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Exhibit No.:____
Issue: The Empire District Electric Company –Acquisition Impact
Witness: W. Keith Wilkins
Type of Exhibit: Rebuttal Testimony
Sponsoring Party: EDESR
File No.: EM-2016-0213

**BEFORE THE PUBLIC SERVICE COMMISSION**

**OF THE STATE OF MISSOURI**

**FILE NO. EM-2016-0213**

# REBUTTAL TESTIMONY AND EXHIBITS

**OF**

**W. KEITH WILKINS**

**ON BEHALF OF**

**THE EMPIRE DISTRICT ELECTRIC SERP RETIREES (EDESR)**

**JULY 20, 2016**

## I. INTRODUCTION AND BACKGROUND

**Q. Please state your name and business address.**

A. My name is W. Keith Wilkins and my business address is as follows:

218 Williamsburg Circle

P. O. Box 456

Brentwood, Tennessee 37024-0456

**Q. Please outline your formal education.**

A. I have a Bachelor of Science in Business Administration degree conferred by Southeast Missouri State University in May 1969 with majors in accounting and mathematics. I have a Masters of Business Administration degree conferred by Vanderbilt University in June 1988.

**Q. By whom are you employed?**

A. I am a self-employed utility consultant.

**Q. What type of professional services do you provide in your Utility Consultant practice?**

A. My utility consulting practice is focused almost exclusively on providing consulting services relative to electric, gas, water, wastewater and cable television utility issues. I have provided consulting services in the areas of accounting, taxation (including payments in-lieu-of taxes), financing, budgeting, wholesale electric and gas supply analysis, cost of service and rate design studies, annexation studies, merger studies, deregulation and competitive strategy studies, management audits, drafting of technical legislation, contract negotiations (purchased power and generation ownership), rate case settlement negotiations and preparation and presentation of expert testimony before local, state and federal regulatory agencies and in various county, state and federal courts. My resume is attached as Exhibit WKW-1.

**Q. Whom do you represent in this proceeding?**

A. I am appearing on behalf of the Empire District Electric SERP Retirees (EDESR).

**Q. What is the purpose of your testimony?**

A. I am testifying on behalf of the SERP recipients who are concerned that the combined organization as a result of the proposed merger is a riskier business model than the stand-alone Empire business model. In light of this, the SERP recipients are seeking additional measures to provide some security that they will continue to receive their earned and promised benefits.

## II. EARNED SERP RETIREMENT BENEFITS

**Q. What is a SERP?**

A. As part of its total compensation and benefits package, Empire provides an annuity benefit from an ERISA (The Employee Retirement Income Security Act of 1974) qualified defined benefit pension plan. All of the current SERP recipients receive an annuity benefit under the defined benefit plan. ERISA limits benefits paid to individuals based on a number of factors, primarily the level of an individual's compensation. Companies, such as Empire, can establish a SERP (Supplemental Executive Retirement Plan) to provide an annuity benefit beyond the limits of the defined benefit plan. More recently, Empire began providing a cash balance plan in lieu of its former defined benefit plan to new employees.

**Q. Why would a company have a SERP?**

A. A SERP allows a company to give a combined pension annuity that is not bound by ERISA limitations. SERP plans are common not only within the utility industry, but in non-utility companies. It is a common vehicle used to allow retirement benefits commensurate with service and salary to be paid that would otherwise be capped in an ERISA qualified defined benefit plan per sections 401(a)(17) and 415(b) of the Internal Revenue Code.

**Q. Can a company default on their SERP obligations?**

A. Yes. Just like any other obligation, if the company enters bankruptcy, or chooses not to make SERP payments, the company can be in default of their obligation.

**Q. Does Empire have a SERP?**

A. Yes, Empire established a SERP January 1, 1994, the "SERP." A copy of the SERP, as amended and restated January 1, 2014, is attached to my testimony as Exhibit WKW-2.

**Q. How are the SERP annuity benefits determined?**

A. Section 3.1 of the SERP defines how an individual's SERP annuity benefit is determined. As stated in Section 1.1 of the SERP, "The purpose of the Plan was and remains to provide the Participant in the Plan with the benefits the Participant would have received . . . except for the limitations on compensation and benefits imposed under sections 401(a)(17) and 415(b) of the Internal Revenue Code . . ." *See Exhibit WKW-2.*

**Q. How are the SERP recipients paid their earned benefits?**

A. SERP recipients are paid a monthly annuity from the general operating funds of the company. *See WKW-2, SERP Section 4.1.*

**Q. What are the risks to the SERP recipients in receiving their earned benefits?**

A. In the event of insolvency, the SERP recipients are treated in the same manner as an unsecured creditor. *See WKW-2, SERP Section 4.1.*

**Q. Can this risk be addressed?**

A. Yes. Pursuant to SERP Section 4.1, Empire can "establish a grantor trust, commonly known as a Rabbi Trust, as a vehicle for accumulating assets needed to pay the promised benefits."

**Q. Will the establishment of a Rabbi Trust guarantee payment of the promised benefits?**

A. No. However, it will mitigate the risk otherwise incurred in a bankruptcy. Instead of an unsecured executory contract between two parties, with funding only available from funds available after a bankruptcy liquidation, a Rabbi Trust provides a funded vehicle from which retirees can claim compensation for their prior work on behalf of Empire.

In *Bank of America v. Moglia*, 330 F.3d 942 (2003), Outboard Marine Corp. had filed for Chapter 7 bankruptcy. It had contributed $14 million to a Rabbi Trust to fund its non-qualified deferred compensation plan. The bankruptcy trustee claimed this amount was available only to the unsecured creditors of Outboard Marine, while Bank of America, the agent for the secured creditors, claimed the money belonged to the secured creditors as well since their security included "general intangibles" which described the Rabbi Trust assets. Judge Posner found that the language in the Rabbi Trust said it could only be reached by the "general creditors" of the company, and this meant the unsecured creditors of the company. If the language of the Trust had said that the trust assets were subject to the claims of all creditors of the company, then the secured creditors would have the valid claim. As such, the court held that the Rabbi Trust assets were subject only to the claims of the unsecured creditors.

This is important because employees and former employees typically have a high priority ranking amongst creditors. As such, in the event of a bankruptcy, a Rabbi Trust will likely be shielded from claims from secured creditors, and receive a high priority from the claims of unsecured creditor claims.

**Q. Can you estimate the size of such a Trust for the SERP?**

A. According to Empire's 2015 Annual Report, the projected benefit obligation for the SERP is $9.886 million. *See Exhibit WKW-3, Reconciliation of Funded Status, SERP, 2015*.

## III. <u>ACQUISTION ANALYSIS</u>

**Q. Have you reviewed the independent and combined balance sheets of Empire and Liberty/Algonquin ("Algonquin")?**

A. Yes, I reviewed Schedule PE-3 in the Direct Testimony of Peter Eichler.

**Q. Did you identify any items that should be of concern to this Commission?**

A. Yes. Goodwill, which is the premium paid to stockholders in this acquisition, results in total goodwill being reported on the balance sheet of the combined companies of $1.029 Billion CND. *See Direct Testimony of Peter Eichler, Schedule PE-3*. This goodwill amount is approximately 11.5% of the balance sheet of the combined companies. *See Id*. A general explanation of how goodwill is subject to impairment testing at least on an annual basis in a company that follows Generally Accepted Accounting Principles, like Empire and Algonquin, is given in Empire's 2015 Form 10-k. *See WKW-4, FN 1, Summary of Significant Accounting Policies, Goodwill (p.69).* Therefore, there is a risk of a write-down of a portion of the goodwill, which would result in a charge to earnings for the amount of the write-down. In some instances, a large write-down could result in earnings so low as to trigger a non-related event such as a violation of credit covenants. Empire has a pre-merger goodwill of about 1.6% of assets. *See Eichler Direct, Schedule PE-3.*

**Q. Was there anything else that caused you concern in your review of the balance sheets?**

A. Algonquin has post-merger negative retained earnings of $608 Million CND. *Id*. This negative balance has consumed about 6% of the balance sheet value of Algonquin. This further weakens the balance sheet to which Empire is attached. Empire on the other hand has strengthened its balance sheet in recent years with a retained earnings balance of $101 Million USD as of 12-31-15. *See Exhibit WKW-10*.

**Q. Will the retained earnings of Empire be placed under pressure by this transaction?**

A. Yes. Empire retained earnings will be under increased pressure by supporting Algonquin's planned dividend growth of 10% per year. This increases the risk to Empire. Ian Robertson, CEO of Algonquin, stated in the Algonquin 2015 annual report at page 5 that "The addition of this large, well run utility to the Algonquin family will support our 10% annual dividend growth target through significant accretion to shareholder cash flows and earnings." *See WKW-5*. This increased dividend pressure will not be supported by the meager savings noted in Peter Eichler's testimony of $640,781 USD in 2017, and which further shrinks to $175,756 USD in 2019. *See Direct Testimony of Peter Eichler, Schedule PE-2.*

**Q. Are these conclusions based on public documents?**

A. Yes. The above conclusions are based on published financial statements and testimony proffered by Algonquin in this case. **[redacted]**

**Q. Is Algonquin's financial profile similar to Empire's?**

A. The Algonquin financial profile is more complex than Empire's, potentially resulting in increased risk if not managed properly. Also, the potential exists for arbitrage in tax rates between Canada and the United States, as well as in currency swings. This obviously increases risk. *See WKW-6.*

**Q. Are the operations of Empire shielded from Algonquin's business?**

A. If Algonquin were to go bankrupt, the assets of Empire could be at risk if ring fencing measures failed or if the operations of Empire or Algonquin were so comingled as to make separation an impossible task. The plan proposed by Algonquin is to have Empire's stock held by Liberty Central, a wholly owned subsidiary of Liberty Utilities and ultimately Algonquin. While Liberty Central may be comprised of only regulated entities, Liberty Utilities and Algonquin will have unregulated utility activity which will subject Liberty Central to greater risk than regulated utility activity.

**Q. Does the Algonquin business model carry the same risk as Empire's?**

A. No. The Algonquin strategy is unclear and appears to be riskier than the Empire public utility service model. Ian Robertson, in the first quarter earnings call in 2016, stated he expected the

Empire deal to be a “one plus one equals more than two” deal apparently with respect to “greening” the Empire generation portfolio. *See WKW-7, p.11*. This strategy may be difficult in the Southwest Power Pool Integrated Marketplace, where there is an abundance of resources, including renewables, in operation, and more planned. *See WKW-11, SPP 2015 Annual Report.* Additionally, Mr. Robertson indicated that Algonquin was looking at expanding to riskier markets in North America, such as Mexico, in pursuit of higher returns. *See WKW-7, p. 8.* Unregulated and international investments are an inherently riskier model than the current Empire model.

**Q. Are both Algonquin and Empire currently rated ‘BBB’ by Standard & Poor’s?**

A. Yes. See *WKW-12*.

**Q. As late as October, 2001, was Utilicorp rated ‘BBB’ by Standard & Poor’s?**

A. Yes. *Id*.

**Q. By July, 2002, what was Aquila, f/k/a Utilitcorp, rated?**

A. Junk status. *Id*.

**Q. Was this downgrade of Aquila because of poor business decisions related to unregulated utility activities?**

A. Yes.

**Q. Since the acquisition of Empire by Algonquin has been announced, has Standard & Poor’s made any announcements regarding Empire?**

A. Yes. While Standard & Poor’s affirmed Empire’s ‘BBB’ rating, they have revised Empire’s outlook to ‘negative’ to correlate Empire’s outlook with Algonquin’s, which is also ‘negative.’ *Id*.

**Q. Will Empire have the same flexibility after this merger that they would have prior to this merger?**

A. No. After the 2011 tornado, Empire's initial response to the financial distress to the company was to suspend the dividend for six months. *See WKW-8*. It is unknown how company management would have reacted if they had been isolated over 1,300 miles away in another country.

**Q. Is the stock premium in Peter Eichler's Direct Testimony at page 9, lines 12-15 accurate?**

A. No. The more realistic measure of the premium offered on Empire stock by Algonquin is not the 21% mentioned in Peter Eichler's testimony, but rather 50% based on the closing price on December 10, 2015, which was the day before the potential Empire sale was reported by the press. *See WKW-9*.

## IV. CONCLUSION

**Q. Does this transaction decrease the ability of Empire to honor its SERP commitments?**

A. Yes. As detailed above in my testimony, the acquisition will leave Empire weaker financially and its parent company open to impairment, subject to the risks of unregulated market activities, and under pressure to deliver profits to fund Algonquin's dividend growth plan and unregulated domestic and international market plans.

**Q. What would the SERP Retirees request if this acquisition is approved?**

A. That Empire be required to create a Rabbi Trust as detailed in the SERP agreement and funded per the provisions of Section 4.1 of the SERP.

**Q. Does this conclude your pre-filed testimony in this case?**

A. Yes. However, I wish to preserve the right to provide additional testimony in the form of sur-rebuttal or at the hearing to rebut the pre-filed testimony filed by another party.

NP

**BEFORE THE PUBLIC SERVICE COMMISSION**
**OF THE STATE OF MISSOURI**

| | | |
|---|---|---|
| **STATE OF TENNESSEE** | ) | |
| | ) | SS |
| **COUNTY OF WILLIAMSON** | ) | |

**AFFIDAVIT OF W. KEITH WILKINS**

W. Keith Wilkins, being first duly sworn, deposes and says that he is the witness who sponsors the accompanying rebuttal testimony and schedules; that said testimony was prepared by him or under his direction and supervision; that if inquiries were made as to the facts in said testimony and schedules, he would respond as therein set forth; and that the aforesaid testimony and schedules are true and correct to the best of his knowledge, information, and belief.

W. Keith Wilkins

W. Keith Wilkins

Subscribed and sworn to before me this 20th day of July, 2016.

Notary Public

SEAN T. CRAMER
STATE OF TENNESSEE NOTARY PUBLIC
WILLIAMSON COUNTY
My Commission Expires June 03, 2019

My commission expires: 6/3/19

Resume Of
**W. Keith Wilkins**
218 Williamsburg Circle
P. O. Box 456
Brentwood, Tennessee 37027-5161
e-mail: wilkins_keith@msn.com
cell & text: (615) 417-1484

Professional Experience

1978 To 1999 and 2003 To Present:

Self-employed Consultant providing services for electric, gas, water, waste water and cable television utilities nationally. Consulting services provided have been in the areas of accounting, taxation (including payments in-lieu-of taxes), financing, budgeting, wholesale electric and gas supply analysis, cost of service studies, rate design studies, annexation studies, merger studies, business valuation studies, deregulation & competitive strategy studies, management audits, drafting of technical legislation, preparation and presentation of expert testimony on behalf of clients before local, state and federal regulatory agencies, and in various county, state and federal courts pertaining to power supply, settlement negotiations, contract negotiations and arbitration proceedings.

1999 To 2003:

Employed by Wisconsin Public Power Inc. (a municipal joint action agency providing power supply and services to municipal utility members), as Chief Financial Officer. Specific responsibilities included the areas of Information Systems, Forecasting & Rates, Human Resources & Administrative Services, Insurance Trust, Finance, Risk Management, Distribution Services, Joint Purchasing and Retail Customer Services.

Major Activities

Participated in the negotiations forming the American Transmission Company ("ATC")—the first for-profit transmission-only company in the United States. ATC is owned by both private utilities, municipal and cooperative utilities.

Participated in the negotiations to develop an operating agreement for a coal fired generating plant to be operated by an investor owned utility but owned by three parties including a municipal joint action agency.

Managed the long-term debt financing for the municipal joint action agency's project development, construction and ownership of a combustion turbine and the refunding of existing debt.

Managed a project to jointly purchase, train, implement and support a customer information system (CIS) and a accounting system for most of the joint action agency members. Each member's database is centralized at the joint action agency main office.

Developed a distribution utility financial planning model (cash-flow based) for the joint action agency members to be used in conjunction with cost of service studies and in making financial presentations to utility commissions, boards or city councils.

Participated in the development of a risk management policy and related procedures pertaining to power supply purchases & sales.

Evaluating possible sale/merger/joint operation of municipal utilities.

**W. Keith Wilkins' Resume**

1975 to 1978:

Worked as an Accounting Consultant with an international consulting and engineering firm on utility ratemaking matters. Reviewed and/or performed electric, gas and water cost of service studies with some work being done in Canada. Provided litigation support and expert testimony in a number of engagements, primarily related to accounting & taxation primarily before the Federal Energy Regulatory Commission.

1971 to 1975:

Employed by Memphis Light, Gas and Water Division as a Rate Analyst. Initially, responsible for planning and conducting cost of service and rate design studies and recommending rate changes for electric, gas and water divisions, preparation of forecasts for number of customers, consumption levels, revenues, and cost of gas and electricity purchased and the computation and implementation of required rate changes resulting from periodic supplier wholesale cost changes. Subsequently assumed the additional responsibilities of Supervisor of Property Accounting that included planning, directing and supervising the maintenance of accounting records for fixed assets currently in use or under construction.

1969 to 1971:

Employed by Sears as an Internal Auditor with responsibility for conducting operational and accounting audits of the catalog sales order plant in Memphis, Tennessee and of the catalog sales order stores throughout a seven state region.

## Educational and Professional Qualifications

Masters of Business Administration degree conferred by Vanderbilt University in June 1988.

Bachelor of Science in Business Administration degree conferred by Southeast Missouri State University in May 1969 with majors in Accounting and Mathematics.

