AltaLink, L.P.

Management's Discussion and Analysis

May 6, 2015

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Management's Discussion and Analysis

This Management's Discussion and Analysis (MD&A) reflects events known to us as of May 6, 2015. 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 has delegated its responsibility for approving this MD&A to the Audit Committee of the Board of Directors. The Audit Committee approved this MD&A for issue on May 6, 2015.

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 months ended March 31, 2015 and 2014, (First Quarter Financial Statements), and our audited financial statements for the years ended December 31, 2014 and 2013 (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 March 31, 2015 and the twelve-month period ended December 31, 2014, respectively. References to "AESO" mean Alberta Electric System Operator; "AFUDC" mean Allowance for Funds Used During Construction; "ATP" mean SNC-Lavalin ATP Inc.; "AUC" mean Alberta Utilities Commission; "BHE" mean Berkshire Hathaway Energy Company; "BHEA" mean BHE AltaLink Ltd."; "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; and "SNC" mean SNC-Lavalin Group 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

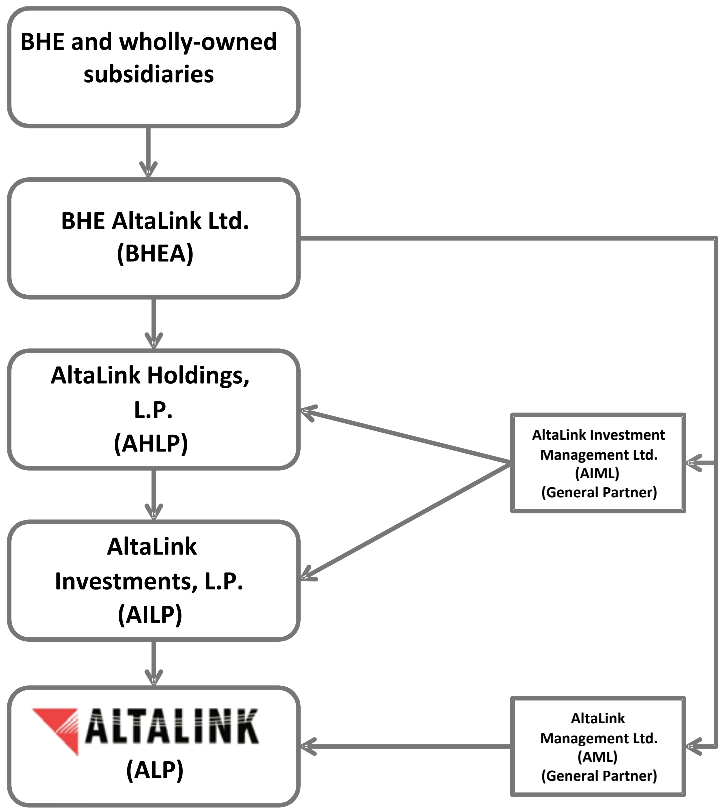
During the three months ended March 31, 2015:

- We invested $336.1 million (three months ended March 31, 2014 - $301.8 million) in capital projects to expand the capacity of the power grid, reinforce the system's reliability, and interconnect new customers;
- We earned comprehensive income of $24.3 million (three months ended March 31, 2014 - $46.2 million), primarily due to the AUC's decision to retroactively reduce our allowed return on equity and decreased our equity ratio for 2013 and 2014;
- We have had exceptional first quarter safety performance with no employee injury incidents, and the combined safety performance of our contractors and employees exceeded our performance over the past several years; and,
- Our first quarter delivery of reliable service to our customers has also exceeded our performance over the past several years.

Our Ownership 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). AHLP is wholly-owned by BHEA, a wholly-owned subsidiary of BHE.

Our headquarters are in Alberta, where we provide reliable, safe and efficient service to Albertans. We are regulated by the AUC, which has a history of strong regulation in the province of Alberta. The AESO directs 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.

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, 2014.

Our Vision and Core Principles

Our vision and strategy is to be the best transmission company in serving customers, while delivering long-term, sustainable solutions.

We use certain measures to determine whether we are meeting our goals and the needs of our customers. During the three months ended March 31, 2015, our recent performance continued to compare favourably to other transmission facility owners in Canada for reliability, safety and cost-effectiveness.

Customer Service

We focus on delivering reliability and exceptional service to our customers.

Reliability

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. 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.

Over the past 12 months, our reliability customer outage times continued to improve, with a strong improvement trend over the past several years. The frequency of service disruptions has increased from the record low levels that we achieved in 2013, largely due to inclement weather in the first quarter of 2015, however our results continue to outperform our Canadian peers.

	Twelve months ended	
	March 31, 2015	March 31, 2014
Duration of outages (SAIDI) [1]		
AltaLink	**0.45**	1.03
Frequency of outages (SAIFI) [2]		
AltaLink	**0.70**	0.63

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.

