Management's Discussion and Analysis

AltaLink, L.P.

October 30, 2014

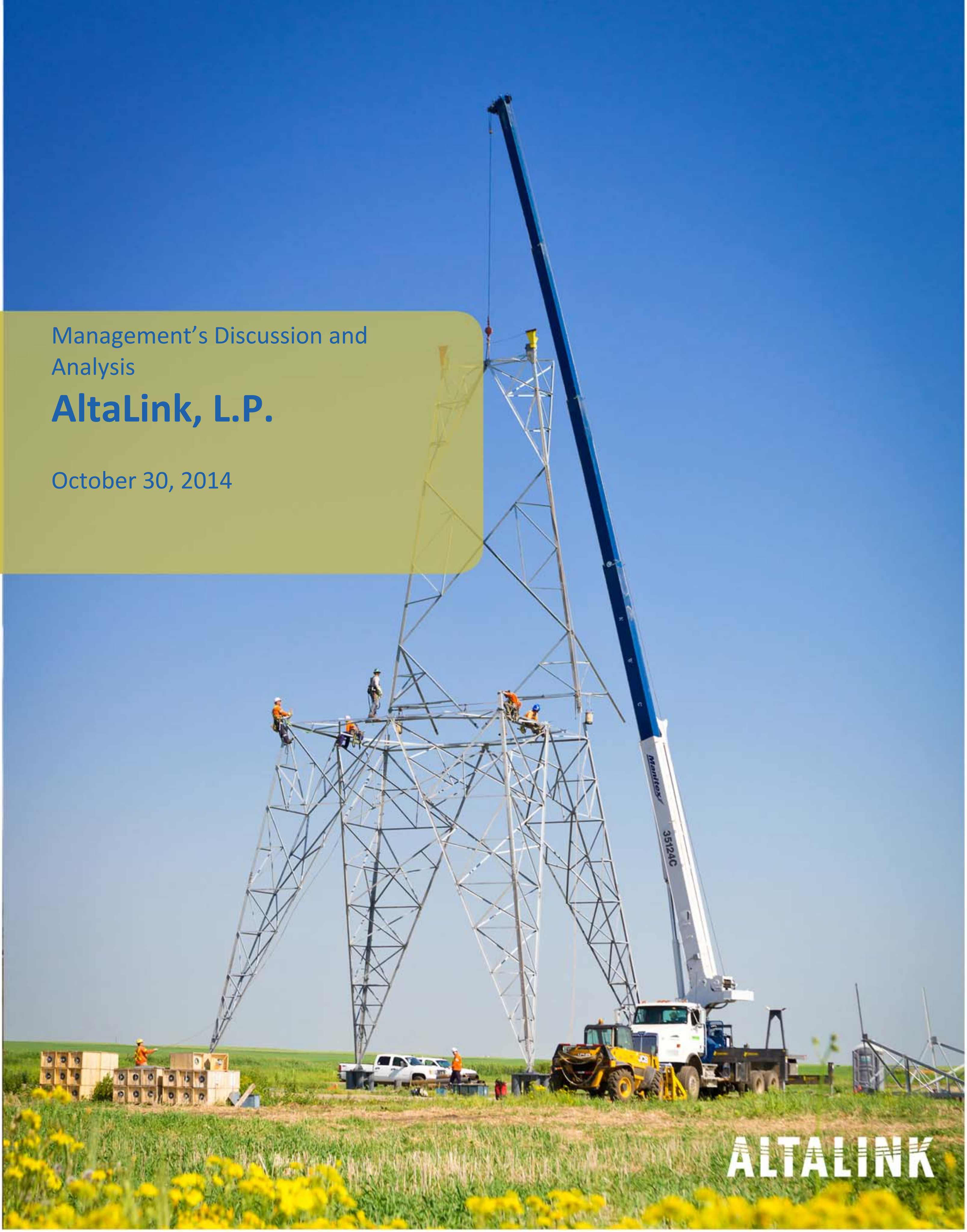


Table of Contents

Management's Discussion and Analysis

This Management's Discussion and Analysis (MD&A) reflects events known to us as of October 30, 2014. This MD&A is intended to provide you with an understanding of our business, our strategy, our performance, our expectations for the future, and how we manage risk and financial resources. Our Board of Directors approved this MD&A on October 30, 2014, based on the recommendation of our Audit Committee, which reviewed this MD&A in accordance with its terms of reference.

You should read this MD&A in conjunction with our legal advisory on Forward Looking Information, which we have included at the end of this MD&A, as well as our unaudited condensed interim financial statements for the three and nine months ended September 30, 2014 and 2013 (Third Quarter Financial Statements), and our audited financial statements for the years ended December 31, 2013 and 2012 (the Financial Statements) and the notes thereto.

The financial information in this MD&A is presented in Canadian dollars, which is our functional currency.

Unless otherwise noted, references in this MD&A to "we", "us", "our", "AltaLink" or "the Partnership" mean AltaLink, L.P. and references to a "quarter" and "year" refer to the three-month period ended September 30, 2014 and the twelve-month period ended December 31, 2013, respectively. References to "AESO" mean Alberta Electric System Operator; "AUC" mean Alberta Utilities Commission; "CEA" mean Canadian Electricity Association; "CWIP" mean Construction Work-In-Progress; "GTA" mean General Tariff Application"; "GCOC" mean Generic Cost of Capital; "IFRS" mean International Financial Reporting Standards; "SNC" mean SNC-Lavalin Group Inc.; and "ATP" mean SNC-Lavalin ATP Inc.

Additional information relating to our business including our Annual Information Form for the year ended December 31, 2013 is available on SEDAR at www.sedar.com.

Executive Summary

Highlights

During the quarter ended September 30, 2014:

- We invested $413.2 million (three months ended September 30, 2013 - $418.6 million) in capital projects to reinforce the reliability of the transmission system for Albertans and to connect new customers to the transmission system;
- We earned comprehensive income of $54.2 million (three months ended September 30, 2013 - $38.4 million); and,
- We put into service four substation projects.

Proposed Sale of AltaLink

On May 1, 2014, SNC announced that it had entered into a binding agreement to sell 100 percent of its interest in AltaLink to MidAmerican (Alberta) Canada Holdings Corporation, which is ultimately owned by Berkshire Hathaway Energy Company (BHE). The parties have received approvals required under the Competition Act and the Investment Canada Act; however, completion of the sale is subject to regulatory approval by the AUC. The parties have filed final arguments with the AUC and we expect that the AUC will issue a decision in 2014. Pending approval of the sale, SNC continues to be the indirect owner of AltaLink. We do not expect the sale to adversely affect our financial strength and we expect BHE to make equity contributions when needed to finance our future capital investments.