**W. Keith Wilkins' Resume**

List of Jurisdictions In Which Consulting Services Have Been Provided

1. Federal Energy Regulatory Commission (Formerly Federal Power Commission)
2. South Dakota Public Utilities Commission
3. Texas Public Utilities Commission
4. District of Columbia Public Service Commission
5. Ohio Public Service Commission
6. Mississippi Public Service Commission
7. Public Service Commission of Maryland
8. South Carolina Public Service Commission
9. West Virginia Public Service Commission
10. Public Service Commission of Wisconsin
11. Circuit Court of Cook County, Illinois, Chancery Division
12. United States District Court, Central District of California
13. Federal Communications Commission
14. Tennessee Valley Authority
15. Indiana Utility Regulatory Commission
16. Michigan Public Service Commission
17. New York Public Service Commission
18. United States District Court, Western District Of Tennessee
19. United States District Court, Middle District Of Tennessee
20. United States District Court, Minnesota District

**W. Keith Wilkins' Resume**

List of Engagements in Which Expert Testimony Has Been Filed

1975 - Northwestern Public Service Commission
South Dakota Public Utilities Commission
Docket No. F-3055

1976 - Central Power and Light Company
Texas Public Utilities Commission
Docket No. 91

1978 - Washington Gas Light Company
District of Columbia Public Service Comm.
Docket 686

1979 - Dayton Power and Light Company
Ohio Public Service Commission
Case No. 78-92-EL-AIR

1979 - Virginia Electric and Power Company
Federal Energy Regulatory Commission
Docket No. ER78-522

1979 - Mississippi Power Company
Mississippi Public Service Commission
Case No. U-3739

1980 - Northern States Power Company
Federal Energy Regulatory Commission
Docket No. ER79-616

1980 - Carolina Power and Light Company
South Carolina Public Service Commission
Docket No. 80-69-E

1981 - Ohio Edison Company
Federal Energy Regulatory Commission
Docket No. ER80-454

1982 - Georgia Power Company
Federal Energy Regulatory Commission
Docket No. ER81-730

1982 - Ohio Edison Company
Public Utilities Commission of Ohio
Case No. 81-1171-EL-AIR

1975 - Southern California Edison Company
Federal Power Commission
Docket No. E-8570

1977- Southern California Edison Company
Federal Power Commission
Docket No. ER76-205

1979 - Carolina Power and Light Company
Federal Energy Regulatory Commission
Docket No. ER77-485

1979 - Wisconsin Power and Light Company
Federal Energy Regulatory Commission
Docket No. ER77-347

1979 - Georgia Power Company
Federal Energy Regulatory Commission
Docket No. ER79-88

1980 - Southern California Edison Company
Federal Energy Regulatory Commission
Docket No. ER79-150

1980 - Chesapeake and Potomac Telephone
Public Service Comm. of Maryland
Case No. 7467

1981 - Carolina Power and Light Company
Federal Energy Regulatory Commission
Docket No ER80-344

1982 - Southern California Edison Company
Federal Energy Regulatory Commission
Docket No. ER81-177

1982 - Carolina Power and Light Company
South Carolina Public Service Comm.
Case No. 81-163-E

1983 - Southern California Edison Company
Federal Energy Regulatory Commission
Docket No. ER82-427

**W. Keith Wilkins' Resume**

List of Engagements in Which Expert Testimony Has Been Filed

1984 - Southwestern Electric Power Company
Federal Energy Regulatory Commission
Docket No. ER83-609

1984 - Appalachian Power Company
West Virginia Public Service Commission
Case No. 83-697-E-42T

1984 - Southern California Edison Company
Federal Energy Regulatory Commission
Docket No. ER84-75

1984 - Wisconsin Electric Power Company
Public Service Commission of Wisconsin
Docket No. 6630-ER-19

1985 - Wisconsin Power and Light Company
Federal Energy Regulatory Commission
Docket No. ER84-576

1985 - Monongahela Power Company
PSC of West Virginia
Case No. 84-768-E-42T

1985 - Village of Niles, Et al., vs. City of Chicago
Circuit Court of Cook County, Illinois, Chancery Division
Case No. 77 CH 3261

1986 - Cities of Anaheim, ET al. vs
Southern California Edison Company
United States District Court
Central District of California
Case No. 78-0810-MML

1986 - Duke Power Company
PSC of South Carolina
Docket No. 86-188-E

1987 - Southern California Edison Company
Federal Energy Regulatory Commission
Docket No. ER87-365

1988 - Northern States Power Company
Federal Energy Regulatory Commission
Docket No. ER88-72

1991 - Wabash Valley Power Association
Michigan Public Service Commission
Case No. U-9765

1991 - Consolidated Edison Co. of New York
State of New York PSC
Case No. 91-E-0462

1992 - Wisconsin Electric Power Company
Federal Energy Regulatory Commission
Docket No. FA88-62-000

1992 - Wisconsin Public Service Corporation
Federal Energy Regulatory Commission
Docket No. EL92-12-000

1994 - Interstate Power Company
Federal Energy Regulatory Commission
Docket No. EL92-25-000 & EL93-30-000

1994 - Consolidated Edison Co. of New York
State of New York PSC
Case No. 94-E-0334

1998 - City of Marshall, MN vs.
Heartland Consumers Power District
United States District Court – MN District
Civil File No. 98-835 RHK/FLN

2002- Menasha Utilities
Public Service Commission of Wisconsin
Docket No. 3560-ER-103

2003 - Wisconsin Public Service Corporation
Federal Energy Regulatory Commission
Docket No. ER03-606-000

**W. Keith Wilkins' Resume**

List of Engagements in Which Expert Testimony Has Been Filed

2004 - City of Cookeville, TN vs.
Upper Cumberland Electric Membership Corporation
United States District Court – Middle District of TN
Civil File No. 2:02-0093

2012- Arbitration Proceeding
Plum Point Generating Unit
On Behalf of
Missouri Joint Municipal Electric Utility Commission

2009 - Arbitration Proceeding
Iatan No. 2 Generating Unit
On Behalf of
Missouri Joint Municipal Electric Utility Commission

# THE EMPIRE DISTRICT ELECTRIC COMPANY

# SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN

(As Amended and Restated Effective January 1, 2014)

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# THE EMPIRE DISTRICT ELECTRIC COMPANY

## SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN
(Effective January 1, 1994)

## ARTICLE I
### Establishment

**1.1** **Establishment and Purpose**. The Empire District Electric Company (the "Employer") adopted The Empire District Electric Company Supplemental Executive Retirement Plan (the "Plan"), effective as of January 1, 1994 (the "Effective Date"). The purpose of the Plan was and remains to provide each Participant in the Plan with the benefits the Participant would have received under The Empire District Electric Company Employees' Retirement Plan (the "Retirement Plan") except for the limitations on compensation and benefits imposed under Sections 401(a)(17) and 415(b) of the Internal Revenue Code of 1986, as amended (the "Code"), or any successor thereto. The Plan was amended and restated as of January 1, 2008, to comply with the requirements of Section 409A of the Code. Effective as of January 1, 2014 (the "Restatement Date"), the Employer hereby further amends and restates the Plan to read as set forth in this document. For purposes of ERISA, the Plan is intended to be "unfunded" and to benefit only a "select group" of management employees of the Employer.

**1.2** **Applicability**. The provisions of this restated Plan shall apply only to a person who terminates employment with the Employer on or after the Restatement Date and shall not apply to any person not in the active employ of the Employer on or after the Restatement Date.

## ARTICLE II
### Participation

**2.1** **Eligibility and Participation**. Each officer of the Employer who is a participant in the Retirement Plan and whose accrued benefit under the Retirement Plan is reduced by either the limitation on compensation imposed by Section 401(a)(17) of the Code or the limitations on benefits imposed by Section 415 of the Code shall become a "Participant" in this Plan as of the thirtieth (30th) day of the calendar year following the calendar year in which such a reduction first occurs; provided that no person shall be or become a Participant hereunder prior to January 1, 1994.

**2.2** **Duration**. Any person who becomes a Participant shall continue to be a Participant as long as the Participant is entitled to benefits hereunder.

## ARTICLE III
## Benefit/Payment

**3.1 Accrued Benefit.**

(a) Benefit Amount. If at any time any benefit otherwise payable under the provisions of the Retirement Plan with respect to a Participant, including any benefit payable to a Participant's spouse or other beneficiary, shall be reduced by reason of the limitations on maximum benefits imposed under Section 415(b) of the Code and/or the limitation on the amount of compensation that may be considered under Section 401(a)(17) of the Code, the Participant, or the Participant's spouse or other beneficiary, shall be entitled to receive a benefit under this Plan (an "Accrued Benefit") equal to the excess, if any, of

(1) The amount of the benefit under the Retirement Plan, calculated without regard to the limitations imposed by Sections 415 and 401(a)(17) of the Code and with any amounts deferred by the Participant under an Employer-sponsored deferred compensation plan treated as compensation for purposes of this determination, over

(2) The amount of the benefit under the Retirement Plan as limited by Sections 401(a)(17) and 415 of the Code.

In calculating the benefit amount described in Paragraph 3.1(a)(1), (i) the compensation of a Participant for years prior to 1994 shall not exceed the Section 401(a)(17) limit in effect for each of those years, and (ii) for 1994 and subsequent years, the compensation of a Participant shall not exceed the Section 401(a)(17) limit that would have applied for each such year if not for the amendment of that provision by the Omnibus Budget Reconciliation Act of 1993 (i.e., the compensation limitation that applies to "grandfathered" participants in governmental plans, which amount is $385,000 for 2014). In the event such dollar limitation is no longer determined by the IRS, the Employer shall adopt an appropriate substitute index to measure increases in the cost of living, and the limit on the compensation to be considered shall be adjusted in accordance with that index.

(b) Vesting. A Participant's Accrued Benefit under this Plan shall vest at the same time, if ever, that the Participant becomes vested in a benefit under the Retirement Plan.

**3.2 Time and Method of Payment.** Subject to Section 6.6, a Participant's Accrued Benefit shall be paid in accordance with an election as to the time and form of payment made by the Participant on or before the date on which the individual first becomes a Participant in the Plan (as described in Section 2.1), pursuant to procedures established by the Employer and consistent with Section 409A of the Code; provided, however, that in the case of an individual who first became a Participant on or before December 31, 2007, the Accrued Benefit shall be paid in accordance with an election as to the time and form of payment made on or before December 31, 2007, pursuant to procedures established by the Employer and consistent with transition rules established by the Internal Revenue Service under Section 409A of the Code. The available options as to the form and time of payment of an Accrued Benefit shall be the same as the payment options that are available for the corresponding benefits under the Retirement Plan on the date the election is made; provided, however, that a Participant may not elect to receive his or her Accrued Benefit in the form of a lump-sum payment. Notwithstanding the foregoing, in accordance with regulations under Section 409A of the Code, a Participant may, at any time prior to his or her benefit commencement date, elect to change the form of payment of his or her Accrued Benefit from one type of life annuity to another actuarially equivalent type of life annuity which is an available option at the time of the change and which has the same scheduled commencement date, and may also change the beneficiary of any such annuity payments that might be due after the Participant's death. For this purpose, actuarial equivalency shall be determined in accordance with the actuarial assumptions set forth in the Retirement Plan.

## ARTICLE IV
## Funding

4.1 **Funding**. All benefits under this Plan shall be paid directly from the general funds of the Employer, and no special or separate fund shall be established and no other segregation of assets shall be made to assure payment. No Participant, spouse, or beneficiary shall have any right, title or interest whatever in or to any investments that the Employer may make to aid the Employer in meeting its obligations hereunder. Nothing contained in this Plan, and no action taken pursuant to its provisions, shall create or be construed to create a trust of any kind, or a fiduciary relationship, between the Employer and any Participant, spouse, or beneficiary of a Participant. To the extent that any person acquires a right to receive payments hereunder, such rights shall be no greater than the right of an unsecured creditor of the Employer. Notwithstanding the foregoing, the Employer may, in its sole discretion establish a grantor trust, commonly known as a Rabbi Trust, as a vehicle for accumulating the assets needed to pay the promised benefits. In the event a Rabbi Trust is established, such trust shall be funded in accordance with an actuarial funding method and actuarial assumptions designed, in the reasonable judgment of an actuary named by the Employer, to replicate the funding policy followed with respect to the Retirement Plan.

## ARTICLE V
## Amendment, Administration

5.1 **Amendment and Termination**. The Employer intends the Plan to be permanent, but it reserves the right at any time to modify, amend, or terminate the Plan, provided that the Employer shall not cancel, reduce, or otherwise adversely affect the amount of benefits of any Participant accrued as of the date of any such modification, amendment, or termination, without the consent of the Participant.

5.2 **Administration**. The Plan shall be administered by the Board of Directors of the Employer, which shall be authorized to interpret the Plan, to adopt rules and practices concerning the administration of the Plan, to resolve questions concerning the eligibility for, or the amount of, an Accrued Benefit, and to delegate all or any portion of its authority hereunder to a committee of the Board of Directors or to designated officers or employees of the Employer.

5.3 **Deduction of Taxes from Amounts Payable**. The Employer may deduct from the amount to be distributed under the Plan such amount as the Employer, in its sole discretion, deems proper for the payment of income, employment, death, succession, inheritance, or other taxes with respect to benefits under the Plan.

5.4 **Indemnification**. The Employer shall indemnify and hold harmless each employee, officer, or director of the Employer to whom is delegated duties, responsibilities, and authority with respect to the Plan against all claims, liabilities, fines and penalties, and all expenses reasonably incurred by or imposed upon the individual (including, but not limited to, reasonable attorney fees) which arise as a result of the individual's actions or failure to act in connection with the operation and administration of the Plan, to the extent lawfully allowable and to the extent that such claim, liability, fine, penalty, or expense is not paid for by liability insurance purchased or paid for by the Employer. Notwithstanding the foregoing, the Employer shall not indemnify any individual for any such amount incurred through any settlement or compromise of any action unless the Employer consents in writing to such settlement or compromise.

5.5 **Expenses**. The expenses of administering the Plan shall be paid by the Employer.

## ARTICLE VI
## Miscellaneous

6.1 **Interests not Transferable**. Benefits payable under this Plan shall not be subject in any manner to anticipation, alienation, sale, transfer, assignment, pledge, encumbrance, charge, garnishment, execution, or levy of any kind, either voluntary or involuntary, including any such liability which is for alimony or other payments for the support of a spouse or former spouse, or for any other relative of a Participant, prior to actually being received by the person entitled to the benefit under the terms of the Plan, and any attempt to anticipate, alienate, sell, transfer, assign, pledge, encumber, charge, or otherwise dispose of any right to benefits payable hereunder shall be void. The Employer shall not in any manner be liable for, or subject to, the debts, contracts, liabilities, engagements, or torts of any person entitled to benefits hereunder. If any person shall attempt to alienate, sell, transfer, assign, pledge, or otherwise encumber a Participant's benefit under this Plan, or if by reason of a Participant's bankruptcy or other event happening at any time such benefit would otherwise devolve upon any other person or would not be enjoyed by the person entitled thereto under the Plan, the Board of Directors of the Employer, in its discretion, may terminate the interest in any such benefit of the person entitled thereto under the Plan and hold or apply it to or for the benefit of such person, or such person's spouse, children, or other dependents, in such manner as the Board of Directors may deem proper.

6.2 **Contract of Employment**. Nothing contained herein shall be construed to constitute a contract of employment between a Participant and the Employer.

6.3 **Headings**. The headings of articles and sections are included solely for convenience of reference, and if there is any conflict between such headings and the text of this Plan, the text shall control.

6.4 **Invalidity**. If any provision of this Plan shall be held invalid or unenforceable, such invalidity or unenforceability shall not affect any other provisions hereof, and the Plan shall be construed and enforced as if such provisions, to the extent invalid or unenforceable, had not been included.

6.5 **Law Governing**. This Plan shall be construed and enforced according to the laws of the State of Missouri, other than its laws respecting choice of law.

6.6 **Compliance with Code Section 409A**. Notwithstanding anything in this Plan to the contrary,

(a) If a Participant is a "specified employee" (within the meaning of Section 409A of the Code and the regulations thereunder and as determined by the Employer in accordance with said Section) at the time of the Participant's separation from service (as defined below), the payment of any benefit under this Plan shall be made no earlier than the date which is 6 months after the date of the Participant's separation from service (or, if earlier than the end of such 6-month period, the date of the Participant's death), and

(b) A Participant shall be deemed to have terminated from employment for purposes of this Plan if and only if the Participant has experienced a "separation from service" within the meaning of said Section 409A and the regulations thereunder.

To the extent any payment under this Plan is subject to the 6-month delay described in Subsection (a), such payment shall be paid immediately after the end of such 6-month period (or the date of the Participant's death, if earlier). The provisions of this Plan shall be interpreted and operated consistently with the requirements of Section 409A of the Code and the regulations thereunder.

6.7 **Compensation Clawback Policy**. In the event the Employer adopts a compensation recovery ("clawback") policy, in accordance with Section 954 of the Dodd-Frank Wall Street Reform and Consumer Protection Act, such policy shall apply to any benefits payable under this Plan to Participants who are subject to that policy.

IN WITNESS WHEREOF, the Employer has caused this restatement of the Plan to be executed on its behalf this 30th day of October, 2014, but to be effective as of January 1, 2014.

**THE EMPIRE DISTRICT ELECTRIC COMPANY**

By: Ronald F. Gatz

Title: Vice-President & COO – Gas

**ATTEST**

By: Janet Watson

Title: Secretary/Treasurer

**Pensions**

Our noncontributory defined benefit pension plan includes all employees meeting minimum age and service requirements. Effective on January 1, 2014, the plan was amended to include a cash balance benefit formula. Employees hired on or after January 1, 2014 will accrue benefits based on a cash balance methodology. Employees hired prior to January 1, 2014 were given a one-time option to convert to the cash balance methodology, or remain with our traditional average annual basic earnings formula, by December 31, 2014. Both benefit formulas allow for a lump sum distribution of vested benefits. Lump sum distributions totaled approximately $15.3 million and $9.0 million during 2015 and 2014, respectively, and did not require settlement accounting according to ASC 715.

Annual contributions to the plan are at least equal to the greater of either minimum funding requirements of ERISA or the accrued cost of the Plan, as required by the Missouri Public Service Commission.

Our net pension liability decreased $2.4 million in 2015, which was recorded as a decrease in regulatory assets as we believe it is probable of recovery through customer rates based on rate orders received in our jurisdictions. The decrease in the liability is primarily due to an increase in discount rates. Our contribution is estimated to be approximately $13.6 million for 2016. We expect future pension funding commitments to continue at least at the level of our accrued cost, as required by our regulator. The actual minimum funding requirements will be determined based on the results of the actuarial valuations and, in the case of 2017, the performance of our pension assets during 2016.

We also have a supplemental retirement program (“SERP”) for designated officers of the Company, which we fund from Company funds as the benefits are paid. The liability for this plan increased $0.7 million in 2015.

Expected benefit payments are as follows (in millions):

| Year | Payments from Trust | Payments from Company Funds |
|---|---|---|
| 2016 | $22.5 | $0.5 |
| 2017 | 22.8 | 0.6 |
| 2018 | 21.5 | 0.5 |
| 2019 | 20.0 | 0.5 |
| 2020 | 20.9 | 0.8 |
| 2021 – 2025 | 97.4 | 2.9 |

**Other Postretirement Benefits (OPEB)**

We provide certain healthcare and life insurance benefits to eligible retired employees, their dependents and survivors through trusts we have established. Participants generally become eligible for retiree healthcare benefits after reaching age 55 with 5 years of service. Employees hired after January 1, 2014 will be offered unsubsidized retiree healthcare benefits upon retirement.

Our net liability decreased $10.0 million in 2015, which was recorded as a decrease in regulatory assets as we believe it is probable of recovery through customer rates based on rate orders received in our jurisdictions. The decrease in the liability is primarily due to a significant actuarial gain resulting from increases in discount rates, the adoption of a new mortality table and positive claims trends. Our funding policy is to contribute annually an amount at least equal to the actuarial cost of postretirement benefits. We expect to be required to fund approximately $4.9 million in 2016.

Estimated benefit payments are as follows (in millions):

| Year | Payments from Trust | Expected Federal Subsidy | Payments from Company Funds |
|---|---|---|---|
| 2016 | $ 2.8 | $0.4 | $0.2 |
| 2017 | 3.2 | 0.4 | 0.2 |
| 2018 | 3.5 | 0.5 | 0.2 |
| 2019 | 3.8 | 0.5 | 0.2 |
| 2020 | 4.1 | 0.6 | 0.2 |
| 2021 – 2025 | 25.0 | 3.7 | 0.8 |

The following tables set forth the Company's benefit plans' projected benefit obligations, the fair value of the plans' assets and the funded status (in thousands).

| | Pension | | SERP | | OPEB | |
|---|---|---|---|---|---|---|
| **Reconciliation of Projected Benefit Obligations:** | **2015** | **2014** | **2015** | **2014** | **2015** | **2014** |
| Benefit obligation at beginning of year | $251,879 | $225,131 | $9,155 | $7,108 | $109,899 | $ 85,332 |
| Service cost | 7,442 | 6,467 | 158 | 153 | 3,713 | 2,601 |
| Interest cost | 10,278 | 10,819 | 382 | 387 | 4,670 | 4,360 |
| Amendments | — | (7,753) | — | (45) | — | — |
| Net actuarial (gain)/loss | (708) | 36,742 | 557 | 1,890 | (14,358) | 20,347 |
| Plan participant's contribution | — | — | — | — | 963 | 850 |
| Benefits and expenses paid | (25,201) | (19,527) | (366) | (338) | (3,839) | (3,897) |
| Federal subsidy | — | — | — | — | 419 | 306 |
| **Benefit obligation at end of year** | **$243,690** | **$251,879** | **$9,886** | **$9,155** | **$101,467** | **$109,899** |

| | Pension | | SERP | | OPEB | |
|---|---|---|---|---|---|---|
| **Reconciliation of Fair Value of Plan Assets:** | **2015** | **2014** | **2015** | **2014** | **2015** | **2014** |
| Fair value of plan assets at beginning of year | $192,674 | $186,547 | $ — | $ — | $83,776 | $79,098 |
| Actual return on plan assets — gain/(loss) | (1,978) | 14,319 | — | — | (955) | 5,030 |
| Employer contribution | 21,350 | 11,335 | — | — | 4,903 | 2,258 |
| Benefits paid | (25,201) | (19,527) | — | — | (3,670) | (3,707) |
| Plan participant's contribution | — | — | — | — | 912 | 804 |
| Federal subsidy | — | — | — | — | 403 | 293 |
| **Fair value of plan assets at end of year** | **$186,845** | **$192,674** | **$ —** | **$ —** | **$85,369** | **$83,776** |

| | Pension | | SERP | | OPEB | |
|---|---|---|---|---|---|---|
| **Reconciliation of Funded Status:** | **2015** | **2014** | **2015** | **2014** | **2015** | **2014** |
| Fair value of plan assets | $ 186,845 | $ 192,674 | $ — | $ — | $ 85,369 | $ 83,776 |
| Projected benefit obligations | (243,690) | (251,879) | (9,886) | (9155) | (101,467) | (109,899) |
| Funded status | **$ (56,845)** | **$ (59,205)** | **$(9,886)** | **$(9,155)** | **$ (16,098)** | **$ (26,123)** |

## THE EMPIRE DISTRICT ELECTRIC COMPANY

### Notes to Consolidated Financial Statements

### 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

**General**

We operate our businesses as three segments: electric, gas and other. The Empire District Electric Company (EDE), a Kansas corporation organized in 1909, is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. As part of our electric segment, we also provide water service to three towns in Missouri. The Empire District Gas Company (EDG) is our wholly owned subsidiary engaged in the distribution of natural gas in Missouri. Our other segment consists of our fiber optics business. See Note 12. Our gross operating revenues in 2015 were derived as follows:

| | | |
|---|---|---|
| Electric segment sales* | | 91.7% |
| On-system revenues | 86.6% | |
| SPP IM revenues | 2.5 | |
| Other revenues | 2.3 | |
| Gas segment sales | | 6.9 |
| Other segment sales | | 1.4 |

* Sales from our electric segment include 0.3% from the sale of water.