The comparative numbers for the twelve months ended March 31, 2014 include one major storm event.

Customer performance

To measure our performance on customer service, we use a third party to survey our customers to garner feedback and perceptions on service attributes that are unique to each customer segment. We use the survey results and feedback to establish specific initiatives aimed at improving our customers' experience.

External engagement

We focus our landowner, government, aboriginal and media engagement practices on providing our stakeholders with timely, easy to understand information about transmission projects and facilities. Our processes are designed to gather stakeholder input to help us identify routes on our new projects with the lowest overall impact on land use and landowners. This engagement continues through the life cycle of our facilities. We survey our landowners after consultation and during construction of significant projects, as well as those who already host our facilities. We use this information to improve our processes and to respond to outstanding concerns.

Employee Commitment

We equip employees with the resources and support they need to be successful. We encourage teamwork and provide a safe, rewarding work environment. We make no compromise when it comes to safety, and we align our short-term and long-term incentive pay with the needs of our customers.

Our leadership team's experience and expertise, combined with our employees' knowledge and commitment to "keeping the lights on" through operational excellence, are key to our ability to deliver customer requirements successfully.

Employee engagement

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.

We retain independent third parties to conduct employee engagement surveys with our people every two years. Our employee engagement scores are in the top decile of Canadian companies.

Safety

The health and safety of our employees and contractors is a core value. Our safety management initiatives encompass all aspects of our safety systems and focus our entire organization on safety accountabilities, responsibilities and culture. We strive to continuously improve our safety performance through focused training and our ongoing commitment to our safety culture and safety management processes.

Our safety performance is continuously improving and we consistently attain superior safety metrics relative to our peers. Our safety statistics include all man-hours worked by contractors and sub-contractors. During 2015, our workplace Injury Frequency Rate improved significantly compared to the preceding twelve-month period.

	Twelve months ended	
	March 31, 2015	March 31, 2014
All-Injury Frequency Rate [1]		
AltaLink	**0.58**	0.73

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

We are committed to public safety and are accredited by the Alberta Safety Codes Council. Alberta Municipal Affairs monitors all accredited companies for compliance with their quality management plans and safety codes. Through our annual reports to Alberta Municipal Affairs, we have confirmed our compliance with all required safety codes.

Environmental Respect

Natural resources are essential for the production of energy. We are committed to using these resources wisely and protecting our environment for the benefit of future generations. Our Environmental RESPECT Policy details this commitment in the areas of Responsibility, Efficiency, Stewardship, Performance, Evaluation, Communication and Training.

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.

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.

Regulatory Integrity

We adhere to a policy of strict regulatory compliance and pursue frequent, open communication with stakeholders regarding our business performance.

As a transmission facility owner, we are regulated by the Alberta Utilities Commission, 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 Alberta Electric System Operator. 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.

Operational Excellence

Together with our employees, we pride ourselves on excellence in every aspect of our work. Our high standards for operations and system maintenance enable us to meet and exceed our customers' expectations, perform our work safely, and preserve our assets.

We focus on keeping the lights on for Albertans and are committed to reinforcing Alberta's transmission infrastructure to ensure that the province's electricity grid can enable future prosperity. Our continuous improvement culture and focus on operational excellence encompasses our project execution programs, maintenance processes, centralized work planning, and scheduling.

We continuously implement business improvements across our organization to deliver reliable and safe transmission service to our customers.

Operations and Asset Management

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. 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 Projects

We execute our capital projects program using an outsourced Engineering, Procurement and Construction Management (EPCM) model. 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.

Financial Strength

We are excellent stewards of our substantial financial resources. Backed by Berkshire Hathaway, we invest in hard assets and focus on long-term opportunities that will contribute to our future 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.

Growth in Regulated Capital Assets

Continued investment in our regulated capital assets 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; (ii) recovery of deemed income taxes; and (iii) recovery of depreciation on our rate base assets.

For the three months ended March 31, 2015 our capital expenditure program included approximately $369 million of expansion projects directly assigned to us by the AESO and $39 million of capital replacement and upgrade projects.