In its regulatory filings, BHE has stated that we will continue to be headquartered in Alberta, providing reliable, safe and efficient service to Albertans. We will continue to be regulated by the AUC, which has a history of strong regulation in the province of Alberta. The AESO will continue to direct us on what to build, operate and maintain.

Our Business and Strategies

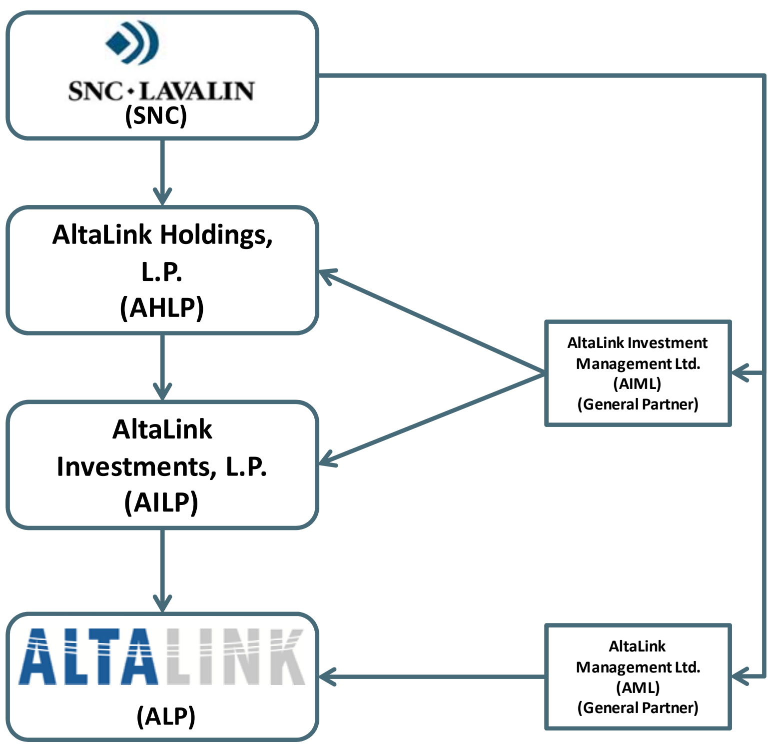
We own and operate regulated electricity transmission facilities in the Province of Alberta. Through our transmission facilities, we deliver electricity safely, reliably and efficiently to approximately 85% of Alberta's population to meet continuously changing customer needs under all operating conditions. We connect generation plants to major load centres, cities and large industrial plants throughout our 212,000 square kilometre service area, which covers a diverse geographic area, including most major urban centres in central and southern Alberta. Our transmission facilities comprise approximately half of the total kilometres in the Alberta Interconnected Electric System, including interconnections with British Columbia's transmission system that link Alberta with the North American western interconnected system.

Our vision is to be the leading owner and operator of regulated electricity transmission in Alberta.

For more details regarding our business and strategies, please refer to the "Our Business and Strategies" section of our MD&A for the year ended December 31, 2013.

Our Partnership Structure

We are a limited partnership, formed under the laws of Alberta on July 3, 2001 pursuant to the Limited Partnership Agreement between AltaLink Management Ltd. (AML), as general partner, and AltaLink Investments, L.P. (AILP), as the sole limited partner. The general partner manages the regulated electricity transmission facilities that we own and operate in the Province of Alberta. Both AILP and its sole limited partner, AltaLink Holdings, L.P. (AHLP) are managed by AltaLink Investment Management Ltd. (AIML).



Our Capability to Deliver Results

We leverage our core competencies and resources to deliver results for our stakeholders.

Financial Strength

We align our financing strategy with the regulated capital structure approved by the AUC and with targets for our key financial metrics. We finance our operations and maintenance capital expenditures from operating cash flows. We intend to fund the growth in capital expenditures from the balance of our operating cash flows, additional borrowings under our capital markets platform, and equity contributions from our limited partner, AILP.

Operations

We design and implement operational, maintenance and capital investment practices to fulfill our commitment to the safe, reliable and cost effective operation of our transmission business. To do so, we employ experienced people with the necessary expertise and knowledge. Our maintenance programs are designed to sustain our existing transmission assets to ensure that those assets operate in an efficient and reliable manner. Our program-based maintenance activities cover the broad functional spectrum of the transmission business, including safety, lines, substations, telecommunications, meters, vehicles, buildings, tools, control centre and information technology. We utilize life extension and long-range asset replacement programs to ensure timely and effective replacement of assets which have reached the end of their useful life.

Capital Project Execution

We execute our capital projects program using an outsourced Engineering, Procurement and Construction Management (EPCM) model. We have entered into contracts with Burns & McDonnell Canada Ltd. and ATP to provide EPCM services for capital projects. This strategic outsourcing arrangement enhances our capability to deliver results to customers by facilitating design and construction of our capital projects in a timely and cost-effective manner.

Organizational Leadership and People

Our leadership team's experience and expertise, combined with our employees' knowledge and dedication to "keeping the lights on" through operational excellence are key to our ability to deliver. We have established a proven track record of reliability, safety and cost effectiveness that compares favourably with our peers and we align our short-term and long-term incentive pay with the needs of our customers.

We strive continuously to attract, retain and develop a high quality workforce to enable us to not only sustain our business, but to remain at the forefront of innovation and continuous improvement. We employ over 800 skilled and dedicated people to deliver on the major transmission projects planned in Alberta.

Environmental Leadership

We provide environmental leadership through innovative practices and sound risk management. In designing and constructing new transmission facilities, we consider ways to reduce land use impacts and improve efficiency. We strive to be leaders in environmental best practices.

Corporate sustainability is one of our core values. Sustainability is important to our overall business strategy, which collectively considers environmental, social and economic aspects in our business planning and decision making. One way that we demonstrate our commitment to sustainability is our Days of Caring initiative, which enables our employees to participate in volunteer opportunities aligned with their personal values.

How We Measure Our Performance

Delivering Customer Value

We use certain key measures to determine whether we are meeting our goals and the needs of our customers. Our performance compares favourably to other transmission facility owners in Canada for reliability, safety and cost effectiveness. Please see our MD&A for the year ended December 31, 2013 for more information on our performance in this area.

Reliability

We have a long-term trend of improving reliability through proactive operating practices and capital investment. Our reliability statistics are consistently better than those of our peers, as reported by the CEA.

A strong, efficient, and reliable transmission system ensures Albertans have access to multiple generation resources from across the province, instead of a limited number of local generation sources. A reliable transmission system also ensures that all generators compete, driving down the price of energy and producing the electricity required to keep Alberta's economy growing.

We operate our transmission system so as to minimize disruption of service to our customers. Nevertheless, severe weather and other unplanned events cause service disruptions to which we respond as quickly as possible. During the twelve months ended September 30, 2014, the duration of service disruptions was similar to levels we experienced in the corresponding period in 2013, as noted in the table below. We also experienced a decrease in the frequency of service disruptions compared to the preceding twelve-month period.