The utility portions of our business are subject to regulation by the Missouri Public Service Commission (MPSC), the State Corporation Commission of the State of Kansas (KCC), the Corporation Commission of Oklahoma (OCC), the Arkansas Public Service Commission (APSC) and the Federal Energy Regulatory Commission (FERC). Our accounting policies are in accordance with the ratemaking practices of the regulatory authorities and conform to generally accepted accounting principles as applied to regulated public utilities.

Our electric operations serve approximately 170,000 customers as of December 31, 2015, and the 2015 electric operating revenues were derived as follows:

| Customer Class | % of revenue |
|---|---|
| Residential | 41.7% |
| Commercial | 31.1 |
| Industrial | 15.9 |
| Wholesale on-system | 3.3 |
| Wholesale off-system | 2.7 |
| Miscellaneous sources, primarily public authorities | 2.8 |
| Other electric revenues | 2.5 |

Our retail electric revenues for 2015 by jurisdiction were as follows:

| Jurisdiction | % of revenue |
|---|---|
| Missouri | 89.0% |
| Kansas | 4.8 |
| Oklahoma | 2.8 |
| Arkansas | 3.4 |

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**THE EMPIRE DISTRICT ELECTRIC COMPANY**

**Notes to Consolidated Financial Statements (Continued)**

Our gas operations serve approximately 43,200 customers as of December 31, 2015, and the 2015 gas operating revenues were derived as follows:

| Customer Class | % of revenue |
|---|---|
| Residential | 63.0% |
| Commercial | 25.6 |
| Industrial | 0.8 |
| Transportation | 8.9 |
| Miscellaneous | 1.7 |

**Basis of Presentation**

The consolidated financial statements include the accounts of EDE, EDG, and our other subsidiaries. The consolidated entity is referred to throughout as "we" or the "Company". All intercompany balances and transactions have been eliminated in consolidation. See Note 12 for additional information regarding our three segments. Certain immaterial reclassifications have been made to prior year information to conform to the current year presentation.

**Use of Estimates**

The preparation of financial statements in conformity with generally accepted accounting principles (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements. Estimates also affect the reported amounts of revenues and expenses during the period. Areas in the financial statements significantly affected by estimates and assumptions include unbilled utility revenues, collectability of accounts receivable, depreciable lives, asset impairment and goodwill impairment evaluations, employee benefit obligations, contingent liabilities, asset retirement obligations, the fair value of stock based compensation, and tax provisions. Actual amounts could differ from those estimates.

**Accounting for the Effects of Regulation**

In accordance with the Accounting Standard Codification (ASC) guidance for regulated operations, our financial statements reflect ratemaking policies prescribed by the regulatory commissions having jurisdiction over our regulated generation and other utility operations (the MPSC, the KCC, the OCC, the APSC and the FERC).

We record a regulatory asset for all or part of an incurred cost that would otherwise be charged to expense in accordance with the ASC guidance for regulated operations which says that an asset should be recorded if it is probable that future revenue in an amount at least equal to the capitalized cost will be allowable for costs for rate making purposes and the current available evidence indicates that future revenue will be provided to permit recovery of the cost. This guidance also indicates that a liability should be recorded when a regulator has provided current recovery for a cost that is expected to be incurred in the future. We follow this guidance for incurred costs or credits that are subject to future recovery from or refund to our customers in accordance with the orders of our regulators.

Historically, all costs of this nature, which are determined by our regulators to have been prudently incurred, have been recoverable through rates in the course of normal ratemaking procedures. Regulatory assets and liabilities are ratably amortized through a charge or credit, respectively, to earnings while being recovered in revenues and fully recognized if and when it is no longer probable that such amounts will be

THE EMPIRE DISTRICT ELECTRIC COMPANY

Notes to Consolidated Financial Statements (Continued)

recovered through future revenues. We generally include amortization of regulatory assets and liabilities in the depreciation and amortization line of our statement of cash flows. We continually assess the recoverability of our regulatory assets. Although we believe it unlikely, should retail electric competition legislation be passed in the states we serve, we may determine that we no longer meet the criteria set forth in the ASC guidance for regulated operations with respect to continued recognition of some or all of the regulatory assets and liabilities. Any regulatory changes that would require us to discontinue application of this guidance based upon competitive or other events may also impact the valuation of certain utility plant investments. Impairment of regulatory assets or utility plant investments could have a material adverse effect on our financial condition and results of operations. (See Note 3 for further discussion of regulatory assets and liabilities)

**Revenue Recognition**

For our utility operations, we use cycle billing and accrue estimated, but unbilled, revenue for services provided between the last bill date and the period end date. Unbilled revenues represent the estimate of receivables for energy and natural gas services delivered, but not yet billed to customers. The accuracy of our unbilled revenue estimate is affected by factors including fluctuations in energy demands, weather, line losses and changes in the composition of customer classes.

**Municipal Franchise Taxes**

Municipal franchise taxes are collected for and remitted to their respective entities and are included in operating revenues and other taxes in the Consolidated Statements of Income. Municipal franchise taxes of $11.4 million, $11.8 million and $11.2 million were recorded for each of the years ended December 31, 2015, 2014 and 2013, respectively.

**Accounts Receivable**

Accounts receivable are recorded at the tariffed rates for customer usage, including applicable taxes and fees and do not bear interest. We review the outstanding accounts receivable monthly, as well as the bad debt write-offs experienced in the past, and establish an allowance for doubtful accounts. Account balances are charged off against the allowance when management determines it is probable the receivable will not be recovered.

**Property, Plant & Equipment**

The costs of additions to utility property and replacements for retired property units are capitalized. Costs include labor, material, an allocation of general and administrative costs, and an allowance for funds used during construction (AFUDC). The original cost of units retired or disposed of and the costs of removal are charged to accumulated depreciation, unless the removed property constitutes an operating unit or system. In this case a gain or loss is recognized upon the disposal of the asset. Maintenance expenditures and the removal of minor property items are charged to income as incurred. A liability is created for any additions to electric or gas utility property that are paid for by advances from developers. For a period of five years we refund to the developer a pro rata amount of the original cost of the extension for each new customer added to the extension. Nonrefundable payments at the end of the five year period are applied as a reduction to the cost of the plant in service. The liability as of December 31, 2015 and 2014 was $2.1 million and $1.9 million, respectively.

**THE EMPIRE DISTRICT ELECTRIC COMPANY**

**Notes to Consolidated Financial Statements (Continued)**

### Depreciation

Provisions for depreciation are computed at straight-line rates in accordance with GAAP consistent with rates approved by regulatory authorities. These rates are applied to the various classes of utility assets on a composite basis. Provisions for depreciation for our other segment are computed at straight-line rates over the estimated useful life of the properties (See Note 2 for additional details regarding depreciation rates).

As of December 31, 2015 and 2014, we had recorded accrued cost of removal of $85.4 million and $82.8 million, respectively, for our electric operating segment. This represents an estimated cost of dismantling and removing plant from service upon retirement, accrued as part of our depreciation rates. We accrue cost of removal in depreciation rates for mass property (including transmission, distribution and general plant assets). These accruals are not considered an asset retirement obligation under the guidance provided on asset retirement obligations within the ASC. We reclassify the accrued cost of dismantling and removing plant from service upon retirement from accumulated depreciation to a regulatory liability. We have a similar cost of removal regulatory liability for our gas operating segment. This amount at December 31, 2015 and 2014 was $8.8 million and $7.7 million, respectively. These amounts are net of our actual cost of removal expenditures.

### Asset Retirement Obligation

We record the estimated fair value of legal obligations associated with the retirement of tangible long-lived assets in the period in which the liabilities are incurred and capitalize a corresponding amount as part of the book value of the related long-lived asset. In subsequent periods, we are required to adjust asset retirement obligations based on changes in estimated fair value, and the corresponding increases in asset book values are depreciated over the useful life of the related asset. Uncertainties as to the probability, timing or cash flows associated with an asset retirement obligation affect our estimate of fair value.

We have identified asset retirement obligations associated with the future removal of certain river water intake structures and equipment at the Iatan Power Plant, in which we have a 12% ownership. We also have a solid waste land fill at the Plum Point Energy Station, and asset retirement obligations associated with the removal of asbestos located at the Riverton and Asbury Plants. As a result of the fuel use transition from coal to natural gas at the Riverton Power Plant, the closure of the Riverton ash landfill was completed, and the related asset retirement obligation was settled during 2014 (Note 11). During 2015 the EPA established a final rule to regulate the disposal of coal combustion residuals (CCRs). As a result of these new rules, an asset retirement obligation of $5.4 million has been recorded for the final closure of the existing ash impoundment at our Asbury Power Plant. Separately, an asset retirement obligation of $4.4 million has been recorded for our interest in the coal ash impoundment at the Iatan Generating Station.

In addition, we have a liability for the removal and disposal of Polychlorinated Biphenyls (PCB) contaminants associated with our transformers and substation equipment. These liabilities have been estimated based upon either third party costs or historical review of expenditures for the removal of similar past liabilities. The potential costs of these future expenditures are based on engineering estimates of third party costs to remove the assets in satisfaction of the associated obligations. This liability will be accreted over the period up to the estimated settlement date.

All of our recorded asset retirement obligations have been estimated as of the expected retirement date, or settlement date, and have been discounted using a credit adjusted risk-free rate ranging from 4.5% to 5.52% depending on the settlement date. Revisions to these liabilities could occur due to changes in the cost estimates, anticipated timing of settlement or federal or state regulatory requirements. During 2014

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the liability for asbestos at the Riverton Power Plant was re-evaluated. Changes in the cost estimates and timing resulted in cash flow revisions for these liabilities.

The balances at the end of 2015 and 2014 are shown below.

| (000's) | Liability Balance 12/31/14 | Liabilities Recognized | Liabilities Settled | Accretion | Cash Flow Revisions | Liability Balance at 12/31/15 |
|---|---|---|---|---|---|---|
| Asset Retirement Obligation | $ 4,847 | $ 9,812 | $ (73) | $ 486 | $ — | $ 15,072 |

| (000's) | Liability Balance 12/31/13 | Liabilities Recognized | Liabilities Settled | Accretion | Cash Flow Revisions | Liability Balance at 12/31/14 |
|---|---|---|---|---|---|---|
| Asset Retirement Obligation | $ 4,190 | $ — | $ (1,175) | $ 172 | $ 1,660 | $ 4,847 |

Upon adoption of the standards on the retirement of long lived assets and conditional asset retirement obligations, we recorded a liability and regulatory asset because we expect to recover these costs of removal in electric and gas rates either through depreciation accruals or direct expenses. We also defer the liability accretion and depreciation expense as a regulatory asset. At December 31, 2015 and 2014, our regulatory assets relating to asset retirement obligations totaled $7.7 million and $5.1 million, respectively.

Also as noted previously under property, plant and equipment, we reclassify the accrued cost of dismantling and removing plant from service upon retirement, which is not considered an asset retirement obligation under this guidance, from accumulated depreciation to a regulatory liability. This balance sheet reclassification has no impact on results of operations.

**Allowance for Funds Used During Construction**

As provided in the FERC regulatory Uniform System of Accounts, utility plant is recorded at original cost, including an allowance for funds used during construction (AFUDC) when first placed in service. The AFUDC is a utility industry accounting practice whereby the cost of borrowed funds and the cost of equity funds applicable to construction programs are capitalized as a cost of construction. This accounting practice offsets the effect on earnings of the cost of financing current construction, and treats such financing costs in the same manner as construction charges for labor and materials.

AFUDC does not represent current cash income. Recognition of this item as a cost of utility plant is in accordance with regulatory rate practice under which such plant costs are permitted as a component of rate base and the provision for depreciation.

In accordance with the methodology prescribed by the FERC, we utilized aggregate rates (on a before-tax basis) of 5.5% for 2015, 6.6% for 2014, and 7.3% for 2013, compounded semiannually.

**Asset Impairments (excluding goodwill)**

We review long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. To the extent that certain assets may be impaired, analysis is performed based on undiscounted forecasted cash flows to assess the recoverability of the assets and, if necessary, the fair value is determined to measure the impairment amount. None of our assets were impaired as of December 31, 2015 and 2014.

THE EMPIRE DISTRICT ELECTRIC COMPANY

Notes to Consolidated Financial Statements (Continued)

**Goodwill**

As of December 31, 2015, the consolidated balance sheet included $39.5 million of goodwill. All of this goodwill was derived from our gas acquisition and recorded in our gas segment, which is also the reporting unit for goodwill testing purposes. Accounting guidance requires us to test goodwill for impairment on an annual basis or whenever events or circumstances indicate possible impairment. Absent an indication of fair value from a potential buyer or a similar specific transaction, a combination of the market and income approaches is used to estimate the fair value of goodwill.

We use the market approach which estimates fair value of the gas reporting unit by comparing certain financial metrics to comparable companies. Comparable companies whose securities are actively traded in the public market are judgmentally selected by management based on operational and economic similarities. We utilize EBITDA (earnings before interest, taxes, depreciation, and amortization) multiples of the comparable companies in relation to the EBITDA results of the gas reporting unit to determine an estimate of fair value.

We also utilize a valuation technique under the income approach which estimates the discounted future cash flows of operations. Our procedures include developing a baseline test and performing sensitivity analysis to calculate a reasonable valuation range. The sensitivities are derived from altering those assumptions which are subjective in nature and inherent to a discounted cash flows calculation. Other qualitative factors and comparisons to industry peers are also used to further support the assumptions and ultimately the overall evaluation. A key qualitative assumption considered in our evaluation is the impact of regulation, including rate regulation and cost recovery for the gas reporting unit. Some of the key quantitative assumptions included in our tests involve: regulatory rate design and results; the discount rate; the growth rate; capital spending rates and terminal value calculations. If negative changes occurred to one or more key assumptions, an impairment charge could result. With the exception of the capital spending rate, the key assumptions noted are significantly determined by market factors and significant changes in market factors that impact the gas reporting unit would somewhat be mitigated by our current and future regulatory rate design. Other risks and uncertainties affecting these assumptions include: changes in business, industry, laws, technology and economic conditions. Actual results for the gas reporting unit indicate a slight decline in gas customer count and demand. A continued decline in customer count or demand coupled with an increase in the discount rate would have adverse impacts on the valuation and could result in an impairment charge in the future. Our forecasts anticipate relatively flat customer counts over the next several years.

We weight the results of the two approaches discussed above in order to estimate the fair value of the gas reporting unit. Our annual test performed as of October 2015 indicated the estimated fair market value of the gas reporting unit to be $18 – $22 million higher than its carrying value at that time. While we believe the assumptions utilized in our analysis were reasonable, adverse developments in future periods could negatively impact goodwill impairment considerations, which could adversely impact earnings. Specifically, the quantitative assumptions noted previously, such as an increase to the discount rate or decline in the terminal value calculation could lead to an impairment charge in the future.

**Fuel and Purchased Power**

*Electric Segment*

Fuel and purchased power costs are recorded at the time the fuel is used, or the power purchased. SPP Integrated Marketplace purchased power is also included in fuel and purchased power costs. The net effects of our SPP IM activity, including SPP IM net revenue and net purchased power costs, flow through our fuel recovery mechanisms in each state.

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**THE EMPIRE DISTRICT ELECTRIC COMPANY**

**Notes to Consolidated Financial Statements (Continued)**

In our Missouri jurisdiction, the MPSC establishes a base cost for the recovery of fuel and purchased power expenses used to supply energy for our fuel adjustment clause (FAC). Beginning with our 2015 rate order, certain transmission costs are also included in the base cost. The FAC permits the distribution to customers of 95% of the changes in fuel and purchased power costs prudently incurred above or below the base cost. Off-system sales margins are also part of the recovery of fuel and purchased power costs. As a result, nearly the entire off-system sales margin flows back to the customer. Rates related to the fuel adjustment clause are modified twice a year subject to the review and approval by the MPSC. In accordance with the ASC guidance for regulated operations, 95% of the difference between the actual costs of fuel and purchased power and the base cost of fuel and purchased power recovered from our customers is recorded as an adjustment to fuel and purchased power expense with a corresponding regulatory asset or regulatory liability. If the actual fuel and purchased power costs are higher or lower than the base fuel and purchased power costs billed to customers, 95% of these amounts will be recovered from or refunded to our customers when the fuel adjustment clause is modified.

In our Kansas jurisdiction, the costs of fuel are recovered from customers through a fuel adjustment clause, based upon estimated fuel costs and purchased power. The adjustments are subject to audit and final determination by regulators. The difference between the costs of fuel used and the cost of fuel recovered from our Kansas customers is recorded as a regulatory asset or a regulatory liability if the actual costs are higher or lower than the costs billed to customers, in accordance with the ASC guidance for regulated operations.

Similar fuel recovery mechanisms are in place for our Oklahoma, Arkansas and FERC jurisdictions.

At December 31, 2015 and 2014, our Missouri, Kansas and Oklahoma fuel and purchased power costs were in a net over-recovered position by $5.9 million and a net under-recovered position of $3.1 million, respectively, which are reflected in our regulatory assets and liabilities.

We receive the renewable attributes associated with the power purchased through our purchased power agreements with Elk River Windfarm LLC and Cloud County Windfarm, LLC. These renewable attributes are converted into renewable energy credits (REC), which are considered inventory, and recorded at zero cost (See Note 11). Revenue from the sale of RECs reduces fuel and purchased power expense.

We have a Stipulation and Agreement with the MPSC granting us authority to manage our emissions allowance inventory in accordance with our Plan for Purchasing and Selling Emissions Allowances (PPSEMA). The PPSEMA allows us to purchase allowances needed for compliance, exchange banked allowances for future vintage allowances and/or monetary value and, in extreme market conditions, to sell allowances outright for monetary value. For compliance year 2015 we did not exchange or sell any allowances, and for compliance year 2014 we purchased 69 NOx annual allowances for compliance. We classify our allowances as inventory and they are recorded at cost, with allocated allowances being recorded at zero cost. The allowances are removed from inventory on a FIFO basis, and used allowances are considered to be a part of fuel expense (See Note 11). We had the following emissions allowances in inventory at December 31, 2015 and 2014:

| Emission Allowances in Inventory | 2015 | 2014 |
|---|---|---|
| Acid Rain SO2 | 11,443 | 872 |
| CSAPR SO2 | 5,861 | — |
| CSAPR NOx (annual) | 500 | — |
| CSAPR NOx (seasonal) | 241 | — |

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*Gas Segment*

Fuel expense for our gas segment is recognized when the natural gas is delivered to our customers, based on the current cost recovery allowed in rates. A Purchased Gas Adjustment (PGA) clause allows EDG to recover from our customers, subject to audit and final determination by regulators, the cost of purchased gas supplies and related carrying costs associated with the Company's use of natural gas financial instruments to hedge the purchase price of natural gas. This PGA clause allows us to make rate changes periodically (up to four times) throughout the year in response to weather conditions and supply demands, rather than in one possibly extreme change per year.