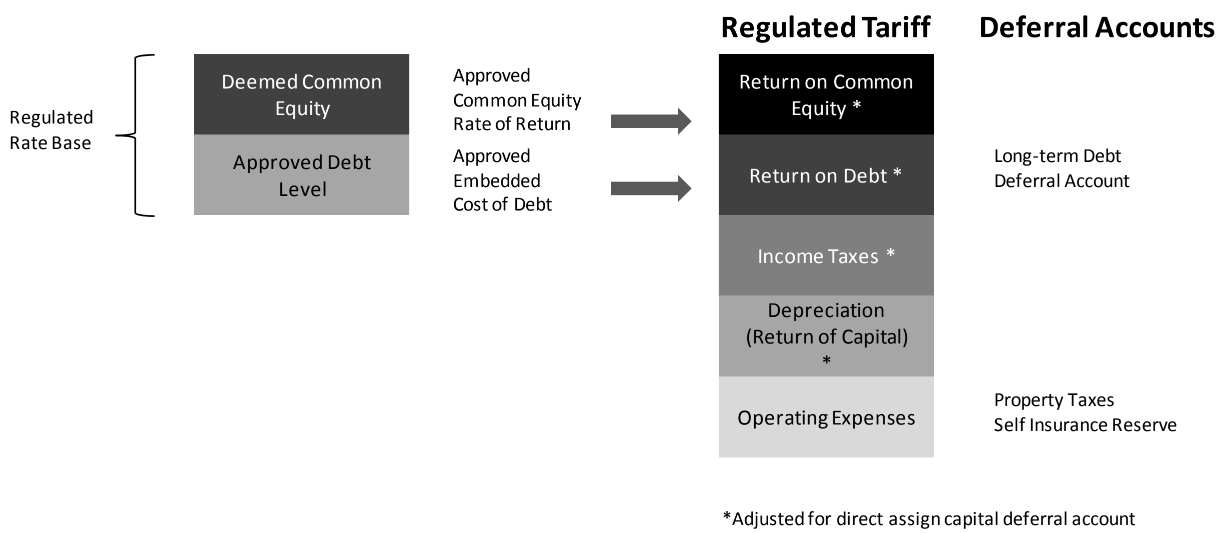
In our general tariff application for 2015 and 2016, we forecast our capital expenditures to be $1.5 billion and $1.1 billion in each of the test years, respectively. We based our direct assign capital forecast, which comprises more than 80% of our total capital expenditures, on the most recent long-range capital plan released by the AESO in January 2014, using the risk-adjusted capital forecasting model accepted by the AUC in its decision on our previous general tariff application. 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. In particular, certain developments that we discuss in the Major Capital Projects section of this MD&A may materially impact our capital expenditure outlook.

Transmission Tariffs

Overview

Under the Electric Utilities Act, we must prepare and file applications with the AUC for approval of tariffs to be paid by the AESO for the use of our transmission facilities, and the terms and conditions governing the use of those facilities. The AUC reviews and approves such tariff applications based on a cost-of-service regulatory model under a forward test year basis.

The following diagram outlines the principal components of our transmission tariff revenue:



For more details regarding our transmission tariffs, please refer to the "Transmission Tariffs" section of our MD&A for the year ended December 31, 2014.

Tariff Applications and Related Decisions

The AESO is responsible for directing the safe, reliable and economic operation of the AIES, including long-term transmission system planning. To meet these long-term planning needs, the AESO has directed us to execute a multi-billion dollar program to expand and reinforce the AIES within our service territory. We are obligated to fulfill these directions pursuant to the Transmission Regulation. Our revenue requirements have and will continue to increase significantly as we deliver the capital projects directed by the AESO.

In November 2014, we filed a general tariff application asking the AUC to approve revenue requirements of $810.5 million and $1,001.6 million for 2015 and 2016, respectively. The forecast increases in our revenue requirements are driven almost entirely by our continuing investment in capital projects, as directed by the AESO. During 2015 and 2016, we expect to complete and energize $2.9 billion and $0.8 billion of direct assign capital projects, respectively. The AUC has established a process which contemplates scheduling an oral hearing no sooner than August 2015.

The following table summarizes the tariff approved for 2014, as well as the tariff requested for 2015 and 2016. The 2014 tariff was approved by the AUC on September 8, 2014, in Decision 2014-258. The revenue requirements in the table below are before any adjustments arising from the 2013 GCOC Decision. The AUC has ordered us to apply by July 31, 2015 to adjust our revenue requirements for 2013, 2014 and 2015 to reflect the final approved ROE and capital structure determinations set out in the 2013 GCOC Decision.

	2016	2015	2014
	Applied for		Approved
(in millions of dollars)			
Return on equity	$ 217.0	$ 168.8	$ 159.0
Return on debt	183.4	140.8	128.0
Operating costs	169.4	153.1	129.5
Miscellaneous revenue	(7.9)	(8.1)	(7.6)
Depreciation and amortization	364.3	296.8	157.5
Income taxes	75.3	59.0	55.0
Revenue requirement	**$ 1,001.6**	**$ 810.5**	**$ 621.4**

**Totals may not add due to rounding*

On January 26, 2015, the AUC issued Decision 3504-D01-2015, approving our 2015 Interim Tariff Application, as filed, thereby authorizing us to bill the AESO $60.8 million monthly, commencing January 1, 2015.