	Twelve months ended	
	September 30, 2014	September 30, 2013
Duration of outages (SAIDI)[1]	**0.87**	0.81
Frequency of outages (SAIFI)[2]	**0.59**	0.72

1. System Availability Interruption Duration Index is the average number of interruption hours per delivery point during a twelve-month period.
2. System Availability Interruption Frequency Index is the average number of interruptions per delivery point during a twelve-month period.

Safety

Our safety management initiatives encompass all aspects of our safety systems, and our safety statistics are consistently stronger than our peers. Our safety statistics include all man-hours worked by contractors and sub-contractors. We strive to continuously improve our safety performance through focused training and our ongoing commitment to our safety culture and safety management processes. During the twelve months ended September 30, 2014, our workplace All Injury Frequency Rate was similar to the rate for the preceding twelve-month period.

	Twelve months ended	
	September 30, 2014	September 30, 2013
All Injury Frequency Rate[1]		
AltaLink	0.81	0.83

1. Number of lost time accidents and medical aid incidents per 200,000 man hours worked by employees and contractors.

Cost Effectiveness

Electricity is at the core of our economy and critical to our society. Therefore, we focus on ensuring reliability of supply to our customers, while delivering services cost effectively. Our continuous improvement culture embraces our project execution programs, maintenance process, centralized work planning, and scheduling. We continue to seek business improvements across our organization while delivering reliable and safe transmission service to our customers.

Financial and Operational Performance

Transmission Tariffs
We recognize revenue based on transmission tariffs approved by the AUC, including adjustments arising from deferral accounts established under those tariffs.

In January 2014, we submitted a compliance filing to the AUC, as directed in Decisions 2013-407 and 2013-459. In the compliance filing, we requested approval from the AUC of revised revenue requirements of $481.3 million and $621.4 million for 2013 and 2014, respectively. On September 8, 2014, the AUC issued Decision 2014-258 approving our compliance filing, as filed, and directed us to invoice the AESO from September 1, 2014 to December 31, 2014 for $60.0 million per month to collect the difference between the final approved tariff and the amount collected in the interim.

We plan to file our general tariff application for the 2015 and 2016 test years during the fourth quarter of 2014. Shortly thereafter, we will file an application with the AUC to set an interim monthly tariff for 2015. Until the 2015 interim monthly tariff is approved, monthly tariffs will remain at the approved 2014 rates.

In Decision 2013-459, the AUC directed us to use a placeholder rate of return on common equity of 8.75% for 2013 and each subsequent year thereafter, pending a final decision on its ongoing GCOC proceeding, for which the AUC has completed its oral hearing and received arguments from all parties.

Growth in Regulated Capital Assets
Continued investment in our regulated capital assets (both rate base and CWIP) provides reliability of supply of transmission service to our customers and is one of the key indicators of future revenue streams. As a regulated utility, we earn most of our net income from allowed returns on equity invested in our regulated capital assets. We calculate our allowed returns on equity by multiplying our mid-year investments in rate base and CWIP by the equity ratio and rate of return approved by the AUC. Our operating cash flow relates primarily to (i) the return on equity on our rate base and, as approved in the 2013-2014 GTA Decision, most of our CWIP; (ii) recovery of deemed income taxes; and (iii) recovery of depreciation on our rate base assets.

For the nine months ended September 30, 2014 our capital expenditure program included approximately $1.3 billion of expansion projects directly assigned to us by the AESO and $79.1 million of capital replacement and upgrade projects.

In the compliance filing for our 2013 - 2014 GTA, we forecasted our 2014 gross direct assigned capital expenditures to be approximately $1.7 billion. Our actual capital program may vary from our regulatory filings, depending on the timing of regulatory approvals, directions from the AESO, and other factors beyond our control. Please see the Major Capital Projects section of our MD&A for the year ended December 31, 2013 for a discussion of certain developments that may materially impact our capital expenditure outlook.

On January 31, 2014, the AESO released an update to its long range capital plan. We intend to provide an updated long-term capital plan in our 2015-16 GTA, which we intend to file in 2014.

Regulated Tariff Revenue

We are an electric utility regulated by the AUC, pursuant to the Electric Utilities Act (Alberta), the Public Utilities Act (Alberta), the Alberta Utilities Commission Act (Alberta) and the Hydro and Electric Energy Act (Alberta). Through various regulatory decisions, these statutes and their respective regulations impact our tariffs, rates, construction, operations and financing.

We receive all of our regulated transmission tariffs, including settlements of deferral and reserve accounts, from the AESO. We and other transmission facility owners are permitted to charge a tariff for the use of our transmission facilities. Such tariffs are regulated by the AUC under the provisions of the Electric Utilities Act in respect of rates and terms and conditions of service. Under the Transmission Regulation, the AUC must consider that it is in the public interest to provide consumers the benefit of unconstrained transmission access to competitive generation and the wholesale electricity market. In regulating transmission tariffs, the AUC must facilitate sufficient investment to ensure the timely upgrade, enhancement or expansion of transmission facilities, and foster a stable investment climate and a continued stream of capital investment for the transmission system.

Major Capital Projects

Transmission Planning and Development

In September 2014, the Government of Alberta amended the Transmission Regulation and enacted a new regulation – the *Transmission Deficiency Regulation*. The Transmission Regulation amendments are technical amendments concerning changes in timing and authority for certain components of the transmission facility approval process, including the legislative requirement for a Need Identification Document. These amendments are not expected to have a material impact on our ability to obtain approval for future facility applications.

The Transmission Deficiency Regulation implements the Province's Market Participant Choice (MPC) and Approved Cost Estimate (ACE) initiatives. MPC allows a Market Participant to construct their own interconnection to the grid in certain circumstances. After an agreed upon period of time, the Market Participant must transfer ownership of the interconnection to the transmission facility owner (TFO) in whose service territory it is located. The Market Participant remains responsible for any costs incurred by the TFO as a result of actions taken by the user during design or construction of the interconnection facility. If the TFO is unable to recover such costs from the Market Participant, the regulation outlines procedures to allow the TFO to recover the costs. These amendments are not expected to have a material impact on our ability to recover costs associated with customer-constructed facilities.

The ACE provisions require a TFO to submit a cost estimate for designated projects to the AUC for approval after obtaining a Permit to Construct. The AUC may make rules for the ACE process and may approve an amount higher or lower than the estimate submitted by the TFO. Actual project costs must be considered prudent if the costs are equal to or less than the ACE. These amendments are not expected to have a material impact on our ability to recover costs associated with projects.

For further details on transmission planning and development in Alberta, please refer to the "Major Capital Projects" section in our MD&A for the year ended December 31, 2013.

