Accounting Changes

I. Inception Gains and Losses

The Corporation restated the Consolidated Statement of Financial Position as at Dec. 31, 2013 to reclassify the inception gains or losses arising from differences between the fair value of a financial instrument at initial recognition (the transaction price) and the amount calculated through a valuation model. These amounts were previously reported as gross contra-risk management assets or liabilities. The adjustment reclassifies them as direct offsets to the value of the derivative contract to which they relate. As a result of the adjustment, long-term risk management assets and long-term risk management liabilities were each reduced by $160 million at Dec. 31, 2013. Corresponding adjustments to the Dec. 31, 2012 Consolidated Statement of Financial Position were immaterial. Refer to *Note 13(C)* for further information on inception gains and losses.

II. Inventory Writedown

The Corporation restated the Consolidated Statements of Earnings (Loss) for the years ended Dec. 31, 2013 and 2012 to reclassify inventory writedown as a component of fuel and purchased power. These amounts were previously reported as standalone components of operating income. The adjustment is intended to better capture within gross margin the generally offsetting effects that changes in future power prices have on mark-to-market gains or losses from economic forward power sale hedges, included in revenue, and on inventory writedown or reversals. As a result of the adjustment, fuel and purchased power for the years ended Dec. 31, 2013 and 2012 increased by $22 million and $44 million, respectively. The inventory writedown for the year ended Dec. 31, 2014 was $19 million.

III. Net Other Operating Income and Losses

The Corporation restated the Consolidated Statements of Earnings (Loss) for the years ended Dec. 31, 2013 and 2012 to reclassify the losses associated with the California claim, the Sundance Units 1 and 2 return to service, and the assumption of pension obligations, as well as gains from insurance recoveries, as a net other operating income and losses group within operating income. Previously, each item was presented in earnings outside of operating income. The Corporation initiated the change as part of its ongoing monitoring of practices concerning additional IFRS measures. As a result of the change, operating income (loss) for the years ended Dec. 31, 2013 and 2012 decreased by $102 million and $254 million, respectively.

C. Comparative Figures

Certain comparative figures have been reclassified to conform to the current period's presentation. These reclassifications did not impact previously reported net earnings.

D. Future Accounting Changes

Accounting standards that have been previously issued by the IASB, but are not yet effective and have not been applied by the Corporation, include:

I. IFRS 9 *Financial Instruments*

In July 2014, on completion of the impairment phase of the project to reform accounting for financial instruments and replace IAS 39 *Financial Instruments: Recognition and Measurement*, the IASB issued the final version of IFRS 9 *Financial Instruments.* IFRS 9 includes guidance on the classification and measurement of financial assets and financial liabilities, impairment of financial assets (i.e. recognition of credit losses), and a new hedge accounting model.

Under the classification and measurement requirements for financial assets, financial assets must be classified and measured at either amortized cost or at fair value through profit or loss or through OCI, depending on the basis of the entity's business model for managing the financial asset and the contractual cash flow characteristics of the financial asset.

The classification requirements for financial liabilities are unchanged from IAS 39. IFRS 9 requirements address the problem of volatility in net earnings arising from an issuer choosing to measure certain liabilities at fair value and require that the portion of the change in fair value due to changes in the entity's own credit risk be presented in OCI, rather than within net earnings.

The new general hedge accounting model is intended to be simpler and more closely focus on how an entity manages its risks, replaces the IAS 39 effectiveness testing requirements with the principle of an economic relationship, and eliminates the requirement for retrospective assessment of hedge effectiveness.

The new requirements for impairment of financial assets introduce an expected loss impairment model that requires more timely recognition of expected credit losses. IAS 39 impairment requirements are based on an incurred loss model where credit losses are not recognized until there is evidence of a trigger event.

IFRS 9 is effective for annual periods beginning on or after Jan. 1, 2018 with early application permitted. The Corporation is assessing the impact of adopting this standard on its consolidated financial statements.

II. IFRS 15 *Revenue from Contracts with Customers*

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers,* which replaces existing revenue recognition guidance with a single comprehensive accounting model. The model specifies that an entity recognizes revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. IFRS 15 is effective for annual reporting periods beginning on or after Jan. 1, 2017 with early application permitted. The Corporation is assessing the impact of adopting this standard on its consolidated financial statements.

4. Acquisitions and Disposals

During 2012, 2013, and 2014, the following acquisitions and disposals took place in the Generation Segment:

A. Acquisitions

I. 2013

On Dec. 20, 2013, the Corporation completed the acquisition of a 144 megawatt ("MW") wind farm in Wyoming ("Wyoming wind farm") from an affiliate of NextEra Energy Resources, LLC. The total cash consideration transferred was U.S.$102 million ($109 million). The acquisition was TransAlta's first wind project in the U.S.

At the acquisition date, the fair value of assets acquired and liabilities assumed was as follows:

Assets:	
Property, plant, and equipment	79
Intangible assets	20
Goodwill	13
Total assets acquired	112
Liabilities:	
Decommissioning and restoration provision	3
Total consideration transferred	**109**

Goodwill arose in the acquisition primarily as a result of the expectation by the Corporation of future market growth and development opportunities in the region. These benefits are not recognized separately from goodwill as they do not meet the recognition criteria for identifiable intangible assets. All of the goodwill is expected to be deductible for tax purposes.

II. 2012

On Sept. 28, 2012, the Corporation acquired the 125 MW Solomon power station located in Western Australia from Fortescue Metals Group Ltd. ("Fortescue") for U.S.$318 million. The facility is fully contracted with Fortescue under a long-term Power Purchase Agreement ("Agreement") with an initial term of 16 years commencing in October 2012, after which Fortescue will have the option to either extend the Agreement for an additional five years under the same terms or to acquire the facility. The Corporation has accounted for the facility and associated Agreement as a finance lease with TransAlta being the lessor *(see Note 7)*.

B. Disposals

I. 2014

On June 12, 2014, the Corporation closed the sale of its 50 per cent ownership of CE Generation, LLC ("CE Gen"), CalEnergy LLC, and the Blackrock development project to MidAmerican Renewables for gross proceeds of U.S.$200.5 million. The original consideration of U.S.$188.5 million was increased as a result of a U.S.$12 million contribution made by the Corporation in May 2014. As a result of the sale, the Corporation recognized a pre-tax gain of $1 million ($2 million after-tax) as part of gain on sale of assets.

On Nov. 25, 2014, the Corporation closed the sale of its 50 per cent ownership of Wailuku Holding Company, LLC for gross proceeds of U.S.$5 million. A pre-tax gain of $1 million ($1 million after-tax) was recognized as part of gain on sale of assets.

The gains include reclassified cumulative translation gains of $7 million on the divested net assets, offset by related cumulative after-tax losses of $7 million from the related net investment hedge.

II. 2013

During 2013, the Corporation realized a pre-tax gain of $10 million relating to the sale of land and a pre-tax gain of $2 million relating to the sale of British Columbia water rights.

5. Expenses by Nature

Expenses classified by nature are as follows:

Year ended Dec. 31	2014		2013 (Restated)*		2012 (Restated)*	
	Fuel and purchased power	**Operations, maintenance, and administration**	Fuel and purchased power	Operations, maintenance, and administration	Fuel and purchased power	Operations, maintenance, and administration
Fuel	**937**	**–**	778	–	645	–
Coal inventory writedown	**19**	**–**	22	–	44	–
Purchased power	**75**	**–**	85	–	63	–
Mine depreciation	**56**	**–**	58	–	41	–
Salaries and benefits	**5**	**280**	5	251	4	261
Other operating expenses	**–**	**262**	–	265	–	238
Total	**1,092**	**542**	948	516	797	499

* *See Note 3(B) for prior period restatements.*

6. Asset Impairment Charges and Reversals

All impairment charges and reversals are reported in the Generation Segment.

A. 2014

I. Centralia Coal

As at Nov. 30, 2014, the Corporation identified the decrease in projected growth in Mid-Columbia power prices as an indicator that the Centralia coal CGU could be impaired. The Centralia coal CGU's carrying amount at that date, net of associated long-term liabilities, was $372 million. The Corporation estimated the fair value less costs of disposal of the CGU, a Level III fair value measurement, utilizing the Corporation's long-range forecast and the following key assumptions:

Mid-Columbia annual average power prices	U.S.$31.00 to 52.00 per MWh
On-highway diesel fuel on coal shipments	U.S.$3.06 to 3.37 per gallon
Discount rates	5.1 to 6.2 per cent

The valuation is subject to measurement uncertainty based on those assumptions, and on inputs to the Corporation's long-range forecast, including changes to fuel costs, operating costs, capital expenses, and the level of contractedness under the Memorandum of Agreement for coal transition established with the State of Washington. The valuation period extended to the assumed decommissioning of the asset, after its projected cessation of operation in its current form in 2025.

Fair value less costs of disposal of the CGU was estimated to approximate its carrying amount, and accordingly, no impairment charge was recorded. Any adverse change in assumptions, in isolation, would have resulted in an impairment charge being recorded. The Corporation continues to manage risks associated with the CGU through optimization of its operating activities and capital plan.

II. Centralia Gas

During 2014, the Corporation sold to external counterparties and transferred to other owned facilities for productive use, assets of the Centralia gas facility, which had been fully impaired and had remained idled since 2010. As a result of the transactions, the Corporation recognized pre-tax impairment reversals of $5 million.

B. 2013

I. Alberta Merchant

As part of the annual impairment review and assessment process in 2013, it was determined that the Corporation's Alberta plants that have significant merchant capacity should be considered one cash-generating unit (the "Alberta Merchant CGU"). Previously, each plant was assessed for impairment individually. The reasons for this change include consideration of the final regulations published by the Canadian federal government in September 2012 governing greenhouse gas emissions and the 50-year total life for Canadian coal-fired power plants; and the Corporation's refinement of its risk management approach and practices regarding its Alberta wholesale market price exposure. The final regulations confirmed additional operating time and increased flexibility for the Corporation's Alberta coal plants and led, in part, to the Corporation broadening its view on the management of its Alberta wholesale market price exposure.

The Corporation reversed previous pre-tax impairment losses of $23 million on various renewables plants that became part of the Alberta Merchant CGU. The Alberta Merchant CGU's recoverable amount was based on an estimate of fair value less costs of disposal using a discounted cash flow methodology, based on the Corporation's long-range forecasts and prices evidenced in the marketplace. Due to a substantial excess of fair value over net book value at other plants included within the Alberta Merchant CGU, valuation assumptions and methodologies were not a significant driver of the impairment reversals.

II. Renewables

During 2013, the Corporation recognized a total pre-tax impairment charge of $4 million related to three contracted hydro assets. The assets were impaired primarily due to an increase in future capital and operating expenses that resulted from the completion of condition assessments. The annual impairment assessments were based on estimates of fair value less costs of disposal derived from long-range forecasts.

C. 2012

I. Sundance Units 1 and 2

During 2012, the Corporation reversed $41 million of the $43 million impairment losses previously taken on Sundance Units 1 and 2. The reversal arose as a result of the additional years of merchant operations expected to be realized at Units 1 and 2 due to amendments to Canadian federal regulations requiring that coal-fired plants be shut down after a maximum of 50 years of operation. The previous draft regulations proposed shutdown after 45 years. The impairment assessment was based on an estimate of fair value less costs of disposal, derived from the cash flows expected to result over the revised useful life of the Units, taking into consideration the provisions of the PPA and prices evidenced in the marketplace.

II. Centralia Coal

The TransAlta Energy Bill and a Memorandum of Agreement was signed on Dec. 23, 2011 that provided a framework for the orderly transition from coal-fired energy produced at the Centralia coal plant and the shutdown of the units in 2020 and 2025. On July 25, 2012, the Corporation announced that it entered into a long-term power agreement to provide electricity from the Centralia coal plant from December 2014 until the facility is fully retired in 2025. As a result of these agreements, the Corporation recognized a pre-tax impairment charge of $347 million during 2012. The impairment assessment was based on whether the carrying amount of the Centralia coal plant was recoverable based on an estimate of fair value less costs of disposal.

III. Renewables

During 2012, the Corporation recognized a pre-tax impairment charge of $18 million related to five assets. The impairments resulted from the completion of the annual impairment assessment based on estimates of fair value less costs of disposal, derived from the long-range forecasts and prices evidenced in the marketplace. The assets were impaired primarily due to expectations regarding lower market prices.

7. Finance Lease Receivables

Amounts receivable under the Corporation's finance leases, comprised of the Fort Saskatchewan cogeneration facility and the Solomon power station finance leases, are as follows:

As at Dec. 31	2014		2013	
	Minimum lease payments	Present value of minimum lease payments	Minimum lease payments	Present value of minimum lease payments
Within one year	55	51	50	46
Second to fifth years inclusive	229	157	209	143
More than five years	479	162	494	160
	763	370	753	349
Less: unearned finance lease income	546	-	548	-
Add: unguaranteed residual value	191	38	175	31
Total finance lease receivables	408	408	380	380
Current portion of finance lease receivables *(Note 12)*	5		3	
Long-term portion of finance lease receivables	403		377	
	408		380	

8. Net Other Operating (Income) Losses

Net other operating (income) losses are comprised of the following:

Year ended Dec. 31	2014	2013	2012
California claim	5	56	-
Insurance recoveries	(10)	(8)	-
Supplier settlement	(9)	-	-
Sundance Units 1 and 2 return to service	-	25	254
Loss on assumption of pension obligations	-	29	-
Net other operating (income) losses	(14)	102	254

A. California Claim

On May 30, 2014, the Corporation announced that its settlement with California utilities, the California Attorney General and certain other parties (the "California Parties") to resolve claims related to the 2000-2001 power crisis in the State of California had been approved by the Federal Energy Regulatory Commission. The settlement provides for the payment by the Corporation of U.S.$52 million in two equal payments and a credit of approximately U.S.$97 million for monies owed to the Corporation from accounts receivable. The first payment of U.S.$26 million was paid in June 2014 and the second is due in 2015. In 2013, the Corporation accrued for the then expected settlement of these disputes with the California Parties, which resulted in a pre-tax charge to 2013 earnings of approximately U.S.$52 million. The finalization of the settlement in May 2014 resulted in an additional pre-tax charge to 2014 earnings of U.S.$5 million.

B. Insurance Recoveries

During 2014, the Corporation received $28 million (2013 – $15 million) in insurance proceeds, of which $18 million (2013 – $7 million) was related to claims for repair costs on certain hydro facilities as a result of flooding in Southern Alberta in June 2013 and was accounted for as a reduction to period operations, maintenance, and administration. The balance, in the amount of $10 million (2013 – $8 million) related to purchases of replacement equipment and business interruption insurance for various prior years' claims.

C. Supplier Settlement

During 2014, the Corporation settled a dispute with a supplier in relation to an equipment failure in prior years.

D. Sundance Units 1 and 2 Return to Service

In December 2010, Units 1 and 2 of the Corporation's Sundance facility were shut down due to conditions observed in the boilers at both units. On July 20, 2012, an arbitration panel concluded that Unit 1 and Unit 2 were not economically destroyed under the terms of the PPA and the Corporation was required to restore the units to service. For the year ended Dec. 31, 2012, a $254 million pre-tax impact of the ruling has been recognized. During 2013, $25 million of components were retired as a result of the work completed on the units to return them to service. Sundance Unit 1 returned to service on Sept. 2, 2013 and Unit 2 returned to service on Oct. 4, 2013.

E. Loss on Assumptions of Pension Obligations

Effective Jan. 17, 2013, the Corporation assumed, through its wholly owned subsidiary, SunHills Mining Limited Partnership ("SunHills"), operations and management control of the Highvale mine from Prairie Mines and Royalty Ltd. ("PMRL"). PMRL employees working at the Highvale mine were offered employment by SunHills, which agreed to assume responsibility for certain pension plan and pension funding obligations, which the Corporation previously funded through the payments made under the PMRL mining contracts. As a result, a pre-tax loss of $29 million was recognized in 2013, along with the corresponding liabilities.

9. Net Interest Expense

The components of net interest expense, which excludes finance lease income, are as follows:

Year ended Dec. 31	**2014**	2013	2012
Interest on debt	**238**	240	227
Interest income	**-**	-	(2)
Capitalized interest *(Note 17)*	**(3)**	(2)	(4)
Ineffectiveness on hedges	**-**	-	4
Interest on finance lease obligations	**1**	-	-
Accretion of provisions *(Note 21)*	**18**	18	17
Net interest expense	**254**	256	242

10. Income Taxes

A. Consolidated Statements of Earnings (Loss)

I. Rate Reconciliations

Year ended Dec. 31	2014	2013	2012
Earnings (loss) before income taxes	**239**	(12)	(445)
Equity loss	**-**	10	15
Net earnings attributable to non-controlling interests	**(37)**	(29)	(37)
Adjusted earnings (loss) before income taxes	**202**	(31)	(467)
Statutory Canadian federal and provincial income tax rate *(%)*	**25.0**	25.0	25.0
Expected income tax expense (recovery)	**51**	(8)	(117)
Increase (decrease) in income taxes resulting from:			
Lower effective foreign tax rates	**(3)**	(21)	(49)
Resolution of uncertain tax matters	**(1)**	(1)	(27)
Divestiture of investment	**(38)**	-	-
Statutory and other rate differences	**-**	(5)	7
Writedown (reversal of writedown) of deferred income tax assets	**(5)**	28	289
Other	**3**	(1)	(1)
Income tax expense (recovery)	**7**	(8)	102
Effective tax rate *(%)*	**3**	26	(22)

II. Components of Income Tax Expense

The components of income tax expense (recovery) are as follows:

Year ended Dec. 31	2014	2013	2012
Current income tax expense	**33**	38	27
Adjustments in respect of current income tax of previous years	**-**	1	(3)
Adjustments in respect of deferred income tax of previous years	**2**	(1)	1
Deferred income tax expense (recovery) related to the origination and reversal of temporary differences	**12**	(68)	(71)
Deferred income tax expense (recovery) resulting from changes in tax rates or laws	**-**	(5)	7
Benefit arising from previously unrecognized tax loss, tax credit, or temporary difference of a prior period used to reduce current income tax expense	**-**	-	(11)
Benefit arising from previously unrecognized tax loss, tax credit, or temporary difference of a prior period used to reduce deferred income tax expense	**(35)**	(1)	(16)
Deferred income tax expense (recovery) arising from the writedown (reversal of writedown) of deferred income tax assets	**(5)**	28	168
Income tax expense (recovery)	**7**	(8)	102

Year ended Dec. 31	2014	2013	2012
Current income tax expense	**33**	39	13
Deferred income tax expense (recovery)	**(26)**	(47)	89
Income tax expense (recovery)	**7**	(8)	102

For the year ended Dec. 31, 2013, the Corporation wrote off deferred income tax assets of $28 million (2012 – $289 million) related to approximately $80 million (2012 – $826 million) of deductible temporary differences of its U.S. operations. The deferred income tax assets related mainly to the tax benefits of losses associated with the Corporation's directly owned U.S. operations. The deferred tax assets were written off as it was no longer considered probable that sufficient taxable income would be available from the Corporation's directly owned U.S. operations to utilize the underlying tax losses, due to reduced price growth expectations. For the year ended Dec. 31, 2014, $5 million of previously written off deferred income tax assets was reversed based on changes to taxable and deductible temporary differences that impact the net U.S. deferred income tax assets. Net operating losses expire between 2021 and 2034.