On December 16, 2014, we filed our 2012-2013 Deferral Accounts Reconciliation Application. Approval of this application, as filed would enable us to collect $30.3 million from the AESO to settle these deferral accounts. We are seeking approval of nearly $1.7 billion of capital projects energized during those years, including our competitively bid EPCM rates.

We have applied to the Alberta Court of Appeal for Leave to appeal Decision 2013-407, which has been adjourned to October 2015. In Decision 2013-407, the AUC directed us to re-forecast the capital project expenditures for 2013 and 2014 EPCM services to reflect a two times labour multiplier and other approved mark-ups. While the AUC has not yet disallowed the new EPCM rates that we negotiated, there is a risk that, in a future direct assign capital deferral account decision, the AUC may disallow a portion of the costs we have incurred for EPCM services in connection with capital projects executed under these relationship agreements.

On March 30, 2015, the Commission issued Decision 3532-D01-2015 approving our application exempting us from the requirement to obtain the AUC"s approval prior to issuing long-term debt during 2015 and 2016.

Credit Metric Relief

In our 2015-2016 general tariff application, we have asked the AUC to continue most, but not all, of the credit rating support measures granted in the period from 2011 through 2014 revenue requirements. Recognizing that our funds from operations will improve in the coming years as our construction work in progress declines with the completion of major capital projects, we have proposed to the AUC that we would discontinue CWIP in Rate Base accounting beginning in 2015, a measure that would reduce customer bills by $115.0 million over the two-year test period. In its future decisions regarding our GTA, the AUC may accept our proposal regarding ongoing credit rating support measures or direct that we refile our application to include or remove various forms of credit rating support, which may significantly increase or decrease our final tariffs for the test years.

In recent tariff and cost of capital decisions, the AUC stated that it was in the best interests of ratepayers for us (and other transmission facility owners) to maintain our current credit ratings. The AUC affirmed its support by approving certain measures to maintain our credit metrics in anticipation of significantly higher capital expenditures which we expected to finance over several years. We attributed the increases in capital expenditures largely to new asset construction projects that we expected the AESO to directly assign to us.

A significant portion of our forecast capital expenditures involves projects that will take several years to complete. Under conventional regulatory tariff practices, we capitalized all costs related to capital projects, including AFUDC until the assets were available for use, at which time we began receiving tariff revenues. An alternative approach, sometimes used in other regulatory jurisdictions for large scale projects, is to allow AFUDC to be collected in current period regulated tariffs. This approach, often referred to as "CWIP in Rate Base", provided us with additional cash flow to service the debt obligations incurred by us to finance the projects. This additional cash flow enabled us to maintain our credit ratings during the construction program to ensure adequate access to capital markets and optimized our cost of capital underlying future tariffs.

In Decision 2011-453, the AUC approved credit metric relief for our 2011 and 2012 transmission tariffs, mainly in the form of CWIP in Rate Base. In Decision 2013-407, the Commission approved the continuation of credit metric relief for 2013, and 2014.

Generic Cost of Capital and Related Decisions

On March 23, 2015, the AUC issued Decision 2191-D01-2015 regarding cost of capital matters applicable to all electricity and natural gas utilities under its jurisdiction, including us. In its decision, the AUC set a deemed capital structure, expressed as proportions of debt and equity, for each utility and prescribed a generic rate of return on common equity to be applied against the common equity component of the deemed capital structures of all utilities. We are required to use the deemed capital structures and generic rate of return on common equity when calculating our tariff revenue requirements.

In Decision 2191-D01-2015, which was retroactively applied to January 1, 2013, the AUC decreased the generic rate of return on common equity applicable to all utilities, and decreased our deemed common equity, as shown in the table below. The Commission also found that no adjustment to the allowed return on equity or capital structure is warranted to account for the application of the principles identified in The Utility Asset Disposition Decision (Decision 2013-417). Please refer to the Regulatory Financial Risk section in our MD&A for the year ended December 31, 2014 for more information with respect to the implications of reduced equity thickness and return on our financial results.

Deemed capital structure and generic returns	**Approved 2015**	Approved 2014	Placeholder 2014	Approved 2013	Placeholder 2013
Deemed capital structure					
Common equity ratio	**36.00%**	36.00%	37.00%	36.00%	37.00%
Debt ratio	**64.00%**	64.00%	63.00%	64.00%	63.00%
Generic returns					
Return on equity	**8.30%**	8.30%	8.75%	8.30%	8.75%

The GCOC decision reduced the revenue that we had had previously recognized for 2013 and 2014 by approximately $11 million and $16 million, respectively.

The approved common equity ratio and generic rate of return on common equity will remain in effect on an interim basis for 2016 and beyond, until changed by the AUC. On April 2, 2015 the AUC issued a letter to all interested parties setting out its intent to commence with a new GCOC proceeding before the end of April, with evidence to be submitted by the fall of 2015 or earlier.