Overview

The following table is an overview of the main projects currently in progress:

Project/ Description	Need Application	Facility Application	Status
Southern Alberta Transmission Reinforcement Large scale project to construct transmission lines and substations across southern Alberta to interconnect up to 2,700 MW of proposed wind generation projects. **Stage I**	AUC approved in 2009	• All applications approved.	• Cassils-Bowmanton energized in December 2013 and Bowmanton to Whitla energized in March 2014. • South Foothills scheduled for 2015 completion.
Stage II	AUC approved in 2009	• One application approved in Q4, 2013. • Multiple applications planned in 2015.	• Construction scheduled for 2016 completion.
Western Alberta Transmission Line Reinforce system backbone between Edmonton and Calgary with a HVDC transmission line and converter substations.	CTI designation in 2009	• Approved in 2012.	• Construction scheduled for 2015 completion.

Project/ Description	Need Application	Facility Application	Status
Heartland Region Transmission Development Double-circuit 500kV transmission line between the Ellerslie Substation and a new substation in the Gibbons-Redwater area and 240kV loop from the new substation to service industrial load.	CTI designation in 2009	• Approved in 2011.	• Completed.
Edmonton Region Transmission System Upgrade Debottleneck 240kV system for load growth and decommissioning of coal-fired generation.	AUC approved in 2009	• All applications approved.	• Completion delayed on one segment due to land access issues.
Foothills Area Transmission Development Expand and construct substations and transmission lines in south Calgary region to reinforce local transmission and further interconnect wind energy into the AIES.	AUC approved in 2013	• All applications approved.	• Construction scheduled for completion in 2015.
Christina Lake Area Development Construction of 240kV transmission line and substations in the Christina Lake area to meet forecasted load growth.	AUC approved in 2012	• All applications approved.	• Black Spruce completed in 2013 and Pike completed in June 2014. • Ipiatik scheduled for completion in 2015.
Red Deer Region Transmission Development Reinforcement and enhancements of the transmission system in the central Alberta region.	AUC approved in 2012	• Two applications approved. • One application filed in 2014. • Two applications planned for 2015.	• One completed. • Awaiting AUC decision.

CTI – Critical Transmission Infrastructure

Non-GAAP Financial Measures

We use certain financial metrics that are not defined under accounting principles generally accepted in Canada, i.e. IFRS.

These non-GAAP financial measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies.

For more details regarding our non-GAAP financial measures, please refer to the "Non-GAAP Financial Measures" section of our MD&A for the year ended December 31, 2013.

Financial Position and Cash Flows

Financial Position

In the following table, we discuss significant changes (over $30.0 million) in our Statement of Financial Position during the nine months ended September 30, 2014. Our Third Quarter Financial Statements include more detailed information regarding the changes in our property, plant and equipment.

	Increase/(Decrease) ($ Millions)	Explanation
Property, plant and equipment (Note 7)	1,259.0	We added $1.4 billion to capital assets and construction work-in-progress, partially offset by $111.0 million in depreciation.
Third party deposits (Note 8)	(32.1)	We received $47.1 million from our customers to fund projects that we build on their behalf and applied $79.2 million to such projects.
Trade and other payables and other non-current liabilities (Note 9)	178.4	Trade payables increased due to the level of capital construction activity in 2014.
Commercial paper and bank credit facilities (Note 10(a))	(33.2)	We repaid a portion of short-term debt with proceeds from long-term debt issued in 2014.
Long-term debt (Note 10(b))	695.7	We issued Medium-Term Notes to finance our capital expenditure program.
Deferred revenue (Note 11)	66.1	We transferred $79.1 million of third party deposits and $16.0 million of funding for salvage costs into deferred revenue. We also recognized $14.6 million of revenue to fund salvage costs, and amortized $14.4 million of third party contributions.
Partner's equity	391.2	We received $276.6 million in equity injections from AILP and generated comprehensive income of $149.4 million. We distributed $34.8 million to our partners.

Cash Flows

	Three months ended		Nine months ended	
	September 30, 2014	September 30, 2013	**September 30, 2014**	September 30, 2013
(in millions of dollars)				
Cash and cash equivalents, beginning of period	**$ 7.1**	$ —	**$ 5.9**	$ 9.2
Cash flow provided by (used in):				
Operating activities	**104.1**	88.2	**253.1**	334.7
Investing activities	**(388.6)**	(374.5)	**(1,156.3)**	(886.5)
Financing activities	**283.7**	286.3	**903.6**	542.6
Cash and cash equivalents, end of period	**$ 6.3**	$ —	**$ 6.3**	$ —

Operating Activities

For the three months ended September 30, 2014, our cash flow from operating activities increased by $15.9 million compared to the same period in 2013. The change is primarily due to an increase in net income, increase in the recovery of depreciation and amortization, and an increase in accounts payable.

For the nine months ended September 30, 2014, our cash flow from operating activities decreased by $81.6 million compared to the same period in 2013, mainly due to the timing of receipt of regulatory decisions. In the first quarter of 2013, we collected over $104.3 million of year-end receivables due from the AESO. In the third quarter of 2014, we have significant accruals for amounts to be collected from the AESO over the remaining months in 2014.

Investing Activities

Compared to the same periods in 2013, our cash flow used in investing activities increased by $14.1 million and $269.8 million for the three and nine months ended September 30, 2014, respectively, primarily due to higher investment in new transmission facilities. We incurred most of our 2014 capital expenditures in connection with major capital projects that we discuss in more detail in the Major Capital Projects section.

Financing Activities

For the three months ended September 30, 2014, cash flow provided by financing activities decreased by $2.6 million compared to the same period in 2013. We issued $225.0 million of Medium-Term Notes, received $90.9 million in equity contributions from AILP, repaid $13.4 million of commercial paper and distributed $11.8 million to AILP. During the same period in 2013, we issued $725.0 million of Medium-Term Notes, received $12.0 million of equity, repaid $436.9 million of commercial paper, and distributed $9.8 million to AILP.

For the nine months ended September 30, 2014, cash flow provided by financing activities increased by $361.0 million compared to the same period in 2013. We issued $705.0 million of Medium-Term Notes and repaid $33.2 million of commercial paper. We also received equity contributions of $276.6 million and distributed $34.8 million to AILP. During the same period in 2013, we issued $725.0 million and repaid $325.0 million of Medium-Term Notes, received $112.5 million of equity, issued $64.0 million of commercial paper, and distributed $29.4 million to AILP.

Commitments

We have contractual commitments for the repayment of long-term debt of approximately $3.4 billion, as disclosed in note 10(c) – *Scheduled principal repayments*, in our Third Quarter Financial Statements.

We are committed to operating leases that have lease terms, which expire between 2014 and 2026. Of the total expected minimum lease payments, approximately 91% relates to our head office leases. See note 15 – *Commitments*, in our Third Quarter Financial Statements.