We calculate the PGA factor based on our best estimate of our annual gas costs and volumes purchased for resale. The calculated factor is reviewed by the MPSC staff and approved by the MPSC. Elements considered part of the PGA factor include cost of gas supply, storage costs, hedging contracts, revenue and refunds, prior period adjustments and transportation costs.

Pursuant to the provisions of the PGA clause, the difference between actual costs incurred and costs recovered through the application of the PGA (including costs, cost reductions and carrying costs associated with the use of financial instruments) are reflected as a regulatory asset or liability. The balance is amortized as amounts are reflected in customer billings.

**Derivatives**

We utilize derivatives to help manage our natural gas commodity market risk resulting from purchasing natural gas, to be used as fuel in our electric business or sold in our natural gas business, on the spot market and to manage certain interest rate exposure. We also acquire Transmission Congestion Rights (TCR) in an attempt to mitigate congestion costs associated with the power we purchase from the SPP Integrated Marketplace (see Note 14).

*Electric Segment*

Pursuant to the ASC guidance on accounting for derivative instruments and hedging activities, derivatives are required to be recognized on the balance sheet at their fair value. On the date a derivative contract is entered into, the derivative is designated as (1) a hedge of a forecasted transaction or of the variability of cash flows to be received or paid related to a recognized asset or liability ("cash-flow" hedge); or (2) an instrument that is held for non-hedging purposes (a "non-hedging" instrument). We record the mark-to-market gains or losses on derivatives used to hedge our fuel and congestion costs as regulatory assets or liabilities. This is in accordance with the ASC guidance on regulated operations, given that those regulatory assets and liabilities are probable of recovery through our fuel adjustment mechanism.

We also enter into fixed-price forward physical contracts for the purchase of natural gas, coal and purchased power. These contracts, if they meet the definition of a derivative, are not subject to derivative accounting because they are considered to be normal purchase normal sales (NPNS) transactions. If these transactions don't qualify for NPNS treatment, they would be marked to market for each reporting period through regulatory assets or liabilities.

*Gas Segment*

Financial hedges for our natural gas business are recorded at fair value on our balance sheet. Because we have a commission approved natural gas cost recovery mechanism (PGA), we record the mark-to-market gain/loss on natural gas financial hedges each reporting period to a regulatory asset/liability account. The regulatory asset/liability account tracks the difference between revenues billed to

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customers for natural gas costs and actual natural gas expense which is trued up at the end of August each year and included in the Actual Cost Adjustment (ACA) factor to be billed to customers during the next year. This is consistent with the ASC guidance on regulated operations, in that we will be recovering our costs after the annual true up period (subject to a prudency review by the MPSC).

Cash flows from hedges for both electric and gas segments are classified within cash flows from operations.

**Pension and Other Postretirement Benefits**

We recognize expense related to pension and other postretirement benefits (OPEB) as earned during the employee's period of service. Related assets and liabilities are established based upon the funded status of the plan compared to the projected benefit obligation. Our pension and OPEB expense or benefit includes amortization of previously unrecognized net gains or losses. Additional income or expense may be recognized when our unrecognized gains or losses as of the most recent measurement date exceed 10% of our postretirement benefit obligation or fair value of plan assets, whichever is greater. For pension benefits and OPEB benefits, unrecognized net gains or losses as of the measurement date are amortized into actuarial expense over ten years.

*Pensions*

We have rate orders with Missouri, Kansas and Oklahoma that allow us to recover pension costs consistent with our GAAP policy noted above. In accordance with the rate orders, we prospectively calculate the value of plan assets using a market-related value method as allowed by the ASC guidance on pension benefits. As a result, we are allowed to record the Missouri, Kansas and Oklahoma portion of any costs above or below the amount included in rates as a regulatory asset or liability, respectively. The MPSC has allowed us to adopt this pension cost recovery methodology for EDG as well.

*Other Postretirement Benefits (OPEB)*

We have regulatory treatment for our OPEB costs similar to the treatment described above for pension costs. This includes the use of a market-related value of assets, the amortization of unrecognized gains or losses into actuarial expense over ten years and the recognition of regulatory assets and liabilities as described above.

Additional guidance in the ASC on employers' accounting for defined benefit pension and other postretirement plans requires an employer to recognize the over funded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity. The guidance also requires an employer to measure the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions. Pension and other postretirement employee benefits tracking mechanisms are utilized to allow for future rate recovery of these obligations. We record these as regulatory assets on the balance sheet rather than as reductions of equity through comprehensive income (See Note 7).

**Unamortized Debt Discount, Premium and Expense**

Discount, premium and expense associated with long-term debt are amortized over the lives of the related issues. Costs, including gains and losses, related to refunded long-term debt are amortized over the lives of the related new debt issues, in accordance with regulatory rate practices.

THE EMPIRE DISTRICT ELECTRIC COMPANY

Notes to Consolidated Financial Statements (Continued)

**Liability Insurance**

We are primarily self-insured for workers' compensation claims, general liabilities, benefits paid under employee healthcare programs and long-term disability benefits. Accruals are primarily based on the estimated undiscounted cost of claims. We self-insure up to certain limits that vary by segment and type of risk. Periodically, we evaluate the level of insurance coverage over the self-insured limits and adjust insurance levels based on risk tolerance and premium expense. We carry excess liability insurance for workers' compensation and public liability claims for our electric segment. In order to provide for the cost of losses not covered by insurance, an allowance for injuries and damages is maintained based on our loss experience. Our gas segment is covered by excess liability insurance for public liability claims, and workers' compensation claims are covered by a guaranteed cost policy (See Note 11).

**Other Noncurrent Liabilities**

Other noncurrent liabilities are comprised of accruals and other accounting estimates not sufficiently large enough to merit individual disclosure. At December 31, 2015, the balance of other noncurrent liabilities is primarily comprised of accruals for self-insurance, customer advances for construction and asset retirement obligations.

**Cash & Cash Equivalents**

Cash and cash equivalents include cash on hand and temporary investments purchased with an initial maturity of three months or less. It also includes checks and electronic funds transfers that have been issued but have not cleared the bank, which are also reflected in current accrued liabilities and were $23.2 million and $28.3 million at December 31, 2015 and 2014, respectively.

*Restricted Cash*

As part of our Plum Point ownership agreement, we are required to have funds available in an escrow account which guarantees payment of certain operating costs. The cash is held at a financial institution and restricted as to withdrawal or use. The amounts restricted, which were $1.8 million at December 31, 2015 and 2014, may increase or decrease based on an annual review.

We are required to post cash collateral with Southwest Power Pool (SPP) to participate in Transmission Congestion Rights (TCR) auctions. The cash is held at a financial institution and restricted as to withdrawal or use. The amounts of such restricted cash were $2.5 million at December 31, 2015 and 2014.

Due to our Plum Point energy station interconnection with Midcontinent Independent System Operator (MISO), we participate in Financial Transmission Rights (FTR) auctions which require us to post cash collateral. The cash is held at a financial institution and restricted as to withdrawal or use. The amounts of such restricted cash were $0.5 million at December 31, 2015 and 2014.

**THE EMPIRE DISTRICT ELECTRIC COMPANY**

**Notes to Consolidated Financial Statements (Continued)**

**Fuel, Materials and Supplies**

Fuel, materials and supplies consist primarily of coal, natural gas in storage and materials and supplies, which are reported at average cost. These balances are as follows (in thousands):

| | 2015 | 2014 |
|---|---|---|
| Electric fuel inventory | $ 30,185 | $ 26,454 |
| Natural gas inventory | 3,868 | 5,040 |
| Materials and supplies | 26,897 | 26,305 |
| TOTAL | $ 60,950 | $ 57,799 |

**Income Taxes**

Deferred tax assets and liabilities are recognized for the tax consequences of transactions that have been treated differently for financial reporting and tax return purposes; measured using statutory tax rates (See Note 9).

Investment tax credits utilized in prior years were deferred and are being amortized over the useful lives of the properties to which they relate. The longest remaining amortization period for investment tax credits is approximately 55 years.

**Accounting for Uncertainty in Income Taxes**

In 2006, the FASB issued guidance which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with the ASC guidance on accounting for income taxes. We file consolidated income tax returns in the U.S. federal and state jurisdictions. With few exceptions, we are no longer subject to U.S. federal, state and local income tax examinations by tax authorities for years before 2010. At December 31, 2015 and 2014, our balance sheet did not include any unrecognized tax benefits. We do not expect any material changes to unrecognized tax benefits within the next twelve months. We recognize interest and penalties, if any, related to unrecognized tax benefits in other expenses.

**Computations of Earnings Per Share**

The ASC guidance on earnings per share requires dual presentation of basic and diluted earnings per share. Basic earnings per share does not include potentially dilutive securities and is computed by dividing net income by the weighted average number of common shares outstanding. Diluted earnings per share assumes the issuance of common shares pursuant to the Company's stock-based compensation plans at the

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beginning of each respective period, or at the date of grant or award if later. Shares attributable to stock options are excluded from the calculation of diluted earnings per share if the effect would be antidilutive.

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| **Weighted Average Number Of Shares** | | | |
| Basic | 43,670,908 | 43,291,031 | 42,781,382 |
| Dilutive Securities: | | | |
| Performance-based restricted stock awards | 19,890 | 8,809 | 12,142 |
| Employee stock purchase plan | 1,249 | 3,422 | 1,729 |
| Stock options | — | — | 61 |
| Time-based restricted stock awards | 25,523 | 10,666 | 7,907 |
| Total dilutive securities | 46,662 | 22,897 | 21,839 |
| Diluted weighted average number of shares | 43,717,570 | 43,313,928 | 42,803,221 |
| Antidilutive Shares | 20,289 | 25,259 | 107,100 |

Potentially dilutive shares are not expected to have a material impact unless significant appreciation of the Company's stock price occurs.

**Stock-Based Compensation**

We have several stock-based compensation plans, which are described in more detail in Note 8. In accordance with the ASC guidance on stock-based compensation, we recognize compensation expense over the requisite service period of all stock-based compensation awards based upon the fair-value of the award as of the date of issuance.

**Recently Issued and Proposed Accounting Standards**

*Revenue from contracts with customers:* In June 2014, the FASB issued new guidance governing revenue recognition. Under the new guidance, an entity is required to recognize revenue in a pattern that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In July 2015, the FASB approved a one year delay in the standard's effective date. The new standard is now effective for interim and annual reporting periods beginning after December 15, 2017. We are evaluating the impact of the adoption of this standard.

*Extraordinary and unusual items:* In January 2015, the FASB issued revised guidance that eliminates from GAAP the concept of extraordinary items. Under the revised guidance, an entity will no longer be required to separately classify, present and disclose events or transactions that are determined to be both unusual in nature and infrequent in occurrence. The revised guidance is effective for interim and annual reporting periods beginning after December 15, 2015. The application of this standard is not expected to have a material impact on our results of operations, financial position or liquidity.

*Presentation of debt issuance costs:* In April 2015, the FASB issued revised guidance addressing the presentation requirements for debt issuance costs. Under the revised guidance, all costs incurred to issue debt are to be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability. The revised guidance is effective for interim and annual reporting periods beginning after December 15, 2015. As of December 31, 2015, we expect that the implementation of this standard would

Exhibit WKW-5

# ANNUAL REPORT 2015

# ALGONQUIN Power & Utilities Corp.

ALGONQUIN POWER & UTILITIES CORP.
Algonquin is a $5 billion North American diversified generation, transmission and distribution utility.

OUR VISION IS CLEAR. To be most admired by customers, communities and investors for our people, passion and performance.

ALGONQUIN
Power & Utilities Corp.

WWW.ALGONQUINPOWERANDUTILITIES.COM

TORONTO STOCK EXCHANGE: AQN

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# AQN ACROSS THE UTILITY SPECTRUM

**Algonquin Power & Utilities is an integrated utility company participating across the utility spectrum - generation, transmission and distribution.**

## DISTRIBUTION

The Distribution Business Group owns and operates regulated water, natural gas and electricity distribution utilities in communities across the United States. We own and operate 34 distribution utilities serving more than 560,000 customer connections across 11 states, with our focus on growth achieved through acquisitions and organic growth opportunities currently totaling $2 billion.

## EMPIRE – COMPLEMENTARY BUSINESS, FAMILIAR TERRITORY

On February 9, 2016 Algonquin announced the acquisition of the Empire District Electric Company ("Empire"). Empire is a regulated water, gas and electric utility serving 218,000 customers in Missouri, Arkansas, Oklahoma and Kansas. Empire's addition is highly complementary to our business, bringing a mix of generation, transmission and distribution operations to our existing presence in the United States. Empire operates water, gas and electric utilities and overlaps states in which we have an established presence. The addition of Empire to the Algonquin and Liberty Utilities family brings increased scale, management depth and new growth opportunities for our mid-states operations.

*"The acquisition of Empire represents a continuation of our disciplined growth strategy. It strengthens and diversifies Algonquin's existing businesses and strategically expands our regulated utility footprint in the mid-west United States. The addition of this large, well run utility to the Algonquin family will support our 10% annual dividend growth target through significant accretion to shareholder cash flows and earnings. Empire's service territories, business lines and corporate culture are highly complementary to Liberty Utilities and we will continue Empire's history of prudently investing in its systems, communities and employees."*

**Ian Robertson, CEO Algonquin Power & Utilities Corp.**

## GENERATION

The Generation Business Group generates and sells electricity produced by a diverse portfolio of renewable and clean energy power generation facilities across North America. We have interests in, own and operate more than 36 contracted hydroelectric, wind, solar, and thermal facilities representing over 1,185 MW of installed generating capacity and have future investment opportunities totalling over $1.8 billion in renewable generation to power our growth.

## TRANSMISSION

The Transmission Business Group is a regulated transmission utility business that focuses on building and investing in natural gas pipeline and electric transmission opportunities across North America.  This group serves to connect our generation and distribution businesses, completing the utility supply chain. The Transmission Business Group is partnering in two natural gas pipeline projects in the north east United States, with an investment opportunity reaching $650 million by 2018.

# Americas Electric Utilities & IPPs

## The Canadian Playbook on Utility Acquisitions [Incl. Transcript]

**Equities**

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**Why are Canadian companies buying so many US utilities of late?**

While there is not a consistent answer, we flag *four key factors*: 1) lower sovereign interest rates in Canada; 2) a market environment for high-yielding equity products, including utilities and a range of other power/energy-oriented investments; 3) improving liquidity with potential for dual-listings; and 4) meaningful tax benefits arising from the 'hybrid' nature of investments made. This last component has garnered substantial questions as investors attempt to quantify the benefits. Effectively investments made into the US are treated as foreign equity investments in Canada with limited tax consequences on repatriated cash. Further these investments can also be treated as leverage in Canada, enabling further deductions. Subsequently, the substantially leveraged investments in the US are treated as interest expense, limiting the income remaining for the equity investment.

**Tax advantages are real; but push on tax reform puts doubts**

In our latest conference call with Partners at the law firm of Osler, Hoskin & Harcourt LLP, Drew Morier and Paul Seraganian describe a backdrop of increasingly stringent rules on interpreting 'hybridity' of investments amidst a wider ongoing effort among OECD countries to limit such tax treatment; see the full transcript below. The partners emphasize first and foremost that investments have likely been predominantly entered into for strategic reasons, particularly when evaluating new transactions where company expectations have and will increasingly haircut the sustainability of the tax treatment of employing 'hybrid' securities for Holding Company leverage. We note there are already limitations employed by IRS as they evaluate proposed structures, with safe harbor established at 1.5:1 debt-to-equity (60%), albeit appropriate capital structure is subject to a comparison across the industry norm (likely providing utility deals with more leeway). We see greater latitude in making this comparison in recent years as many US utilities have increasingly employed holding company leverage to achieve EPS growth amidst the low interest rate environment.

**But what about US utility regulators? Concerns on authorized equity too.**

Despite the leverage, thus far utility acquisitions have not received pushback from state-level US utility regulators seeking to reflect the higher holding company leverage into the authorized utility capital structure of subsidiaries. We note this trend could be bucked by the Missouri Public Service Commission in the pending acquisition of EDE by Algonquin, where MO has a historic policy of incorporating holding company leverage into rates. This remains part of an overarching concern we have looking to M&A holistically, with regulators focusing on retaining benefits of increased leverage and evaluation of new structures. For instance, how will regulators opt to treat REITs if continued to expand to include Utilities?

**Recent focus on tax inversions and earnings stripping is further headwind**

While the treatment of 'hybrid' instruments between US & Canada is separate and distinct from recent scrutiny by IRS of tax inversions, we flag a wider ongoing effort to curtail tax-motivated transactions. As such, we see a potential for a slow-down of such deals, particularly after the latest limitations by IRS. The fundamental question remains will valuation premiums exist in Canada persist such that deals can still be done accretively without the benefit of these tax benefits.

**What Canadian deals have happened? Several in just the last year**

We flag a series of Canadian acquisition have transpired in recent years, with four in the last 12-months: starting with TE-EMA, ITC-FTS, EDE-AQN, and most recently TransCanada (TRP) – Columbia Pipeline Group (CPGX). Other previous deals include the FTS-UNS Energy and FTS-CH Energy Group in 2013 and 2012, respectively. We note this trend is not limited to Canadian companies either with IBR merging with UIL to create a domestically listed utility-renewable subsidiary.

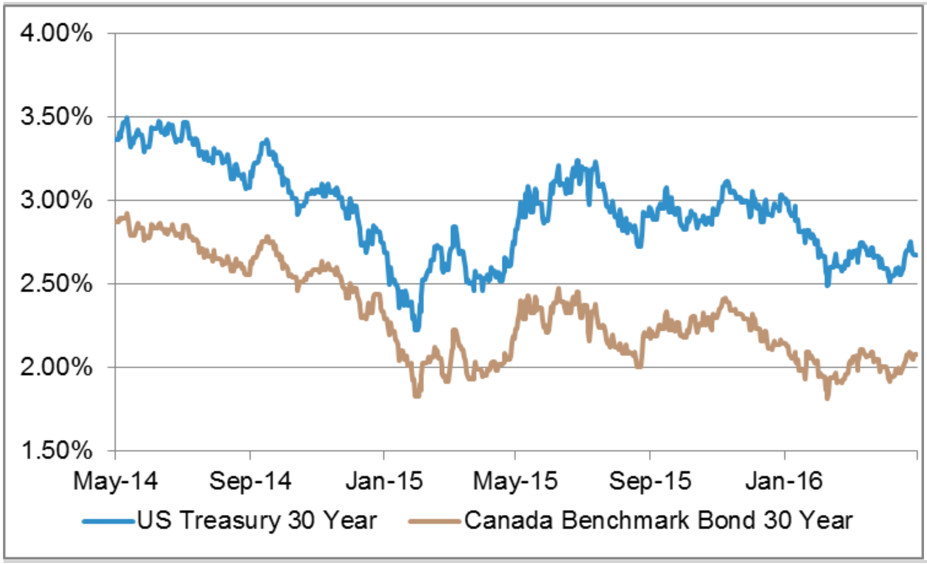
**Canadian involvement has not been limited to just corporate M&A**

We flag a growing interest in Canadian company investment into the US for organic growth as well. For instance TransAlta (TA) is among other Canadian companies specifically stating their intention to invest in US renewable asset development and expanding their US footprint. We also note the EMA acquisition of TE was predicated as part of a wider gas platform extension from its Northeast US footprint down to the Southeast as well, lending itself to investments beyond just its latest utility acquisition footprint.

# Contrasting the US and Canadian Backdrop

The forward yield on US treasuries continues to be at a higher level vs the Canadian benchmark bond with a ~50bp premium relatively consistent over the past year.

**Figure 1: Yield Comparison: US 30 YR Treasury vs Canadian Benchmark Bond 30 YR**




Source: FactSet

**Despite lower interest rates and tax benefits, Canadian utilities are trading at a slight P/E discount to US peers but a smaller sample size**

Fortis, Emera, and Algonquin are trading at 16.0x 2018E consensus EPS, a 40bp discount versus US utilities. The dividend yields are also notably higher on the Canadian utilities.