In a press release dated March 25, 2015, DBRS indicated that its opinion is that the quality of the regulatory regime, which is the main rating factor for regulated utilities, is deteriorating in Alberta. As evidence, DBRS referred to the recently announced 2013 GCOC decision and the November 2013 Utilities Asset Disposition (UAD) decision.

DBRS indicated that regulatory risk had increased because of the reduction of 1% in equity thickness for most utilities, the reduction in the return on equity (ROE) and the fact that the reductions are retroactive to 2013. The reduction in equity thickness means that there is now a limited buffer before equity thickness falls to the bottom-score range, Poor, which is below 35%. In addition, the reduction in the approved rate of return marks the lowest ROE for investor-owned utilities in Canada over the past ten years. DBRS also indicated that the most surprising part of the decision is that it is retroactive to 2013. This effectively created regulatory lag of more than two years, which appears to be longer than for most jurisdictions in North America.

In a utility sector briefing dated April 21, 2015, S&P also indicated that it was concerned that the regulatory framework in Alberta had a negative trend. On April 23, 2015, S&P issued a generic report which elaborated on how their assessment of a utility regulatory advantage is one of the most important factors in their credit analysis of regulated utilities. All else being equal, companies with lower regulatory advantage scores have significantly lower debt leverage to qualify for the same financial risk assessment as those with stronger scores.

We and other Alberta Utilities applied to the Alberta Court of Appeal for Leave to Appeal Decision 2191-D01-2015. Our appeal is based on, among other things, the AUC's failure to compensate us in the return allowed by the AUC for any amount relating to the increased risk to which the AUC has exposed us as a result of the Utility Asset Disposition Decision, which was released on November 26, 2013. In addition, the AUC failed to compensate us by not assessing additional factors required to set a return on equity for 2013 and 2014, in compliance with the fair return standard. We plan to file a Review and Variance (R&V) application related to this decision in the second quarter of 2015.

In addition, together with the other utilities regulated by the AUC, we had previously applied to the AUC for R&V of Decision 2011-474, which was the AUC's decision on the 2011 GCOC proceeding. On June 4, 2012, the AUC issued Decision 2012-154, rejecting the R&V application on the basis that its statements regarding stranded asset risk were unnecessary for the AUC to make a determination of the issues. The AUC then held that issues relating to stranded asset risk should be evaluated in a broader Utility Asset Disposition Proceeding.

In 2012, the utilities regulated by the AUC, including us, applied to the Alberta Court of Appeal for Leave to Appeal, based on, among other things, the AUC's finding that utilities bear the risk of stranded assets. The Leave to Appeal was granted, and the appeal is scheduled to be heard on June 8 and 9, 2015.

On November 26, 2013 the AUC issued Decision 2013-417, in which it determined that certain losses or gains related to asset dispositions are to be borne by the shareholders. The AUC did not direct any changes with respect to retirements in the ordinary course of business. However, they directed that the costs of all assets that are no longer used and useful must be removed from rate base and any under or over recovery of costs related to extraordinary retirements are to be borne by the utility.

We and other utilities regulated by the AUC have been granted Leave to Appeal the AUC's decision with the Alberta Court of Appeal. The appellants will argue that the AUC erred, among other things, by failing to apply the express statutory standard applicable to Transmission Facility Owners with regard to the process for removing assets from rate base that are no longer used or required to be used in the provision of utility services. We expect the appeal to be heard in June 2015 in conjunction with the utilities' appeal of AUC Decision 2011-474.

Major Capital Projects

Transmission Planning and Development

For details on transmission planning and development in Alberta, please refer to the "Overview of the Electricity Industry in Alberta", "Transmission Planning and Development", "Our Transmission Facilities" and "Major Capital Projects" sections of our MD&A for the year ended December 31, 2014.

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 Whitla energized in 2013 and 2014. • South Foothills scheduled for 2015 completion.
Stage II	AUC approved in 2009	• Two applications approved. • One application planned in 2015.	• Medicine Hat and Blackie scheduled for 2016 completion. • Chapel Rock facility application to be filed in Q4, 2015.
Western Alberta Transmission Line Reinforce system backbone between Edmonton and Calgary with a HVDC transmission line and converter substations.	Critical Transmission Infrastructure designation in 2009	• Approved in 2012.	• Construction scheduled for 2015 completion.
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 and Pike completed in 2013 and 2014. • Ipiatik scheduled for completion in 2016 or late 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 2015/2016.	• Completion scheduled for 2017. • Hearing is set for Q2, 2015.

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, 2014.