We also have contractual commitments for the purchase of property, plant and equipment as at September 30, 2014 of approximately $1.4 billion. Of these commitments, approximately 88% are with ATP, a wholly-owned subsidiary of SNC.

Liquidity and Capital Resources

Liquidity

We generally issue commercial paper to finance our day-to-day cash requirements. The commercial paper program, together with our two lines of credit and anticipated long-term debt issuance, provides us with sufficient liquidity to finance our planned operations and capital projects.

The aggregate of our bank credit facilities at September 30, 2014 was $1.3 billion (December 31, 2013 - $1.3 billion). The $1.2 billion commercial paper backstop facility provides support to our commercial paper program, under which $5.6 million (December 31, 2013 – $42.5 million) was outstanding as at September 30, 2014. All bank credit facilities may be used for general corporate purposes. As at September 30, 2014, we had approximately $1.3 billion of liquidity remaining under those facilities.

We consider our liquidity arrangements to be adequate to accommodate our expected capital expenditures and working capital requirements over the next few years.

During 2014, we issued $350.0 million of Series 2014-1 and $130.0 million of Series 2014-2 Medium-Term Notes. We also re-opened our existing 2012-1 Medium-Term Notes to issue an additional $225.0 million at a discount of $5.9 million, resulting in net proceeds of $219.1 million. This discount will be amortized over the term of the related debt.

As at September 30, 2014, we have issued $2,205.0 million (December 31, 2013 - $1,500.0 million) of Medium-Term Notes under the $2,500.00 million Short Form Base Shelf Prospectus, which expires in December 2014.

We plan to finance our projected capital investments, working capital requirements and any maturities of long-term debt through a prudent combination of cash flow from operating activities, new long-term debt, and equity contributions from AILP.

We use short-term interest-bearing instruments with major Canadian banks to invest temporary cash balances and amounts we receive from customers in advance of construction and operating and maintenance charges. We remit to the AESO all investment income related to deposits received from customers for construction projects and retain investment income we earn on deposits received from customers for future operating and maintenance costs.

Liquidity, Coverage and Capital Ratios [1]

	Twelve months ended September 30, 2014	2013
(in millions)		
Net income	**$ 212.1**	$ 131.1
Loss on disposal of assets	**11.3**	1.6
Finance costs	**123.7**	83.4
EBIT	**347.1**	216.1
Depreciation and amortization	**166.0**	121.4
EBITDA	**513.1**	337.5
Finance costs	**(123.7)**	(83.4)
FFO	**$ 389.4**	$ 254.1
Interest expense	**$ 124.3**	$ 82.8

	As at September 30, 2014	2013
Letters of credit	**$ 5.9**	$ 1.6
Short-term debt	**9.3**	65.7
Long-term debt	**3,400.2**	2,201.5
Total debt	**3,415.4**	2,268.8
Total equity	**2,204.8**	1,531.6
Total capitalization	**$ 5,620.2**	$ 3,800.4

	Twelve months ended September 30, 2014	2013
EBIT interest coverage	**2.79X**	2.61X
EBITDA interest coverage	**4.13X**	4.07X
FFO interest coverage	**3.13X**	3.07X
FFO/Debt	**11.40%**	11.20%
Total debt/total capitalization [2]	**60.77%**	59.70%

1. Refer to "Non-GAAP Financial Measures" for further information concerning the non-GAAP financial measures used in this table. The methodology for calculating EBIT, EBITDA and FFO has changed this quarter to better align with the methods used by our rating agencies.
2. The AltaLink Master Trust Indenture contains a debt to total capitalization covenant with a limit of 75%.

Working Capital

At September 30, 2014, our working capital deficiency was $531.8 million, compared with approximately $646.8 million at September 30, 2013. The working capital deficiency includes drawn bank credit, commercial paper and trade payables.

In the future, we expect that we will continue to have a working capital deficiency due to our system expansion plans. The electricity transmission industry is a long-cycle capital-intensive business that requires sufficient cash to fund capital expansion projects and planned maintenance. We fund our transmission business from cash provided by operating activities, and to the extent necessary, through equity injections from AILP and borrowings under our commercial paper program or drawings on our committed bank credit facilities.

Earnings Coverage

	Twelve months ended September 30, 2014	2013
Earnings-to-interest coverage on total debt [1,2]	**2.34X[3]**	1.89X[3]

1. Earnings-to-interest coverage on total debt is a non-GAAP financial measure. As a result of distributing securities by way of a medium-term note program using the debt shelf procedures, we must include updated earnings coverage ratios in conjunction with our financial statements. Refer to "Non-GAAP Financial Measures" for further information concerning the non-GAAP financial measures used in this MD&A.
2. Earnings-to-interest coverage on total debt equals income before interest expense (including amortization of deferred financing fees) on all indebtedness and income taxes divided by annual interest requirements on long-term debt (including capitalized interest). We calculate this ratio by giving pro-forma effect to any long-term debt issued during the period and the use of the proceeds from such long-term debt issues.
3. Our interest requirement on short and long-term debt for the twelve months ended September 30, 2014 was $145.4 million (September 30, 2013 - $113.0 million), including the pro-forma effect of interest payable on the Series 2012-1 (reopener), 2013-1, 2013-2, 2013-3, 2013-4, 2014-1 and 2014-2 Medium-Term Notes. Our earnings before interest and income tax for the twelve months ended September 30, 2014, for the purposes of calculating this ratio, were approximately $340.3 million (September 30, 2013 - $213.9 million).

Credit Ratings

	Nine months ended September 30, 2014	2013
DBRS - Commercial Paper[1]	**R-1 (low)**	R-1 (low)
DBRS - Medium-Term Notes (secured) [1]	**A**	A
Standard & Poor's - Medium-Term Notes (secured) [2]	**A-**	A-

1. On May 2, 2014, DBRS placed the "A" rated Medium-Term Notes and the R-1 (low) rated Commercial Paper of AltaLink Under Review with Developing Implications. This action followed the announcement that Berkshire Hathaway Energy Company ("BHE") has agreed to purchase AltaLink from SNC-Lavalin Group Inc. DBRS also stated the ratings of AltaLink will likely be removed from Under Review with Developing Implications should the purchase by BHE be executed as planned. On May 29, 2014 DBRS confirmed these ratings.
2. On January 17, 2014, Standard & Poor's confirmed the above rating and revised their outlook from negative to stable. The rating was affirmed by Standard & Poor's on May 5, 2014.

Results of Operations

Revenue

	Three months ended		Nine months ended	
	September 30, 2014	September 30, 2013	**September 30, 2014**	September 30, 2013
(in millions of dollars)				
Operations	**$ 169.9**	$ 118.4	**$ 478.0**	$ 332.1
Other	**13.6**	7.1	**31.4**	20.1

Revenue From Operations

Revenue from operations includes all revenue earned from providing electricity transmission services. The principal components of our transmission tariff include recovery of forecast operating costs, deemed income taxes, depreciation and amortization expenses, and return on rate base.