**Figure 2: Comps Comparison: Canadian Utilities vs Regulated US Utilities**

| | | | Market Cap. | Price | Dividend | P/E Multiple | | | | EV / EBITDA Multiple | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Canadian Utilities | Ticker | Rating | (CAD in Mn) | 5/1/2016 | Yield | 2016E | 2017E | 2018E | 2019E | 2016E | 2017E | 2018E |
| Fortis | FTS-ca | Not Rated | 11,265 | 39.96 | 3.75% | 18.4 | 16.2 | 15.9 | 16.4 | 7.8 | na | na |
| Emera | EMA-ca | Not Rated | 6,737 | 45.32 | 4.19% | 18.7 | 16.4 | 15.0 | 14.1 | 10.8 | 10.0 | na |
| Algonquin Power & Utilities Corp. | AQN-ca | Not Rated | 2,808 | 10.98 | 4.70% | 27.8 | 18.4 | 17.2 | 16.4 | 4.1 | 4.1 | na |
| Average - Canadian Utilities | | | | | 4.21% | 21.7 | 17.0 | 16.0 | 15.6 | 7.6 | 7.0 | na |
| Average - Regulated US Utilities | | | | | 3.39% | 18.4 | 17.4 | 16.4 | 15.5 | 9.0 | 8.8 | 8.4 |

Source: FactSet and UBS Estimates. Not Rated Companies are FactSet; UBS Estimates are basis for regulated US Utilities multiples.

The same largely holds true for Canadian YieldCos although these vehicles are now trading at a slightly lower yield than US peers. This is a change from ~18-months ago when US YieldCos were trading at a premium for their DPS growth at the time.

**Figure 3: Comps Comparison: Canadian YieldCos vs Primary YieldCos (Ex TERP)**

| | | | Market Cap. | Price | Div Yield | | | | Div Yield Growth | | | | EV / EBITDA Multiple | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Canadian YieldCos | Ticker | Rating | (CAD in Mn) | 5/1/2016 | 2016E | 2017E | 2018E | 2019E | 2016E | 2017E | 2018E | 2019E | 2016E | 2017E | 2018E |
| Tranaslta Renewables | RNW-ca | Not Rated | 2,362 | 12.38 | 7% | 7% | 8% | 8% | 7% | 4% | 3% | 0% | 9.4 | 9.6 | -2.9 |
| Brookfield Renewables | BEP.UT-ca | Not Rated | 10,009 | 36.33 | 6% | 6% | 7% | 7% | -3% | 5% | 6% | 0% | 9.6 | 5.6 | -2.3 |
| Capital Power Corporation | CPX-ca | Not Rated | 1,709 | 17.77 | 8% | 9% | 9% | 9% | 6% | 6% | 4% | 0% | 7.6 | 7.3 | -3.5 |
| Capstone Infrastructure Corporation | CSE-ca | Not Rated | 478 | 4.89 | 6% | na | na | na | na | na | na | na | na | na | na |
| Innergex Renewable Energy Inc. | INE-ca | Not Rated | 1,495 | 13.85 | 5% | 5% | 5% | 5% | 3% | 3% | 3% | 0% | 14.4 | 14.3 | na |
| Average - Canadian YieldCos | | | | | 6% | 7% | 7% | 7% | | | | | 11.0 | 10.8 | na |
| Average - Primary YieldCos Ex- TERP | | | | | 6% | 7% | 8% | 8% | | | | | 10.3 | 9.2 | 9.1 |

Source: FactSet

# Transcript of Call with Drew Morier and Paul Seraganian (Osler, Hoskin & Harcourt):

## Transcript

**Julien Dumoulin-Smith:** Good morning everyone. We're joined this morning by Drew Morier and his colleague, Paul Seraganian, to discuss some of the Canadian deals of late and understand some of the nuances specific to the tax background on how they're structured.

They're both partners over at the Osler, Hoskin & Harcourt LLP. Drew is up in Toronto; Paul down here in the States. With that I'll turn it over to Drew to provide some background on how these deals are structured.

**Drew Morier:** Good morning Julien. Thanks very much. Good morning everybody. As Julien said, my name is Drew Morier. I'm a Partner with Osler, Hoskin & Harcourt. We are a full-service business law firm based largely in Toronto but with offices throughout Canada as well as in the United States, practicing US tax law with a focus on servicing our Canadian clients.

Osler acted for Emera in relation to the upcoming acquisition of TECO Energy, and I provided tax advice to Emera in respect of that acquisition. And I specialize in cross-border tax matters. Also recently I advised TransCanada in relation to its acquisition of Columbia Pipeline.

Julien asked me to take you through, high-level, how these transactions are typically structured. And when I say these transactions, I mean a takeover by a Canadian public company of a US public company.

From a corporate technical perspective, these are usually done by way of reverse merger where the US holding company of the Canadian group forms a merger subsidiary as a shell company. That merger subsidiary merges with the target. The target survives and the target shareholders receive the right to get the merger consideration, whether it is cash, shares, or a combination of cash and shares.

From a tax perspective, just to give you an idea of the differentials, the Canadian corporate tax rate is around 25 to 26% versus 35% in the United States. That's the headline tax rate.

In terms of the tax structuring elements of these transactions, what we see most commonly is the drive and desire to get debt financing into the US to finance some or all of the acquisition.

So what we do from a tax perspective is try to ensure that debt financing is done in a way that is as efficient as possible. And that usually involves some sort of structured arrangement whereby there is a deduction in the United States, but that doesn't result in corresponding income inclusion in Canada or anywhere else in the Canadian parents group. And this is obviously for internal debt financing.

Just in terms of the environment on the tax side with respect to these deals, I think we've seen a lot of discussion recently about international tax arbitrage, about tax morality, about trying to ensure that governments around the world are getting their fair share.

So we've seen quite a bit of pressure on these tax-efficient financing arrangements that typically rely on hybridity in the sense that an instrument is debt in one country but treated as equity in the other country.

Or an entity is treated as a taxable entity in one country but as a flow through in another country so that the tax consequences of a particular payment or receipt are different in each of the jurisdictions.

Although these transactions rely in large part on these tax-efficient financing structures, we've been advising our clients that due to the international pressures on these arrangements, they shouldn't really count on their longevity in terms of pricing these deals.

**Julien Dumoulin-Smith**: Great, Drew, I appreciate it. Let's kick off the conversation, just coming back, is the discrepancy in the corporate tax rates… what is the effective rate alternately realized by entities in Canada on income in the US?

Obviously there's a 35% stated income tax rate. But because of the nature of these being investments and loans into the US, how do you think about the effective tax rate here?

**Drew Morier**: Paul, do you have a sense of that?

**Paul Seraganian**: Well certainly, the macro effect of the arbitrage that these deals often try to create between creating deductions in a higher tax jurisdiction and moving income at either no inclusion or second best at the lower rates of Canadian tax, it's all directed towards bringing down that marginal rate.

And usually different industries have difference capacities for debt levels in the United States and other forms of shelter. Generally speaking, the more stable the cash flow, the higher the capacity for debt. And the higher capacity for debt, the greater opportunity for reducing the effective tax rate.

Broadly speaking, it's difficult to put a number around this. But I think the objective certainly is to walk away with an effective rate of tax on an enterprise basis that is well south of the 35%.

**Julien Dumoulin-Smith**: Got it. Can you walk through a little bit more how it's structured vis-à-vis why is it not simply the 25% that applies otherwise? And how does it actually mechanically work when you think about owing US authorities a tax figure versus Canadian authorities a tax figure as well?

Maybe those are two separate questions. How does it reconcile versus the 25% that would in theory be owed? And also, how does typically the cash ultimately get paid out even on the effective?

**Paul Seraganian**: Just speaking from the US side for a second, I think there's not a direct correlation between… acquisition financing ultimately is pumped into the United States but it's originating in Canada let's say.

There's not a direct one-for-one correlation between a deduction at the 35% rate and income inclusion and interest income on the other side of the border at a 25% rate.

If that were all that was going on, then the cross-border debt would really just have the effect of arbitraging to the extent you can put on debt. Arbitraging out of the 35% and into the 25% rate, which would be OK. But I think people tend to look for something more effective than that.

There are opportunities, there are a few different tax-efficient financing structures that are out there, that are the usual suspects.

Generally speaking – and we can talk about the specifics more later – but the point of these financing techniques is to try and create interest deductions in the United States that don't result in full inclusion somewhere else at a 25% effective rate.

Through hybridity that Drew was referring to earlier, or through financing structures that are located in third countries that lightly tax the interest payment that the US company is making, you can actually reduce the overall effective rate of tax to well below 25% on that interest income.

Imagine for example a Canadian company financing a US subsidiary through, let's just say, a Luxembourg financing entity. You know the ways that these deals are put together, are evolving a little bit to adjust to some of the developments coming out of the OECD and some of the developments coming out of European tax policy.

But the paradigmatic concept is that you would have an interest deduction in the United States; interest income in Luxembourg that is subject to an effective-rated tax that's quite low – 1 or 2%. And then the cash that's paid as interest from the United States to Luxembourg when it's brought back, the objective is to try to bring that back as exempt surplus, where when it gets to Canada, it's not subject to an additional layer of tax.

**Drew Morier**: The other element of that, if I may interrupt, is that Canada has a very generous regime when it comes to allowing interest deductions on money borrowed to earn foreign income.

And we also have a generous exemption system, which means that to the extent that foreign active business earnings are repatriated to Canada, we don't tax those repatriations. But we also allow debt to be used to finance those foreign subsidiaries and may allow an interest deduction in Canada for that debt.

You get almost a double credit for every dollar of interest paid if you get a deduction in the US and a separate deduction in Canada without a corresponding income inclusion for the interest that's paid notionally from the US to Canada.

You can see why global tax authorities might be concerned about these kinds of structures, which have been, to be honest, very heavily exploited in cross-border transactions.

**Julien Dumoulin-Smith**: Got it. I'd be curious if you can go back over that just a little bit quickly, especially for folks on the line who might not be as familiar. The interest deduction, can you elaborate a little bit more about how to think about that in a hypothetical situation in the US? And more importantly, how that applies the hybridity back in Canada.

Generically speaking, one is not typically making a direct equity investment, at least for US purposes. It is typically a loan that is made to the US subsidiary for the cash to make the investment, as far as I understand it. And then subsequently the cash is repatriated back; the interest income on the loan to the US. Is that a good way to think about it? And can you kind of elaborate from there?

**Drew Morier**: The main idea is that you find an instrument that's treated as equity from a Canadian perspective, because when the Canadian receives dividends on that equity, those dividends, if they're paid out of the right kind of earnings, are not taxable in Canada.

While at the same time, ensuring that instrument is recognized or treated as debt in the US. That's kind of the basic concept, and this can carry over to hybrid entities as well.

To keep it simple, you've got an instrument that's equity from a Canadian perspective and debt from the US perspective. When you borrow money in Canada, use that borrowed money to invest in the equity instrument and you get an interest deduction.

From the US perspective, they pay deductible interest on that instrument, it's received in Canada as a tax-free dividend because it's equity from our perspective. Furthermore we're allowed an interest deduction from having borrowed money to make that investment.

**Paul Seraganian**: And I'd add to that, just to take it back analytically, one step before, we talk about hybridity, I think when you're thinking about an acquisition in the United States and you're thinking about, how do I get money from Canada, let's say.

Or it could be any jurisdiction, but we're talking about Canada here, into the acquisition vehicle in the United States to make the acquisition, the starting point from a US perspective is to assess how much debt capacity your existing US operations – assuming you already have some – how much debt you can actually layer into that. Because it's frequently the case, if not always the case, that you can't finance the acquisition 100% with something that the US would regard as debt.

There are limits in how much debt can be put into the United States. So you really have to first consider, under general debt equity principles, the US doesn't like heavily levered companies.

And if you purport to put too much debt on a US company, at some point – no one knows quite where that line is – the IRS will re-characterize for US tax purposes some of that financing as equity. Which means correspondingly, the interest deductions you thought you were going to get on that financing won't be there because there simply aren't interest deductions on equities.

That's a macro limit on how much debt financing you can push in the United States. There's another earnings stripping limitation that we have that says even if the underlying instrument is respected as debt, we will limit the amount of interest deductions that you can take in any given year, essentially to 50% of your EBITDA.

You need to build that limitation into your modelling and your debt-sizing thinking. But once you've made a determination of how much debt you can safely layer into the United States, then you move to this question of, can I now do that efficiently? Can I make that debt the type of hybrid efficient debt that Drew was referring to before?

**Julien Dumoulin-Smith**: Right. Can you talk a little bit more about how you determine the maximum permissible leverage? Is that a soft number or is there really something more tangible that you can calculate and back into on that?

**Paul Seraganian**: It's evolving, interestingly, and I'll refer to that in a second. But it's really the question of how much debt you can put into a US company. It's been the central question of US tax law for at least 50 years. And the rules for making that determination have been basically, Congress and the IRS have not really regulated and it's been driven by a court decision.

This is one of those areas where it's very much – you look at common law judicial decisions that, one by one, set out rough parameters for considering how much debt a company can take. And it's much more art I would say, than science. But there are norms that have evolved.

And what you're really looking for is a reasonable expectation of repayment. So what you try to project both subjectively and objectively with cash flow projections is that the amount of debt you're purporting to put into the company has a reasonable expectation of repayment when you look at the cash flow projections of the underlying US company. And you can say to yourself, even if you stress those cash flow projections to a reasonable extent, you don't foresee the likelihood of the US company defaulting on an interest payment or not being able to repay principal or refinance principal… doesn't seem objectively likely.

As I said, that's where the art comes in because different people draw lines differently. But in an industry where the underlying cash flows are stable, like typically in the utility industry, it's stable cash flows… you can, typically speaking – have greater levels of debt. Where cash flow is more erratic, like say, in the natural resources sector, where the cash flow could be a direct function of prices, which are all over the place, it's harder to project a stable stream of cash flows. Therefore, your ability to definitely absorb debt is a little weaker.

**It's all over the place. There are safe harbors in the US law, which says a debt-to-equity ratio of 1.5 to 1 or less,** you have no earnings stripping issues. But in reality, in most industrial industries, it's not uncommon to see three, four, five, six, even up to 6-to-1 debt-to-equity ratios.

You usually do some sort of quantitative analysis. You look at comparables that are out there for capitalization levels and you try and cobble together a reasonable argument based on those factors.

<u>But two weeks ago on April 4, the IRS and Treasury Department released a very significant package of regulations that directly impact cross-border or any related party debt financing.</u>

The heart of what Drew and I are speaking about here is, related party debt financing just so happens across the border and creates these efficient arbitrage opportunities.

But what the IRS has said in issuing these regulations is, we think that people are taking too many liberties with related party debt to try and generate the type of benefits that we're talking about here today.

Although many people believe the prime motivation for the IRS in releasing these new rules was to further bludgeon or attempt to bludgeon the stream of outbound inversion transactions that we've all been reading quite a bit about, by attacking one of the pillars of those transactions, which is to, on a post-inversion basis, layer up the expatriate of the US company with debt to try and drive a defective rate of US down.

So it's true that inversion transactions typically feature, after the inversion is complete, a levering up of the US subsidiary. But these regulations do not limit themselves to just those bad actors, in the IRS' view. They apply across the board to all related party debt, including the debt we're talking about here today.

And these rules… I won't take too deep a dive into them. Suffice it to say that they represent a fundamental shift in how the IRS will approach related party debt.

They are proposed. They're not final. But certain elements of them have a retroactive effect to April 4, if they are finalized. And they basically do three things.

They allow the IRS to, for the first time, bifurcate debt and treat if you have a purported debt instrument, they allow the IRS to say, we're going to respect 70% of that as debt because we think your facts of 70% strong.

But the last 30% or the last 20% of the debt, your facts, your objective reasonable expectation of repayment, is weak and we're going to sever the instrument and attack that last 20 or 30%. They never were able to successfully do that. It was always an all or nothing proposition which confounded the IRS.

The second thing these rules do is place all sorts of new documentation, recordkeeping requirements on parties that try to put this related party cross-border debt in place. So companies are going to have to be much more meticulous in their recordkeeping and keeping evidence of the reasonable expectation of repayment.

And lastly, and then I'll complete my summary of these new rules (and these could potentially be retroactive to April 4), cross-border debt like the debt we're talking about here will mandatorily be treated as equity, which means all bets are off. All of the interest deductions associated with it are gone.

It's re-characterized as preferred stock. So it's a very serious sanction against the instrument if within three years of that related party's debt issuance… and that three-year window is both after and before, so it spreads three years in each direction. It looks backwards three years and forward three years.

If within that probationary period, one of three types of prohibited transactions occurs involving the financed entity, then that debt that was put in place on the related party basis will suffer the sanction of being mandatorily treated as equity.

This is what's reverberating to the core of tax planners through the United States right now. It's a very significant development. And it effectively means the people that are doing large cross-border transactions, US acquisitions that have debt financing, they're not dead in the water in the sense that they can't do the debt financing subject to otherwise, the old rules.

But they have to be very careful that they haven't in the past or they won't in the future, during that effectively six-year probationary period, engage in one of these other types of transactions.

That puts some limits and parameters in terms of what companies can do. It's imperative that the company as a whole recognizes what those parameters are and bends over backwards not to violate those.

**Julien Dumoulin-Smith**: Yes, that's a lot of great detail there. Just to run with that a step further, can you elaborate: Do you think that these new rules place a limit on the kinds of Canadian/US utility transactions that we've seen?

And the reason why I bring it up specifically is because so many of the comps in the sector are so levered already. I can understand in a sector that might not necessarily be traditionally highly leveraged for your employee structure that effectively depends on substantial inter-company leverage.

But in this instance, given the comp group is still leveraged, does that allow for greater latitude here.

And when we're talking about that one to five or two to one or whatever... you mentioned the safe harbor earlier, is that at the holding company level?

So if you have a utility, for instance, that's already at 50/50, is it more about the capitalization of the holding company itself that it's basically on a two to one basis or 1.5 to one basis, that could be leveraged subsequently? Where does that one to 1.5 ratio apply?

**Paul Seraganian**: Yes. I don't want to elevate the significance of debt-to-equity ratios as if it's some sort of stand-alone litmus test for debt equity treatment.

But it's important… it's really properly thought of as one of several objective indicators of financial strength that one looks to. Interest coverage ratios and other things are also important. But debt to equity ratio has always enjoyed sort of a conspicuous spot in terms of debt equity analysis, so people tend to talk about it quite a bit.

To answer your second question, what you're looking at when you're thinking about this ratio is, you're thinking about the debt capacity of the US borrowing group.

So what you're doing is a pro forma assessment of the US borrowing group and looking at its debt-to-equity ratio. Because it's the debt issued by that group and backed by the credit of that group whose status is at stake.

You would look at a US holding company and its operating subsidiaries as an integrated borrower and assess their debt-to-equity ratio. And I think you would do your best to determine the equity value on a fair market value basis of the pro forma US group and use that... and obviously eliminate in consolidation any intra-US affiliate debt.

You're really looking at third-party debt and debt owed by the US group to other members of the non-US enterprise. That's the basic building block for how you put together the debt-to-equity ratio.

And in terms of interaction of the new rules with the fact that the comp set is already highly levered, I think what that would suggest to me is, to split the response of the two.

First, if the feeling is that there's not much additional… because of the high leverage ratios already… there's not much additional capacity for debt, then that would lead you to the conclusion that you can can't put on much new debt. Therefore, there's not much for the new rules to even apply to in the first place. I think that might be one probably overly-simplistic way to think about it.

But assuming for a second that you were willing to lever more heavily than the comps, one of these US targets, and you wanted to put some new debt into that. Or it was under-levered to begin with and you thought you have some capacity to put new debt in.

There's nothing about the utilities sector per se that I can think of, that would suggest it's more at risk, or frankly less at risk, of problems – if I could put it that way – under these new rules.

I know that answer is a little cryptic because really it turns on one's assessment of whether or not the US target is likely to do one of these three bad things that could cause the mandatory re-characterization of debt versus equity.

But there's nothing about the industry or norms or cash flow management that typically prevails in the industry that would lead me to believe that you're any better or worse off than anyone else when it comes to these new rules.