B. Consolidated Statements of Changes in Equity

The aggregate current and deferred income tax related to items charged or credited to equity are as follows:

Year ended Dec. 31	2014	2013	2012
Income tax expense (recovery) related to:			
Net impact related to cash flow hedges	**88**	12	(15)
Net impact related to net investment hedges	**(8)**	(5)	2
Net actuarial gains (losses)	**(7)**	11	(8)
Common and preferred share issuance costs	**(1)**	–	(5)
Income tax expense (recovery) reported in equity	**72**	18	(26)

C. Consolidated Statements of Financial Position

Significant components of the Corporation's deferred income tax assets (liabilities) are as follows:

As at Dec. 31	2014	2013
Net operating loss carryforwards	**716**	665
Future decommissioning and restoration costs	**101**	91
Property, plant, and equipment	**(916)**	(923)
Risk management assets and liabilities, net	**(144)**	(24)
Employee future benefits and compensation plans	**68**	60
Interest deductible in future periods	**81**	63
Allowance for doubtful accounts	**–**	18
Foreign exchange differences on U.S.-denominated debt	**48**	6
Deferred coal rights revenue	**14**	13
Other deductible temporary differences	**2**	7
Net deferred income tax liability, before writedown of deferred income tax assets	**(30)**	(24)
Writedown of deferred income tax assets	**(359)**	(317)
Net deferred income tax liability, after writedown of deferred income tax assets	**(389)**	(341)

The net deferred income tax liability is presented in the Consolidated Statements of Financial Position as follows:

As at Dec. 31	2014	2013
Deferred income tax assets[1]	**45**	118
Deferred income tax liabilities	**(434)**	(459)
Net deferred income tax liability	**(389)**	(341)

1 The deferred income tax assets presented on the Consolidated Statements of Financial Position are recoverable based on estimated future earnings and tax planning strategies. The assumptions used in the estimate of future earnings are based on the Corporation's long-range forecasts.

D. Contingencies

As of Dec. 31, 2014, the Corporation had recognized a net liability of $7 million (2013 – $8 million) related to uncertain tax positions. The change in the liability for uncertain tax positions is as follows:

Balance, Dec. 31, 2012	(9)
Increase as a result of tax positions taken during a prior period	(3)
Decrease as a result of settlements with taxation authorities	4
Balance, Dec. 31, 2013	(8)
Decrease as a result of settlements with taxation authorities	1
Balance, Dec. 31, 2014	**(7)**

11. Non-Controlling Interests

The Corporation's subsidiaries and operations that have non-controlling interests are as follows:

Subsidiary/Operation	Non-controlling interest owned by
TransAlta Cogeneration L.P.	49.99% – Canadian Power Holdings Inc.
TransAlta Renewables	29.70% – Public shareholders[1]
Kent Hills wind farm[2]	17% – Natural Forces Technologies Inc.

1 As at Dec. 31, 2013, the non-controlling interest was 19.3%.
2 Owned by TransAlta Renewables.

TransAlta Cogeneration, L.P. operates a portfolio of cogeneration facilities in Canada and owns 50 per cent of a coal facility. TransAlta Renewables owns and operates a portfolio of 28 renewable power generation facilities in Canada and owns an economic interest in a wind facility in the U.S.

Summarized financial information relating to subsidiaries with significant non-controlling interests is as follows:

A. TransAlta Cogeneration L.P.

Year ended Dec. 31	**2014**	2013	2012
Revenues	**305**	295	306
Net earnings	**71**	48	69
Total comprehensive income	**72**	71	57
Amounts attributable to the non-controlling interest:			
Net earnings	**35**	24	34
Total comprehensive income	**35**	36	28
Distributions paid to Canadian Power Holdings Inc.	**56**	46	55

As at Dec. 31	**2014**	2013
Current assets	**58**	56
Long-term assets	**588**	632
Current liabilities	**(64)**	(56)
Long-term liabilities	**(59)**	(68)
Total equity	**(523)**	(564)
Equity attributable to Canadian Power Holdings Inc.	**(260)**	(280)

B. TransAlta Renewables

On May 28, 2013, the Corporation formed a new subsidiary, TransAlta Renewables, to provide investors with the opportunity to invest directly in a highly contracted portfolio of renewable power generation facilities. The Corporation retains control over TransAlta Renewables, and therefore consolidates TransAlta Renewables.

On Aug. 9, 2013, the Corporation transferred 28 indirectly owned wind and hydroelectric generating assets to TransAlta Renewables through the sale of all the issued and outstanding shares of two subsidiaries: Canadian Hydro Developers, Inc. ("CHD") and Western Sustainable Power Inc. On Aug. 29, 2013, TransAlta Renewables completed an Initial Public Offering and issued 22.1 million common shares for gross proceeds of $221 million. After completion of these transactions and at Dec. 31, 2013, the Corporation owned 92.6 million common shares of TransAlta Renewables, representing an 80.7 per cent ownership interest. In total, the Corporation received $207 million in cash consideration net of commissions and expenses. The excess of consideration received over the net book value of the Corporation's divested interest was $4 million and was recognized in retained earnings (deficit).

On April 29, 2014, the Corporation completed a secondary offering of 11,950,000 common shares of TransAlta Renewables at a price of $11.40 per common share. The offering resulted in gross proceeds to the Corporation of approximately $136 million. Following completion of the offering and at Dec. 31, 2014, TransAlta owns approximately 70.3 per cent of the common shares of TransAlta Renewables. As a result of the transaction, the carrying amount of the non-controlling interests was increased by $109 million to reflect the approximate 10.4 per cent increase in their relative interest in TransAlta Renewables and a $20 million gain, net of tax and issuance costs, attributable to common shareholders, was recognized directly in retained earnings (deficit).

Non-controlling interest in TransAlta Renewables arose on formation of the subsidiary in August 2013, and 2012 comparative information is, therefore, not provided. The net earnings, distributions, and equity attributable to non-controlling interests includes the 17 per cent non-controlling interest in the 150 MW Kent Hills wind farm, located in New Brunswick.

Year ended Dec. 31	**2014**	2013
Revenues	**233**	245
Net earnings	**52**	53
Total comprehensive income	**52**	54
Amounts attributable to the non-controlling interests:		
Net earnings and total comprehensive income	**15**	5
Distributions paid to non-controlling interests	**28**	9

As at Dec. 31	**2014**	2013
Current assets	**61**	59
Long-term assets	**1,903**	1,954
Current liabilities	**(241)**	(100)
Long-term liabilities	**(682)**	(846)
Total equity	**(1,041)**	(1,067)
Equity attributable to non-controlling interests	**(334)**	(237)

12. Trade and Other Receivables

As at Dec. 31	**2014**	2013
Gross trade accounts receivable	**415**	522
Allowance for doubtful accounts	**-**	(49)
Net trade receivables	**415**	473
Income taxes receivable	**5**	8
Current portion of finance lease receivables *(Note 7)*	**5**	3
Collateral paid *(Note 14)*	**25**	20
Trade and other receivables	**450**	504

The change in the allowance for doubtful accounts is as follows:

Balance, Dec. 31, 2012	46
Change in foreign exchange rates	3
Balance, Dec. 31, 2013	49
Change in foreign exchange rates	7
Settlement of California claim *(Note 8)*	(56)
Balance, Dec. 31, 2014	-

13. Financial Instruments

A. Financial Assets and Liabilities – Classification and Measurement

Financial assets and financial liabilities are measured on an ongoing basis at cost, fair value, or amortized cost *(see Note 2(C))*. The following table outlines the carrying amounts and classifications of the financial assets and liabilities:

Carrying value as at Dec. 31, 2014

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents	–	–	43	–	43
Trade and other receivables	–	–	450	–	450
Long-term portion of finance lease receivables	–	–	403	–	403
Risk management assets					
Current	93	180	–	–	273
Long-term	393	9	–	–	402
Financial liabilities					
Accounts payable and accrued liabilities	–	–	–	481	481
Dividends payable	–	–	–	55	55
Risk management liabilities					
Current	39	89	–	–	128
Long-term	75	19	–	–	94
Long-term debt and finance lease obligations[1]	–	–	–	4,056	4,056

Carrying value as at Dec. 31, 2013 *(Restated – see Note 3(B))*

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents	–	–	42	–	42
Trade and other receivables	–	–	504	–	504
Long-term portion of finance lease receivables	–	–	377	–	377
Risk management assets					
Current	17	96	–	–	113
Long-term	90	26	–	–	116
Financial liabilities					
Accounts payable and accrued liabilities	–	–	–	447	447
Dividends payable	–	–	–	85	85
Risk management liabilities					
Current	20	65	–	–	85
Long-term	72	31	–	–	103
Long-term debt and finance lease obligations[1]	–	–	–	4,347	4,347

1 *Includes current portion.*

B. Fair Value of Financial Instruments

The fair value of a financial instrument is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair values can be determined by reference to prices for that instrument in active markets to which the Corporation has access. In the absence of an active market, the Corporation determines fair values based on valuation models or by reference to other similar products in active markets.

Fair values determined using valuation models require the use of assumptions. In determining those assumptions, the Corporation looks primarily to external readily observable market inputs. However, if not available, the Corporation uses inputs that are not based on observable market data.

I. Levels I, II, and III Fair Value Measurements and Transfers between Fair Value Levels

The Level I, II, and III classifications in the fair value hierarchy utilized by the Corporation are defined below. The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based on the lowest level input that is significant to the derivation of the fair value.

a. 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 at the measurement date. In determining Level I fair values, the Corporation uses quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange.

b. Level II

Fair values are determined, directly or indirectly, using inputs that are observable for the asset or liability.

Fair values falling within the Level II category are determined through the use of quoted prices in active markets, which in some cases are adjusted for factors specific to the asset or liability, such as basis, credit valuation, and location differentials. The Corporation's commodity risk management Level II financial instruments include over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models and regression or extrapolation formulas, where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets, and implied volatilities for options.

In determining Level II fair values of other risk management assets and liabilities and long-term debt measured and carried at fair value, the Corporation uses observable inputs other than unadjusted quoted prices that are observable for the asset or liability, such as interest rate yield curves and currency rates. For certain financial instruments where insufficient trading volume or lack of recent trades exists, the Corporation relies on similar interest or currency rate inputs and other third-party information such as credit spreads.

c. *Level III*

Fair values are determined using inputs for the asset or liability that are not readily observable.

The Corporation may enter into commodity transactions for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques such as the Black-Scholes, mark-to-forecast, and historical bootstrap models with inputs that are based on historical data such as unit availability, transmission congestion, demand profiles for individual non-standard deals and structured products, and/or volatilities and correlations between products derived from historical prices.

The Corporation also has various contracts with terms that extend beyond a liquid trading period. As forward market prices are not available for the full period of these contracts, the value of these contracts is derived by reference to a forecast that is based on a combination of external and internal fundamental modelling, including discounting. As a result, these contracts are classified in Level III.

The Corporation has a Commodity Exposure Management Policy (the "Policy"), which governs both the commodity transactions undertaken in its proprietary trading business and those undertaken to manage commodity price exposures in its generation business. The Policy defines and specifies the controls and management responsibilities associated with commodity trading activities, as well as the nature and frequency of required reporting of such activities.

Methodologies and procedures regarding commodity risk management Level III fair value measurements are determined by the Corporation's risk management department. Level III fair values are calculated within the Corporation's energy trading risk management system based on underlying contractual data as well as observable and non-observable inputs. Development of non-observable inputs requires the use of judgment. To ensure reasonability, system-generated Level III fair value measurements are reviewed and validated by the risk management and finance departments. Review occurs formally on a quarterly basis or more frequently if daily review and monitoring procedures identify unexpected changes to fair value or changes to key parameters.

The effect of using reasonably possible alternative assumptions as inputs to valuation techniques from which the Level III commodity risk management financial instruments fair values are determined at Dec. 31, 2014 is estimated to be a +/- $120 million (2013 +/- $105 million) impact to the carrying value of the financial instruments. Fair values are stressed for volumes and prices. An amount of +/- $92 million (2013 +/- $87 million) in the stress value stems from a long-dated power sale contract that is designated as a cash flow hedge, while the remaining +/-$28 million (2013 +/- $18 million) accounts for the rest of the portfolio. The variable volumes are stressed up and down one standard deviation from historically available production data. Prices are stressed for longer-term deals where there are no liquid market quotes using various internal and external forecasting sources to establish a high and a low price range.

Information about the significant unobservable inputs used in determining Level III fair values is as follows:

Description	Effects on fair value as at Dec. 31, 2014	Valuation technique	Unobservable input	Range
Unit contingent power purchases	(53)	Historical bootstrap	Price discount Volumetric discount[1]	0.3-1.5 per cent 0-10 per cent
Long-term power sale – Alberta	(13)	Long-term price forecast	Illiquid future power prices (per MWh)	$91-$99
Long-term power sale – U.S.	511	Long-term price forecast	Illiquid future power prices (per MWh)	U.S.$41-U.S.$50
Coal supply revenue sharing	(1)	Black-Scholes and exotic valuation techniques	Volumes (MWh) Illiquid commodity forward price volatilities Illiquid future power prices (per MWh) Illiquid future coal prices (per ton)	17-25 per cent of available generation 13-36 per cent U.S.$22-U.S.$62 U.S.$14-U.S.$16
Unit contingent power sales	(3)	Black-Scholes	Illiquid commodity forward price volatilities	32-67 per cent
Transmission and financial transmission rights	(1)	Historical bootstrap	Illiquid forward power price spreads (per MWh)	U.S.$(12)-U.S.$13 and $0-$6
Structured products in Eastern markets	3	Option valuation techniques and historical bootstrap	Implied volatilities Correlations Non-standard shape factors	26-86 per cent 53-82 per cent 69-103 per cent

1 *A change in the volumetric discount, could, depending on other market dynamics, result in a directionally similar change in the price discount.*

Description	Effects on fair value as at Dec. 31, 2013	Valuation technique	Unobservable input	Range
Unit contingent power purchases	43	Historical bootstrap	Price discount Volumetric discount[1]	0-2 per cent 0-14 per cent
Long-term power sale – Alberta	(9)	Long-term price forecast	Illiquid future power prices (per MWh)	$52-$91
Long-term power sale – U.S.	234	Long-term price forecast	Illiquid future power prices (per MWh)	U.S.$32-U.S.$79
Coal supply revenue sharing	(12)	Black-Scholes	Volumes (MWh) Illiquid future implied volatilities in MidC power	18-25 per cent of available generation 35 per cent
Unit contingent power sales	(5)	Black-Scholes	Illiquid commodity forward price volatilities	55 per cent

1 *A change in the volumetric discount, could, depending on other market dynamics, result in a directionally similar change in the price discount.*

The effects on fair values of significant unobservable inputs exclude the effects of observable inputs such as liquidity and credit discounts.

d. *Transfers between Fair Value Levels*

Fair value Level transfers can occur where the availability of inputs that are used to determine fair values have changed. A transfer from Level III to Level II occurs where inputs that were not readily observable have become observable during the period. The Corporation's policy is for Level transfers to occur at the end of each period. During 2014, there were no (2013 – $28 million) fair value transfers from Level III net commodity risk management assets to Level II net commodity risk management assets. During 2013, the contract terms were determined to be within a liquid trading period where observable prices were available. Previously, the trade terms of these contracts were beyond a liquid trading period where forward price forecasts were not available for the full period of the contract.

II. Commodity Risk Management Assets and Liabilities

Commodity risk management assets and liabilities include risk management assets and liabilities that are used in the Energy Marketing and Generation segments in relation to trading activities and certain contracting activities. To the extent applicable, changes in net risk management assets and liabilities for non-hedge positions are reflected within earnings of the Energy Marketing and Generation business segments.

The following table summarizes the key factors impacting the fair value of the commodity risk management assets and liabilities by classification level during the years ended Dec. 31, 2014 and 2013, respectively:

	Hedges			**Non-Hedges**			**Total**		
	Level I	**Level II**	**Level III**	**Level I**	**Level II**	**Level III**	**Level I**	**Level II**	**Level III**
Net risk management assets (liabilities) at Dec. 31, 2013	–	(66)	55	–	14	11	–	(52)	66
Changes attributable to:									
Market price changes on existing contracts	–	(13)	260	–	6	20	–	(7)	280
Market price changes on new contracts	–	3	–	–	131	(80)	–	134	(80)
Contracts settled	–	17	(1)	–	29	(48)	–	46	(49)
Net risk management assets (liabilities) at Dec. 31, 2014	**–**	**(59)**	**314**	**–**	**180**	**(97)**	**–**	**121**	**217**
Additional Level III information:									
Gains recognized in OCI			260			–			260
Total gains (losses) included in earnings before income taxes			1			(60)			(59)
Unrealized losses included in earnings before income taxes relating to net liabilities held at Dec. 31, 2014			–			(108)			(108)

	Hedges			Non-Hedges			Total		
	Level I	Level II	Level III	Level I	Level II	Level III	Level I	Level II	Level III
Net risk management assets (liabilities) at Dec. 31, 2012	–	(63)	3	(1)	79	28	(1)	16	31
Changes attributable to:									
Market price changes on existing contracts	–	(18)	(6)	–	(21)	26	–	(39)	20
Market price changes on new contracts	–	5	58	–	(21)	(1)	–	(16)	57
Contracts settled	–	10	–	1	(51)	(14)	1	(41)	(14)
Transfers out of Level III	–	–	–	–	28	(28)	–	28	(28)
Net risk management assets (liabilities) at Dec. 31, 2013	–	(66)	55	–	14	11	–	(52)	66
Additional Level III information:									
Gains recognized in OCI			52			–			52
Total gains included in earnings before income taxes			–			25			25
Unrealized gains included in earnings before income taxes relating to net assets held at Dec. 31, 2013			–			11			11

III. Other Risk Management Assets and Liabilities

Other risk management assets and liabilities primarily include risk management assets and liabilities that are used in hedging non-energy marketing transactions, such as interest rates, the net investment in foreign operations, and other foreign currency risks. Changes in other risk management assets and liabilities related to hedge positions are reflected within net earnings when such transactions have settled during the period or when ineffectiveness exists in the hedging relationship.

Other risk management assets and liabilities, with total net value of $115 million as at Dec. 31, 2014 (2013 – $27 million), are classified as Level II fair value measurements.

IV. Other Financial Assets and Liabilities

The fair value of financial liabilities measured at other than fair value is as follows:

	Fair value				Total
	Level I	Level II	Level III	Total	carrying value
Long-term debt[1] – Dec. 31, 2014	**–**	**4,091**	**–**	**4,091**	**3,918**
Long-term debt[1] – Dec. 31, 2013	–	4,367	–	4,367	4,262

1 *Includes current portion and excludes $64 million (Dec. 31, 2013 – $60 million) of debt measured and carried at fair value.*

The fair values of the Corporation's debentures and senior notes are determined using prices observed in secondary markets. Non-recourse and other long-term debt fair values are determined by calculating an implied price based on a current assessment of the yield to maturity.

The carrying amount of other short-term financial assets and liabilities (cash and cash equivalents, trade accounts receivable, collateral paid, accounts payable and accrued liabilities, collateral received, and dividends payable) approximates fair value due to the liquid nature of the asset or liability.

C. Inception Gains and Losses

The majority of derivatives traded by the Corporation are based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using inputs that are not readily observable. Refer to *Note 13(B)* for fair value Level III valuation techniques used. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the "transaction price") and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings (loss) only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the Consolidated Statements of Financial Position in risk management assets or liabilities, and is recognized in net earnings (loss) over the term of the related contract. The difference between the transaction price and the fair value determined using a valuation model, yet to be recognized in net earnings (loss), and a reconciliation of changes is as follows:

As at Dec. 31	2014	2013	2012
Unamortized net gain at beginning of year	**160**	5	4
New inception gains	**23**	156	3
Amortization recorded in net earnings during the year	**5**	(1)	(2)
Unamortized net gain at end of year	**188**	160	5

During 2013, the Corporation finalized a contract to sell power in the U.S. Pacific Northwest region. The contract was designated as an all-in-one cash flow hedge. As a result, the contract was recognized as a risk management asset at fair value. The fair value was classified as Level III, which resulted in the recognition of an inception gain. The inception gain was deferred and recorded as an offset to the risk management asset.