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 three months ended March 31, 2015. Our First 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 8)	311.9	We added $363.1 million to capital assets and construction work-in-progress, partially offset by $49.9 million in depreciation.
Trade and other payables and other non-current liabilities (Note 10)	105.5	Trade payables increased mainly due to the level of capital construction activity, higher deferral account liabilities and the impact of the GCOC decision.
Commercial paper and bank credit facilities (Note 11)	193.0	We issued additional commercial paper to finance our capital construction activity in 2015.

Cash Flows

	Three months ended March 31, 2015	Three months ended March 31, 2014
(in millions of dollars)		
Cash and cash equivalents, beginning of period	**$ 12.8**	$ 5.9
Cash flow provided by (used in):		
Operating activities	**123.9**	87.0
Investing activities	**(329.1)**	(284.1)
Financing activities	**193.4**	191.2
Cash and cash equivalents, end of period	**$ 1.0**	$ —

Operating Activities

Compared to the same period in 2014, our cash flow from operating activities increased by $36.9 million for the three months ended March 31, 2015. The change is primarily due to an increase in the recovery of depreciation and amortization, an increase in our regulatory accounts payable, partially offset by an increase in our regulatory accounts receivable due to the filing of our deferral account application. The increase in the regulatory accounts payable is due to the impact of the AUC Decision on the 2013 GCOC proceeding for the approved 2013 and 2014 return on equity and equity thickness.

Investing Activities

For the three months ended March 31, 2015, our cash flow used in investing activities increased by $45.0 million compared to the same period in 2014. The change is primarily due to higher 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 March 31, 2015, cash flow provided by financing activities increased by $2.2 million compared to the same period in 2014. We issued $193.0 million of commercial paper. During the same period in 2014, we issued $150.2 million of commercial paper, received $52.7 million of equity, and distributed $11.5 million to AILP.

Commitments

We have contractual commitments for the repayment of long-term debt of approximately $3,700.0 million, as disclosed in note 11 – Scheduled principal repayments, in our First Quarter Financial Statements.

We are committed to operating leases that have lease terms, which expire between 2015 and 2026. Of the total expected minimum lease payments, approximately 90% relates to our head office leases. See note 16 – *Commitments*, in our First Quarter Financial Statements.

We also have contractual commitments associated with the construction of new facilities as at March 31, 2015 of $797.4 million (December 31, 2014 - $979.4 million). Of these commitments, approximately 74% are with one EPCM provider (December 31, 2014 – approximately 81%).

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 March 31, 2015 was $1.0 billion (December 31, 2014 - $1.0 billion). The $925.0 million commercial paper backstop facility provides support to our commercial paper program, under which $314.1 million (December 31, 2014 – $121.2 million) was outstanding as at March 31, 2015. All bank credit facilities may be used for general corporate purposes. As at March 31, 2015, we had approximately $680.8 million 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.

By December 31, 2014, the Partnership had fully utilized its $2,500.0 million Medium-Term Notes Short Form Base Shelf Prospectus. The Short Form Base Shelf Prospectus expired in December 2014 and we will continue to use this format for raising debt in the future. We expect to issue a new shelf prospectus in the second quarter of 2015.

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 issued by highly rated counterparties 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]

(in millions)	Twelve months ended March 31, 2015	2014
Net income	**$ 194.3**	$ 180.6
Loss on disposal of assets	**16.0**	7.1
Finance costs	**132.6**	99.3
EBIT	**342.9**	287.0
Depreciation and amortization	**182.0**	144.8
EBITDA	**524.9**	431.8
Capitalised borrowing costs	**(12.1)**	(1.0)
Finance costs	**(132.6)**	(99.3)
FFO	**$ 380.2**	$ 331.5
Interest expense and amortization of financing fees	**$ 144.6**	$ 100.3

	As at March 31, 2015	2014
Letters of credit	**$ 5.1**	$ 4.6
Short-term debt	**314.1**	192.6
Long-term debt	**3,695.1**	2,701.3
Total debt	**4,014.3**	2,898.5
Total equity	**2,456.6**	1,901.0
Total capitalization	**$ 6,470.9**	$ 4,799.5

	Twelve months ended March 31, 2015	2014
EBIT interest coverage	**2.37X**	2.86X
EBITDA interest coverage	**3.63X**	4.30X
FFO interest coverage	**2.63X**	3.30X
FFO/Debt	**9.47%**	11.44%
Total debt/total capitalization [2]	**62.04%**	60.39%

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 changed in 2014 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 March 31, 2015, our working capital deficiency was $755.8 million, compared with $761.9 million at March 31, 2014. 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 March 31,	
	2015	2014
Earnings-to-interest coverage on total debt [1,2]	**2.14X[3]**	2.32X[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 March 31, 2015 was $158.0 million (March 31, 2014 - $122.5 million), including the pro-forma effect of interest payable on the Series 2012-1 (reopener), 2014-1, 2014-2 and 2014-3 Medium-Term Notes. Our earnings before interest and income tax for the twelve months ended March 31, 2015, for the purposes of calculating this ratio, were approximately $338.5 million (March 31, 2014 - $284.0 million).