**Julien Dumoulin-Smith**: Got it. And to clarify, when you're talking about holding company leverage… or when you're talking about the leverage metrics at the holding company level. If you're talking about capitalizing that, it's, say, two-thirds debt, one-third equity.

And subsequently again, you're investing that as an equity check back into a US utility op-co or whatever it may be.

**Paul Seraganian**: You're investing it… so you put two-thirds; one-third into the hold-co and then the whole thing would go down into the operating company is what you're saying?

**Julien Dumoulin-Smith**: No, that would go into the operating company as an equity check or something basically.

**Paul Seraganian**: In that situation, if you said, what's the relevant debt-to-equity ratio, it's two to one, if that were all that were going on, right. Because your top…

**Julien Dumoulin-Smith**: Right, yes, I suppose you would have two-thirds debt at the hold-co and then subsequently that would constitute, say, a 50% equity check back into the op-co level.

So your effective leverage net/net is not two-thirds, one at the holding company. But the true leverage is, you include the 50% of the op-co and then the two-thirds of debt at the hold-co that effectively uses the equity check.

**Paul Seraganian**: Well I guess I thought about it more simply. So if you have a Canadian company, let's say, and it sets up a US hold-co, and the US hold-co acquires a US op-co, that's the structure. And then layer the financing on top of that.

At the Canadian company, all the money comes from Canada. If you put two-thirds in as a loan and then one-third in as equity, where were you going after that in terms of cash?

**Julien Dumoulin-Smith**: Well two-thirds in as a loan, but then that ultimately goes down into a further US operating subsidiary.

**Paul Seraganian**: Right. But IRS would look at that situation as OK, where's the cross-border debt in question that's issued by the holding company? That's the debt I've got to think about. Is it debt or equity?

And from a debt equity perspective, the ratio would be… it's being capitalized two-thirds debt, one-third equity. So it's got a two to one debt-to-equity ratio.

Can the underlying cash flows generated by the combination of the holding company and the operating company reasonably be expected to service that debt, if you pressure them in some stressed kind of way.

And can you reasonably expect to have enough cash to repay the debt at maturity or refinance the debt at maturity. And if the answers to those questions are yes, then you should be comfortable that the two-thirds coming from Canada would be respected as debt.

If you change that fraction to three-quarters debt, a quarter equity; or seven-eighths debt, obviously, you start to get less certain about that.

**Julien Dumoulin-Smith**: Got it. All right, that all makes a lot of sense. Let me come back to the core question. Do you see these new rules limiting in any fashion the continued trend of having Canadian investments back in the US?

It's clearly not anything close to a tax inversion. It's a true US investment amidst a low-interest-rate environment in Canada. But do you see some of these tax advantages coming under scrutiny such that you would actually see a slowdown of corporate strategies now?

**Drew Morier**: I think before Paul answered that, just in terms of the fundamental tax juice that we get out of these deals, which arises out of this hybridity, I think we're seeing increased pressure on that particular element.

So we have the base erosion, profit-shifting process that's been going on for about three years now. And they've come up with a set of global minimum standards in some cases; recommendations in other cases. And everyone who's participated in this project is expected to implement these proposals.

And among those proposals is a concept that would shut down, the benefit that arises from hybridity, whether it be a hybrid instrument or a hybrid entity.

As I mentioned at the outset, we tell our clients not to count on the benefit of these tax-efficient financing structures when they're pricing their deals. And I think that they're taking that advice on board and they're considering that these deals make sense, even without the additional benefit that the tax-efficient financing is adding to the transactions.

I don't think that it's tax that's driving these transactions. Julien, you mentioned the interest rate environment in Canada. And Paul, I don't know if you want to answer about the potential chilling impact of the new US rules.

**Paul Seraganian**: Yes. I agree with everything Drew just said. Those are certainly concerns. And frankly, those probably would have a more direct impact than the new debt rules in the United States, I think.

I think it's early days with respect to these new US rules. And there will be a very healthy comment period where, no doubt, a lot of interest groups will be – and stakeholders will be lobbying the Treasury Department to change the arc of these rules. But I think we're going to end up with some reasonable facsimile of them when all is said and done.

We'll have to wait and see how the IRS wields this new power out there in the real world. But they really shouldn't slow down or chill the use of cross-border related party debt in these transactions, or more broadly, these transactions generally.

What they will do is they will bring maybe a little bit more discipline in terms of how taxpayers document, record, substantiate verifiably, the debt character and the financial wherewithal of the purported borrower to repay that debt.

And knowing that the IRS can come in and attack the last 10%, or the last bit of your debt, will encourage people to probably be, at the margin, slightly more conservative than they would have otherwise been in terms of financing.

And these rules will have effects in terms of you'll have to carefully monitor the way that you move cash… your Treasury functions essentially. How you move cash cross-border during those three-year probationary periods. Some of the things that you might like to do like pay cross-border dividends, you just won't be able to do or you'll have limited capacity to do.

So I think my current assessment of the rules, understanding that the trajectory is not yet clear, is that they will make people a little less aggressive and put a premium on being well-documented and being very careful about what you do in the future and how you manage your cash flow functions in the future.

But I don't expect them to materially impact the flow of transactions that we're seeing that otherwise make good economic sense.

**Julien Dumoulin-Smith**: Great. Just coming back to the underlying strategy and rationale, having looked at whatever the specific transactions this last little bit here, have you see any evolution in the thinking and structuring and thought process behind them?

Even Emera [last year, *2015]* versus others recently. Is there an evolution on how these things are being done over time that you're observing?

**Drew Morier**: I think the value of the tax is retreating in the sense that the tax advantages used to be very important to the pricing of these deals.

As the international tax landscape has evolved to the point where we are now, where clients are being very cautious about being aggressive, and are not counting on continuing tax arbitrage benefits, I think we've seen the importance of the tax structuring be minimized, to a certain extent, which is so obviously very important.

But when you look at the matrix of why these deals make sense and where the values are, the importance of tax is declining because the landscape is such that we have less leeway in terms of structuring transactions in a way that gives rise to significant tax efficiency.

That's one thing I'm seeing changing. That people are counting less and less on the value of these exotic tax structures when they're thinking about whether these transactions make sense.

That's the major thing that we're seeing as a result of the international tax atmosphere that we're in right now.

**Julien Dumoulin-Smith**: Right. And just to be specific about it, when did that realization start to play into those conversations that you alluded to? When was it not relevant if you will, that they could.

**Drew Morier**: Well I think everyone has seen the news, right? You've got multinational companies being excoriated by the press for not paying their fair share.

You've got the Starbucks case, you've got the Google case, you've got Apple. So you didn't see tax in the news five years ago, right? This is a fairly recent development where companies are now starting to think about how their tax plans would look if they ended up on the front page of the paper.

We've got the Panama papers being released, which although not directly related with our clients or with this audience, casts a shadow over tax planning as an institution, if you like.

I think it has really been over the last five years and especially the last two or three years where the OECD at the political level has said, we need to shut this down.

So the OECD's BEPS project – base erosion profit shifting – which is directly aimed at corporate tax (international tax planning) – has resulted in an environment where companies are not willing to be as aggressive as they use to be, or not willing to do things that may be legal to the extent that they don't look good. And they're having to think about corporate responsibility in terms of where and how much tax they're paying. It's been, I'd say, the last three years especially, that's been a factor in thinking about how to structure these transactions.

**Julien Dumoulin-Smith**: Got it. Perhaps just to take that a last step, is there a definitive date that folks are looking for generally that's, hey, we're going to get resolution on this one way or another?

Obviously these concerns are lingering out there. But there is no specific hard date that folks are looking for to get resolution on hybridity; yes or no, or anything like that?

**Drew Morier**: There's no date. The BEPS project has been extraordinarily ambitious in terms of setting out objectives. And they've moved very quickly and reached a global consensus or a consensus among those countries that have participated about high-level principles.

Where we see the failure of the BEPS project if there is one is that the implementation is going to be extraordinarily difficult. Nobody really wants to be a first mover. We've seen some movement in the European Union on hybrid instruments. But with respect to Canada, it is not going to do anything unless the United States does something to, be frank. Because they're the most important trading partner, and we don't see any benefit in moving first.

We think we have a fairly sophisticated and well established tax system. There's a prophylactic effect in the fact that these proposals have been made. But nobody is quite sure when, on account of the US context, when either Canada or the US is going to act.

I think these new proposals on interest in the US form part of that conversation. So we're having to take those rules into account. But in terms of the shutting down the effect of these hybrid rules, there is no fixed state, but it's coming.

**Julien Dumoulin-Smith**: I think to come back to the questions that I would have, a little bit more broadly, the US utility and specifically the renewables sector, has a lot of tax credits. You also see in the US industry, MLPs that themselves have a specific tax treatment. As you looked at the asset class, have you encountered these kinds of issues? And how have you reconciled them? I would be curious, are there any complexities?

For instance, I suppose with an MLP structure or something that would be eligible for an MLP, have you seen a lot of those assets go to Canada? Is it because the tax benefit or the shifts are not as real? Obviously there would probably be a C-Corp structure that you would put in place as the intermediate holding company.

And on the same thing on the tax credit side for production tax credit or something from a win asset or what have you? I imagine there's not a lot of taxable income there for entities on that side as well. But, any wrinkles around these structures?

**Paul Seraganian**: Well I can take a crack at that Julien. I think on the MLP side, the ingredient creating the tax efficiency of those structures is very different, right?

It comes from not relying so much on the mechanism of interest deductions, which is the mechanism we're been talking about today… you're not relying so much on the interest to reduce the effective rate of tax on those income streams, but rather on other items like depreciation and those things, because of the flow-through character of the MKP flowing directly out to the MLP unit-holder.

But in terms of crossing borders, bringing those instruments into Canadian hands, it's very difficult to do on a retail basis. I'm not really sure if that was where your question was going. Because once you bring that flow-through income and put that in the hands of a non-US person, there are inefficiencies that creep in by virtue of the fact that our withholding rules and the like aren't particularly friendly to non-US investors.

From a cash flow basis, a lot of income gets withheld at the MLP level. And the non-US investor in the MLP, if they tried to hold MLP units directly, would need to file a return in the United States to get a refund. And that's just really not what retail investors are interested in.

And you mentioned the possibility of putting it in some sort of a corp over top EMLP, and that would be the issuer for Canadian investors. So far at least we haven't really seen that be particularly efficient. I think there are some issuers out there that are attempting to do that. But at least last time I checked that, it hasn't really taken off. So it hasn't really found a home yet.

We haven't seen a tremendous amount of MLPs either being to retail investors in Canada, at least so far. We have seen Canadian companies that are in the right sectors think about setting up their own MLPs, which would be traded in the United States and offered to US investors as a financing vehicle essentially for them to maybe help de-lever their balance sheets.

But again, market conditions haven't been tremendous for that lately because most of the assets that you would look at doing that for would be oil and gas. And we haven't seen too many. We know that people are thinking about that and we haven't seen too many people actually follow through on those types of MLP opportunities.

And in terms of renewables, I think there are tax-efficient financing mechanisms that are out there for the renewables space, solar in particular, that have been specifically sanctioned. They call them tax equity financings. Specifically sanctioned by Congress and extended by Congress.

Basically those are financings that let banks or other taxable US actors provide financing to a renewable project that is essentially debt. But they have allocated to them the economic benefit of the credits that those projects create, which effectively increases the yield to the financing party, which lowers the cost of capital to the financed party by virtue of shifting the tax credits to someone that can actually use them.

And I think that Canadian banks or other large financial institutions have expressed some interest in looking at the possibility of entering into those types of financing arrangements. Tax equity arrangements which have typically… at least so far those financings have been predominantly done by US taxable entities – banks or big companies with a lot of taxable income.

So there are signs of cross-border activity in those types of financing arenas. But so far, at least to my knowledge, we haven't seen see a tremendous amount of activity.

**Julien Dumoulin-Smith**: Got it. Excellent. I'm getting one question here via email: ITC in particular has a pretty high-debt-to-equity ratio, or they call it 75% already, at the holding company structure.

Would there be an ability to continue to increase unused incremental hybrid financing above and beyond that? Forget ITC for a second, but if you've already got meaningful holding company leverage, I presume that would impede your ability to put in place these hybrid securities that would be treated as debt for US tax purposes.

**Paul Seraganian**: Good question. I think the starting point: there are two factors to keep in mind. The first is a collective assessment. You think about, OK, how does my debt-to-equity ratio compare to my peer group. And the more of an outlier you become, the more that puts more pressure on your debt-equity analysis, generally speaking.

So if you're an outlier then you probably can expect to have more attention thrown on you. It doesn't necessarily mean that you can't put more debt, it just means that you're starting to single yourself out.

But what's most important is the strength of your underlying financial fundamentals – cash flow projections again, and your ability to service the debt even if your cash flows experience difficulties, which would put some stress on your cash flow that you think is reasonably emblematic of reasonably expected worst-case scenarios.

And if your cash flow projects show that you're able to service the debt without any default or breach of your obligations on the debt instrument, and that your asset base is sufficiently strong that you should be able to refinance that debt when it comes due or sell assets to pay it off or whatever, then you can keep adding… the theory, at least, is you can keep adding debt until you reach a point where those cash flows start to be at risk of servicing the debt.

So in a lot of industries, companies go in excess of three to one. And it's really a function of the stability of your cash flow. Can you put more than three to one? In this particular case, I think you'd really need to look at the strength of the cash flow.

**Julien Dumoulin-Smith**: Got it. That makes sense. Well Drew, Paul, I think we're almost to the top of the hour here. Is there anything else, closing remarks or anything before we top it out for the weekend?

**Drew Morier**: Not from me. Thanks Julien.

**Paul Seraganian**: Other than to say thank you for the opportunity to talk to you guys. It was fun.

**Julien Dumoulin-Smith**: Yes, thank you. Incredibly complicated subject. Appreciate you taking the time to do it. Thank you all for listening as well. We'll talk to you all next week.

END

### Valuation Method and Risk Statement

Risks for Utilities and Independent Power Producers (IPPs) primarily relate to volatile commodity prices for power, natural gas, and coal. Risks to IPPs also stem from load variability, and operational risk in running these facilities. Rising coal and, to a certain extent, uranium prices could pressure margins as the fuel hedges roll off Competitive Integrateds. Further, IPPs face declining revenues as in the money power and gas hedges roll off. Other non-regulated risks include weather and for some, foreign currency risk, which again must be diligently accounted in the company's risk management operations. Major external factors, which affect our valuation, are environmental risks. Environmental capex could escalate if stricter emission standards are implemented. We believe a nuclear accident or a change in the Nuclear Regulatory Commission/Environment Protection Agency regulations could have a negative impact on our estimates.

Risks for regulated utilities include the uncertainty around the composition of state regulatory Commissions, adverse regulatory changes, unfavorable weather conditions, variance from normal population growth, and changes in customer mix. Changes in macroeconomic factors will affect customer additions/subtractions and usage patterns

## Required Disclosures

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**UBS Investment Research: Global Equity Rating Definitions**

| 12-Month Rating | Definition | Coverage[1] | IB Services[2] |
|---|---|---|---|
| **Buy** | FSR is > 6% above the MRA. | 49% | 32% |
| **Neutral** | FSR is between -6% and 6% of the MRA. | 38% | 26% |
| **Sell** | FSR is > 6% below the MRA. | 14% | 19% |
| **Short-Term Rating** | **Definition** | **Coverage[3]** | **IB Services[4]** |
| **Buy** | Stock price expected to rise within three months from the time the rating was assigned because of a specific catalyst or event. | <1% | <1% |
| **Sell** | Stock price expected to fall within three months from the time the rating was assigned because of a specific catalyst or event. | <1% | <1% |

Source: UBS. Rating allocations are as of 31 March 2016.
1:Percentage of companies under coverage globally within the 12-month rating category.
2:Percentage of companies within the 12-month rating category for which investment banking (IB) services were provided within the past 12 months.
3:Percentage of companies under coverage globally within the Short-Term rating category.
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Exhibit WKW-7

# Algonquin Power & Utilities' (AQUNF) CEO Ian Robertson on Q1 2016 Results - Earnings Call Transcript

May 13, 2016 2:33 PM ET
by: SA Transcripts

Algonquin Power & Utilities Corp (OTCPK:AQUNF) Q1 2016 Earnings Conference Call May 13, 2016 10:00 AM ET

**Executives**

Christopher Jarratt – Vice Chair

Ian Robertson – Chief Executive Officer

David Bronicheski – Chief Financial Officer

**Analysts**

Paul Lechem – CIBC

Rupert Merer – National Bank

Sean Steuart – TD Securities

Jeremy Rosenfield – Industrial Alliance Securities

Eric Tang – BMO

**Operator**

Thank you for standing by. This is the conference operator. Welcome to the Algonquin Power & Utilities Corp. 2016 First Quarter Results Conference Call. As a reminder, all participants are in listen-only mode, and the conference is being recorded. [Operator Instructions]

I would now like to turn the conference over to Christopher Jarratt, Vice Chair of Algonquin Power & Utilities Corp. Please go ahead, Mr. Jarratt.

**Christopher Jarratt**

Thank you. Good morning, everyone, and thanks for joining us for our 2016 first quarter conference call. My name is Chris Jarratt, and I am the Vice Chair of Algonquin Power & Utilities Corp., and joining me on the call today are Ian Robertson, our Chief Executive Officer, and David Bronicheski, our Chief Financial Officer.

Today we are happy to be hosting the call from the Empire District Electric offices, which are located in Joplin, Missouri. Also as usual for this call, we have a supplemental webcast presentation that you can access from our webpage. To access this presentation, please go to our home page, algonquinpowerandutilities.com, and you will find instructions on how to gain access.

This presentation, along with additional information on our Q1 2016 results, is also available for download on our website. As usual, on this call, we will be providing information that relates to future events and expected financial positions which should be considered forward-looking. And we will provide additional details at the end of this call. You can also review our full disclosure on forward-looking information and non-GAAP financial measures on our website. We will be reading the full disclosure at the end of the call.

This morning, Ian will discuss the first quarter growth highlights. David will follow with financial highlights, and then Ian will conclude with our 2016 outlook. We will open the lines for questions at the end of the earnings presentation, and I would ask you that you restrict your questions to two and then re-queue if you have additional.

Now, I would like to turn things over to Ian to present some of our first quarter growth highlights.

**Ian Robertson**

Thanks, Chris. And good morning, everyone. Thanks for taking the time to dial in this morning. As Chris mentioned, I would like to start by thanking the Empire team for their hospitality for allowing us to host the call from their offices here in lovely downtown Joplin.

I will say that the strong culture of connections which are apparent between Empire and Algonquin are certainly providing me comfort and confidence with respect to the ease of integration - the coming integration of our two businesses.

So I'll take a couple of minutes to walk you through some of the highlights, certainly from my perspective, before I turn things over to David to detail financial results. And I there is three things that I would like to highlight this morning.

First, I think we're pleased with the strong start to the year, solid financial performance, $148 million in adjusted EBITDA. It represents close to 30% increase over the same quarter last year. Pleased with the material gains and adjusted funds from operation and adjusted share earnings of close to 20% and 24%, respectively.

But secondly, and perhaps I think more importantly, it was another quarter in which the diversification and resilience of our portfolio showed its worth. With one of the warmest winters on record behind us that negatively affected some of our financial results and our electricity and natural gas sales.

I think we're pleased to see the generation business group was able to carry the load with strong performance from good wind and solar resource conditions. And I think it's this reduced performance volatility from the portfolio, it's providing a solid source of shareholder value.

And lastly, the third highlight is I think the growth aspect of the Algonquin story is remaining clearly visible and intact. The financial results include the gains and earnings from new assets within both the generation and distribution business groups.

Together with support of a number of recently completed rate cases, completing the Park Water acquisition early in the quarter allowed the 75,000 new customers to contribute to the results of our distribution businesses in California and Montana. We look forward to future gains from initiatives on both sides, or actually on the generation distribution and the transmission groups coming forward.

Within the generation group, we continue to push forward on our projects under construction: our 10 megawatt Bakersfield II Solar project in California is nearing completion.