14. Risk Management Activities

A. Net Risk Management Assets and Liabilities

Aggregate net risk management assets and liabilities are as follows:

As at Dec. 31, 2014

	Net investment hedges	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total
Commodity risk management					
Current	–	(2)	–	93	91
Long-term	–	257	–	(10)	247
Net commodity risk management assets	–	255	–	83	338
Other					
Current	–	56	–	(2)	54
Long-term	–	55	6	–	61
Net other risk management assets (liabilities)	–	111	6	(2)	115
Total net risk management assets	–	366	6	81	453

As at Dec. 31, 2013 *(Restated – see Note 3(B))*

	Net investment hedges	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total
Commodity risk management					
Current	–	(15)	–	30	15
Long-term	–	4	–	(5)	(1)
Net commodity risk management assets (liabilities)	–	(11)	–	25	14
Other					
Current	1	11	–	1	13
Long-term	–	7	7	–	14
Net other risk management assets	1	18	7	1	27
Total net risk management assets	1	7	7	26	41

Additional information on derivative instruments has been presented on a net basis below.

I. Netting Arrangements

Information about the Corporation's financial assets and liabilities that are subject to enforceable master netting arrangements or similar agreements is as follows:

As at Dec. 31	**2014**				2013			
	Current financial assets	**Long-term financial assets**	**Current financial liabilities**	**Long-term financial liabilities**	Current financial assets	Long-term financial assets	Current financial liabilities	Long-term financial liabilities
Gross amounts recognized	578	608	(380)	(98)	385	285	(342)	(69)
Gross amounts set-off	(204)	(10)	204	10	(157)	–	156	1
Net amounts as presented in the Consolidated Statements of Financial Position	374	598	(176)	(88)	228	285	(186)	(68)

II. Hedges

a. *Net Investment Hedges*

i. Hedges of Foreign Operations

The Corporation's hedges of its net investment in foreign operations are comprised of U.S.-dollar-denominated long-term debt with a face value of U.S.$580 million (2013 – U.S.$850 million) and the following foreign currency forward contracts:

As at Dec. 31	2014			2013			
Notional amount sold	**Notional amount purchased**	**Fair value asset**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value asset	Maturity
Foreign Currency Forward Contracts							
AUD235	**CAD221**	**–**	**2015**	AUD200	CAD188	1	2014
–	**–**	**–**	**–**	USD10	CAD11	–	2014

During 2014, following the divestiture of CE Gen *(see Note 4)*, the Corporation de-designated U.S.$180 million of U.S.-denominated debt from its net investment hedge of U.S. operations. Reclassification from AOCI of the cumulative translation adjustment of the disposed foreign operation and the related cumulative net investment hedge amounts have been included in the gain on disposition. In 2014, the Corporation also de-designated an additional U.S.$90 million of U.S.-denominated debt from its net investment hedge of other U.S. operations. This change did not impact earnings or AOCI in the period. Prospectively, the de-designated tranches of U.S.-denominated debt are being hedged with foreign currency derivative instruments.

During 2013, the Corporation de-designated $20 million of U.S.-dollar denominated debentures from its net investment hedges.

b. *Cash Flow Hedges*

i. Commodity Risk Management

The Corporation's outstanding commodity derivative instruments designated as hedging instruments are as follows:

As at Dec. 31	2014		2013	
Type *(thousands)*	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**4,977**	**–**	5,977	–
Natural gas *(GJ)*	**963**	**32,113**	963	35,775
Oil *(gallons)*	**–**	**6,720**	–	4,116

During 2014, unrealized pre-tax gains of $3 million (2013 – $1 million, 2012 – nil) were released from AOCI and recognized in earnings due to hedge ineffectiveness for accounting purposes. All designated hedging relationships were effective as of Dec. 31, 2014.

During 2014, unrealized pre-tax gains of $2 million (2013 – nil, 2012 – $90 million gain) related to certain power hedging relationships that were previously de-designated and deemed ineffective for accounting purposes were released from AOCI and recognized in net earnings. The cash flow hedges were in respect of future power production expected to occur between 2012 and 2017. In the first quarter of 2011, the production was assessed as highly probable not to occur based on then forecast prices. These unrealized gains were calculated using then current forward prices that changed between then and the time the contracts settled. Had these hedges not been deemed ineffective for accounting purposes, the revenues associated with these contracts would have been recorded in net earnings when settled, the majority of which occurred during 2012; however, the expected cash flows from these contracts would not change.

As at Dec. 31, 2014, cumulative gains of $3 million related to certain cash flow hedges that were previously de-designated and no longer meet the criteria for hedge accounting continue to be deferred in AOCI and will be reclassified to net earnings as the forecasted transactions occur or immediately if the forecasted transactions are no longer expected to occur.

ii. Foreign Currency Rate Risk Management

The Corporation uses foreign exchange forward contracts to hedge a portion of its future foreign-denominated receipts and expenditures, and both foreign exchange forward contracts and cross-currency swaps to manage foreign exchange exposure on foreign-denominated debt not designated as a net investment hedge.

As at Dec. 31	2014				2013			
Notional amount sold	**Notional amount purchased**	**Fair value asset (liability)**	**Maturity**		Notional amount sold	Notional amount purchased	Fair value asset (liability)	Maturity
Foreign Exchange Forward Contracts – foreign-denominated receipts/expenditures								
CAD194	**USD180**	**16**	**2015–2018**		CAD220	USD205	2	2014–2018
AUD49	**JPY4,522**	**(1)**	**2015–2017**		–	–	–	–
USD4	**CAD4**	**–**	**2015**		USD4	CAD4	–	2014
CAD2	**EUR2**	**–**	**2015**		CAD3	EUR2	–	2014
Foreign Exchange Forward Contracts – foreign-denominated debt								
CAD59	**USD50**	**–**	**2015**		CAD52	USD50	2	2014
–	**–**	**–**	**–**		CAD106	USD100	1	2014
–	**–**	**–**	**–**		CAD310	USD300	9	2014
–	**–**	**–**	**–**		USD100	CAD107	–	2014
–	**–**	**–**	**–**		CAD22	USD20	–	2014
Cross-Currency Swaps – foreign-denominated debt								
CAD530	**USD500**	**50**	**2015**		CAD530	USD500	4	2015
CAD434	**USD400**	**28**	**2017**		–	–	–	–
CAD192	**USD180**	**18**	**2018**		–	–	–	–

iii. Effect of Cash Flow Hedges

The following tables summarize the pre-tax amounts recognized in and reclassified out of OCI related to cash flow hedges:

Year ended Dec. 31, 2014					
	Effective portion			**Ineffective portion**	
Derivatives in cash flow hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss reclassified from OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss recognized in earnings**
		Revenue	**24**	Revenue	**(3)**
Commodity contracts	**212**	Fuel and purchased power	**14**	Fuel and purchased power	**–**
Foreign exchange forwards on commodity contracts	**14**	Revenue	**(1)**	Revenue	**–**
Foreign exchange forwards on project hedges	**(1)**	Property, plant, and equipment	**–**	Foreign exchange (gain) loss	**–**
Foreign exchange forwards on U.S. debt	**(9)**	Foreign exchange (gain) loss	**6**	Foreign exchange (gain) loss	**–**
Cross-currency swaps	**89**	Foreign exchange (gain) loss	**(94)**	Foreign exchange (gain) loss	**–**
Forward starting interest rate swaps	**–**	Interest expense	**6**	Interest expense	**–**
OCI impact	**305**	**OCI impact**	**(45)**	**Net earnings impact**	**(3)**

Year ended Dec. 31, 2013

	Effective portion			Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
		Revenue	17	Revenue	(2)
Commodity contracts	11	Fuel and purchased power	19	Fuel and purchased power	–
Foreign exchange forwards on commodity contracts	11	Revenue	2	Revenue	–
Foreign exchange forwards on project hedges	–	Property, plant, and equipment	2	Foreign exchange (gain) loss	–
Foreign exchange forwards on U.S. debt	33	Foreign exchange (gain) loss	(38)	Foreign exchange (gain) loss	–
Cross-currency swaps	33	Foreign exchange (gain) loss	(29)	Foreign exchange (gain) loss	–
Forward starting interest rate swaps	–	Interest expense	6	Interest expense	–
OCI impact	88	OCI impact	(21)	Net earnings impact	(2)

Year ended Dec. 31, 2012

	Effective portion			Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
		Revenue	13	Revenue	(90)
Commodity contracts	36	Fuel and purchased power	2	Fuel and purchased power	–
Foreign exchange forwards on commodity contracts	(3)	Revenue	1	Revenue	–
Foreign exchange forwards on project hedges	(3)	Property, plant, and equipment	7	Foreign exchange (gain) loss	–
Foreign exchange forwards on U.S. debt	(20)	Foreign exchange (gain) loss	30	Foreign exchange (gain) loss	–
Cross-currency swaps	(6)	Foreign exchange (gain) loss	13	Foreign exchange (gain) loss	–
Forward starting interest rate swaps	(15)	Interest expense	2	Interest expense	3
OCI impact	(11)	OCI impact	68	Net earnings impact	(87)

Over the next 12 months, the Corporation estimates that $7 million of after-tax gains will be reclassified from AOCI to net earnings. These estimates assume constant natural gas and power prices, interest rates, and exchange rates over time; however, the actual amounts that will be reclassified may vary based on changes in these factors.

c. Fair Value Hedges

i. Interest Rate Risk Management

The Corporation has converted a portion of its fixed interest rate debt with a rate of 6.65 per cent (2013 – 6.65 per cent) to a floating interest rate based on the U.S. LIBOR rate using interest rate swaps as outlined below:

As at Dec. 31	**2014**		2013		
Notional amount	**Fair value asset**	**Maturity**	Notional amount	Fair value asset	Maturity
USD50	**6**	**2018**	USD50	7	2018

Including the interest rate swaps above, 4 per cent of the Corporation's debt as at Dec. 31, 2014 is subject to floating interest rates (2013 – 21 per cent).

ii. Effects of Fair Value Hedges

The following table summarizes the pre-tax impact on the Consolidated Statements of Earnings (Loss) of fair value hedges, including any ineffective portion:

Year ended Dec. 31		**2014**	2013	2012
Derivatives in fair value hedging relationships	**Location of gain (loss) recognized in earnings**			
Interest rate contracts	Net interest expense	**(1)**	(2)	(16)
Long-term debt	Net interest expense	**1**	2	15
Earnings (loss) impact		**–**	–	(1)

III. Non-Hedges

The Corporation enters into various derivative transactions as well as other contracting activities that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting. As a result, the related assets and liabilities are classified as held for trading. The net realized and unrealized gains or losses from changes in the fair value of these derivatives are reported in earnings in the period the change occurs.

a. Commodity Risk Management

As at Dec. 31	**2014**		2013	
Type *(thousands)*	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**30,821**	**23,685**	34,741	24,456
Natural gas *(GJ)*	**156,898**	**198,969**	215,730	224,661
Emissions *(tonnes)*	**50**	**75**	70	70
Heating oil *(gallons)*	**–**	**–**	–	9,576

b. Other Non-Hedge Derivatives

As at Dec. 31	**2014**			2013			
Notional amount sold	**Notional amount purchased**	**Fair value asset (liability)**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value asset	Maturity
Foreign Exchange Forward Contracts							
CAD264	**USD227**	**1**	**2015**	CAD91	USD85	1	2014
AUD63	**CAD61**	**1**	**2015**	–	–	–	–
AUD47	**USD40**	**3**	**2015-2016**	–	–	–	–
AUD10	**EUR7**	**–**	**2015**	–	–	–	–
Derivatives embedded in supplier contracts[1]							
USD40	**AUD47**	**(7)**	**2015-2016**	–	–	–	–
EUR7	**AUD10**	**–**	**2015**	–	–	–	–

1 *Result from payments that are not denominated in the functional currency of either party under a contract with a supplier.*

c. *Total Return Swaps*

The Corporation has certain compensation and deferred and restricted share unit programs, the values of which depend on the common share price of the Corporation. The Corporation has fixed a portion of the settlement cost of these programs by entering into a total return swap for which hedge accounting has not been applied. The total return swap is cash settled every quarter based upon the difference between the fixed price and the market price of the Corporation's common shares at the end of each quarter.

d. *Effect of Non-Hedges*

For the year ended Dec. 31, 2014, the Corporation recognized a net unrealized gain of $46 million (2013 – loss of $40 million, 2012 – loss of $123 million) related to commodity derivatives.

For the year ended Dec. 31, 2014, a gain of $10 million (2013 – gain of $8 million, 2012 – loss of $4 million) related to foreign exchange and other derivatives was recognized and is comprised of a net unrealized gain of $2 million (2013 – loss of $1 million, 2012 – gain of $1 million) and a net realized gain of $8 million (2013 – gain of $9 million, 2012 – loss of $5 million).

B. Nature and Extent of Risks Arising from Financial Instruments

The following discussion is limited to the nature and extent of risks arising from financial instruments.

I. Market Risk

a. *Commodity Price Risk*

The Corporation has exposure to movements in certain commodity prices in both its electricity generation and proprietary trading businesses, including the market price of electricity and fuels used to produce electricity. Most of the Corporation's electricity generation and related fuel supply contracts are considered to be contracts for delivery or receipt of a non-financial item in accordance with the Corporation's expected own use requirements and are not considered to be financial instruments. As such, the discussion related to commodity price risk is limited to the Corporation's proprietary trading business and commodity derivatives used in hedging relationships associated with the Corporation's electricity generating activities.

i. Commodity Price Risk – Proprietary Trading

The Corporation's Energy Marketing Segment conducts proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue, and gain market information.

In compliance with the Policy, proprietary trading activities are subject to limits and controls, including Value at Risk ("VaR") limits. The Board approves the limit for total VaR from proprietary trading activities. VaR is the most commonly used metric employed to track and manage the market risk associated with trading positions. A VaR measure gives, for a specific confidence level, an estimated maximum pre-tax loss that could be incurred over a specified period of time. VaR is used to determine the potential change in value of the Corporation's proprietary trading portfolio, over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations. VaR is estimated using the historical variance/covariance approach.

VaR is a measure that has certain inherent limitations. The use of historical information in the estimate assumes that price movements in the past will be indicative of future market risk. As such, it may only be meaningful under normal market conditions. Extreme market events are not addressed by this risk measure. In addition, the use of a three-day measurement period implies that positions can be unwound or hedged within three days, although this may not be possible if the market becomes illiquid.

The Corporation recognizes the limitations of VaR and actively uses other controls, including restrictions on authorized instruments, volumetric and term limits, stress-testing of individual portfolios and of the total proprietary trading portfolio, and management reviews when loss limits are triggered.

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at Dec. 31, 2014 associated with the Corporation's proprietary trading activities was $5 million (2013 – $2 million, 2012 – $2 million).

ii. Commodity Price Risk – Generation

The Generation Segment utilizes various commodity contracts to manage the commodity price risk associated with electricity generation, fuel purchases, emissions, and byproducts, as considered appropriate. A Commodity Exposure Management Policy is prepared and approved annually, which outlines the intended hedging strategies associated with the Corporation's generation assets and related commodity price risks. Controls also include restrictions on authorized instruments, management reviews on individual portfolios, and approval of asset transactions that could add potential volatility to the Corporation's reported net earnings.

TransAlta has entered into various contracts with other parties whereby the other parties have agreed to pay a fixed price for electricity to TransAlta. While not all of the contracts create an obligation for the physical delivery of electricity to other parties, the Corporation has the intention and believes it has sufficient electrical generation available to satisfy these contracts and, where able, has designated these as cash flow hedges for accounting purposes.

As a result, changes in market prices associated with these cash flow hedges do not affect net earnings in the period in which the price change occurs. Instead, changes in fair value are deferred until settlement through AOCI, at which time the net gain or loss resulting from the combination of the hedging instrument and hedged item affects net earnings.

VaR at Dec. 31, 2014 associated with the Corporation's commodity derivative instruments used in generation hedging activities was $27 million (2013 – $42 million, 2012 – $5 million).

On asset-backed physical transactions, the Corporation's policy is to seek own use contract status or hedge accounting treatment. For positions and economic hedges that do not meet hedge accounting requirements or for short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at Dec. 31, 2014 associated with these transactions was $7 million (2013 – $11 million, 2012 – $9 million).

b. *Interest Rate Risk*

Interest rate risk arises as the fair value or future cash flows of a financial instrument can fluctuate because of changes in market interest rates. Changes in interest rates can impact the Corporation's borrowing costs and the capacity payments received under the PPAs. Changes in the cost of capital may also affect the feasibility of new growth initiatives.

The possible effect on net earnings and OCI, due to changes in market interest rates affecting the Corporation's floating rate debt, interest-bearing assets, financial instruments measured at fair value through profit or loss, and hedging interest rate derivatives, is outlined below. The sensitivity analysis has been prepared using management's assessment that a 15 basis point (2013 – 25 basis point, 2012 – 50 basis point) increase or decrease is a reasonable potential change over the next quarter in market interest rates.

Year ended Dec. 31	**2014**		2013		2012	
	Net earnings increase[1]	**OCI loss**[1]	Net earnings increase[1]	OCI loss[1]	Net earnings increase[1]	OCI loss[1]
Basis point change	**–**	**–**	2	–	4	–

1 *This calculation assumes a decrease in market interest rates. An increase would have the opposite effect.*

c. *Currency Rate Risk*

The Corporation has exposure to various currencies, such as the euro, the U.S. dollar, the Japanese yen, and the Australian dollar, as a result of investments and operations in foreign jurisdictions, the net earnings from those operations, and the acquisition of equipment and services from foreign suppliers.

The foreign currency risk sensitivities outlined below are limited to the risks that arise on financial instruments denominated in currencies other than the functional currency.

The possible effect on net earnings and OCI, due to changes in foreign exchange rates associated with financial instruments denominated in currencies other than the Corporation's functional currency, is outlined below. The sensitivity analysis has been prepared using management's assessment that an average four cent (2013 – five cent, 2012 – five cent) increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter.

Year ended Dec. 31	**2014**		2013		2012	
Currency	**Net earnings increase (decrease)[1]**	**OCI gain[1,2]**	Net earnings increase[1]	OCI gain[1,2]	Net earnings decrease[1]	OCI gain[1,2]
USD	**4**	**5**	2	8	(2)	11
EUR	**–**	**–**	–	–	–	1
AUD	**(2)**	**–**	–	–	–	–
Total	**2**	**5**	2	8	(2)	12

1 *These calculations assume an increase in the value of these currencies relative to the Canadian dollar. A decrease would have the opposite effect.*

2 *The foreign exchange impact related to financial instruments designated as hedging instruments in net investment hedges has been excluded.*

II. Credit Risk

Credit risk is the risk that customers or counterparties will cause a financial loss for the Corporation by failing to discharge their obligations, and the risk to the Corporation associated with changes in creditworthiness of entities with which commercial exposures exist. The Corporation actively manages its exposure to credit risk by assessing the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts. The Corporation makes detailed assessments of the credit quality of all counterparties and, where appropriate, obtains corporate guarantees, cash collateral, and/or letters of credit to support the ultimate collection of these receivables. For commodity trading and origination, the Corporation sets strict credit limits for each counterparty and monitors exposures on a daily basis. TransAlta uses standard agreements that allow for the netting of exposures and often include margining provisions. If credit limits are exceeded, TransAlta will request collateral from the counterparty or halt trading activities with the counterparty. TransAlta is exposed to minimal credit risk for Alberta Coal PPAs as receivables are substantially all secured by letters of credit.

The Corporation uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for counterparties. The following table outlines the distribution, by credit rating, of financial assets as at Dec. 31, 2014:

(Per cent)	**Investment grade**	**Non-investment grade**	**Total**
Accounts receivable	**89**	**11**	**100**
Risk management assets	**100**	**–**	**100**

The Corporation's maximum exposure to credit risk at Dec. 31, 2014, without taking into account collateral held or right of set-off, is represented by the current carrying amounts of accounts receivable and risk management assets as per the Consolidated Statements of Financial Position. Letters of credit and cash are the primary types of collateral held as security related to these amounts. The maximum credit exposure to any one customer for commodity trading operations and hedging, including the fair value of open trading, net of any collateral held, at Dec. 31, 2014 was $29 million (2013 – $23 million).