Compared to the same periods in 2013, our revenue from operations increased by $51.5 million and $145.9 million for the three and nine months ended September 30, 2014, respectively, primarily due to additional return from our increased investments in capital assets.

Other Revenue

Other revenue includes revenue received from third parties, including contributions towards the construction of certain assets.

Compared to the same periods in 2013, cost recovery revenue from third parties increased by $6.5 million and $11.3 million for the three and nine months ended September 30, 2014, respectively. Revenue associated with costs recovered from third parties has no net income impact. The variances are primarily due to the volume of transmission construction services provided to third parties during these periods, which fluctuates in response to the need for such services and is not predictable.

Comprehensive Income

	Three months ended		**Nine months ended**	
	September 30, 2014	September 30, 2013	**September 30, 2014**	September 30, 2013
(in millions of dollars)				
Comprehensive Income	**$ 54.2**	$ 38.4	**$ 149.4**	$ 98.6

Our comprehensive income for the three and nine months ended September 30, 2014 increased by $15.8 million and $50.8 million, respectively, compared to the same periods in 2013, primarily due to increased return from our investment in electricity transmission infrastructure.

Operating Expenses

	Three months ended		**Nine months ended**	
	September 30, 2014	September 30, 2013	**September 30, 2014**	September 30, 2013
(in millions of dollars)				
Operating expenses	**$ 28.7**	$ 22.6	**$ 82.1**	$ 64.5

Our operating expenses include salaries and wages, contracted manpower and general and administration costs. Our operating expenses for the three and nine months ended September 30, 2014 increased by $6.1 million and $17.6 million, respectively, compared to the same periods in 2013. The increase is due to a higher number of employees in 2014 compared to 2013 and the corresponding increase in salaries and benefits, including incentive payments, as well as increased contracted labour costs.

Property Taxes, Salvage, and Other

	Three months ended		**Nine months ended**	
	September 30, 2014	September 30, 2013	**September 30, 2014**	September 30, 2013
(in millions of dollars)				
Property taxes, salvage and other	**$ 21.4**	$ 12.8	**$ 54.6**	$ 36.4

Property taxes, salvage and other expenses are recovered dollar for dollar through regulated deferral and reserve account mechanisms. To the extent that actual costs vary from amounts approved in our tariff, the difference is refunded to or collected from the AESO.

Our property taxes, salvage and other expenses increased by $8.6 million and $18.2 million, respectively, for the three and nine months ended September 30, 2014 compared to the same periods in 2013. The increase for the quarter is mainly the cost of repairing facilities as a result of the 2013 flood, which have been transferred from CWIP to the self insurance reserve. For the year-to-date, the increase is due to flood recovery costs, the timing of salvage costs incurred, increases in annual structure payments and property tax expense as a result of assets put into service. For more details of these costs, please see Note 14(b) of the Q3 financial statements.

Depreciation and Amortization

	Three months ended		Nine months ended	
	September 30, 2014	September 30, 2013	**September 30, 2014**	September 30, 2013
(in millions of dollars)				
Depreciation and amortization	**$ 42.4**	$ 30.9	**$ 123.0**	$ 90.1

We calculate depreciation and amortization on a straight-line basis using various rates which are approved by the AUC. Depreciation for the three and nine months ended September 30, 2014 increased by $11.5 million and $32.9 million, respectively, compared to the same periods in 2013, primarily as a result of an increase in capital projects that have been completed and added to our regulatory rate base.

Finance Costs

	Three months ended		Nine months ended	
	September 30, 2014	September 30, 2013	**September 30, 2014**	September 30, 2013
(in millions of dollars)				
Finance costs	**$ 34.7**	$ 21.1	**$ 95.3**	$ 62.8

Finance costs include interest costs and amortization of deferred financing fees less capitalized borrowing costs. Our interest expense for the three and nine months ended September 30, 2014 increased by $13.6 million and $32.5 million, respectively, compared to the same periods in 2013, primarily due to interest costs on approximately $1.2 billion of long-term debt that was issued in the last twelve months.

Earnings before Interest, Taxes, Depreciation and Amortization (EBITDA)

	Three months ended		Nine months ended	
	September 30, 2014	September 30, 2013	**September 30, 2014**	September 30, 2013
(in millions of dollars)				
EBITDA	**$ 133.5**	$ 90.0	**$ 372.7**	$ 251.3

Our EBITDA for the three and nine months ended September 30, 2014 increased by $43.5 million and $121.4 million, respectively, compared to the same periods in 2013. The reason for this increase is similar to that noted above for the change in our comprehensive income for the same period. Please refer to "Non-GAAP Financial Measures" for more information about how we calculate EBITDA.

Selected Financial Information Derived from our Financial Statements

	Three months ended		Nine months ended	
	September 30, 2014	September 30, 2013	**September 30, 2014**	September 30, 2013
Net income per unit ($/unit)	**0.163**	0.116	**0.450**	0.298
Distributions per unit ($/unit)	**0.036**	0.030	**0.105**	0.089
Total assets ($ millions)	**7,127.1**	5,327.0	**7,127.1**	5,327.0
Short and long-term debt ($ millions) [1]	**3,409.5**	2,267.2	**3,409.5**	2,267.2

1. The balance is shown before deducting the deferred financing fees, which have been offset against this amount in the Financial Statements, in accordance with IFRS.

Summary of Quarterly Financial Information

Quarter ended	Revenue ($ millions)	Net income ($ millions)	Units outstanding (millions)	Net income per unit ($/unit)
September 30, 2014	**183.6**	**54.2**	**331.9**	**0.163**
June 30, 2014	168.5	49.0	331.9	0.148
March 31, 2014	157.4	46.2	331.9	0.139
December 31, 2013	181.9	62.7	331.9	0.189
September 30, 2013	125.5	38.4	331.9	0.116
June 30, 2013	117.5	33.4	331.9	0.100
March 31, 2013	109.2	27.2	331.9	0.082
December 31, 2012	119.8	32.2	331.9	0.097
September 30, 2012	97.6	27.3	331.9	0.082
June 30, 2012	96.7	25.9	331.9	0.078
March 31, 2012	92.5	22.9	331.9	0.069
December 31, 2011	122.5	30.7	331.9	0.092

Risk Management

Our transmission business is subject to risks and uncertainties, including those described below. Our goal is to manage these risks to reasonably protect us from unacceptable outcomes including undesirable financial results. You should carefully consider these risk factors and uncertainties in addition to the other information contained in this MD&A, the corresponding financial statements, our Annual Information Form, press releases, material change reports and our other continuous disclosure documents. For more details regarding our risk factors and uncertainties, please refer to the "Risk Factors and Uncertainties" section of our MD&A for the year ended December 31, 2013.