Credit Ratings

,	Three months ended March 31,	
	2015	2014
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 December 2, 2014 DBRS removed the rating from Under Review with Developing Implications and confirmed the existing ratings all with stable trends.
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 December 3, 2014.

Results of Operations

Revenue

	Three months ended	
	March 31, 2015	March 31, 2014
(in millions of dollars)		
Operations	**$ 169.4**	$ 148.1
Generic cost of capital adjustments	**(27.2)**	—
Other	**11.5**	9.3
	$ 153.7	$ 157.4

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 2014, our revenue from operations increased by $21.3 million for the three months ended March 31, 2015, primarily due to additional return from our increased investments in capital assets.

Generic cost of capital adjustments

The regulatory decision adjustments for the three-months ended March 31, 2015 are due to the AUC Decision arising from the GCOC proceeding, which reduced the generic rate of return on common equity from 8.75% to 8.30% and reduced the common equity ratio from 37% to 36% retroactively for 2013 and 2014.

Other revenue

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

Compared to the same periods in 2014, cost recovery revenue from third parties increased by $2.2 million for the three months ended March 31, 2015. Revenue associated with costs recovered from third parties is received on a cost recovery basis and there is 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	
	March 31, 2015	March 31, 2014
(in millions of dollars)		
Comprehensive Income	**$ 24.3**	$ 46.2

Our comprehensive income for the three months ended March 31, 2015 decreased by $21.9 million, compared to the same period in 2014, primarily due to the AUC Decision arising from the 2013 GCOC proceeding.

Operating expenses

	Three months ended	
	March 31, 2015	March 31, 2014
(in millions of dollars)		
Operating expenses	**$ 31.0**	$ 25.8

Our operating expenses include salaries and wages, contracted manpower and general and administration costs. Our operating expenses for the three months ended March 31, 2015 increased by $5.2 million compared to the same period in 2014. The increase for the three months ended March 31, 2015 is primarily due to an increase in vegetation management costs and an increase in costs incurred to provide services to other utilities.

Property taxes and other

	Three months ended	
	March 31, 2015	March 31, 2014
(in millions of dollars)		
Property taxes, salvage and other	**$ 15.8**	$ 14.8

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 $1.0 million for the three months ended March 31, 2015 compared to the same period in 2014. The increase is due to increases in annual structure payments and property tax expense as a result of assets put into service and the timing of salvage costs incurred. For more details of these costs, please see Note 15 of the First Quarter Financial Statements.

Depreciation and amortization

	Three months ended	
	March 31, 2015	March 31, 2014
(in millions of dollars)		
Depreciation and amortization	**$ 53.3**	$ 40.4

We calculate depreciation and amortization on a straight-line basis using various rates which are approved by the AUC. Depreciation for the three months ended March 31, 2015 increased by $12.9 million, compared to the same period in 2014, 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	
	March 31, 2015	March 31, 2014
(in millions of dollars)		
Finance costs	**$ 28.1**	$ 29.2

Finance costs include interest costs and amortization of deferred financing fees less capitalized borrowing costs. Our finance costs for the three months ended March 31, 2015 decreased by $1.1 million, compared to the same period in 2014. Our interest costs increased significantly in the first quarter of 2015 compared to the same period in 2014 as a result of an increase in our debt obligations. However, this increase was offset by a significant increase in capitalized borrowing costs ($10.9 million) as a result of reverting to the AFUDC model for recognizing transmission tariff revenue, which replaced the CWIP in rate base model that we had used in 2014.

Earnings before interest, taxes, depreciation and amortization

	Three months ended	
	March 31, 2015	March 31, 2014
(in millions of dollars)		
EBITDA	**$ 106.9**	$ 116.8

Our EBITDA for the three months ended March 31, 2015 decreased by $9.9 million, compared to the same period in 2014. The reason for this decrease is similar to that noted above for the change in our comprehensive income for the same period. Please refer to the "Liquidity" section of this MD&A for more information about how we calculate EBITDA.

Selected financial information derived from our financial statements

	Three months ended	
	March 31, 2015	March 31, 2014
Net income per unit ($/unit)	**0.073**	0.139
Distributions per unit ($/unit)	**0.030**	0.035
Total assets ($ millions)	**7,934.2**	6,346.9
Short and long-term debt ($ millions) [1]	**4,009.2**	2,894.0

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)
March 31, 2015	**153.7**	**24.3**	**331.9**	**0.073**
December 31, 2014	219.0	66.8	331.9	0.201
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

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, please refer to the "Risk Management" section of our MD&A for the year ended December 31, 2014.