The Corporation utilizes an allowance for doubtful accounts to record potential credit losses associated with trade receivables. A reconciliation of the account for the year is presented in *Note 12*.

III. Liquidity Risk

Liquidity risk relates to the Corporation's ability to access capital to be used for proprietary trading activities, commodity hedging, capital projects, debt refinancing, and general corporate purposes. Investment grade ratings support these activities and provide better access to capital markets through commodity and credit cycles. TransAlta is focused on strengthening its financial position and maintaining stable investment grade credit ratings.

Counterparties enter into certain electricity and natural gas purchase and sale contracts for the purposes of asset-backed sales and proprietary trading. The terms and conditions of these contracts may require the counterparties to provide collateral when the fair value of the obligation pursuant to these contracts is in excess of any credit limits granted. Downgrades in creditworthiness by certain credit rating agencies may decrease the credit limits granted and accordingly increase the amount of collateral that may have to be provided.

TransAlta manages liquidity risk by monitoring liquidity on trading positions; preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital; reporting liquidity risk exposure for proprietary trading activities on a regular basis to the Risk Management Committee, senior management, and the Board; and maintaining investment grade credit ratings.

A maturity analysis of the Corporation's net financial liabilities, as at Dec. 31, 2014, is as follows:

	2015	2016	2017	2018	2019	2020 and thereafter	Total
Accounts payable and accrued liabilities	481	–	–	–	–	–	481
Long-term debt[1]	738	29	466	878	402	1,472	3,985
Commodity risk management (assets) liabilities	(74)	(17)	(16)	(24)	(23)	(184)	(338)
Other risk management (assets) liabilities	(53)	(6)	(30)	(26)	–	–	(115)
Interest on long-term debt[2]	178	171	166	129	104	723	1,471
Dividends payable	55	–	–	–	–	–	55
Total	**1,325**	**177**	**586**	**957**	**483**	**2,011**	**5,539**

1 *Excludes impact of hedge accounting and includes drawn credit facilities that are currently scheduled to mature between 2016 and 2018.*

2 *Not recognized as a financial liability on the Consolidated Statements of Financial Position.*

C. Collateral

I. Financial Assets Provided as Collateral

At Dec. 31, 2014, the Corporation provided $25 million (2013 – $20 million) in cash as collateral to regulated clearing agents as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents.

II. Financial Assets Held as Collateral

At Dec. 31, 2014, the Corporation received nil (2013 – nil) in cash collateral associated with counterparty obligations. Under the terms of the contracts, the Corporation may be obligated to pay interest on the outstanding balances and to return the principal when the counterparties have met their contractual obligations, or when the amount of the obligation declines as a result of changes in market value. Interest payable to the counterparties on the collateral received is calculated in accordance with each contract.

III. Contingent Features in Derivative Instruments

Collateral is posted in the normal course of business based on the Corporation's senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Corporation's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs. If a material adverse event resulted in the Corporation's senior unsecured debt falling below investment grade, the counterparties to such derivative instruments could request ongoing full collateralization.

As at Dec. 31, 2014, the Corporation had posted collateral of $73 million (2013 – $94 million) in the form of letters of credit on derivative instruments primarily in a net liability position. Certain derivative agreements contain credit-risk-contingent features, including a credit rating downgrade to below investment grade, which if triggered would result in the Corporation having to post an additional $86 million (2013 – $88 million) of collateral to its counterparties based upon the value of the derivatives at Dec. 31, 2014.

IV. Gain on Sale of Collateral

During September 2012, the Corporation sold, for net proceeds of U.S.$33 million, its claim against MF Global Inc. pertaining to the return of U.S.$36 million of collateral that had been previously posted by the Corporation. As a result, a pre-tax gain of $15 million ($11 million after-tax) was realized in 2012.

In October 2011, MF Global Holdings Ltd. filed for bankruptcy protection in the United States. MF Global Holdings Ltd. is the parent company of MF Global Inc., which was used by TransAlta as a broker-dealer for certain commodity transactions. MF Global Inc. had not filed for bankruptcy in 2011 but, under the U.S. *Securities Investor Protection Act of 1970*, the Securities Investor Protection Corp. was overseeing a liquidation of the broker-dealer to return assets to customers. The Corporation's claim, filed during the first quarter of 2012, related primarily to the Corporation's collateral on foreign futures transactions.

15. Inventory

Inventory held in the normal course of business, which includes coal, emission credits, and natural gas, is valued at the lower of cost and net realizable value. Inventory held for Energy Marketing, which includes natural gas and emission credits and allowances, is valued at fair value less costs to sell.

The components of inventory are as follows:

As at Dec. 31	2014	2013
Coal	**39**	53
Deferred stripping costs	**15**	13
Natural gas	**12**	5
Purchased emission credits	**5**	6
Total	**71**	77

The change in inventory is as follows:

Balance, Dec. 31, 2012	93
Net additions	7
Writedowns	(22)
Change in foreign exchange rates	(1)
Balance, Dec. 31, 2013	77
Net additions	14
Writedowns	(19)
Change in foreign exchange rates	(1)
Balance, Dec. 31, 2014	**71**

No inventory is pledged as security for liabilities.

16. Investments

Until February 2014, the Corporation's investments in joint ventures included investments in CE Gen, Wailuku, and CalEnergy LLC. See *Note 4* for further details regarding the divestitures.

The change in investments is as follows:

Balance, Dec. 31, 2012	172
Equity loss	(10)
Equity contribution	17
Change in foreign exchange rates	13
Balance, Dec. 31, 2013	192
Change in foreign exchange rates	4
Divestitures *(Note 4)*	(196)
Balance, Dec. 31, 2014	**-**

17. Property, Plant, and Equipment

A reconciliation of the changes in the carrying amount of property, plant, and equipment is as follows:

	Land	Coal generation	Gas generation	Renewable generation	Mining property and equipment	Assets under construction	Capital spares and other[1]	Total
Cost								
As at Dec. 31, 2012	75	5,384	1,870	2,536	959	342	315	11,481
Additions	–	–	–	–	–	534	27	561
Additions – finance lease	–	–	–	–	33	–	–	33
Acquisition of Wyoming wind farm *(Note 4)*	–	–	–	78	–	–	1	79
Disposals	(1)	–	–	–	(3)	–	–	(4)
Impairment (charges) reversals *(Note 6)*	–	–	(1)	21	–	–	–	20
Revisions and additions to decommissioning and restoration costs	–	(3)	(7)	–	15	–	–	5
Retirement of assets	–	(159)	(13)	(13)	(17)	–	–	(202)
Change in foreign exchange rates	1	65	(26)	–	4	–	1	45
Transfers	2	357	35	235	75	(723)	25	6
As at Dec. 31, 2013	77	5,644	1,858	2,857	1,066	153	369	12,024
Additions	–	3	–	–	–	466	18	487
Additions – finance lease	–	–	–	–	58	–	–	58
Disposals	–	–	(34)	(1)	–	1	–	(34)
Impairment charges *(Note 6)*	–	–	–	(2)	–	–	–	(2)
Impairment reversals *(Note 6)*	–	–	9	2	–	–	–	11
Revisions and additions to decommissioning and restoration costs	–	11	4	(1)	10	–	–	24
Retirement of assets	–	(96)	(20)	(4)	(4)	–	–	(124)
Change in foreign exchange rates	2	92	4	7	4	(6)	3	106
Transfers	3	149	48	24	25	(273)	6	(18)
As at Dec. 31, 2014	**82**	**5,803**	**1,869**	**2,882**	**1,159**	**341**	**396**	**12,532**
Accumulated depreciation								
As at Dec. 31, 2012	–	2,510	874	532	442	–	79	4,437
Depreciation	–	263	99	91	57	–	13	523
Retirement of assets	–	(121)	(10)	(10)	(10)	–	–	(151)
Disposals	–	–	–	–	(3)	–	–	(3)
Change in foreign exchange rates	–	40	(12)	–	2	–	(2)	28
Impairment reversals *(Note 6)*	–	–	–	2	–	–	–	2
Transfers	–	–	(5)	–	–	–	–	(5)
As at Dec. 31, 2013	–	2,692	946	615	488	–	90	4,831
Depreciation	–	272	103	98	55	–	13	541
Retirement of assets	–	(84)	(19)	(1)	(2)	–	–	(106)
Disposals	–	–	(29)	–	–	–	–	(29)
Change in foreign exchange rates	–	61	4	1	3	–	–	69
Impairment reversals *(Note 6)*	–	–	3	–	–	–	–	3
Transfers	–	–	(15)	–	–	–	–	(15)
As at Dec. 31, 2014	**–**	**2,941**	**993**	**713**	**544**	**–**	**103**	**5,294**
Carrying amount								
As at Dec. 31, 2012	75	2,874	996	2,004	517	342	236	7,044
As at Dec. 31, 2013	77	2,952	912	2,242	578	153	279	7,193
As at Dec. 31, 2014	**82**	**2,862**	**876**	**2,169**	**615**	**341**	**293**	**7,238**

1 Includes major spare parts and stand-by equipment available, but not in service, and spare parts used for routine, preventative, or planned maintenance.

The Corporation capitalized $3 million of interest to PP&E in 2014 (2013 – $2 million) at a weighted average rate of 5.75 per cent (2013 – 5.46 per cent).

In 2014, operations began at a processing facility that the Corporation contracted a third party to construct and operate. The facility recovers fine coal out of pond slurry at the Corporation's Centralia mine as part of restoration activities. Recovered coal fines can be used as fuel at the coal plant. As a result of certain contractual provisions, the Corporation recognized a finance lease asset and an obligation in the amount of estimated minimum lease payments of U.S.$34 million, corresponding at inception to the penalties payable by the Corporation if it elects to terminate the agreement. Coal volume and slurry processing payments, net of the amortization and accretion of the financial lease obligation, are deemed to constitute contingent rents under the arrangement. Other finance lease additions are for mining equipment at the Highvale mine.

The carrying amount of total assets under finance leases as at Dec. 31, 2014 was $78 million (2013 – $29 million).

18. Goodwill

Goodwill acquired through business combinations has been allocated to CGUs that are expected to benefit from the synergies of the acquisitions, as follows:

As at Dec. 31	2014	2013
Canadian Renewables and Alberta Merchant	**417**	417
Energy Marketing	**30**	30
U.S. Operations	**15**	13
Total goodwill	**462**	460

For purposes of the 2014 and 2013 annual goodwill impairment review, the Corporation determined the recoverable amount of the Canadian Renewables and Alberta Merchant group of CGUs by calculating the fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts for the period extending to the last planned asset retirement in 2073. The resulting fair value measurement is categorized within Level III of the fair value hierarchy.

The key assumptions impacting the determination of fair value for the Canadian Renewables and Alberta Merchant group of CGUs are electricity production and sales prices. Forecasts of electricity production for each facility are determined taking into consideration contracts for the sale of electricity, historical production, regional supply-demand balances, and capital maintenance and expansion plans. Forecasted sales prices for each facility are determined by taking into consideration contract prices for facilities subject to long- or short-term contracts, forward price curves for merchant plants, and regional supply-demand balances. Where forward price curves are not available for the duration of the facility's useful life, prices are determined by extrapolation techniques using historical industry and company-specific data. Alberta Merchant electricity prices used in the 2014 models ranged between $31 to $276 per MWh during the forecast period (2013 – $41 to $263 per MWh). Discount rates used for the goodwill impairment calculation in 2014 ranged from 5.4 per cent to 6.9 per cent (2013 – 4.9 per cent to 7.1 per cent). No reasonably possible change in the assumptions would have resulted in an impairment of goodwill.

No impairment of goodwill arose in 2014 or 2013.

19. Intangible Assets

A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Coal rights	Software and other	Power contracts	Intangibles under development	Total
Cost					
As at Dec. 31, 2012	158	133	173	40	504
Additions	20	–	–	29	49
Acquisition of Wyoming wind farm *(Note 4)*	–	7	13	–	20
Retirements	–	(10)	–	–	(10)
Transfers	–	50	–	(47)	3
As at Dec. 31, 2013	178	180	186	22	566
Additions	–	8	–	26	34
Retirements	–	(3)	–	–	(3)
Change in foreign exchange rates	–	3	–	–	3
Transfers	–	18	–	(14)	4
As at Dec. 31, 2014	**178**	**206**	**186**	**34**	**604**
Accumulated amortization					
As at Dec. 31, 2012	100	93	27	–	220
Amortization	4	21	8	–	33
Retirements	–	(10)	–	–	(10)
As at Dec. 31, 2013	104	104	35	–	243
Amortization	2	21	8	–	31
Retirements	–	(3)	–	–	(3)
Change in foreign exchange rates	–	2	–	–	2
As at Dec. 31, 2014	**106**	**124**	**43**	**–**	**273**
Carrying amount					
As at Dec. 31, 2012	58	40	146	40	284
As at Dec. 31, 2013	74	76	151	22	323
As at Dec. 31, 2014	**72**	**82**	**143**	**34**	**331**

20. Other Assets

The components of other assets are as follows:

As at Dec. 31	**2014**	2013
Deferred licence fees	**16**	18
Project development costs	**29**	36
Deferred service costs	**18**	19
Long-term prepaids, receivables, and other	**29**	18
Keephills Unit 3 transmission deposit	**6**	6
Total other assets	**98**	97

Deferred licence fees consist primarily of licences to lease the land on which certain generating assets are located, and are amortized on a straight-line basis over the useful life of the generating assets to which the licences relate.

Deferred service costs are TransAlta's contracted payments for shared capital projects required at the Genesee Unit 3 and Keephills Unit 3 sites. These costs are amortized over the life of these projects.

The Keephills Unit 3 transmission deposit is TransAlta's proportionate share of a provincially required deposit. The full amount of the deposit is anticipated to be reimbursed over the next seven years to 2021, as long as certain performance criteria are met.

21. Decommissioning and Other Provisions

The change in decommissioning and other provision balances is as follows:

	Decommissioning and restoration	Restructuring	Other	Total
Balance, Dec. 31, 2012	262	8	42	312
Liabilities incurred	4	–	29	33
Liabilities settled	(24)	(5)	(2)	(31)
Accretion	17	–	1	18
Revisions in estimated cash flows	16	–	2	18
Revisions in discount rates	(12)	–	–	(12)
Reversals[1]	–	(3)	(11)	(14)
Acquisition of Wyoming wind farm *(Note 4)*	3	–	–	3
Change in foreign exchange rates	4	–	1	5
Balance, Dec. 31, 2013	270	–	62	332
Liabilities incurred	3	–	19	22
Liabilities settled	(16)	–	(31)	(47)
Accretion	18	–	–	18
Revisions in estimated cash flows	–	–	3	3
Revisions in discount rates	24	–	–	24
Reversals	–	–	(2)	(2)
Change in foreign exchange rates	6	–	–	6
Balance, Dec. 31, 2014	**305**	**–**	**51**	**356**

1 *The reversal of other provisions includes Sundance Units 1 and 2 and Sundance Unit 3 provisions that were reversed as a result of the conclusions of the respective arbitration decisions in 2012.*

	Decommissioning and restoration	Restructuring	Other	Total
Balance, Dec. 31, 2013	270	–	62	332
Current portion	22	–	5	27
Non-current portion	248	–	57	305
Balance, Dec. 31, 2014	**305**	**–**	**51**	**356**
Current portion	**28**	**–**	**6**	**34**
Non-current portion	**277**	**–**	**45**	**322**

A. Decommissioning and Restoration

A provision has been recognized for all generating facilities and mines for which TransAlta is legally, or constructively, required to remove the facilities at the end of their useful lives and restore the sites to their original condition. TransAlta estimates that the undiscounted amount of cash flow required to settle these obligations is approximately $1.0 billion, which will be incurred between 2015 and 2072. The majority of the costs will be incurred between 2020 and 2050. At Dec. 31, 2014, the Corporation had provided a surety bond in the amount of U.S.$140 million (2013 – U.S.$136 million) in support of future decommissioning obligations at the Centralia coal mine. At Dec. 31, 2014, the Corporation had provided letters of credit in the amount of $115 million (2013 – $115 million) in support of future decommissioning obligations at the Alberta mine. Some of the facilities that are co-located with mining operations do not currently have any decommissioning obligations recorded as the obligations associated with the facilities are indeterminate at this time.

B. Restructuring Provisions

On Oct. 30, 2012, the Corporation announced a restructuring of resources as part of its ongoing strategy to continuously improve operational excellence and accelerate the growth of the company. Approximately 165 positions were eliminated. In 2012, a provision and a related pre-tax restructuring expense of $13 million were recognized. On completion of the restructuring in 2013, the balance of the provision in the amount of $3 million was reversed.

C. Other Provisions

Other provisions include an amount related to a portion of the Corporation's fixed price commitments under several natural gas transportation contracts for firm transportation that is not expected to be used. Accordingly, the unavoidable costs of meeting these obligations exceed the economic benefits expected to be received. The contracts extend to 2018 and 2020.

Other provisions also include provisions arising from ongoing business activities and include amounts related to commercial disputes between the Corporation and customers or suppliers. Information about the expected timing of settlement and uncertainties that could impact the amount or timing of settlement has not been provided as this may impact the Corporation's ability to settle the provisions in the most favourable manner.

22. Long-Term Debt and Finance Lease Obligations

A. Amounts Outstanding

The amounts outstanding are as follows:

As at Dec. 31		**2014**			2013	
	Carrying value	**Face value**	**Interest[1]**	Carrying value	Face value	Interest[1]
Credit facilities[2]	**96**	**96**	**2.8%**	852	852	2.6%
Debentures	**1,043**	**1,051**	**6.1%**	1,269	1,251	6.1%
Senior notes[3]	**2,444**	**2,436**	**4.9%**	1,797	1,809	5.6%
Non-recourse[4]	**380**	**383**	**5.9%**	376	380	5.9%
Other	**19**	**19**	**5.9%**	28	28	6.3%
	3,982	**3,985**		4,322	4,320	
Finance lease obligations	**74**			25		
	4,056			4,347		
Less: current portion of long-term debt	**(738)**			(209)		
Less: current portion of finance lease obligations	**(13)**			(8)		
Total current long-term debt and finance lease obligations	**(751)**			(217)		
Total long-term debt and finance lease obligations	**3,305**			4,130		

1 *Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.*
2 *Composed of bankers' acceptances and other commercial borrowings under long-term committed credit facilities. Foreign-denominated amounts included in the balance are nil at Dec. 31, 2014 and U.S.$300 million at Dec. 31, 2013.*
3 *U.S. face value at Dec. 31, 2014 – U.S.$2.1 billion (Dec. 31, 2013 – U.S.$1.7 billion).*
4 *Includes U.S.$20 million at Dec. 31, 2014 (Dec. 31, 2013 – U.S.$20 million).*

Credit facilities are drawn on the Corporation's $1.5 billion committed syndicated bank credit facility and on the Corporation's U.S.$300 million committed bilateral facility. The $1.5 billion committed syndicated bank facility is the primary source for short-term liquidity after the cash flow generated from the Corporation's business. The Corporation's four-year revolving $1.5 billion committed syndicated credit facility, last renewed in June 2014, matures in 2018. The U.S.$300 million bilateral credit facility has a four-year term to 2017. Interest rates on the credit facilities vary depending on the option selected – Canadian prime, bankers' acceptances, U.S. LIBOR, or U.S. base rate – in accordance with a pricing grid that is standard for such facilities. The Corporation also has $240 million available in committed bilateral credit facilities, which mature in 2016.