Risk Controls and Other Mitigating Measures

We have instituted controls and other mitigating measures to manage the risks we face. Under our risk management program, we conduct annual risk evaluations to identify and assess our most significant risks and the strategies through which we manage them.

Insurance and Statutory Liability Protection

Our current insurance policies provide coverage for a variety of losses and expenses that could impact our business. This insurance coverage includes general liability, physical loss of or damage to property and boiler and machinery (including substations), property, terrorism, directors' and officers' liability, fiduciary liability, employment practices liability, crime, non-owned aircraft liability, and vehicle liability. We believe the extent of this coverage is prudent in the context of our transmission business and utility industry practice, and we anticipate that this coverage will be maintained.

Consistent with past AUC decisions, we do not carry insurance for loss of, or damage to, transmission lines, towers, poles, or physical damage to certain owned vehicles. It is not always possible or economically feasible to insure against all risks on our assets or for other exposure to liabilities, and we may decide not to carry insurance against certain risks as a result of high premiums or for other reasons. In accordance with prudent industry practice and AUC directives, we self insure against certain risks for which commercial insurance is not maintained. In the event of an uninsured loss greater than $100,000, we would apply to the AUC to recover the loss through increased funding to our self-insurance reserve or through an increased tariff.

The Liability Protection Regulation limits our liability in the course of carrying out our duties, responsibilities and functions under the Electric Utilities Act to direct loss or damage arising from our negligence, wilful misconduct or breach of contract. Direct loss or damage is defined in the regulation to exclude loss of profits, loss of revenue, loss of production, loss of earnings, loss of contract or other indirect, special or consequential loss or damage.

Risk Factors and Uncertainties

Despite our initiatives in managing risks, there can be no assurance that one or more of them will not adversely affect our business. Our results of operations, financial position and performance and, accordingly, the value of our outstanding securities, could be adversely affected if we are unable to adequately control or mitigate the effects of such risks on our business.

The following are the more significant items that have an impact on our financial position and results of operations. Risk factors and uncertainties have not materially changed during three and nine months ended September 30, 2014.

- Regulated operations
- Project execution
- Regulatory financial
- Reliability
- Restructuring of electricity industry
- Capital resources
- Labour relations
- Availability of people
- Environment, health and safety
- Electric and magnetic fields
- Annual impairment tests
- Competition
- Credit ratings
- Cyber security
- Utility asset disposition decision and Slave Lake decision regarding stranded assets.

Transactions with Related Parties

In the normal course of business, we enter into various transactions with AML, AILP, AIML, and AHLP. We record these transactions at exchange values based on normal commercial rates. AML employs the people who provide administrative and operational services to our business. We have indemnified AML for all associated expenses and liabilities.

We have incurred construction related services costs of $331.1 million and $1,001.7 million with ATP during the three and nine months ended September 30, 2014, compared to $412.7 million and $1,156.5 million, respectively, for the same periods in 2013. On September 30, 2014, our accounts payable and accrued liabilities included $456.9 million owing to ATP, compared to $287.9 million at December 31, 2013.

Please see note 12 – *Related party transactions* in the Third Quarter Financial Statements for more details.

Legal Proceedings and Contingencies

We have not commenced and are not currently contemplating any legal proceedings that would have a material impact on our financial results.

From time to time we are subject to legal proceedings, assessments, claims and regulatory matters in the ordinary course of business.

In June, 2009, we were served with an action alleging that we and the Plaintiff had concluded a binding agreement for the sale to the Plaintiff of certain lands.

In addition, in September 2014, we and TransAlta Utilities were served with a number of actions in relation to a grass fire that occurred in 2012. The Plaintiffs allege that damage was caused to cultivated and grazing land, fences and housing by a failure of transmission equipment and that there was soil erosion, loss of use of grazing land, and impacts to crop yield as a result of the fire. They claim that the fire was a result of negligence by us and TransAlta in operating, maintaining and repairing the transmission equipment.

We intend to defend ourselves vigorously against these claims. If we were not successful in our defence related to the grass fire action, we have insurance in place that would meet the costs of any judgement awarded against us. At this time, in our opinion, we do not expect that any of these matters will result in a material adverse effect on our financial position or financial performance.

Off Balance Sheet Arrangements

Disclosure is required of all off-balance sheet 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 off-balance sheet arrangements. Please see note 15 – *Commitments* in the Third Quarter Financial Statements for details of capital and lease commitments.

Critical Accounting Estimates

The preparation of our financial statements requires us to make estimates and assumptions that affect amounts reported in the financial statements and accompanying notes. The more significant estimates that have an impact on our financial condition and the results of our operations are disclosed in note 2(d) – *Use of estimates and judgement*, in the Third Quarter Financial Statements.

Accounting Changes

Please see note 3(e) in the Third Quarter Financial Statements for more details regarding our assessment of the impact on our financial statements of adopting the following new or revised standards.

IFRS for entities with rate-regulated activities

IFRS 14 – *Regulatory deferral accounts* was issued by the IASB in January 2014 to provide interim guidance for the recognition of amounts related to rate-regulated activities until the IASB completes its comprehensive project on this topic. IFRS 14 is effective for financial periods beginning on or after January 1, 2016. As the interim standard is restricted to first-time adopters of IFRS, and we have been fully compliant with IFRS since 2011, this interim standard does not have any impact on our financial statements or disclosures.

The IASB regulatory activities consultative group was active in the development of the interim standard and continues to be involved in the wider research project, which we anticipate will result in full recognition of assets and liabilities arising from regulated activities. The IASB issued a Discussion Paper with respect to the comprehensive project on September 17, 2014 in which it describes a type of rate regulation that contains elements of both cost recovery and incentive approaches. The Discussion Paper refers to this as "defined rate regulation".

Adoption of standards and amendments effective on or after January 1, 2014

In May, 2013, the IASB issued IFRIC Interpretation 21 – *Levies*. The interpretation is effective from January 1, 2014 and provides guidance on the accounting for levies, other than income taxes, imposed on reporting entities by governments. The interpretation clarifies the obligating event that gives rise to a liability to pay a levy.

We implemented these requirements in the first quarter of 2014. They did not have any effect on our financial statements.

The IASB also issued amendments to a number of standards under its Annual Improvement Projects for 2010-2012 and 2011-2013. These amendments did not have a material impact on our financial statements.

Standards and amendments that will be effective after 2014

IFRS 15 – *Revenue from contracts with customers* was issued jointly by the IASB and the US Financial Accounting Standards Board in May 2014 to provide a single revenue model to use in the recognition of revenue from contracts with customers. IFRS 15 is effective for financial periods beginning on or after January 1, 2017. We are evaluating the impact of this standard on our financial statements.