200 megawatts of wind in Odell in Minnesota is targeting completion in July. And lastly, on the 2016 to do list, 150 megawatts worth of wind up in the thumb of Michigan is advancing towards commercial operation at the end of this year.

Shifting to the transmission front, we are obviously disappointed that Kinder Morgan's own internal struggles impacted their Northeast energy direct pipeline and therefore an investment opportunity for us.

Obviously pleased that we structured the opportunity with the optionality that we built into it. But we are also comfortable that other transmission opportunities are presenting themselves. We are continuing to advance our California intrastate electricity transmission project. Phase 1 of that investment is scheduled for completion this year.

And it might also be noted that Empire brings close to $300 million Canadian in existing electro transmission assets to the business and presents more than $30 million a year in near-term investment opportunities.

And then lastly, with respect to our distribution business and the Empire acquisition, we're pleased to report that in March of this year, we submitted our FERC application, as well as applications for transfer approval in Oklahoma, Kansas, Missouri, and Arkansas, and the work is already bearing fruit.

So the FERC approval was granted on May 6 of this year, and we're also pleased that the first of the four state commissions has granted their approval with Oklahoma Corporation Commission signing an order as recently as yesterday.

June 16 is the date for the Empire special meeting of shareholders to hold a vote on the transaction, and we are cautiously optimistic that the reception will be extremely positive.

While it's early in the process, and we are making progress, we don't underestimate the work that needs to be done and we're going to continue to work with the Empire team and the regulatory agencies to bring the transaction to conclusion.

But as I sort of started the conversation about the corporate cultural alignment, it's really showing as we work our way through the regulatory approval processes. I think there is a very close connection between our respective organizations.

And so lastly, with the strength of solid financial performance through last year and a start to this year that was equally strong. We're pleased to announce yesterday that the Board of Directors approved a 10% increase to our dividend, and it's now US $0.4235 per common share, and I think that 10% increase is consistent with our dividend growth target, which we've communicated to the capital markets.

And I will highlight that this is the sixth year, consecutive year of double-digit annual growth in our dividends from a percentage perspective. And then, as we look forward to the pipeline of growth opportunities in front of us, we are confident that those increases certainly over the next little while – we're comfortable that they are going be supportive of our growth targets.

So with that, David, why don't you take it over from a financial results perspective.

**David Bronicheski**

Thanks Ian, and good morning, everybody. We're pleased to be reporting strong financial results for the first quarter here in 2016. And when you get off to a good start, that likely means you are going to have a very good year.

As Ian mentioned, the diversification of our portfolio and success of our growth program is clearly evident in our results. Even though we had warmer weather than average in some of our utilities systems in the US, our revenues, net of the commodity pass-though cost, were still up $37 million in the quarter compared to the first quarter of last year, an increase of 19%.

As we look at our adjusted EBITDA in the first quarter, it totaled $148 million, a 29% increase over the amount reported in the same quarter a year ago. The increase in EBITDA over the previous year was due to strong wind and hydrology, which contributed $8.8 million of additional EBITDA, which more than offset the effects of the warmer winter at our distribution utilities, which had lower EBITDA by approximately $4.6 million, compared to Q1 of 2015.

Our growth program saw two new generating stations come online: Bakersfield and Morse. As well, we had our newest utility, Park Water and collectively they all contributed about $9.5 million of new EBITDA.

Finally, we continue to demonstrate effective management of our investment and rate base and our regulatory processes. We had positive rate case settlements contributing more than $3 million of new EBITDA in the quarter. All in all, I think we are quite pleased with the quarter and say it was quite successful.

For the three months ended March 31, adjusted EPS was $0.21, up 24% from the previous year. Our adjusted FFO, $121.8 million, and that is up 21% compared to Q1 a year ago. And both of those metrics really underscore the Board's decision to increase the dividend this quarter by 10%.

Now turning briefly to our financing initiatives, we were pleased that we have been able to satisfy all of our equity capital needs for our acquisition of Empire. Our convertible debenture offering was well received in the capital markets. It was oversubscribed and had strong institutional support. As a result, the over-allotment option was exercised by our underwriters, bringing the total equity capital to $1.15 billion.

With respect to our debt requirements, we will be meeting with key fixed income investors over the next several months, and we expect to be active in the US private placement market come the fall to complete our financing for Empire.

So with that, I will turn things back over to Ian.

**Ian Robertson**

Thanks, David. As we move through the balance of the year, I think we feel that there's lots to look forward to. We remain committed to our growth plan, both this year and next. I think we are well-positioned to deliver on our 2016 capital initiatives. Construction's proceeding on the Odell and Deerfield projects; rate cases are well underway in California and Arizona.

We are obviously going to continue to work with our partners here at Empire to facilitate the approval of the acquisition by both their shareholders and the regulatory agencies, and I think we're off to a great start at that.

Work is proceeding with respect to the integration of the businesses, and frankly, the objective is having one plus one equaling more than two in the context of Empire and Algonquin and we feel strongly that that opportunity continues.

But lastly, there is obviously no rest. The growth plan takes continual work. We're continuing to focus on growing the pipeline. We think there are strong tailwinds to the whole renewable energy sector here in North America, and we are working hard to add more opportunities to the pipeline.

We think that both Canada and the US have lots to offer in terms of continued growth for this organization going forward, and so we are comfortable with certainly where we sit today, and obviously look forward to bringing more opportunities to you as they develop.

So, Operator, with that we will open up the lines for any questions.

**Question-and-Answer Session**

**Operator**

Thank you. [Operator Instructions] And our first question will come from Paul Lechem of CIBC.

**Paul Lechem**

Thanks, good morning.

**Ian Robertson**

Good morning, Paul.

**Paul Lechem**

Morning, just on the Northeast energy direct project, do you have any financial exposure to the cancellation? Did you invest any amounts that will be unrecoverable at this point?

**Ian Robertson**

Well, we certainly had an investment of a few million dollars. I think that is highlighted in our MD&A. We have no financial exposure, if you want to think of it, that would sit outside of that, no contingent liabilities or liabilities related to the cancellation, other than potentially the forfeiture of the investment we've made to date.

I will highlight interestingly, though, that just because Kinder Morgan wasn't able to proceed with the project, that doesn't actually solve the problem of gas constraints in the Northeast.

So I think we are thrilled that there are - there are going to be continued opportunities for us to participate in that solution, whether it's expansion of existing pipelines, perhaps building some new infrastructure ourselves, or frankly something a little bit off the normal fairway in terms of expanding our LNG project to help deal with the constraints. I think our enthusiasm for the Northeast and participating in that solution in creating investment opportunities isn't dampened at all, Paul.

**Paul Lechem**

Yes, I was going to ask about, are you in discussions at all with Spectra's Access Northeast project, or is this something that wouldn't fit in with your footprint as well?

**Ian Robertson**

Well, I think obviously Spectra has got a number of expansions underway, but they are not the only guys who could look at an opportunity. You think of Iroquois TCPL and PNGTS as a potential path to bring shale gas in to the Northeast. Obviously, could come from the South, as you mentioned, through to the Spectra pipeline.

I think, and as I said I think interestingly that LNG could be an interesting component of the solution to the Northeast constraints. You will recall at our investor day, I think we said that pipelines in LNG both can participate in the solution. We are not sure exactly who is the winner is going to be, but we want to back both horses, so that whoever wins, we've got a ride in that race.

And so, I think right now, Paul, we are agnostic as to what the right solution is, but the demand is still there. You know we ourselves have continued demand to supply the needs of our customers and the other LDCs that were left in the lurch, if you want to think of it that way, from Kinder's decision also continue to have needs. So I think there is great opportunity.

**Paul Lechem**

Okay, just another question, if I may. On the hydro facilities, the global adjustment revenues you discussed in the MD&A. Can you give a bit more color around how much that was, and what that will be going forward. What the benefit will be going forward. Thanks.

**David Bronicheski**

We are expecting that annually, going forward, it is going to be an extra $1.5 million to $2 million per year of revenue, and that is starting to be reflected, obviously, in this quarter's results. There will be a retroactive component under GAAP.

We are not allowed to actually recognize that retroactive amount until the cash actually hits our bank account. We are expecting that to happen either late in Q2 or early Q3.

**Paul Lechem**

Great. Thanks very much, guys.

**Ian Robertson**

Thanks, Paul.

**Operator**

Our next question comes from Rupert Merer of National Bank.

**Rupert Merer**

Good morning, everyone.

**Ian Robertson**

Hey, Rupert.

**Rupert Merer**

Outside of the transmission opportunities you discussed, what is your current view on the rate-based growth opportunities in your existing distribution business, and maybe with Empire coming in as well?

**Ian Robertson**

Well, I mean, I guess one of the ways to look at it, we sort of saw Empire as bringing themselves forward, 4% to 5% growth opportunities within their business, and they are pretty much 100% regulated earnings themselves. And that we are continuing to grow the rest of our business.

It's a couple hundred million dollars worth of CapEx going into our businesses, including Park Water. As you know, part of the thesis for Park Water was the latent capital investment opportunity, and that's probably closer to 8% to 10%, in terms of rate-based growth.

So combine the two together, and you are probably talking somewhere between 5% and 10% growth just on the regulated side. As you obviously know, we enjoyed the benefit of the growthiness of the IPP business, which can supplement that. So it's probably tending, it's about 5% and trending towards double digits, Rupert.

**Rupert Merer**

So with the IPP business, you talked a little in your comments about potential for growth there. Do you see that growing from 25% of the business to something bigger again? How do you view the future opportunities, thinking maybe a little more long-term?

**Ian Robertson**

Sure. I think our position, as we articulated it, is that this 10 seconds, the pendulum for us upon the closing of Empire will have swung, as you accurately point out, to over 70% from a regulated perspective. But I don't think people should see that as somehow as a strategic set point change for the organization.

And as I've often articulated, one of the huge benefits of bringing Empire into the Algonquin portfolio is that, we will call it the headroom. It's occasioned by that in terms of being able to grow the IPP business.

We obviously love the opportunity where our entrepreneurial spirit can be brought to bear to surface opportunities in the IPP business. So you should definitely expect us to be sort of continually aggressive on finding IPP opportunities. As I mentioned earlier, I think the tailwinds for the sector are quite strong, with the extension of the PTCs and the ITCs.

I think the continued environmental pressures, and maybe most importantly, the continued economic trends that make wind, certainly today, and solar, hopefully tomorrow, just the economic choice for providing new energy.

So, Rupert, the foot is not coming off the gas pedal at all on the IPP side of the business, and we're certainly, you would expect to see that pendulum quite happily swing back toward the 50/50, unless of course we can keep growing the utility business and keep it there. But no way are we taking our foot off the gas on the IPP side.

**Rupert Merer**

Just a quick follow-up, then, if you were to look at the return opportunities in the market today, sort of your after-tax levered IRRs, how do they compare in the distribution opportunity versus the IPP opportunity?

**Ian Robertson**

Well, as you well know, when one looks at the return metrics associated with the distribution business, really an ROE or an equity unlevered return, because the benefit of leverage, quite understandably, is for ratepayers, and so consequently we look at it, we look at our investment in that from an equity perspective.

And ROEs, I think we are pleased to be able to say, remain relatively stable. We are not seeing continued erosion in those ROEs. In recent settlements, they have been 9%, 9.5% and even trending toward 10%. So that is obviously good news.

The IPP business is quite different. Obviously, that is where the benefit of leverage is for our account, and so we look at it on an unlevered, after-tax IRR basis, and you know that we are seeing projects, our focus is north of 8%, certainly on the winning side, on an unlevered basis, and if you look at our - the leverage strategies that we use, you can probably think of that as 50/50. So that brings the equity return into the teens.

So it's just a different business proposition, but we certainly think the risk return profiles are equally attractive on both sides. I'm not sure if that is responsive to your question, Rupert.

**Rupert Merer**

Yes, very much. So, thanks for the color Ian…

**Ian Robertson**

Yes. Thanks, Rupert.

**Operator**

And the next question comes from Sean Steuart of TD Securities.

**Sean Steuart**

Thanks. Good morning, everyone.

**Ian Robertson**

Hey, Sean.

**Sean Steuart**

Couple of questions. Maybe I misread it that it looks like Val EO and Great Bay Solar have been reclassified into the development pipeline versus the construction pipeline. Any changes to those projects we should be aware of?

**Ian Robertson**

No. I think it's probably changes more, as we think of our pipeline and our workload. Both of those projects received their final permits, and so the decision to kind of go ahead with those rests solely with us.

But that we felt, until we were actually digging holes in the ground, maybe it felt a little bit inappropriate to put them in an, quote unquote, in construction category. And so consequently, we wanted to leave them in development.

And the question is, well why aren't you digging holes in the ground if you have all of your permits? Well, two things have happened: one, certainly, we've got lots to do, as you know, 350 megawatts of wind and another 10 megawatts of solar that are actually under construction right now, and so obviously there is lots of work underway.

And the extension - the second thing, what the extension of the ITCs for another five years has given us certainly takes the pressure off something like Great Bay Solar, which prior to the extension last year of the ITC/ PTCs, would have to have come online by December 31 of this year.

I think we said we've got the opportunity to defer this for a few months while we are busy; there's nothing to be gained by loading up the construction group. I think that is just obviously creates risk where it doesn't need to be any, because of the time pressures. And the second thing is - that applies obviously to both Val EO and Great Bay.

The other thing that we are obviously considering is the extension of the ITCs has its own implications, which we're working our way through, from a supply demand dynamic within Maryland and the supply of SRECs. What the heck is that going to do to the SREC market?

I guess it is a good news, bad news story. The good news is that the solar carveout has been increased as a percentage under the legislation governing SRECs, so therefore compliance buyers need to buy more SRECs in terms of a percentage of their delivered energy.

The bad news is the extension of the ITC obviously creates incentive for a continued supply, so it is balancing the increased demand and the increased supply, and to understand where that market is going, because obviously SRECs are an important component of the solar equation as it stands today.

So I think we're just being cautious, Sean. I don't think you should see it that those projects have hit any roadblocks from a permitting or construction perspective. It's just being prudent.

**Sean Steuart**

Understood. And just following on that, and Rupert's earlier question, with respect to generation growth aspirations, you guys are clearly comfortable with tax equity and with the extension on the PTC/ ITC side.

Given that, and very competitive bidding internationally for renewable procurements, is there any reason we should expect you to look outside the US in the mid-term for generation growth?

**Ian Robertson**

I mean, I don't know if your use of mid-term was intentional. I think the short-term is no, man, we have lots to do, so that's probably a fair, I'd respond we would not be looking outside of North America in the short term.

Mid-term is a little bit longer. I think we have to watch the evolution of the market, and as I've said in previous earnings calls, understanding what is happening in the international market is not a process that you want to undertake when you need go to the international markets.

So you will hear us, if you follow the scuttlebutt in places like Mexico, the RFP that's underway right there. We are getting ourselves up the learning curve in terms of those marketplaces, so that we can always be making that risk/ return evaluation to see whether introducing country risk, and maybe a different currency risk to our shareholders, is offset by higher returns. But it's not something that is near-term to us, but mid-term, I think I will have to be a little more cagey, Sean, and say not really sure.

**Sean Steuart**

Good enough. Thanks, Ian.

**Ian Robertson**

Thanks, Sean.

**Operator**

And the next question will come from Nelson Ng of RBC capital.

**Unidentified Analyst**

Hey guys, this is Orhan actually filling in for Nelson, right now. Most of my questions have been asked, but just had a follow-up on the OAFC Global Adjustment payment? You said that there's going to be a retroactive payment in late Q2 or early Q3. Do you have any idea of roughly what it's going to be?

**David Bronicheski**

For us, rough calculations for us, $8 million to $10 million.

**Unidentified Analyst**

And then I guess it's dependent on whether or not they will appeal the whole process, right? This is not a guaranteed amount.

**Ian Robertson**

Well, it is Ian speaking. The appeal has to go to the Supreme Court of Canada, and I'm not sure that this is an issue of public policy in front of the Supreme Court.

**Unidentified Analyst**

Okay. Fair enough. And then with regards to CapEx timing, I noticed that you spent about $80 million this quarter, and just looking at your budget for the year of $700 million to $925 million, could you provide some color on the timing of that? Were there any delays due to weather, or is everything going as expected, and that amount still holds?

**David Bronicheski**

Yes, the guidance we have in there still holds. The $700 million to $900 million is obviously inclusive of the Q1 spend, just to be clear on that. Q1 does tend to be a lower quarter for us on the capital.

You can imagine that a number of our distribution utilities in the Northeastern US don't get around to doing a lot of construction in the wintertime. The same thing for our development projects as well. So you will see the CapEx spend accelerate in Q2 and particularly Q3 of this year.

**Unidentified Analyst**

Okay, fair enough. That will be it for me. Thanks.

**David Bronicheski**

Thanks.

**Operator**

And next we have question from Jeremy Rosenfield of Industrial Alliance Securities.

**Jeremy Rosenfield**

Thanks. Good morning, everyone.

**Ian Robertson**

Hey, Jeremy.

**Jeremy Rosenfield**

Just couple of quick question. First, when you look at the power portfolio, Odell I think you have the option to exercise to acquire the remaining 50% after that project hits COD, if I'm not mistaken? Can you talk about what considerations would go into you exercising or choosing not to exercise that?

**Ian Robertson**

Sure. I mean I think first of all let me say you did get it technically correct, in a relatively short period of time, 30 or 60 days, after the project hits COD, the option to exercise comes up. I think we obviously always structure our opportunities with as much flexibility and optionality that is possible.

I think there's nothing that would lead us to believe right now that as we look at the project and we look at its completion, that owning the other 50% wouldn't be is attractive as owning that first 50%, but I don't think we are - we are not pre-committed, if you will, to exercising the option.

But I think from your perspective, if you're thinking of modeling that business, I mean we are not unhappy with the first 50%, and so therefore we probably wouldn't be unhappy with the second 50 might be the way I would look at it, Jeremy.

**Jeremy Rosenfield**

Okay. Good, fair enough. Then a question I think I've probably asked on previous calls, and I'm sorry if I'm bringing it up again, but as you look out to potentially post-closing, still early, but post-closing an acquisition of Empire, you look at the overall portfolio, and there some assets that are getting to be relatively small.

Are you thinking sort of ahead as to if some of those assets may no longer fit within the overall business because they are now relatively small and kind of marginal? Have you thought about potentially monetizing some of that?

**Ian Robertson**

I think one always looks at the portfolio composition in the context of who you are at the time and whether a 1 megawatt hydro plant, that's kind of which were making reference to - still continues to fit in a portfolio of a $10 billion business. We have to ask ourselves those questions.

Though I will say that our grouping, if you will of small hydro assets, still feels to be rational and reasonable. As you think about them geographically, they support each other from an efficiency and economies of scale perspective, so absent sort of making the decision to divest ourselves, if you will, of the entire small hydro portfolio, I'm not sure there is a thesis for getting rid of any one of the individual assets.

And so I don't think that the growth that is going to be evidenced by bringing Empire into the mix somehow fundamentally changes our look at our current portfolio. We think each one of those assets continues to contribute appropriately to the business.

We certainly, as I said, look at this quarter's results and maybe just going back to my opening comments about the diversification and the resilience of the portfolio. Man, it was the hydro guys who carried the load this quarter, and it's hard not to enjoy the orthogonality of risk that's associated with those different businesses.

So I guess I will respond to you the same way as last time, Jeremy, is we are comfortable with the portfolio composition, but it is something that we always keep our eye on. But nothing at this stage.

**Jeremy Rosenfield**

Okay, perfect. I will leave it there for the moment and get back in queue.

**Ian Robertson**

Thanks, Jeremy.

**Operator**

[Operator Instructions] And our next question will come from Eric Tang of BMO.

**Eric Tang**

Hi, guys. This is Eric filling in for Ben. Most of my questions have been answered. Just a quick one. Given the volume downside we saw in Q1, are there any plans to decouple some of your utilities in the Northeast?

**Ian Robertson**

Well, let me start by saying, I guess from our perspective, we have to look at our results across the portfolio. And so yes, on an individual asset basis, some are up and some are down, and so we like to think that the quarter was nice and solid, when you look at it across the portfolio.