Of the $2.1 billion (2013 – $2.1 billion) of committed credit facilities, $1.6 billion (2013 – $0.9 billion) is not drawn, and is available as of Dec. 31, 2014, subject to customary borrowing conditions. In addition to the $1.6 billion available under the credit facilities, TransAlta also has $43 million of available cash and cash equivalents.

Debentures bear interest at fixed rates ranging from 5.0 per cent to 7.3 per cent and have maturity dates ranging from 2019 to 2030. During the second quarter of 2014, the Corporation's $200 million 6.45 per cent medium-term notes matured and were paid out. During 2013, the Corporation issued $400 million of senior unsecured medium-term notes that carry a coupon rate of 5.00 per cent, payable semi-annually, at an issue price equal to 99.516 per cent of the principal amount of the notes.

Senior notes bear interest at rates ranging from 1.90 per cent to 6.65 per cent and have maturity dates ranging from 2015 to 2040. In June 2014, the Corporation issued U.S.$400 million of senior notes due in 2017 that carry a coupon rate of 1.90 per cent, payable semi-annually, at an issue price equal to 99.887 per cent of the principal amount of the notes. A total of U.S.$580 million of the senior notes has been designated as a hedge of the Corporation's net investment in U.S. foreign operations. During 2013, the Corporation's U.S.$300 million 5.75 per cent senior notes matured and were paid out.

Non-recourse debt consists of debentures that have maturity dates ranging from 2015 to 2018 and bear interest at rates ranging from 5.3 per cent to 7.3 per cent.

Other consists of an unsecured commercial loan obligation that bears interest at 5.9 per cent and matures in 2023, requiring annual payments of interest and principal. Notes payable for the Windsor plant matured and were paid out in November 2014.

TransAlta's debt has terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2014, the Corporation was in compliance with all debt covenants.

B. Restrictions

Debentures of $344 million issued by the Corporation's CHD subsidiary include restrictive covenants requiring the proceeds received from the sale of assets to be reinvested into similar renewables assets.

C. Principal Repayments

	2015	2016	2017	2018	2019	2020 and thereafter	Total
Principal repayments[1]	738	29	466	878	402	1,472	**3,985**

1 Excludes impact of derivatives and includes drawn credit facilities that are currently scheduled to mature in 2015 and 2017.

D. Finance Lease Obligations

Amounts payable for mining assets and other finance leases are as follows:

As at Dec. 31	**2014**		2013	
	Minimum lease payments	**Present value of minimum lease payments**	Minimum lease payments	Present value of minimum lease payments
Within one year	**16**	**16**	9	9
Second to fifth years inclusive	**43**	**37**	18	16
More than five years	**30**	**21**	–	–
	89	**74**	27	25
Less: interest costs	**15**	**–**	2	–
Total finance lease obligations	**74**	**74**	25	25
Current portion of finance lease obligations	**13**		8	
Long-term portion of finance lease obligations	**61**		17	
	74		25	

E. Letters of Credit

Letters of credit are issued to counterparties under various contractual arrangements with the Corporation and certain subsidiaries of the Corporation. If the Corporation or its subsidiary does not perform under such contracts, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. Any amounts owed by the Corporation or its subsidiaries under these contracts are reflected in the Consolidated Statements of Financial Position. All letters of credit expire within one year and are expected to be renewed, as needed, in the normal course of business. The total outstanding letters of credit as at Dec. 31, 2014 was $396 million (2013 – $370 million) with no (2013 – nil) amounts exercised by third parties under these arrangements.

23. Defined Benefit Obligation and Other Long-Term Liabilities

The components of defined benefit obligation and other long-term liabilities are as follows:

As at Dec. 31	2014	2013
Defined benefit obligation *(Note 28)*	**226**	200
Deferred coal revenues	**58**	52
Long-term incentive accruals *(Note 27)*	**13**	16
Other	**52**	72
Total	**349**	340

Deferred coal revenues consist of amounts received from the Corporation's Keephills Unit 3 joint operation partner for future coal deliveries. These amounts are being amortized into revenue over the life of the coal supply agreement, since commercial operations of Keephills Unit 3 began on Sept. 1, 2011.

Other includes $12 million (2013 – $13 million) relating to a reimbursement received for costs of the New Richmond terminal station, which is being amortized into revenue over the term of the related PPA, and nil (2013 – $28 million) relating to the California claim *(see Note 8)*.

24. Common Shares

A. Issued and Outstanding

TransAlta is authorized to issue an unlimited number of voting common shares without nominal or par value. Changes in the common shares issued are as follows:

As at Dec. 31	2014		2013	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of year	**268.2**	**2,916**	254.7	2,730
Issued under the dividend reinvestment and share purchase plan	**6.8**	**85**	13.5	186
	275.0	**3,001**	268.2	2,916
Amounts receivable under Employee Share Purchase Plan	**–**	**(2)**	–	(3)
Issued and outstanding, end of year	**275.0**	**2,999**	268.2	2,913

B. Shareholder Rights Plan

The primary objective of the Shareholder Rights Plan is to provide the Board sufficient time to explore and develop alternatives for maximizing shareholder value if a takeover bid is made for the Corporation and to provide every shareholder with an equal opportunity to participate in such a bid. The Shareholder Rights Plan was originally approved in 1992, and has been revised since that time to ensure conformity with current practices. As required, the Shareholder Rights Plan must be put before the Corporation's shareholders every three years for approval, and was last approved on April 23, 2013.

When an acquiring shareholder commences a bid to acquire 20 per cent or more of the Corporation's common shares, other than by way of a Permitted Bid, where the offer is made to all shareholders by way of a takeover bid circular, the rights granted under the Shareholder Rights Plan become exercisable by all shareholders except those held by the acquiring shareholder. Each right will entitle a shareholder, other than the acquiring shareholder, to acquire an additional $200 worth of common shares for $100.

C. Premium Dividend™, Dividend Reinvestment, and Optional Common Share Purchase Plan (the "Plan")

On Feb. 21, 2012, the Corporation added a Premium Dividend™ Component to its existing dividend reinvestment plan. The amended and restated plan provided eligible shareholders with two options: i) to reinvest dividends at a current three per cent discount to the average market price towards the purchase of new common shares of the Corporation (the Dividend Reinvestment Component) or; ii) to receive a premium cash payment equivalent to 102 per cent of the reinvested dividends (the Premium Dividend™ Component).

The Corporation suspended the Premium Dividend™ Component of the Plan following the payment of the quarterly dividend on July 1, 2013. The Corporation's Dividend Reinvestment and Optional Common Share Purchase Plan, separate components of the Plan, remain effective in accordance with their current terms.

On Jan. 1, 2015, 1.9 million common shares were issued for dividends reinvested.

There have been no other transactions involving common shares between the reporting date and the date of completion of these consolidated financial statements.

D. Earnings per Share

Year ended Dec. 31	2014	2013	2012
Net earnings (loss) attributable to common shareholders	141	(71)	(615)
Basic and diluted weighted average number of common shares outstanding	273	264	235
Net earnings (loss) per share attributable to common shareholders, basic and diluted	0.52	(0.27)	(2.62)

E. Dividends

On Jan. 23, 2015, the Corporation declared a quarterly dividend of $0.18 per common share, payable on April 1, 2015.

Dividends per common share declared in 2014 were $0.72 (2013 and 2012 – $1.16).

25. Preferred Shares

A. Issued and Outstanding

All preferred shares issued and outstanding are non-voting cumulative redeemable fixed rate first preferred shares.

As at Dec. 31	2014		2013	
Series	Number of shares *(millions)*	Amount	Number of shares *(millions)*	Amount
Series A	12.0	293	12.0	293
Series C	11.0	269	11.0	269
Series E	9.0	219	9.0	219
Series G	6.6	161	–	–
Issued and outstanding, end of year	38.6	942	32.0	781

The holders are entitled to receive cumulative fixed quarterly cash dividends at a specified rate, as approved by the Board. After an initial period of approximately five years from issuance and every five years thereafter ("Rate Reset Date"), the fixed rate resets to the sum of the then five-year Government of Canada bond yield (the fixed rate "Benchmark") plus a specified spread. Upon each Rate Reset Date, they are also:

- Redeemable at the option of the Corporation, in whole or in part, for $25.00 per share, plus all declared and unpaid dividends at the time of redemption.
- Convertible at the holder's option into a specified series of non-voting cumulative redeemable floating rate first preferred shares that pay cumulative floating rate quarterly cash dividends, as approved by the Board, based on the sum of the then Government of Canada three-month Treasury Bill rate (the floating rate "Benchmark") plus a specified spread. The cumulative floating rate first preferred shares are also redeemable at the option of the Corporation and convertible back into each original cumulative fixed rate first preferred share series, at each subsequent Rate Reset Date, on the same terms as noted above.

Characteristics specific to each first preferred share series as at Dec. 31, 2014, are as follows:

Series	Rate during term	Annual dividend rate per share *($)*	First Rate Reset Date	Rate spread over Benchmark *(per cent)*	Convertible to Series
A	Fixed	1.15	March 31, 2016	2.03	B
B	Floating	–	–	2.03	A
C	Fixed	1.15	June 30, 2017	3.10	D
D	Floating	–	–	3.10	C
E	Fixed	1.25	Sept. 30, 2017	3.65	F
F	Floating	–	–	3.65	E
G[1]	Fixed	1.325	Sept. 30, 2019	3.80	H
H	Floating	–	–	3.80	G

1 *On Aug. 15, 2014, the Corporation completed a public offering of 6.6 million Series G preferred shares for gross proceeds of $165 million (net proceeds of $161 million after issue costs, net of tax effects).*

B. Dividends

The following table summarizes the preferred share dividends declared in 2014, 2013, and 2012:

Series	**2014**	2013	2012
A	**14**	14	14
C[1]	**13**	13	14
E	**11**	11	4
G[2]	**3**	–	–
Total for the year	**41**	38	32

1 *2012 includes dividends of $0.0969 per share ($1 million in total) for the period from Nov. 29, 2011 to Dec. 31, 2011.*
2 *2014 includes dividends for the period from issuance on Aug. 15, 2014 to Dec. 31, 2014.*

On Jan. 23, 2015, the Corporation declared a quarterly dividend of $0.2875 per share on the Series A and Series C preferred shares, $0.3125 per share on the Series E preferred shares, and $0.33125 per share on the Series G preferred shares, all payable March 31, 2015.

26. Accumulated Other Comprehensive Income (Loss)

The components of, and changes in, accumulated other comprehensive income (loss) are as follows:

	2014	2013
Currency translation adjustment		
Opening balance, Jan. 1	**(36)**	(38)
Gains on translating net assets of foreign operations, net of reclassifications to net earnings	**68**	37
Losses on financial instruments designated as hedges of foreign operations, net of reclassifications to net earnings, net of tax[1]	**(51)**	(35)
Balance, Dec. 31	**(19)**	(36)
Cash flow hedges		
Opening balance, Jan. 1	**4**	(37)
Gains on derivatives designated as cash flow hedges, net of reclassifications to net earnings and to non-financial assets, net of tax[2]	**169**	41
Balance, Dec. 31	**173**	4
Employee future benefits		
Opening balance, Jan. 1	**(30)**	(61)
Net actuarial gains (losses) on defined benefit plans, net of tax[3]	**(20)**	31
Balance, Dec. 31	**(50)**	(30)
Accumulated other comprehensive income (loss)	**104**	(62)

1 *Net of income tax recovery of 9 for the year ended Dec. 31, 2014 (2013 – 5 recovery).*
2 *Net of income tax expense of 94 for the year ended Dec. 31, 2014 (2013 – 12 expense).*
3 *Net of income tax recovery of 7 for the year ended Dec. 31, 2014 (2013 – 11 expense).*

27. Share-Based Payment Plans

The Corporation has the following share-based payment plans:

A. Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") Plan

Under the PSU and RSU Plan, grants may be made annually, but are measured and assessed over a three-year performance period. Grants are determined as a percentage of participants' base pay and are converted to PSUs or RSUs on the basis of the Corporation's common share price at the time of grant. Vesting of PSUs is subject to achievement over a three-year period of three performance measures: growth in funds from operation per share, growth in free cash flow per share, and growth in the Corporation's total shareholder return relative to the S&P/TSX Composite Index. RSUs are subject to a three-year cliff-vesting requirement. RSUs and PSUs track the Corporation's share price over the three-year period and accrue dividends as additional units at the same rate as dividends paid on the Corporation's common shares. The Human Resources Committee of the Board has the discretion to determine whether payments on settlement are made through purchase of shares on the open market or in cash. The expense related to this plan is recognized during the period earned, with the corresponding payable recorded in liabilities. The liability is valued at the end of each reporting period using the closing price of the Corporation's common shares on the Toronto Stock Exchange ("TSX").

The pre-tax compensation expense related to PSUs and RSUs was $8 million (2013 – $6 million, 2012 – $1 million), which is included in operations, maintenance, and administration expense in the Consolidated Statements of Earnings (Loss).

B. Deferred Share Unit ("DSU") Plan

Under the DSU plan, members of the Board and executives may, at their option, purchase DSUs using certain components of their fees or pay. A DSU is a notional share that has the same value as one common share of the Corporation and fluctuates based on the changes in the value of the Corporation's common shares in the marketplace. DSUs accrue dividends as additional DSUs at the same rate as dividends are paid on the Corporation's common shares.

DSUs are redeemable in cash and may not be redeemed until the termination or retirement of the Director or executive from the Corporation.

The Corporation accrues a liability and expense for the appreciation in the common share value in excess of the DSU's purchase price and for dividend equivalents earned. The pre-tax compensation expense related to the DSUs was less than $1 million in each of the years ended Dec. 31 2014, 2013, and 2012.

C. Stock Option Plans

The Corporation is authorized to grant employees options to purchase up to an aggregate of 13.0 million common shares at prices based on the market price of the shares on the TSX as determined on the grant date. The Corporation has reserved 13.0 million common shares for issue.

Options granted under the stock option plan may not be exercised until one year after grant and thereafter at an amount not exceeding 25 per cent of the grant per year on a cumulative basis until the fifth year, after which the entire grant may be exercised until the tenth year, which is the expiry date. In Canada, this plan is offered to all full-time and part-time employees below the level of manager. In the U.S., this plan is offered to all full-time and part-time employees. In Australia, options under this plan are not physically granted; rather, employees receive the equivalent value of shares in cash when exercised. This plan is offered to all full-time and part-time employees in Australia below the level of manager.

The total options outstanding and exercisable under these stock option plans at Dec. 31, 2014 are outlined below:

	Options outstanding			Options exercisable	
Range of exercise prices *($ per share)*	**Number outstanding at Dec. 31, 2014** *(millions)*	**Weighted average remaining contractual life** *(years)*	**Weighted average exercise price** *($ per share)*	**Number exercisable at Dec. 31, 2014** *(millions)*	**Weighted average exercise price** *($ per share)*
16.80-24.07	0.8	3.8	21.37	0.8	21.37
31.97-40.12	0.6	3.1	33.03	0.6	33.03
16.80-40.12	**1.4**	**4.5**	**26.20**	**1.4**	**26.20**

No stock options were granted in 2014, 2013, or 2012. The pre-tax expense recognized arising from equity-settled share-based payment transactions was nil (2013 – nil, 2012 – $1 million).

D. Performance Share Ownership Plan ("PSOP")

Under the terms of the PSOP, participants received grants that, after three years, made them eligible to receive a set number of common shares, including the value of reinvested dividends over the period, or cash equivalent up to the maximum of the grant amount plus any accrued dividends thereon.

The granting of PSOP units was discontinued following the 2012-2014 grant and the plan was terminated on Dec. 31, 2014.

In 2014, pre-tax PSOP compensation expense recovery was $7 million (2013 – $6 million recovery, 2012 – $3 million expense), which is included in operations, maintenance, and administration expense. In 2014, no common shares (2013 – nil, 2012 – 55,418 common shares at $15.12 per share) were issued.

E. Employee Share Purchase Plan

Under the terms of the employee share purchase plan, the Corporation will extend an interest-free loan (up to 30 per cent of an employee's base salary) to employees below executive level and allow for payroll deductions over a three-year period to repay the loan. Executives are not eligible for this program in accordance with the Sarbanes-Oxley legislation. An agent purchases these common shares on the open market on behalf of employees at prices based on the market price of the shares as determined on the date of purchase. Employee sales of these shares are handled in the same manner. At Dec. 31, 2014, amounts receivable from employees under the plan totalled $2 million (2013 – $3 million).

28. Employee Future Benefits

A. Description

The Corporation sponsors registered pension plans in Canada and the U.S. covering substantially all employees of the Corporation in these countries and specific named employees working internationally. These plans have defined benefit and defined contribution options, and in Canada there is an additional supplemental defined benefit plan for certain employees whose annual earnings exceed the Canadian income tax limit. Except for the Highvale pension plans acquired in 2013, the Canadian and U.S. defined benefit pension plans are closed to new entrants. The U.S. defined benefit pension plan was frozen effective Dec. 31, 2010, resulting in no future benefits being earned.

The latest actuarial valuations for accounting purposes of the Canadian and U.S. pension plans was at Dec. 31, 2014 and Jan. 1, 2014, respectively. The latest actuarial valuation for accounting purposes of the Highvale pension plan was at Dec. 31, 2013. The measurement date used for all plans to determine the fair value of plan assets and the present value of the defined benefit obligation was Dec. 31, 2014.

Funding of the registered pension plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, or more, depending on funding status, and every year in the United States. The last actuarial valuations for funding purposes of the Canadian registered plans were completed in early 2014 with an effective date of Dec. 31, 2013. The last actuarial valuation for funding purposes of the U.S. pension plan was Jan. 1, 2014.

The supplemental pension plan is solely the obligation of the Corporation. The Corporation is not obligated to fund the supplemental plan but is obligated to pay benefits under the terms of the plan as they come due. The Corporation has posted a letter of credit in the amount of $64 million to secure the obligations under the supplemental plan.

The Corporation provides other health and dental benefits to the age of 65 for both disabled members and retired members through its other post-employment benefits plans. The latest actuarial valuation for accounting purposes of the Canadian and U.S. plans was as at Dec. 31, 2013 and Jan. 1, 2014, respectively. The measurement date used to determine the present value of the defined benefit obligation for both plans was Dec. 31, 2014.