In the second quarter of 2014, the IASB issued amendments to the following standards: IFRS 11 – *Accounting for acquisitions of interests in joint operations,* IAS 16 – *Property, plant and equipment,* and IAS 38 – *Clarification of acceptable methods of depreciation and amortization* amendments. These amendments are effective for financial periods beginning on or after January 1, 2016. We are evaluating the impact of these amendments on our financial statements and we do not expect them to have any material impact.

On September 25, 2014, the IASB also issued amendments to four standards under its Annual Improvements Project for 2012-2014. The following amendments are effective for financial periods beginning on or after January 1, 2016: IFRS 5 – *Non-current assets held for sale and discontinued operations*, IFRS 7 – *Financial instruments: disclosures*, IAS 19 – *Employee benefits*, and IAS 34 – *Interim financial reporting*. These are relatively minor amendments and we are evaluating the impact of these amendments on our financial statements.

In addition, the IASB issued narrow-scope amendments to IAS 27 – *Separate financial statements* in August 2014, and to IFRS 10 – *Consolidated financial statements*, and IAS 28 – *Investments in associates and joint ventures* in September 2014. These amendments are effective for financial periods beginning on or after January 1, 2016. These are relatively minor amendments and we are evaluating the impact of these amendments on our financial statements.

Future Accounting Changes That May Impact Our Financial Statements

Update on the International Accounting Standards Board (IASB) work plan and rate-regulated project

The first component of the IASB's comprehensive rate-regulated activities project has been completed, with the issuance of IFRS 14 - *Regulatory Deferral Accounts* in January 2014.

The second component is the consideration of whether rate regulation creates assets or liabilities that should be recognised in accordance with IFRS. On September 17, 2014 the IASB issued a Discussion Paper, the objective of which is to seek comments on whether or not the distinguishing features of defined rate regulation sufficiently capture the types of rate regulation that have the most significant financial effects. The Discussion Paper does not include any specific accounting proposals. Instead, it explores the information about rate-regulated activities that is most likely to be useful to users of financial statements. It also outlines possible approaches that the IASB could consider in deciding how best to report the financial effects of rate regulation. Comments on the Discussion Paper are to be provided to the IASB by January 15, 2015.

Forward Looking Information

This MD&A contains certain statements or disclosures that may constitute forward-looking information under applicable securities laws. All statements and disclosures, other than those of historical fact, which address activities, events, outcomes, results or developments that we anticipate or expect may or will occur in the future (in whole or in part) should be considered forward-looking information. In some cases, forward-looking information can be identified by terms such as ”anticipate”, ”believe”, “contemplate”, “continue”, “could”, “enable”, “expect”, “forecast”, “future”, “intend”, “may”, “plan”, “potential”, “will” or other comparable terminology.

Forward-looking information presented in such statements or disclosures may, without limitation, relate to: applications to the AUC for approval of, among other things, our revenue requirements (including deferral and reserve accounts, capital structure and return-on-equity, financing plans, treatment of costs for applicable test periods including income taxes, operating expenses, depreciation, capital costs for direct assigned projects and maintenance programs, financing costs related to long-term debt and short-term borrowing, and projected growth in our rate base and assets under construction); transmission system expansion forecasts; the anticipated direct assignment of transmission development projects to us from the AESO pursuant to approved need applications or competitive bidding processes; the timing and development of transmission projects and the anticipated capital costs of such projects; business strategy, plans and objectives of management for future operations; forecast business results; the achievement of certain operational and performance measures and the resulting effect on compensation of executive officers; and our anticipated financial performance or condition.

Various factors or assumptions are typically applied in drawing conclusions or making the forecasts or projections set out in forward-looking information. These factors and assumptions include, but are not limited to:

- no changes in the legislative and operating framework for Alberta's electricity market that are adverse to us;
- decisions from the AUC concerning outstanding tariff and other applications that are consistent with past regulatory practices and decisions and are obtained in a timely manner;
- approved rates-of-return and deemed capital structures for our transmission business that are sufficient to foster a stable investment climate;
- a stable competitive environment;
- obtaining sufficient capital on acceptable terms to finance our transmission system expansion;
- no significant event occurring outside the ordinary course of business such as a natural disaster or other calamity; and,
- no risk of stranded assets.

These assumptions and factors are based on information currently available to us including information obtained by us from third-party industry analysts. In some occurrences, material assumptions and factors are presented or discussed elsewhere in this document in connection with the statements or disclosure containing the forward-looking information. We caution prospective investors that the foregoing list of material factors and assumptions is not exhaustive.

The forward-looking information in statements or disclosures in this MD&A is based (in whole or in part) upon factors which may cause our actual results, performance or achievements to differ materially from those contemplated (whether expressly or by implication) in the forward-looking information. These factors are based on information currently available to us including information obtained by us from third-party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the risks associated with being subject to extensive regulation including risks associated with AUC action or inaction;
- the risk that the AUC does not provide specific relief to support us in sustaining our credit metrics over a growth period characterized by large, multi-year transmission facilities projects;
- the risk that transmission projects are not directly assigned to us by the AESO or that we are not designated for filing a facility application;
- the risk that we are not able to arrange sufficient, cost-effective financing to repay maturing debt and to fund capital expenditures and other obligations;
- the risk that system expansion plans are delayed;
- the risks that the actual costs of completing a transmission project significantly exceed estimated costs;
- the risks to our facilities posed by severe weather, other natural disasters or catastrophic events and the limitations on our insurance coverage for losses resulting from these events;
- the potential for service disruptions and increased costs if we fail to maintain and improve our aging asset base;
- the risks associated with forecasting our revenue requirements and the possibility that we could incur operational, maintenance and administrative costs above those included in our approved revenue requirement; and,
- the risk that transmission expansion that is directed to us by the AESO becomes stranded and our recovery of the related cost is impaired.

We caution prospective investors that the above list of risk factors is not exhaustive. Other factors, which could cause our actual results, performance or achievements to differ materially from those contemplated (whether expressly or by implication) in the forward-looking statements or other forward-looking information, are disclosed in our publicly filed disclosure documents, including those disclosed under "Risk Factors and Uncertainties" in this MD&A and under "Risk Factors" in our Annual Information Form.

Risk factors that could lead to such differences include, without limitation, legislative and regulatory developments that could affect costs or revenues, the speed and degree of competition entering the market, global capital markets conditions and activity, timing and extent of changes in prevailing interest rates, currency exchange rates, inflation levels and general economic conditions in geographic areas where we operate, results of financing efforts, changes in counterparty risks, and the impact of accounting standards issued by standard setters.

All forward-looking information is given as of October 30, 2014. We are not obligated to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by applicable laws. Because of these risks, uncertainties and assumptions, readers should not place undue reliance on these forward-looking statements. Any forward-looking information contained in this document is expressly qualified by this statement.