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 certain 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 past prudent industry practice and certain past 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. On October 29, 2014 the AUC issued Decision 2014-297 on ATCO Electric Ltd's 2012 Distribution Deferral Account Application. In this decision, the AUC ruled that where it determined that a loss was "extraordinary", that the costs of that loss are to the account of the utility's shareholders.

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 the three months ended March 31, 2015, compared to those disclosed in our MD&A for the year ended December 31, 2014.

- Regulated operations
- Project execution
- Regulatory financial and stranded asset risk
- 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

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.

As of December 1, 2014, we are fully owned by BHE, and SNC and ATP ceased to be related parties at that time.

We had no related party transactions with ATP during the three months ended March 31, 2015, compared to $354.8 million for the same period in 2014. On March 31, 2015, we had no related parties accounts payable and accrued liabilities with ATP, compared to $439.2 million at November 30, 2014.

Please refer to note 13 – *Related party transactions* in the First 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 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 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.

In 2013 a road construction company damaged another utility's transmission line, causing loss of power. Two refinery owners filed statements of claim for damages against the construction company, who in turn filed third party claims against us and another utility.

The AUC approved a project to upgrade a transmission line that is located on land owned by a First Nation, which refused to allow us to access its land. In December 2014, the First Nation filed a Statement of Claim against a number of parties, including us, which was amended in Q1, 2015. The claim alleges trespass by us, and seeks damages.

To assist the AUC in making a final prudence determination for the Southwest construction project, the AUC engaged an external firm to audit the project with respect to cost, consultation and schedule. The audit report was issued in April, 2015, raising concerns with some costs incurred by us during the project. The AUC has initiated a process to review the report and to make a final decision on the prudence of all Southwest project costs.

We intend to defend ourselves vigorously against these claims. 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 refer to note 16 – *Commitments* in the First 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 in our First Quarter Financial Statements.

Accounting Changes

Please see note 4 in our First Quarter Financial Statements for more details regarding our assessment of the impact on our financial statements of adopting the following new or revised standards.

New standards effective after 2015

IFRS 14 – *Regulatory deferral accounts* 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 the Partnership has been fully compliant with IFRS since 2011, the issuance of the interim standard does not have any impact on our financial statements or our disclosures.

IFRS 15 – *Revenue from contracts* with customers was issued by the IASB 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 July 2014, the IASB issued IFRS 9 – *Financial instruments*, which is effective for financial periods beginning on or after January 1, 2018. We are evaluating the impact of this standard on our financial statements.

Amendments to standards effective after 2015

In 2014, the IASB issued amendments to a number of standards. These amendments are effective for financial periods beginning on or after January 1, 2016. In our opinion, these are relatively minor amendments and we are evaluating the impact of these amendments on our financial statements.

In 2014, the IASB also issued amendments to standards under its Annual Improvements Project for 2012-2014, which are effective for financial periods beginning on or after January 1, 2016. In our opinion, these are relatively minor amendments and we are evaluating the impact of these amendments on our financial statements.

Update on the IASB work plan and rate-regulated project

In September 2014, the IASB published a Discussion Paper "Reporting the Financial Effects of Rate Regulation" (the Discussion Paper) to gather input about financial reporting challenges created when an entity's activities are subject to rate regulation. The Discussion Paper sought to identify what information about the economic and financial effects of rate regulation is most relevant to users of financial statements. It considered how that information might best be presented or disclosed, either within IFRS financial statements or through other routes, such as the management commentary.

The closing date for comments on the Discussion Paper was January 15, 2015. The IASB received more than 110 comment letters and held various outreach events to obtain further input.

The IASB considered the input gathered from the comment letters and the outreach activities at its meeting on February 18, 2015. The Rate-regulated Activities Consultative Group provided further input at its meeting with IASB members on March 4, 2015.

The summary of the input received to date indicates that:

- There is strong support for recognising within IFRS financial statements the rights and obligations created by defined rate regulation.
- Users of financial statements often seek information about the financial effects of rate regulation from other sources. They would prefer to obtain the information in a more accessible and comparable format within audited IFRS financial statements.
- The Discussion Paper is a good starting point to identify the distinguishing characteristics of rate-regulatory schemes that exist in practice. Consequently, there is strong support for using this as the basis for ongoing discussions about how best to report the financial effects of rate regulation.
- There is limited support for the IASB to develop disclosure-only requirements.

There are several key issues, such as measurement, presentation and disclosure, that need to be addressed before the IASB can come to a conclusion on the recognition of regulatory balances. The IASB staff is considering the input that has been received to date and will develop proposals to be considered by the IASB during 2015. The staff will also continue to seek input from the members of the Consultative Group.

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 May 6, 2015. 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.