B. Costs Recognized

The costs recognized in net earnings during the year on the defined benefit, defined contribution, and other post-employment benefits plans are as follows:

Year ended Dec. 31, 2014	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**6**	**2**	**2**	**10**
Administration expenses	**2**	**–**	**–**	**2**
Interest cost on defined benefit obligation	**23**	**4**	**1**	**28**
Interest on plan assets	**(18)**	**–**	**–**	**(18)**
Defined benefit expense	**13**	**6**	**3**	**22**
Defined contribution expense	**18**	**–**	**–**	**18**
Net expense	**31**	**6**	**3**	**40**

Year ended Dec. 31, 2013	Registered	Supplemental	Other	Total
Current service cost	6	3	2	11
Administration expenses	2	–	–	2
Interest cost on defined benefit obligation	21	3	1	25
Interest on plan assets	(15)	–	–	(15)
Defined benefit expense	14	6	3	23
Defined contribution expense	18	–	–	18
Net expense	32	6	3	41

Year ended Dec. 31, 2012	Registered	Supplemental	Other	Total
Current service cost	2	2	1	5
Administration expenses	2	–	–	2
Interest cost on defined benefit obligation	18	3	2	23
Interest on plan assets	(13)	–	–	(13)
Defined benefit expense	9	5	3	17
Defined contribution expense	20	–	–	20
Net expense	29	5	3	37

C. Status of Plans

The status of the defined benefit pension and other post-employment benefit plans is as follows:

As at Dec. 31, 2014	**Registered**	**Supplemental**	**Other**	**Total**
Fair value of plan assets	**427**	**8**	**–**	**435**
Present value of defined benefit obligation	**(565)**	**(86)**	**(30)**	**(681)**
Funded status – plan deficit	**(138)**	**(78)**	**(30)**	**(246)**
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	**(14)**	**(5)**	**(1)**	**(20)**
Other long-term liabilities	**(124)**	**(73)**	**(29)**	**(226)**
Total amount recognized	**(138)**	**(78)**	**(30)**	**(246)**

As at Dec. 31, 2013	Registered	Supplemental	Other	Total
Fair value of plan assets	394	7	–	401
Present value of defined benefit obligation	(517)	(74)	(27)	(618)
Funded status – plan deficit	(123)	(67)	(27)	(217)
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	(12)	(4)	(1)	(17)
Other long-term liabilities	(111)	(63)	(26)	(200)
Total amount recognized	(123)	(67)	(27)	(217)

D. Plan Assets

The fair value of the plan assets of the defined benefit pension and other post-employment benefit plans is as follows:

	Registered	**Supplemental**	**Other**	**Total**
Fair value of plan assets as at Dec. 31, 2012	294	5	–	299
Acquisition of Highvale pension plan	72	–	–	72
Interest on plan assets	15	–	–	15
Net return on plan assets	29	–	–	29
Contributions	18	7	3	28
Benefits paid	(33)	(5)	(3)	(41)
Administration expenses	(2)	–	–	(2)
Effect of translation on U.S. plans	1	–	–	1
Fair value of plan assets as at Dec. 31, 2013	**394**	**7**	**–**	**401**
Interest on plan assets	**18**	**–**	**–**	**18**
Net return on plan assets	**33**	**–**	**–**	**33**
Contributions	**14**	**5**	**1**	**20**
Benefits paid	**(33)**	**(4)**	**(1)**	**(38)**
Administration expenses	**(2)**	**–**	**–**	**(2)**
Effect of translation on U.S. plans	**3**	**–**	**–**	**3**
Fair value of plan assets as at Dec. 31, 2014	**427**	**8**	**–**	**435**

The fair value of the Corporation's defined benefit plan assets by major category is as follows:

Year ended Dec. 31, 2014	Level I	Level II	Level III	Total
Equity securities				
Canadian	**–**	**102**	**–**	**102**
U.S.	**–**	**49**	**–**	**49**
International	**–**	**70**	**–**	**70**
Private	**–**	**–**	**5**	**5**
Bonds				
AAA	**–**	**57**	**–**	**57**
AA	**1**	**54**	**–**	**55**
A	**1**	**64**	**–**	**65**
BBB	**–**	**16**	**–**	**16**
Below BBB	**–**	**1**	**–**	**1**
Money market and cash and cash equivalents	**4**	**11**	**–**	**15**
Total	**6**	**424**	**5**	**435**

Year ended Dec. 31, 2013	Level I	Level II	Level III	Total
Equity securities				
Canadian	–	99	–	99
U.S.	–	47	–	47
International	–	70	–	70
Private	–	–	6	6
Bonds				
AAA	–	46	–	46
AA	1	58	–	59
A	1	45	–	46
BBB	–	13	–	13
Below BBB	–	2	–	2
Money market and cash and cash equivalents	3	10	–	13
Total	5	390	6	401

Plan assets do not include any common shares of the Corporation at Dec. 31, 2014 and Dec. 31, 2013. The Corporation charged the registered plan $0.1 million for administrative services provided for the year ended Dec. 31, 2014 (2013 – $0.1 million).

E. Defined Benefit Obligation

The present value of the obligation for the defined benefit pension and other post-employment benefit plans is as follows:

	Registered	Supplemental	Other	Total
Present value of defined benefit obligation as at Dec. 31, 2012	424	77	34	535
Acquisition of Highvale pension plan	99	–	–	99
Current service cost	6	3	2	11
Interest cost	21	3	1	25
Benefits paid	(33)	(5)	(3)	(41)
Actuarial loss arising from demographic assumptions	20	3	–	23
Actuarial gain arising from financial assumptions	(28)	(5)	(3)	(36)
Actuarial (gain) loss arising from experience adjustments	6	(2)	(5)	(1)
Effect of translation on U.S. plans	2	–	1	3
Present value of defined benefit obligation as at Dec. 31, 2013	517	74	27	618
Current service cost	**6**	**2**	**2**	**10**
Interest cost	**23**	**4**	**1**	**28**
Benefits paid	**(33)**	**(4)**	**(1)**	**(38)**
Actuarial (gain) loss arising from demographic assumptions	**4**	**–**	**(2)**	**2**
Actuarial loss arising from financial assumptions	**50**	**8**	**3**	**61**
Actuarial (gain) loss arising from experience adjustments	**(5)**	**2**	**(1)**	**(4)**
Effect of translation on U.S. plans	**3**	**–**	**1**	**4**
Present value of defined benefit obligation as at Dec. 31, 2014	**565**	**86**	**30**	**681**

The weighted average duration of the defined benefit plan obligation as at Dec. 31, 2014 is 13.7 years.

F. Contributions

The expected employer contributions for 2015 for the defined benefit pension and other post-employment benefit plans are as follows:

	Registered	Supplemental	Other	Total
Expected employer contributions	14	5	2	21

G. Assumptions

The significant actuarial assumptions used in measuring the Corporation's defined benefit obligation for the defined benefit pension and other post-employment benefit plans are as follows:

	As at Dec. 31, 2014			As at Dec. 31, 2013		
(per cent)	**Registered**	**Supplemental**	**Other**	Registered	Supplemental	Other
Accrued benefit obligation						
Discount rate	**3.8**	**3.8**	**3.8**	4.6	4.5	4.5
Rate of compensation increase	**3.0**	**3.0**	**-**	3.0	3.0	-
Assumed health care cost trend rate						
Health care cost escalation	**-**	**-**	**7.6**[1]	-	-	7.7[3]
Dental care cost escalation	**-**	**-**	**4.0**	-	-	4.0
Provincial health care premium escalation	**-**	**-**	**5.0**	-	-	5.0
Benefit cost for the year						
Discount rate	**4.6**	**4.5**	**4.5**	4.1	4.0	3.9
Rate of compensation increase	**3.0**	**3.0**	**-**	3.0	3.0	-
Assumed health care cost trend rate						
Health care cost escalation	**-**	**-**	**7.8**[2]	-	-	7.4[4]
Dental care cost escalation	**-**	**-**	**4.0**	-	-	4.0
Provincial health care premium escalation	**-**	**-**	**5.0**	-	-	3.5

1 *Post- and pre-65 rates; decreasing gradually to 5 per cent by 2019-2020 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.35 per cent per year to 5 per cent in 2024 for Canada.*

2 *Post- and pre-65 rates; decreasing gradually to 5 per cent by 2016-2019 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.35 per cent per year to 5 per cent in 2024 for Canada.*

3 *Post- and pre-65 rates; decreasing gradually to 5 per cent by 2016-2019 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.35 per cent per year to 5 per cent in 2024 for Canada.*

4 *Post- and pre-65 rates; decreasing gradually to 5 per cent by 2016-2019 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.5 per cent per year to 5 per cent in 2018 for Canada.*

H. Sensitivity Analysis

The following table outlines the estimated increase in the net defined benefit obligation assuming certain changes in key assumptions:

	Canadian plans			U.S. plans	
Year ended Dec. 31, 2014	**Registered**	**Supplemental**	**Other**	**Pension**	**Other**
1% decrease in the discount rate	**73**	**13**	**2**	**4**	**1**
1% increase in the salary scale	**8**	**11**	**-**	**-**	**-**
1% increase in the health care cost trend rate	**-**	**-**	**2**	**-**	**1**
10% improvement in mortality rates	**17**	**2**	**-**	**1**	**-**

29. Joint Arrangements

Joint arrangements at Dec. 31, 2014 included the following:

Joint operations	Fuel type	Ownership *(per cent)*	Description
Sheerness	Coal	50	Coal-fired plant in Alberta, of which TA Cogen has a 50 per cent interest, operated by ATCO Power
Genesee Unit 3	Coal	50	Coal-fired plant in Alberta operated by Capital Power Corporation
Keephills Unit 3	Coal	50	Coal-fired plant in Alberta operated by TransAlta
TransAlta MidAmerican Partnership	Gas	50	Strategic partnership to develop, build, and operate new natural gas-fuelled electricity generation projects in Canada
Goldfields Power	Gas	50	Gas-fired plant in Australia operated by TransAlta
Fort Saskatchewan	Gas	60	Cogeneration plant in Alberta, of which TA Cogen has a 60 per cent interest, operated by TransAlta
Fortescue River Gas Pipeline	Gas	43	Joint venture to build and operate natural gas pipeline in Western Australia to transport natural gas to the Corporation's Solomon power station
McBride Lake	Renewables	50	Wind generation facilities in Alberta operated by TransAlta
Soderglen	Renewables	50	Wind generation facilities in Alberta operated by TransAlta
Pingston	Renewables	50	Hydro facility in British Columbia operated by TransAlta

Joint ventures	Business activity	Ownership *(per cent)*	Description
TAMA Transmission LP	Transmission	50	Strategic partnership to develop and operate transmission projects in Alberta

30. Change in Non-Cash Operating Working Capital

Year ended Dec. 31	2014	2013	2012
(Use) source:			
Accounts receivable	**59**	125	(22)
Prepaid expenses	**(1)**	(7)	3
Income taxes receivable	**1**	(14)	(10)
Inventory	**7**	15	(3)
Accounts payable, accrued liabilities, and provisions	**8**	(51)	(8)
Income taxes payable	**(1)**	6	(16)
Change in non-cash operating working capital	**73**	74	(56)

31. Capital

TransAlta's capital is comprised of the following:

As at Dec. 31	2014	2013	Increase/ (decrease)
Long-term debt[1]	**4,056**	4,347	**(291)**
Equity			
Common shares	**2,999**	2,913	**86**
Preferred shares	**942**	781	**161**
Contributed surplus	**9**	9	**–**
Deficit	**(770)**	(735)	**(35)**
Accumulated other comprehensive income (loss)	**104**	(62)	**166**
Non-controlling interests	**594**	517	**77**
Less: available cash and cash equivalents[2]	**(43)**	(42)	**(1)**
Less: fair value assets of hedging instruments on long-term debt[3]	**(96)**	(16)	**(80)**
Total capital	**7,795**	7,712	**83**

1 *Includes finance lease obligations, amounts under credit facilities, and current portion of long-term debt.*

2 *The Corporation includes available cash and cash equivalents as a reduction in the calculation of capital as capital is managed internally and evaluated by management using a net debt position. In this regard, these funds may be available, and used to facilitate repayment of debt.*

3 *The Corporation includes the fair value of hedging instruments on debt in an asset, or liability, position as a reduction, or increase, in the calculation of capital, as the carrying value of the related debt has either increased, or decreased, due to changes in foreign exchange rates.*

TransAlta's overall capital management strategy and its objectives in managing capital have remained unchanged from Dec. 31, 2013 and are as follows:

A. Maintain an Investment Grade Credit Rating

The Corporation operates in a long-cycle and capital-intensive commodity business, and it is therefore a priority to maintain an investment grade credit rating as it allows the Corporation to access capital markets at reasonable interest rates. Key rating agencies assess TransAlta's credit rating using a variety of methodologies, including financial ratios. These methodologies and ratios are not publicly disclosed. TransAlta's management has developed its own definitions of metrics, ratios, and targets to manage the Corporation's capital. These metrics and ratios are not defined under IFRS, and may not be comparable to those used by other entities or by rating agencies.

As at Dec. 31	2014	2013[1]	Target
Adjusted comparable funds from operations to adjusted interest coverage *(times)*	**3.8**	3.7	4 to 5
Adjusted comparable funds from operations to adjusted net debt *(%)*	**16.9**	15.2	20 to 25
Adjusted net debt to comparable earnings before interest, taxes, depreciation, and amortization *(times)*	**4.2**	4.6	3 to 4

1 *Prior year figures have been restated to conform to the current year's presentation. To align more closely to credit rating agencies' calculation of key ratios, the Corporation now uses debt balances at period-end, includes finance lease obligations as debt and finance lease interest in interest, and treats 50 per cent of dividends paid on preferred shares as interest and 50 per cent of issued preferred shares as debt. In prior periods, the Corporation used average debt and did not treat preferred shares as debt or preferred dividends as interest.*

Adjusted comparable funds from operations ("FFO") to interest coverage is calculated as comparable FFO plus interest on debt (net of interest income and capitalized interest) divided by interest on debt plus 50 per cent of dividends paid on preferred shares less interest income. Comparable FFO is calculated as cash flow from operating activities before changes in working capital and is adjusted for transactions and amounts that the Corporation believes are not representative of ongoing cash flows from operations. Adjusted comparable FFO to interest coverage increased compared to 2013. The Corporation's goal is to maintain this ratio in a range of four to five times.

Adjusted comparable FFO to net debt is calculated as cash flow from operating activities before changes in working capital less 50 per cent of dividends paid on preferred shares divided by total debt plus 50 per cent of issued preferred shares less cash and cash equivalents. Adjusted comparable FFO to net debt increased in 2014 compared to 2013 due to lower debt levels in 2014. The Corporation's goal is to maintain this ratio in a range of 20 to 25 per cent.

Adjusted net debt to comparable earnings before interest, taxes, depreciation, and amortization ("EBITDA") is calculated as net debt (current and long-term debt plus 50 per cent of outstanding preferred shares less available cash and cash equivalents) divided by comparable EBITDA. Comparable EBITDA is calculated as earnings before interest, taxes, depreciation, and amortization and is adjusted for transactions and amounts that the Corporation believes are not representative of ongoing business operations. Adjusted net debt to comparable EBITDA in 2014 increased compared to 2013. The Corporation's goal is to maintain this ratio in a range of three to four times.

At times, the credit ratios may be outside of the specified target ranges while the Corporation realigns its capital structure. During 2014, the Corporation took several steps to strengthen its financial position and reduce debt, using the proceeds from the sale of CE Gen, Blackrock, CalEnergy, and Wailuku *(see Note 4)*, the secondary offering of TransAlta Renewables common shares *(see Note 11)*, and the offering of preferred shares *(see Note 25)* to pay down credit facility borrowings, repay the scheduled maturity of a debenture, and increase liquidity. During 2013, the Corporation also used the approximate $221 million in gross proceeds from the initial public offering of TransAlta Renewables common shares *(see Note 11)* to pay down debt. The Corporation utilizes the proceeds from dividends reinvested under the Dividend Reinvestment and Share Purchase Plan as a continued source of equity.

Management routinely monitors forecasted net earnings, cash flows, capital expenditures, and scheduled repayment of debt with a goal of meeting the above ratio targets and to meet dividend and property, plant, and equipment expenditure requirements.

B. Ensure Sufficient Cash and Credit is Available to Fund Operations, Pay Dividends, Distribute Payments to Subsidiaries' Non-Controlling Interests, and Invest in Property, Plant, and Equipment

For the year ended Dec. 31, 2014 and 2013, net cash outflows, after cash dividends paid on common shares, property, plant, and equipment additions, and business acquisitions, are summarized below:

Year ended Dec. 31	2014	2013	Increase (decrease)
Cash flow from operating activities	**796**	765	**31**
Dividends paid on common shares	**(140)**	(116)	**(24)**
Dividends paid on preferred shares	**(41)**	(38)	**(3)**
Distributions paid to subsidiaries' non-controlling interests	**(84)**	(55)	**(29)**
Property, plant, and equipment expenditures	**(487)**	(561)	**74**
Acquisition of Wyoming wind farm	**-**	(109)	**109**
Inflow (outflow)	**44**	(114)	**158**

TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2014, $1.6 billion (2013 – $0.9 billion) of the Corporation's available credit facilities were not drawn.

Periodically, TransAlta accesses capital markets, as required, to help fund some of these periodic net cash outflows, to maintain its available liquidity, and to maintain its capital structure and credit metrics within targeted ranges.

During 2014, the Corporation completed a secondary offering of the common shares of TransAlta Renewables for gross proceeds to the Corporation of approximately $136 million; issued 6.6 million Series G preferred shares for gross proceeds of $165 million; issued U.S.$400 million of senior notes; and repaid $200 million of medium-term notes that matured.

During 2013, the Corporation issued $400 million of senior unsecured medium-term notes, received $221 million in gross proceeds from the initial public offering of TransAlta Renewables, and repaid U.S.$300 senior notes on maturity.

Dividends on the Corporation's common shares are at the discretion of the Board. In determining the payment and level of future dividends, the Board considers the Corporation's financial performance, its results of operations, cash flow and needs with respect to financing ongoing operations and growth, balanced against returning capital to shareholders.

32. Related Party Transactions

Details of the Corporation's principal operating subsidiaries are as follows:

Subsidiary	Country	Ownership *(per cent)*	Principal activity
TransAlta Generation Partnership	Canada	100	Generation and sale of electricity
TransAlta Cogeneration, L.P.	Canada	50.01	Generation and sale of electricity
TransAlta Centralia Generation, LLC	U.S.	100	Generation and sale of electricity
TransAlta Energy Marketing Corp.	Canada	100	Energy marketing
TransAlta Energy Marketing (U.S.), Inc.	U.S.	100	Energy marketing
TransAlta Energy (Australia), Pty Ltd.	Australia	100	Generation and sale of electricity
TransAlta Renewables Inc.	Canada	70.3	Generation and sale of electricity

Transactions between the Corporation and its subsidiaries have been eliminated on consolidation and are not disclosed.

Transactions with Key Management Personnel

TransAlta's key management personnel include the President and CEO, the Chief Officers, the Executive Vice Presidents, and the Vice President, Gas and Renewables, all who report directly to the President and CEO, and the members of the Board.

Key management personnel compensation is as follows:

Year ended Dec. 31	**2014**	2013	2012
Total compensation	**13**	15	12
Comprised of:			
Short-term employee benefits	**8**	7	8
Post-employment benefits	**2**	2	1
Other long-term benefits	**–**	1	1
Termination benefits	**–**	2	–
Share-based payments	**3**	3	2

33. Commitments

In addition to commitments disclosed elsewhere in the financial statements, the Corporation has entered into a number of fixed purchase and transportation contracts, transmission and electricity purchase agreements, coal supply and mining agreements, long-term service agreements, and agreements related to growth and major projects either directly or through its interests in joint ventures. Approximate future payments under these agreements are as follows:

	Natural gas, transportation, and other purchase contracts	Transmission and power purchase agreements	Coal supply and mining agreements	Long-term service agreements	Non-cancellable operating leases	Growth	Total
2015	43	12	159	119	11	207	551
2016	29	9	137	120	10	50	355
2017	13	3	44	105	8	175	348
2018	12	4	45	33	8	8	110
2019	7	2	46	31	8	–	94
2020 and thereafter	101	6	605	172	54	–	938
Total	**205**	**36**	**1,036**	**580**	**99**	**440**	**2,396**

A. Natural Gas, Transportation, and Other Purchase Contracts

Several of the Corporation's plants have fixed price natural gas purchase and related transportation contracts in place. Other fixed price purchase contracts relate to commitments for services at certain facilities.

B. Transmission and Power Purchase Agreements

TransAlta has several agreements to purchase 400 MW of Pacific Northwest transmission network capacity. Provided certain conditions for delivering the service are met, the Corporation is committed to the transmission at the supplier's tariff rate whether it is awarded immediately or delivered in the future after additional facilities are constructed.

C. Coal Supply and Mining Agreements

Various coal supply and associated rail transport contracts are in place to provide coal for use in production at the Centralia coal plant. The coal supply agreements allow TransAlta to take delivery of coal at fixed volumes and prices, with dates extending to 2024.

Commitments related to mining agreements include the Corporation's share of commitments for mining agreements related to its Sheerness and Genesee Unit 3 joint operations, and certain other mining royalty agreements.

D. Long-Term Service Agreements

TransAlta has various service agreements in place, primarily for inspections and repairs and maintenance that may be required on natural gas facilities, coal facilities, and turbines at various wind facilities.

E. Operating Leases

TransAlta has operating leases in place for buildings, vehicles, and various types of equipment.

During the year ended Dec. 31, 2014, $10 million (2013 – $10 million, 2012 – $13 million) was recognized as an expense in respect of these operating leases. No sublease payments were received or made, nor were any contingent rental payments made in respect of these operating leases.

F. Growth

Commitments for growth relate to the South Hedland power station, the Australian natural gas pipeline to the Solomon power station, and transmission upgrades.

G. TransAlta Energy Bill Commitments

As part of the Bill and Memorandum of Agreement ("MoA") signed into law in the State of Washington, the Corporation has committed to fund U.S.$55 million over the life of the Centralia coal plant to support economic and community development, promote energy efficiency, and develop energy technologies related to the improvement of the environment. The MoA contains certain provisions for termination and in certain circumstances this funding or part thereof would no longer be required.

H. Other

A significant portion of the Corporation's electricity and thermal production are subject to PPAs and long-term contracts. The majority of these contracts include terms and conditions customary to the industry in which the Corporation operates. The nature of commitments related to these contracts includes: electricity and thermal capacity, availability, and production targets; reliability and other plant-specific performance measures; specified payments for deliveries during peak and off-peak time periods; specified prices per MWh; risk sharing of fuel costs; and retention of heat rate risk.

34. Contingencies

TransAlta is occasionally named as a party in various claims and legal proceedings that arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed, and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in the Corporation's favour or that such claims may not have a material adverse effect on TransAlta. Inquiries from regulatory bodies may also arise in the normal course of business, to which the Corporation responds as required.

35. Segment Disclosures

A. Description of Reportable Segments

The Corporation has three reportable segments as described in *Note 1*.

A portion of operations, maintenance, and administration costs incurred in the Energy Marketing Segment and the Corporate Segment are allocated to other segments based on an estimate of operating expenses and a percentage of resources dedicated to providing support and services. Segment operations, maintenance, and administration costs are comprised of expenses net of intersegment allocations. In prior years, the Energy Marketing intersegment charge and recovery was presented as a distinct line item as a component of operating income (loss). Comparative figures have been reclassified to conform to the current year's presentation.

B. Reported Segment Earnings and Segment Assets

I. Earnings Information

Year ended Dec. 31, 2014	**Generation**	**Energy Marketing**	**Corporate**	**Total**
Revenues	**2,515**	**108**	**-**	**2,623**
Fuel and purchased power	**1,092**	**-**	**-**	**1,092**
Gross margin	**1,423**	**108**	**-**	**1,531**
Operations, maintenance, and administration	**447**	**32**	**63**	**542**
Depreciation and amortization	**512**	**-**	**26**	**538**
Asset impairment reversals	**(6)**	**-**	**-**	**(6)**
Taxes, other than income taxes	**28**	**-**	**1**	**29**
Net other operating (income) losses	**(19)**	**5**	**-**	**(14)**
Net operating income (loss)	**461**	**71**	**(90)**	**442**
Finance lease income	**49**	**-**	**-**	**49**
Gain on sale of assets	**2**	**-**	**-**	**2**
Net interest expense				**(254)**
Earnings before income taxes				**239**

Year ended Dec. 31, 2013 *(Restated – see Note 3(B))*	Generation	Energy Marketing	Corporate	Total
Revenues	2,213	79	-	2,292
Fuel and purchased power	948	-	-	948
Gross margin	1,265	79	-	1,344
Operations, maintenance, and administration	432	18	66	516
Depreciation and amortization	501	1	23	525
Asset impairment charges (reversals)	(18)	-	-	(18)
Restructuring provision	(2)	-	(1)	(3)
Taxes, other than income taxes	26	-	1	27
Net other operating losses	46	56	-	102
Operating income (loss)	280	4	(89)	195
Finance lease income	46	-	-	46
Equity loss	(10)	-	-	(10)
Gain on sale of assets	-	-	12	12
Net interest expense				(256)
Foreign exchange gain				1
Loss before income taxes				(12)

Year ended Dec. 31, 2012 *(Restated – see Note 3(B))*	Generation	Energy Marketing	Corporate	Total
Revenues	2,207	3	–	2,210
Fuel and purchased power	797	–	–	797
Gross margin	1,410	3	–	1,413
Operations, maintenance, and administration	401	16	82	499
Depreciation and amortization	489	–	20	509
Asset impairment charges	324	–	–	324
Restructuring provision	5	–	8	13
Taxes, other than income taxes	27	–	1	28
Net other operating losses	254	–	–	254
Operating losses	(90)	(13)	(111)	(214)
Finance lease income	16	–	–	16
Equity loss	(15)	–	–	(15)
Gain on sale of assets	3	–	–	3
Gain on sale of collateral	–	15	–	15
Net interest expense				(242)
Other income				1
Foreign exchange loss				(9)
Loss before income taxes				(445)

Included in the Generation Segment revenue is $21 million (2013 – $22 million, 2012 – $23 million) of incentives received under a Government of Canada program in respect of power generation from qualifying wind and hydro projects.

Total rental income, including contingent rent, related to certain PPAs and other long-term contracts that meet the criteria of operating leases, is included in the Generation Segment revenues, and was $219 million for the year ended Dec. 31, 2014 (2013 – $208 million, 2012 – $188 million).

II. Selected Consolidated Statements of Financial Position Information

As at Dec. 31, 2014	**Generation**	**Energy Marketing**	**Corporate**	**Total**
Goodwill	**432**	**30**	**–**	**462**
Total segment assets	**9,274**	**246**	**313**	**9,833**

As at Dec. 31, 2013	Generation[1]	Energy Marketing	Corporate	Total
Goodwill	430	30	–	460
Total segment assets *(Restated – see Note 3(B))*	9,093	244	287	9,624

1 *Total Generation Segment assets include $192 million related to investments in joint arrangements accounted for using the equity method.*

III. Selected Consolidated Statements of Cash Flows Information

Year ended Dec. 31, 2014	**Generation**	**Energy Marketing**	**Corporate**	**Total**
Additions to non-current assets:				
Property, plant, and equipment	**481**	**1**	**5**	**487**
Intangible assets	**9**	**8**	**17**	**34**

Year ended Dec. 31, 2013	Generation	Energy Marketing	Corporate	Total
Additions to non-current assets:				
Property, plant, and equipment	554	–	7	561
Intangible assets	5	6	21	32

Year ended Dec. 31, 2012	Generation	Energy Marketing	Corporate	Total
Additions to non-current assets:				
Property, plant, and equipment	684	–	19	703
Intangible assets	7	1	31	39

IV. Depreciation and Amortization on the Consolidated Statements of Cash Flows

The reconciliation between depreciation and amortization reported on the Consolidated Statements of Earnings (Loss) and the Consolidated Statements of Cash Flows is presented below:

Year ended Dec. 31	**2014**	2013	2012
Depreciation and amortization expense on the Consolidated Statements of Earnings	**538**	525	509
Depreciation included in fuel and purchased power *(Note 5)*	**56**	58	41
Gain on disposal of property, plant, and equipment	**1**	2	14
Depreciation and amortization on the Consolidated Statements of Cash Flows	**595**	585	564

C. Geographic Information

I. Revenues

Year ended Dec. 31	**2014**	2013	2012
Canada	**1,989**	1,898	1,789
U.S.	**516**	287	300
Australia	**118**	107	121
Total revenue	**2,623**	2,292	2,210

II. Non-Current Assets

	Property, plant, and equipment		**Intangible assets**		**Other assets**		**Goodwill**	
As at Dec. 31	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013
Canada	**6,422**	6,538	**296**	295	**66**	57	**417**	417
U.S.	**552**	517	**25**	24	**14**	21	**45**	43
Australia	**264**	138	**10**	4	**18**	19	**–**	–
Total	**7,238**	7,193	**331**	323	**98**	97	**462**	460

D. Significant Customer

During the year ended Dec. 31, 2014, sales to one customer in the Generation Segment represented 12 per cent of the Corporations's total revenue.

36. Subsequent Events

A. Restructuring

On Jan. 14, 2015, the Corporation initiated a significant cost-reduction initiative at the Corporation's Canadian Coal operations, resulting in the elimination of positions. Costs associated with the initiative are expected to total $10 million.

B. Bond Issuance

On Feb. 11, 2015, the Corporation and its partner issued bonds secured by their jointly owned Pingston facility. The Corporation's share of gross proceeds was $45 million. The bonds bear interest at the annual fixed interest rate of 2.95 per cent, payable semi-annually with no principal repayments until maturity in May 2023. Proceeds were used to repay the $35 million secured debenture bearing interest at 5.28 per cent. Excess proceeds, net of transaction costs, are to be used for general corporate purposes.

Eleven-Year Financial and Statistical Summary

(in millions of Canadian dollars, except where noted)

Year ended Dec. 31	2014	2013	2012
Financial Summary			
Statement of Earnings			
Revenues	**2,623**	2,292	2,210
Operating income	**442**	195	(214)
Net earnings (loss) attributable to common shareholders	**141**	(71)	(615)
Statement of Financial Position			
Total assets	**9,833**	9,624	9,503
Current portion of long-term debt, net of cash and cash equivalents	**708**	175	582
Long-term debt	**3,305**	4,130	3,610
Non-controlling interests	**594**	517	330
Preferred shares	**942**	781	–
Equity attributable to shareholders	**3,284**	2,906	3,018
Total invested capital	**8,833**	8,509	7,540
Cash Flows			
Cash flow from operating activities	**796**	765	520
Cash flow used in investing activities	**(292)**	(703)	(1,048)
Common Share Information *(per share)*			
Net earnings (loss)	**0.52**	(0.27)	(2.62)
Comparable earnings[1]	**0.25**	0.31	0.50
Dividends paid on common shares	**0.83**	1.16	1.16
Book value *(at year-end)*	**8.52**	7.92	8.78
Market price:			
High	**14.94**	16.86	21.37
Low	**9.81**	12.91	14.11
Close *(Toronto Stock Exchange at Dec. 31)*	**10.52**	13.48	15.12
Ratios *(percentage except where noted)*			
Adjusted net debt to invested capital	**56.3**	60.7	61.0
Adjusted net debt to invested capital excluding non-recourse debt	**54.1**	58.7	59.0
Adjusted net debt to comparable EBITDA *(times)*[1]	**4.2**	4.6	4.6
Return on equity attributable to common shareholders	**6.3**	(3.2)	(25.9)
Comparable return on equity attributable to common shareholders[1]	**3.0**	3.7	4.9
Return on capital employed	**5.8**	2.8	(3.1)
Comparable return on capital employed[1]	**5.1**	5.2	5.3
Price to comparable earnings *(times)*	**42.1**	43.5	30.2
Earnings coverage *(times)*	**1.7**	0.8	(1.0)
Dividend payout ratio based on net earnings	**139.0**	(431.0)	(44.1)
Dividend payout ratio based on comparable earnings[1]	**288.2**	377.8	231.6
Dividend payout ratio based on comparable funds from operations[1,2]	**26.4**	43.1	25.1
Comparable EBITDA *(in millions of Canadian dollars)*[1]	**1,036**	1,023	1,015
Dividend coverage *(times)*	**5.6**	6.3	4.7
Dividend yield	**7.9**	8.6	7.7
Adjusted comparable FFO to adjusted net debt[2]	**16.9**	15.2	16.7
Comparable FFO before interest to adjusted interest coverage *(times)*[2]	**3.8**	3.7	3.3
Weighted average common shares for the year *(in millions)*	**273**	264	235
Common shares outstanding at Dec. 31 *(in millions)*	**275**	268	255
Statistical Summary			
Number of employees	**2,786**	2,772	2,084
Generating Capacity *(MW)*[3]			
Coal (Canadian and U.S.)	**5,111**	5,111	4,551
Gas[4]	**1,531**	1,779	1,731
Renewables (wind and hydro)	**2,203**	2,202	2,058
Equity investments	**–**	396	390
Total generating capacity	**8,845**	9,488	8,730
Total generation production *(GWh)*	**45,002**	42,482	38,750

Financial data presented is based on IFRS. Financial data for 2009 and prior is based on Canadian GAAP. Prior year figures that appear within the MD&A have been restated to conform with the current year's presentation. All other prior year figures have not been restated.

1 *These ratios were calculated using non-IFRS measures. Periods for which the non-IFRS measure was not previously disclosed have not been calculated.*
2 *2013 has been adjusted for the impacts associated with the California claim. 2012 has been adjusted for the impacts associated with Sundance Units 1 and 2 arbitration.*
3 *2014, 2013 and 2012 are gross capacity which reflects the basis of consolidation of underlying results. Prior year figures are as previously reported.*
4 *Includes finance leases.*

Ratio Formulas

Adjusted net debt to invested capital = long-term debt and finance lease obligations including current portion and fair value (asset) liability of hedging instruments on debt + 50 per cent issued preferred shares – cash and cash equivalents/ long-term debt including current portion + non-controlling interests + equity attributable to shareholders – 50 per cent issued preferred shares – cash and cash equivalents

Adjusted net debt to comparable EBITDA = long-term debt and finance lease obligations including current portion and fair value (asset) liability of hedging instruments on debt – cash and cash equivalents + 50 per cent issued preferred shares / comparable EBITDA

Return on equity attributable to common shareholders = net earnings attributable to common shareholders excluding gain on discontinued operations or earnings on a comparable basis / equity attributable to common shareholders excluding Accumulated Other Comprehensive Income ("AOCI")

Earnings coverage = net earnings attributable to shareholders + income taxes + net interest expense / 50 per cent dividends paid on preferred shares + interest on debt – interest income

2011	2010	2009	2008	2007	2006	2005	2004
2,618	2,673	2,770	3,110	2,775	2,677	2,664	2,838
645	487	378	533	541	157	421	478
290	255	181	235	309	45	199	170
9,780	9,635	9,762	7,815	7,157	7,460	7,741	8,133
284	202	(51)	194	600	296	(66)	(103)
3,721	3,823	4,411	2,564	1,837	2,221	2,605	3,058
358	431	478	469	496	535	559	616
–	–	–	–	–	175	175	175
3,274	3,120	2,929	2,510	2,299	2,428	2,543	2,473
7,637	7,576	7,767	5,737	5,232	5,655	5,756	6,061
690	838	580	1,038	847	490	619	613
(608)	(765)	(1,598)	(581)	(410)	(261)	(242)	(65)
1.31	1.16	0.90	1.18	1.53	0.22	1.01	0.88
1.05	0.97	0.90	1.46	1.31	1.16	0.88	0.70
1.16	1.16	1.16	1.08	1.00	1.00	1.00	1.00
12.08	12.85	13.41	12.70	11.39	11.99	12.80	12.74
23.24	23.98	25.30	37.50	34.00	26.91	26.66	18.75
19.45	19.61	18.11	21.00	23.79	20.22	17.67	15.25
21.02	21.15	23.48	24.30	33.35	26.64	25.41	18.05
52.5	53.1	56.1	48.1	46.8	44.5	43.9	47.4
60.0	50.7	52.6	45.6	44.0	41.0	39.9	42.5
3.8	–	–	–	–	–	–	–
10.6	9.6	6.9	9.4	13.1	1.8	7.0	6.5
8.4	8.0	6.9	11.6	10.5	9.2	6.8	5.1
8.3	6.6	5.7	7.7	9.8	2.4	7.1	7.5
7.0	6.0	5.8	9.6	9.7	9.0	7.4	–
20.2	21.8	26.1	20.6	21.8	121.1	26.7	21.7
2.7	2.2	1.9	2.8	3.3	0.5	2.3	1.9
66.9	125.1	129.8	91.5	65.6	447.7	113.0	120.0
84.3	149.8	129.8	74.1	76.4	86.0	113.3	150.4
24.0	39.6	–	–	–	–	–	–
1,044	955	888	1,006	980	–	–	–
3.5	4.0	2.6	4.8	4.2	2.4	3.1	3.2
5.5	5.5	4.9	4.4	3.0	3.8	3.9	5.5
20.1	19.6	20.5	31.7	30.7	26.2	23.0	18.5
4.4	4.6	4.9	7.2	6.6	5.5	4.7	4.1
222	219	201	199	202	201	197	193
224	220	218	198	201	202	199	194
2,235	2,389	2,343	2,200	2,201	2,687	2,657	2,505
4,325	4,688	4,967	4,942	4,942	4,887	4,885	4,778
1,567	1,648	1,843	1,913	1,960	1,953	1,933	2,444
1,974	1,950	1,965	1,218	1,122	1,122	1,117	1,115
390	390	–	–	–	–	–	–
8,256	8,676	8,775	8,073	8,024	7,962	7,935	8,337
41,012	48,614	45,736	48,891	50,395	48,213	51,810	54,560

Return on capital employed = earnings before non-controlling interests and income taxes + net interest expense or comparable earnings before non-controlling interests and income taxes + net interest expense/ invested capital excluding AOCI

Dividend yield = dividend per common share / current year's close price

Dividend payout ratio = common share dividends / net earnings attributable to common shareholders excluding gain on discontinued operations or earnings on a comparable basis or funds from operations – 50 per cent dividends paid on preferred shares

Price to comparable earnings ratio = current year's close price / comparable earnings per share

Comparable funds from operations before interest to adjusted interest coverage = comparable funds from operations + interest on debt – interest income – capitalized interest / interest on debt + 50 per cent dividends paid on preferred shares – interest income

Dividend coverage = cash flow from operating activities / cash dividends paid on common shares

Adjusted comparable funds from operations to adjusted net debt = comparable funds from operations – 50 per cent dividends paid on preferred shares/ period end long-term debt and finance lease obligations including fair value (asset) liability of hedging instruments on debt + 50 per cent issued preferred shares – cash and cash equivalents

Comparable EBITDA = operating income + depreciation and amortization per the Consolidated Statements of Cash Flows +/- non-comparable items

Plant Summary

As of January 31, 2015	Facility	Capacity (MW)[1]	Ownership (%)	Net capacity ownership interest (MW)[1,2]	Fuel	Revenue source	Contract expiry date
Western Canada 39 Facilities	Sundance, AB[3]	2,141	100%	2,141	Coal	Alberta PPA[4]/Merchant[5]	2017-2020
	Keephills, AB	790	100%	790	Coal	Alberta PPA/Merchant[6]	2020
	Genesee 3, AB	466	50%	233	Coal	Merchant	–
	Keephills 3, AB	463	50%	232	Coal	Merchant	–
	Sheerness, AB	780	25%	195	Coal	Alberta PPA	2020
	Poplar Creek, AB	356	100%	356	Gas	LTC[7]/Merchant	2023
	Fort Saskatchewan, AB	118	30%	35	Gas	LTC	2019
	Brazeau, AB	355	100%	355	Hydro	Alberta PPA	2020
	Big Horn, AB	120	100%	120	Hydro	Alberta PPA	2020
	Spray, AB	103	100%	103	Hydro	Alberta PPA	2020
	Ghost, AB	51	100%	51	Hydro	Alberta PPA	2020
	Rundle, AB	50	100%	50	Hydro	Alberta PPA	2020
	Cascade, AB	36	100%	36	Hydro	Alberta PPA	2020
	Kananaskis, AB	19	100%	19	Hydro	Alberta PPA	2020
	Bearspaw, AB	17	100%	17	Hydro	Alberta PPA	2020
	Pocaterra, AB	15	100%	15	Hydro	Merchant	–
	Horseshoe, AB	14	100%	14	Hydro	Alberta PPA	2020
	Barrier, AB	13	100%	13	Hydro	Alberta PPA	2020
	Taylor, AB	13	100%	13	Hydro	Merchant	–
	Interlakes, AB	5	100%	5	Hydro	Alberta PPA	2020
	Belly River, AB	3	100%	3	Hydro	Merchant	–
	Three Sisters, AB	3	100%	3	Hydro	Alberta PPA	2020
	Waterton, AB	3	100%	3	Hydro	Merchant	–
	St. Mary, AB	2	100%	2	Hydro	Merchant	–
	Upper Mamquam, BC	25	100%	25	Hydro	LTC	2025
	Pingston, BC	45	50%	23	Hydro	LTC	2023
	Bone Creek, BC	19	100%	19	Hydro	LTC	2031
	Akolkolex, BC	10	100%	10	Hydro	LTC	2015
	Summerview 1, AB	70	100%	70	Wind	Merchant	–
	Summerview 2, AB	66	100%	66	Wind	Merchant	–
	Ardenville, AB	69	100%	69	Wind	Merchant	–
	Blue Trail, AB	66	100%	66	Wind	Merchant	–
	Castle River, AB[8]	44	100%	44	Wind	Merchant	–
	McBride Lake, AB	75	50%	38	Wind	LTC	2024
	Soderglen, AB	71	50%	35	Wind	Merchant	–
	Cowley Ridge, AB	16	100%	16	Wind	Merchant	–
	Cowley North, AB	20	100%	20	Wind	Merchant	–
	Sinnott, AB	7	100%	7	Wind	Merchant	–
	Macleod Flats, AB	3	100%	3	Wind	Merchant	–
Total Western Canada		**6,541**		**5,313**			
Eastern Canada 16 Facilities	Sarnia, ON	506	100%	506	Gas	LTC	2022-2025
	Mississauga, ON	108	50%	54	Gas	LTC	2018
	Ottawa, ON	74	50%	37	Gas	LTC	2017-2033
	Windsor, ON	68	50%	34	Gas	LTC/Merchant	2016
	Ragged Chute, ON	7	100%	7	Hydro	LTC	2029
	Misema, ON	3	100%	3	Hydro	LTC	2027
	Galetta, ON	2	100%	2	Hydro	LTC	2030
	Appleton, ON	1	100%	1	Hydro	LTC	2030
	Moose Rapids, ON	1	100%	1	Hydro	LTC	2030
	Wolfe Island, ON	198	100%	198	Wind	LTC	2029
	Melancthon, ON[9]	200	100%	200	Wind	LTC	2026-2028
	Le Nordais, QC	99	100%	99	Wind	LTC	2033
	Kent Hills, NB[9]	150	83%	125	Wind	LTC	2033-2035
	New Richmond, QC	68	100%	68	Wind	LTC	2033
Total Eastern Canada		**1,484**		**1,334**			
United States 3 Facilities	Centralia, WA	1,340	100%	1,340	Coal	LTC/Merchant	2025
	Wyoming Wind, WY	144	100%	144	Wind	LTC	2028
	Skookumchuck, WA	1	100%	1	Hydro	LTC	2020
Total United States		**1,485**		**1,485**			
Australia 7 Facilities	Parkeston, WA	110	50%	55	Gas	LTC	2016
	Southern Cross, WA[10]	245	100%	245	Gas/Diesel	LTC	2023
	Solomon Power Station	125	100%	125	Gas/Diesel	LTC	2028
	South Hedland[11]	150	100%	150	Gas/Diesel	LTC	2042
Total Australia		**630**		**575**			
Total		**10,140**		**8,707**			

1 *Megawatts are rounded to the nearest whole number; columns may not add due to rounding.*
2 *Accounts for 100% of TransAlta Renewables assets.*
3 *Includes a 15 MW uprate on Sundance unit 3; the resulting increased capacity will not be realized until the generator stator is replaced.*
4 *PPA refers to Power Purchase Arrangement.*
5 *Merchant capacity refers to uprates on unit 4 (53 MW), unit 5 (53 MW), and unit 6 (44 MW).*
6 *Merchant capacity refers to uprates on unit 1 (12 MW) and unit 2 (12 MW).*
7 *LTC refers to Long-Term Contract.*
8 *Includes seven individual turbines at other locations.*
9 *Comprised of two facilities.*
10 *Comprised of four facilities.*
11 *Plant is under construction and expected to be fully commissioned in mid-2017.*

Board of Directors


William D. Anderson


John P. Dielwart


Timothy W. Faithfull


Dawn L. Farrell


Alan J. Fohrer

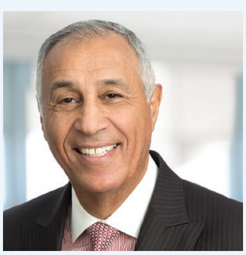

Ambassador Gordon D. Giffin


P. Thomas Jenkins


C. Kent Jespersen


Michael M. Kanovsky


Karen E. Maidment


Yakout Mansour


Georgia R. Nelson


Dr. Martha C. Piper

According to a 2014 survey commissioned by the *Calgary Herald*, TransAlta's board is the most diverse among Calgary's Top 100 companies.

Shareholder Information

Annual Meeting

The Annual Meeting of Shareholders will be held at 11:00 a.m. MST, on Tuesday, April 28, 2015 at the Metropolitan Conference Centre 333 - 4th Avenue S.W., Calgary, Alberta.

Transfer Agent

CST Trust Company*
P.O. Box 700 Station "B"
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Website
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Exchanges

Toronto Stock Exchange (TSX)
New York Stock Exchange (NYSE)

Ticker Symbols

TransAlta Corporation common shares:
TSX: TA, NYSE: TAC
TransAlta Corporation preferred shares:
TSX: TA.PR.D, TA.PR.F, TA.PR.H, TA.PR.J

* *CST Trust Company has succeeded CIBC Mellon Trust Company as our transfer agent. On Nov. 1, 2010, CIBC Mellon Trust Company sold its issuer services business to Canadian Stock Transfer Company Inc., which operated the business on their behalf until Aug. 30, 2013, at which time CST Trust Company, an affiliate of Canadian Stock Transfer Company Inc., received federal approval to commence business.*

Special Services for Registered Shareholders

Service	Description
Dividend reinvestment and optional share purchase plan[1]	Conveniently reinvest your TransAlta dividends and purchase common shares without brokerage costs
Direct deposit for dividend payments	Automatically have dividend payments deposited to your bank account
Account consolidations	Eliminate costly duplicate mailings by consolidating account registrations
Address changes and share transfers	Receive tax slips and dividends without the delays resulting from address and ownership changes

To use these services please contact our transfer agent.
1 Also available to non-registered shareholders.

Stock Splits and Share Consolidations

Date	Events
May 8, 1980	Stock split
Feb. 1, 1988	Stock split[1]
Dec. 31, 1992	Reorganization – TransAlta Utilities shares exchanged for TransAlta Corporation shares[2] 1:1

The valuation date value of common shares owned on Dec. 31, 1971, adjusted for stock splits, is $4.54 per share.
1 The adjusted cost base for shares held on Jan. 31, 1988, was reduced by $0.75 per share following the Feb. 1, 1988 share split.
2 TransAlta Utilities Corporation became a wholly owned subsidiary of TransAlta Corporation as a result of this reorganization.

Dividend Declaration for Common Shares

Dividends are paid quarterly as determined by the Board. Dividends on our common shares are at the discretion of the Board. In determining the payment and level of future dividends, the Board considers our financial performance, our results of operations, cash flow and needs, with respect to financing our ongoing operations and growth, balanced against returning capital to shareholders. The Board continues to focus on building sustainable earnings and cash flow growth.

Common Share Dividends Declared in 2014

Payment Date	Record Date	Ex-Dividend Date	Dividend
April 1, 2014	March 4, 2014	Feb. 28, 2014	$0.18
July 1, 2014	May 30, 2014	May 28, 2014	$0.18
Oct. 1, 2014	Aug. 29, 2014	Aug. 27, 2014	$0.18
Jan. 1, 2015	Dec. 1, 2014	Nov. 27, 2014	$0.18

Dividends are paid on the first of the month in January, April, July and October. When a dividend payment date falls on a weekend or holiday, the payment is made on the following business day. Only dividend payments that have been approved by the Board of Directors are included in this table.

Submission of Concerns Regarding Accounting or Auditing Matters

TransAlta has adopted a procedure for employees, shareholders or others to report concerns or complaints regarding accounting or other matters on an anonymous, confidential basis to the Audit and Risk Committee of the Board of Directors. Such submissions may be directed to the Audit and Risk Committee c/o the Vice-President and Corporate Secretary of the Corporation.

Dividend Declaration for Preferred Shares

Series A: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.15 per share from the date of issue Dec. 10, 2010 to but excluding March 31, 2016.

Series C: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.15 per share from the date of issue Nov. 29, 2011 to but excluding June 30, 2017.

Series E: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.25 per share from the date of issue Aug. 10, 2012 to but excluding Sept. 30, 2017.

Series G: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.35 per share from the date of issue Aug. 15, 2014 to but excluding Sept. 30, 2019.

Preferred Share Dividend Declared in 2014

Series A

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2014	March 4, 2014	Feb. 28, 2014	$0.2875
June 30, 2014	May 30, 2014	May 28, 2014	$0.2875
Sept. 30, 2014	Aug. 29, 2014	Aug. 27, 2014	$0.2875
Dec. 31, 2014	Dec. 1, 2014	Nov. 27, 2014	$0.2875

Series C

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2014	March 4, 2014	Feb. 28, 2014	$0.2875
June 30, 2014	May 30, 2014	May 28, 2014	$0.2875
Sept. 30, 2014	Aug. 29, 2014	Aug. 27, 2014	$0.2875
Dec. 31, 2014	Dec. 1, 2014	Nov. 27, 2014	$0.2875

Series E

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2014	March 4, 2014	Feb. 28, 2014	$0.3125
June 30, 2014	May 30, 2014	May 28, 2014	$0.3125
Sept. 30, 2014	Aug. 29, 2014	Aug. 27, 2014	$0.3125
Dec. 31, 2014	Dec. 1, 2014	Nov. 27, 2014	$0.3125

Series G

Payment Date	Record Date	Ex-Dividend Date	Dividend
Dec. 31, 2014	Dec. 1, 2014	Nov. 27, 2014	$0.5010[1]

Dividends are paid on the last day of the month in March, June, September, and December. When a dividend payment date falls on a weekend or holiday, the payment is made on the following business day. Only dividend payments that have been approved by the Board of Directors are included in this table.

1 The first quarterly dividend payable is based on a longer period, starting from the issue date of Aug. 15, 2014 to Dec. 31, 2014.

Voting Rights

Common shareholders receive one vote for each common share held.

Additional Information

Requests can be directed to:

Investor Relations
TransAlta Corporation
110 - 12th Avenue S.W.
P.O. Box 1900, Station “M”
Calgary, Alberta T2P 2M1

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1.800.387.3598 toll-free
Calgary/outside North America:
403.267.2520

E-mail
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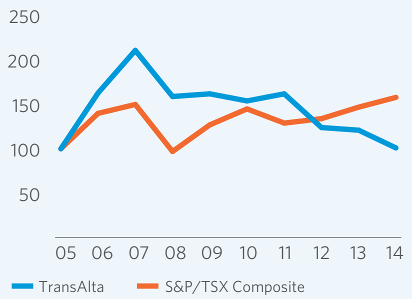
Website
www.transalta.com

Shareholder Highlights



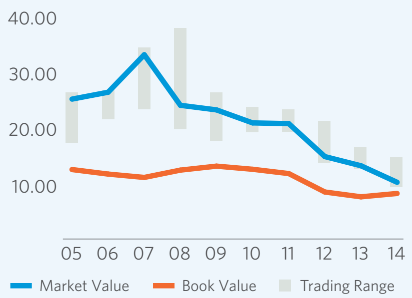
Total Shareholder Return vs. S&P/TSX Composite Index

Year ended Dec. 31 *($)*

	05	06	07	08	09	10	11	12	13	14
TransAlta	100	163	211	159	162	154	162	124	121	101
TSX/S&P Composite	100	140	150	97	127	145	129	134	147	158

This chart compares what $100 invested in TransAlta and the S&P/TSX Composite at the end of 2004 would be worth today, assuming the reinvestment of all dividends.

Source: Thompson Financial



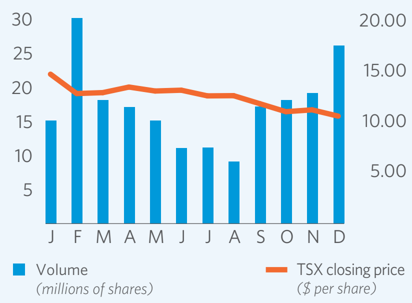
Ten-Year Trading Range and Market Value vs. Book Value

Year ended Dec. 31 *($ per share)*

	05	06	07	08	09	10	11	12	13	14
Market Value	25.41	26.64	33.35	24.30	23.48	21.15	21.02	15.12	13.48	10.52
Book Value	12.80	11.99	11.39	12.70	13.41	12.85	12.08	8.78	7.92	8.52

Amounts presented or included in calculations prior to 2010 represent Canadian Generally Accepted Accounting Principles (GAAP) figures and have not been restated under International Financial Reporting Standards (IFRS).

Source: Thompson Financial and TransAlta

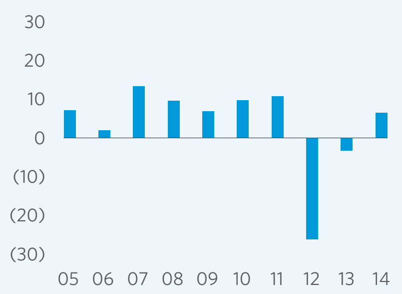


Monthly Volume and Market Prices

(2014)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Volume (millions)	15	30	18	17	15	11	11	9	17	18	19	26
TSX closing price	14.66	12.75	12.84	13.39	13.00	13.08	12.52	12.54	11.75	10.96	11.14	10.52

Source: Thompson Financial



Return on Common Shareholders' Equity

(%)

	05	06	07	08	09	10	11	12	13	14
ROE	7.0	1.8	13.1	9.4	6.9	9.6	10.6	(25.9)	(3.2)	6.3

Amounts presented or included in calculations prior to 2010 represent GAAP figures and have not been restated under IFRS.

During the year, we revised the way in which we calculate our ratios in order to align more closely with how we understand some credit rating agencies calculate them. The figures for 2013 and 2012 have been restated to conform with the current year's presentation.

Source: TransAlta

Corporate Information

Corporate Governance: New York Stock Exchange Disclosure Differences

TransAlta's Corporate Governance Guidelines, Board Charter, Committee Charters, position descriptions for the Chair, Committee Chair, President & CEO, and codes of business conduct and ethics are available on our website at www.transalta.com. Also available on our website is a summary of the significant ways in which TransAlta's corporate governance practices differ from those required to be followed by U.S. domestic companies under the New York Stock Exchange's listing standards. Currently there are no differences between our governance practices and those of the New York Stock Exchange.

Ethics Help-Line

The Audit and Risk Committee of the Board of Directors has established an anonymous and confidential toll-free telephone number, fax line and e-mail address for employees, contractors, shareholders and other stakeholders to call with respect to accounting irregularities, ethical violations, or any other matters they wish to bring to the attention of the Board.

The Ethics Help-Line number is **1.888.806.6646**
Fax: **403.267.7985**
E-mail: **ethics_helpline@transalta.com**

Any communications to the Board of Directors may also be sent to **corporate_secretary@transalta.com**

TransAlta Corporate Officers

Dawn L. Farrell
President and Chief Executive Officer

Donald Tremblay
Chief Financial Officer

Brett M. Gellner
Chief Investment Officer

Dawn E. de Lima
Chief Human Resources and Communications Officer

John H. Kousinioris
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Cynthia Johnston
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Vice-President Legal and Corporate Secretary

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Vice-President and Treasurer

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Vice-President, Gas and Renewables Operations

Aron J. Willis
Vice-President, Australia

Glossary of Key Terms

Alberta Power Purchase Arrangement (PPA)
A long-term arrangement established by regulation for the sale of electric energy from formerly regulated generating units to PPA buyers.

Availability
A measure of time, expressed as a percentage of continuous operation 24 hours a day, 365 days a year, that a generating unit is capable of generating electricity, regardless of whether or not it is actually generating electricity.

Boiler
A device for generating steam for power, processing or heating purposes, or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes of the boiler shell.

Biomass Co-Firing
When used as a supplemental fuel in an existing coal-fired boiler, biomass can provide the following benefits: lower fuel costs, more fuel flexibility, reduced waste to landfills, and reductions in sulfur oxide, nitrogen oxide, and carbon dioxide emissions.

Capacity
The rated continuous load-carrying ability, expressed in megawatts, of generation equipment.

Carbon Capture and Storage (CCS)
An approach to mitigating the contribution of greenhouse gas emissions to global warming, which is based on capturing carbon dioxide emissions from industrial operations and permanently storing them in deep underground formations.

Coal Beneficiation
Beneficiation of coal by reducing ash and/or moisture is found to improve the efficiency of power plant boilers, increase plant capacity factors and reduce the greenhouse gas emissions from power plants.

Cogeneration
A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating, or cooling purposes.

Combined Cycle
An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Derate
To lower the rated electrical capability of a power generating facility or unit.

Expected Capacity
Plant capacity after consideration of station service use, planned outages, forced and maintenance outages, and derates.

Flue Gas Desulphurization Unit (Scrubber)
Equipment used to remove sulphur oxides from the combustion gases of a boiler plant before discharge to the atmosphere. Chemicals, such as lime, are used as the scrubbing media.

Force Majeure
Literally means "greater force". These clauses excuse a party from liability if some unforeseen event beyond the control of that party prevents it from performing its obligations under the contract.

Gasification
Reacting raw material, such as coal, at high temperatures with a controlled amount of oxygen and steam. Carbon dioxide can be removed from the resulting syngas fuel.

Gigajoule (GJ)
A metric unit of energy commonly used in the energy industry. One GJ equals 947,817 Btu.

Gigawatt (GW)
A measure of electric power equal to 1,000 megawatts.

Gigawatt Hour (GWh)
A measure of electricity consumption equivalent to the use of 1,000 megawatts of power over a period of one hour.

Greenhouse Gas (GHG)
Gases having potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, and perfluorocarbons.

Heat Rate
A measure of conversion, expressed as Btu/MWh, of the amount of thermal energy required to generate electrical energy.

Megawatt (MW)
A measure of electric power equal to 1,000,000 watts.

Megawatt Hour (MWh)
A measure of electricity consumption equivalent to the use of 1,000,000 watts of power over a period of one hour.

Merchant Assets
TransAlta uses the term merchant to describe assets that have contracts with terms of less than five years. Given our low-to-moderate risk profile, TransAlta contracts a significant portion of its merchant capability through short and medium-term contracts.

Net Maximum Capacity
The maximum capacity or effective rating, modified for ambient limitations, that a generating unit or power plant can sustain over a specific period, less the capacity used to supply the demand of station service or auxiliary needs.

Oxygen Combustion
Based on the principle that if coal burns in an environment where nitrogen is absent or minimized, the resulting carbon dioxide will be more concentrated and therefore easier to capture.

Renewable Power
Power generated from renewable terrestrial mechanisms including wind, geothermal, solar, and biomass with regeneration.

Reserve Margin
An indication of a market's capacity to meet unusual demand or deal with unforeseen outages/shutdowns of generating capacity.

Spark Spread
A measure of gross margin per MW (sales price less cost of natural gas).

Supercritical Combustion Technology
The most advanced coal-combustion technology in Canada employing a supercritical boiler, high-efficiency multi-stage turbine, flue gas desulphurization unit (scrubber), bag house, and low nitrogen oxide burners.

Turbine
A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam, or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction or a mixture of the two.

Turnaround
Periodic planned shutdown of a generating unit for major maintenance and repairs. Duration is normally in weeks. The time is measured from unit shutdown to putting the unit back on line.

Unplanned Outage
The shutdown of a generating unit due to an unanticipated breakdown.

Uprate
To increase the rated electrical capability of a power generating facility or unit.

Value at Risk (VaR)
A measure used to manage exposure to market risk from commodity risk management activities.

In an effort to be environmentally responsible, please notify your financial institution to avoid duplicate mailings of this annual report.

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