Obviously, I think with respect specifically to your question on the Northeast and the impact of the incredibly warm winter that we suffered, certainly New Hampshire as a state doesn't have particularly progressive decoupling provisions, that's just a fact. There are initiatives underway for that to happen.

We are obviously cheering from the sidelines for those initiatives. They are not initiatives that we can unilaterally implement, but we can certainly try to provide testimony and guidance back to the commission as to the benefit, and to be frank, it's not just benefit to us, it's benefit to the ratepayers as well from our perspective.

I think everybody likes predictability and stability, and those are some of the best, from our perspective, I think the right way to go. So we are pursuing them. We are supportive of them. But unfortunately the reality is they just not in place, certainly in New Hampshire.

But as I said earlier to Jeremy's call, isn't it great that we have a portfolio where in this case the generation group stepped up, if you want to think of it that way, with stronger-than-expected or stronger-than-average results to make up for some of those shortfalls. And it's interesting, I'm not a climatologist, but one wonders, of course, whether the wetter weather and the windier weather are somehow influenced by the same weather patterns that brought us the warmer weather in the Northeast.

So maybe this is a natural hedge that exists. But the fact of the matter is the portfolio did better as a result of having that diversification. So I'm not sure if that, Eric, is where you wanted to go with the question?

**Eric Tang**

That answers it fair enough. Just going back to the Empire acquisition. What is your longer-term accretion, I guess target budgeted for beyond three years? Do you have a target in mind at the moment?

**Ian Robertson**

From an accretion point of view, three years out, obviously we are hoping to bring more to the investment opportunity, that was clearly in the portfolio of CapEx that was reflected in our acquisition numbers.

Those were numbers that we frankly cribbed from the existing Empire management team. This gets back to the comment earlier where our real objective is to make sure that one plus one equals more than two in terms of being able to find growth opportunities.

We've talked about them in the past, this idea of greening the Empire portfolio. The idea of bringing more natural gas and renewables to the Empire mix. Those are all part of the longer-term thesis associated with this opportunity.

And that strategic planning is number one on the agenda as we integrate these businesses and we look out beyond just the near three-year term that the CapEx model within Empire has been currently feathered into our results.

**Eric Tang**

Okay, thanks. Fair enough. That's all the questions I have.

**Ian Robertson**

Thanks, Eric.

**Operator**

And next we have a follow-up question from Sean Steuart of TD Securities.

**Sean Steuart**

Thanks. Just one follow-up, guys. The LNG potential in Massachusetts, I think when you guys initially talked about it, you were anticipating some regulatory hurdles being met early this year. Any update you can give us on that project?

**Ian Robertson**

Yes, I would say the regulatory hurdles, there are really two things that are being done from a regulatory perspective: is the national grids approval of their precedent agreement - their agreement to be an off taker for that is in front of the Mass DPU. And right now their approval is expected within this quarter, maybe next quarter in terms of that approval.

The other hurdle, obviously that we have in front of us, is our own FERC application. We obviously want to make sure that the National Grid as a customer is solid before we go to the expense of filing our FERC approval.

I think getting revenue certainty, if you want to think of it that way, for National Grid is something you are going to see in the next quarter or so. And perhaps to add my own follow-on to that answer, as we think about the implications of the Kinder Morgan decision regarding the Northeast energy direct, I mentioned that LNG can certainly potentially play a role in dealing with those supply constraints in the Northeast.

And so consequently ourselves, we may be looking at expanding that project substantially to meet some of those needs, not just for National Grid but for Energy North and some of the other utilities in the area.

So I don't think that the ink is dry, if you will, Sean, on the conceptualization of that project, and maybe the Northeast Energy direct troubles may translate into Northeast Energy Center, which is what we call our LNG facilities, to its benefit.

**Sean Steuart**

Okay. Thanks for the detail.

**Ian Robertson**

Thanks.

**Operator**

And we have another follow-up question and that comes from Jeremy Rosenfield of Industrial Alliance Securities.

**Ian Robertson**

Jeremy, we are going to have to charge you for this one, but go ahead.

**Jeremy Rosenfield**

Okay, as long as it is not too much. Just on the debt financing conditions and the strategy for potentially locking in some rates on the debt financing that would be associated with the Empire acquisition, are you looking at potentially doing some of that sooner, or do you want to wait until you get closer to the closing date?

**David Bronicheski**

Just generally when it comes to hedging strategies, we're always somewhat reluctant, I will say, to get ahead of ourselves. Clearly, I think we want to get past the Empire shareholder vote.

We are confident it will be successful, but we don't want to prejudge anything, and so once we do get through that, I think that will be a time when we will do a reassessment of the hedging strategy both from an interest rate perspective and a currency perspective, but at this point in time we haven't locked anything down.

**Jeremy Rosenfield**

Okay. And then just maybe a final question, on Amherst Island, still in the waiting process here, kind of frustrating overall. Do you have any considerations, when you take away how long it has taken for Amherst Island, when you think about doing more projects in Ontario, with the LRP II that was just recently unveiled, how does that factor into your thinking, I guess, going forward.

**Ian Robertson**

Well, I think your use of the word frustrating was probably pretty appropriate. Let me just comment first about kind of where Amherst actually stands right now, is that the ERT is coming to a conclusion.

We are hoping that process wraps up within the next 30 days. I think final arguments are expected to be lodged within, I will call it next couple, three weeks, and so that process will come to an end.

But then when you step, and so we're cautiously optimistic that the ERT, which is really a review of the Ministry of Environments work on the permitting process, will be proven to have been appropriate. But then you step back, and you ask yourself the question, does the permitting paradigm in Ontario, how does it look at compared to other states?

And the short answer is, there is no doubt about it, it is an outlier. There is a complexity, and there is an overhead associated with it, and one needs to think about that in the context of the risk returns associated with Ontario projects. And in some respects, that's a sad statement make because we are obviously proud to be from the province, but at the same time when we look at a project like a Odell, or we look at a project like Great Bay Solar in Maryland, or frankly we look at Chaplin and some of the other projects in some of the other provinces. It really does feel quite different. And so I think if your observation is that Ontario has a level of complexity, I think no truer words were ever spoken.

**Jeremy Rosenfield**

That being said, you still expect to be participating in LRP II here?

**Ian Robertson**

I think we've got sites. We've got opportunities. As we mentioned last earnings call, obviously it was disappointing that the effort that has been put into those sites up until now has been, we didn't - we weren't able to capture it in LRP I. It doesn't make the sites any less valuable. They continue to be locked up.

We are working on building the areas that we were perhaps in which they evidenced a shortfall, and that is community involvement and perhaps first nation participation. These are all the things that maybe made the economics of our project, while they were competitive it was perhaps some of the ancillary areas of the evaluation grade which we fell short.

So sure, we want to continue to participate in the process, but you have to take into account the fact that it's a very complex, and arguably expensive, and maybe you can read parenthetically risky jurisdiction. It just is what it is. I guess I am making an observation and not an accusation.

**Jeremy Rosenfield**

Sure. Good. Thanks, I appreciate it.

**Ian Robertson**

Thanks for the call.

**Operator**

[Operator Instructions] Showing no further questions, we will conclude the question-and-answer session. I would like to turn the conference back over to Mr. Robertson for any closing remarks.

**Ian Robertson**

Thanks, Operator. Thanks, everyone for joining us on the call this morning. Thanks to all the analysts for their questions. And then lastly, a final thanks to the Empire team for their hospitality of allowing us to host the call here from Joplin, and with that I will turn things back over to Chris to give you our disclaimer statement. Chris?

**Christopher Jarratt**

Certain written or oral statements contained in this call are forward-looking within the meaning of certain securities laws and reflect the views of Algonquin Power & Utilities Corp. with respect to future events based on assumptions relating to, among other things, the performance of the Company's assets and the business, financial, and regulatory climates in which it operates. These forward-looking statements include, among other things, other statements with respect to the expected performance of the Company and its future plans and its dividends to shareholders. Since forward-looking statements relate to future events and conditions by their very nature, they require us to make assumptions and involve inherent risks and uncertainties.

We caution that although we believe our assumptions are reasonable, in circumstances these risks and uncertainties give rise to the possibility that our actual results may differ materially from the expectations set out in the forward-looking statements. Material risks include those presented in Company's most recent annual financial results, the annual information form, and most recent quarterly management discussion and analysis. Given these risks, undue reliance should not be placed on these forward-looking statements. In addition, such statements are made based on information available and expectations as of the date of this call, and such expectations may change after this date.

APUC reviews material forward-looking information presented not less frequently than on a quarterly basis. APUC is not obligated to, nor does it intend to, update or revise any forward-looking statements, whether as a result of new information or future developments or otherwise, except as required by law.

With respect to GAAP financial measures, the terms adjusted net earnings; adjusted earnings before interest; taxes; depreciation and amortization; EBITDA, adjusted funds from operations; per-share cash provided by operating activities; net energy sales; and net utility sales, collectively, the quote-unquote financial measures, are used on this call throughout the Company's financial disclosures. The financial measures are not recognized measures under the generally accepted accounting principles, or GAAP.

There is no standardized measure of these financial measures; consequently, APUC's methods of calculation these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. Calculation and analysis of the financial measures and a description of the use of non-GAAP financial measures can be found in the most recently published management discussion and analysis available on the Company's website and sedar.com. Per-share cash provided by operating activities is not a substitute measure of performance for earnings per share. Amounts represented per-share cash provided by operating activities do not represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against APUC. Thank you very much.

**Operator**

The conference is now concluded. You may disconnect your lines at this time. Thank you for participating and have a pleasant day.



## Algonquin Power & Utilities (OTCPK:AQUNF): Q1 EPS of $0.21

## Revenue of $341.7M (-10.5% Y/Y)

## Press Release

# Comments (0)

# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

# FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the fiscal year ended December 31, 2011**

**or**

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the transition period from to .**

**Commission file number: 1-3368**

# THE EMPIRE DISTRICT ELECTRIC COMPANY
(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **Kansas**<br>(State of Incorporation) | **44-0236370**<br>(I.R.S. Employer Identification No.) |
| **602 S. Joplin Avenue, Joplin, Missouri**<br>(Address of principal executive offices) | **64801**<br>(zip code) |

**Registrant's telephone number: (417) 625-5100**

**Securities registered pursuant to Section 12(b) of the Act:**

| Title of each class | Name of each exchange on which registered |
|---|---|
| Common Stock ($1 par value) | New York Stock Exchange |

**Securities registered pursuant to Section 12(g) of the Act: None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

| | | | |
|---|---|---|---|
| Large accelerated filer ☒ | Accelerated filer ☐ | Non-accelerated filer ☐<br>(Do not check if a smaller reporting company) | Smaller reporting company ☐ |

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the registrant's voting common stock held by nonaffiliates of the registrant, based on the closing price on the New York Stock Exchange on June 30, 2011, was approximately $807,349,000.

As of February 1, 2012, 42,023,966 shares of common stock were outstanding.

The following documents have been incorporated by reference into the parts of the Form 10-K as indicated:

| | |
|---|---|
| The Company's proxy statement, filed pursuant to Regulation 14A under the Securities Exchange Act of 1934, for its Annual Meeting of Stockholders to be held on April 26, 2012 | Part of Item 10 of Part III<br>All of Item 11 of Part III<br>Part of Item 12 of Part III<br>All of Item 13 of Part III<br>All of Item 14 of Part III |

## DIVIDENDS

Holders of our common stock are entitled to dividends if, as, and when declared by the Board of Directors, out of funds legally available therefore, subject to the prior rights of holders of any outstanding cumulative preferred stock and preference stock. Payment of dividends is determined by our Board of Directors after considering all relevant factors, including the amount of our retained earnings (which is essentially our accumulated net income less dividend payouts). A reduction of our dividend per share, partially or in whole, could have an adverse effect on our common stock price.

In response to the expected loss of revenues resulting from the May 22, 2011 tornado, our level of retained earnings and other relevant factors, our Board of Directors suspended our quarterly dividend for the third and fourth quarters of 2011. On February 2, 2012, the Board of Directors re-established the dividend and declared a quarterly dividend of $0.25 per share on common stock payable on March 15, 2012 to holders of record as of March 1, 2012. As of December 31, 2011, our retained earnings balance was $33.7 million (compared to $5.5 million at December 31, 2010) after paying out $26.7 million in dividends during 2011.

Our diluted earnings per share were $1.31 for the year ended December 31, 2011 and were $1.17 and $1.18 for the years ended December 31, 2010 and 2009, respectively. Dividends paid per share were $0.64 for the year ended December 31, 2011 and $1.28 for each of the years ended December 31, 2010 and 2009.

Under Kansas corporate law, our Board of Directors may only declare and pay dividends out of our surplus or, if there is no surplus, out of our net profits for the fiscal year in which the dividend is declared or the preceding fiscal year, or both. Our surplus, under Kansas law, is equal to our retained earnings plus accumulated other comprehensive income/(loss), net of income tax. However, Kansas law does permit, under certain circumstances, our Board of Directors to transfer amounts from capital in excess of par value to surplus. In addition, Section 305(a) of the Federal Power Act (FPA) prohibits the payment by a utility of dividends from any funds "properly included in capital account". There are no additional rules or regulations issued by the FERC under the FPA clarifying the meaning of this limitation. However, several decisions by the FERC on specific dividend proposals suggest that any determination would be based on a fact-intensive analysis of the specific facts and circumstances surrounding the utility and the dividend in question, with particular focus on the impact of the proposed dividend on the liquidity and financial condition of the utility.

In addition, the EDE Mortgage and our Restated Articles contain certain dividend restrictions. The most restrictive of these is contained in the EDE Mortgage, which provides that we may not declare or pay any dividends (other than dividends payable in shares of our common stock) or make any other distribution on, or purchase (other than with the proceeds of additional common stock financing) any shares of, our common stock if the cumulative aggregate amount thereof after August 31, 1944 (exclusive of the first quarterly dividend of $98,000 paid after said date) would exceed the sum of $10.75 million and the earned surplus (as defined in the EDE Mortgage) accumulated subsequent to August 31, 1944, or the

Exhibit WKW-9

# The Empire District Electric Company

## Annual 2015 Investor Update

*02/26/2016*

*Riverton Unit 12 Combined Cycle Conversion*

EMPIRE

SERVICES YOU COUNT ON

# Forward Looking Statements

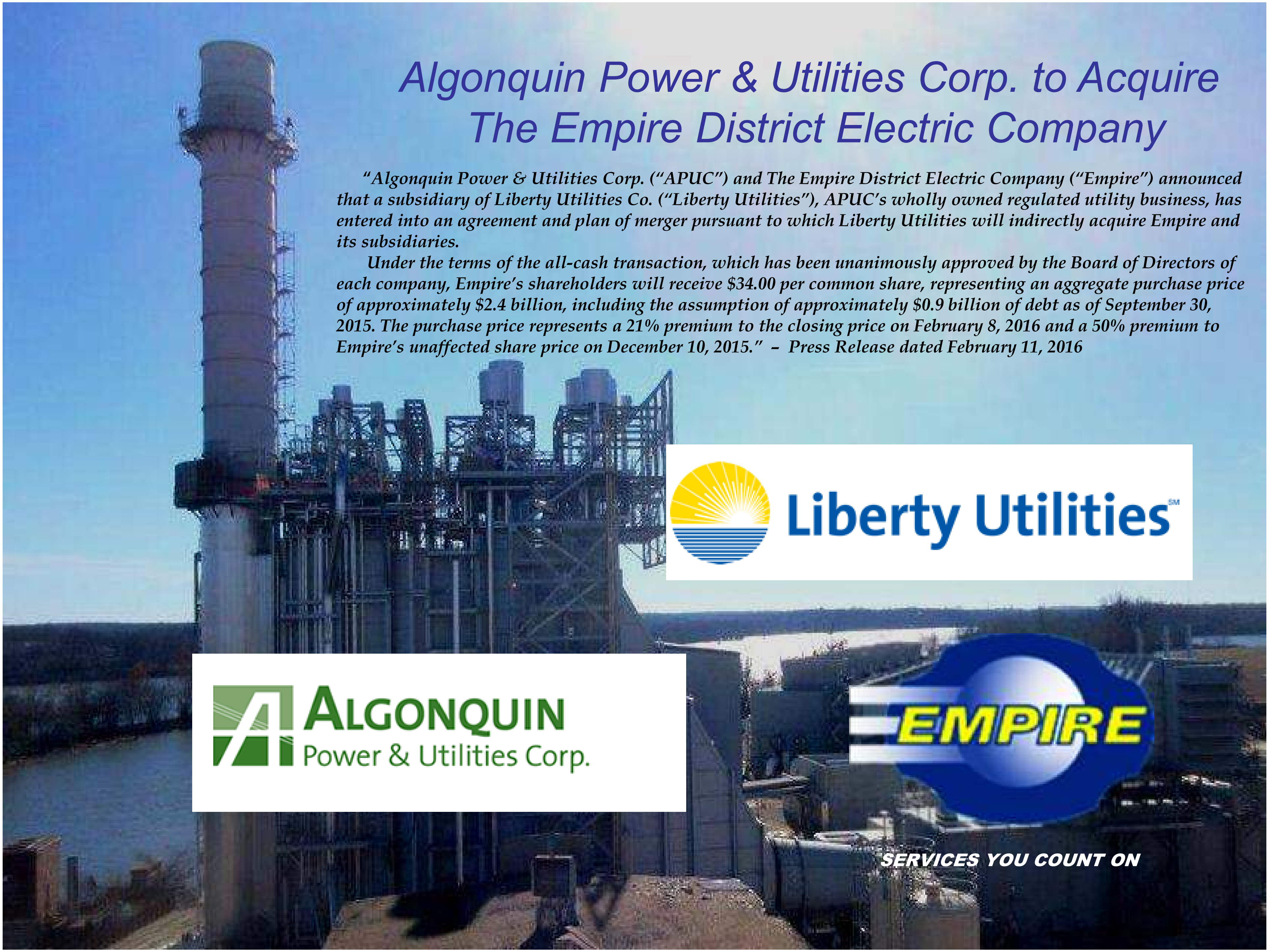
Certain matters discussed in this presentation are “forward-looking statements” intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. Statements that are not historical facts, including statements about beliefs, expectations, estimates, projections, goals, forecasts, assumptions, risks and uncertainties, are forward-looking statements. Forward-looking statements are often characterized by the use of words such as “believes,” “estimates,” “expects,” “projects,” “may,” “intends,” “plans,” “anticipates,” “pro forma,” “predicts,” “seeks,” “could,” “would,” “will,” “can,” “continue” or “potential” and the negative of these terms or other comparable or similar terminology or expressions. The forward-looking statements in this presentation include, without limitation, statements relating to Liberty Utilities proposed acquisition of Empire, shareholder and regulatory approvals, and the completion of the proposed transaction. These statements reflect Empire’s management’s current beliefs and are based on information currently available to Empire management. Forward-looking statements involve significant risk, uncertainties and assumptions. Certain factors or assumptions have been applied in drawing the conclusions contained in the forward-looking statements (some of which may prove to be incorrect). Empire cautions readers that a number of factors could cause actual results, performance or achievement to differ materially from the results discussed or implied in the forward-looking statements. Important factors that could cause actual results, performance and results to differ materially from those indicated by any such forward-looking statements include risks and uncertainties relating to the following: (i) the risk that Empire may be unable to obtain shareholder approval for the proposed transaction or that Liberty Utilities or Empire may be unable to obtain governmental and regulatory approvals required for the proposed transaction, or required governmental and regulatory approvals may delay the proposed transaction; (ii) the occurrence of any event, change or other circumstances that could give rise to the termination of the merger agreement; or could otherwise cause the failure of the merger to close; (iii) the risk that a condition to the closing of the proposed transaction may not be satisfied; (iv) the failure to obtain any financing necessary to complete the merger; (v) the outcome of any legal proceedings, regulatory proceedings or enforcement matters that may be instituted against Empire and others relating to the merger agreement; (vi) the receipt of an unsolicited offer from another party to acquire assets or capital stock of Empire that could interfere with the proposed merger; (vii) the timing to consummate the proposed transaction; (viii) disruption from the proposed transaction making it more difficult to maintain relationships with customers, employees, regulators or suppliers; (ix) the diversion of management time and attention on the transaction; (x) general worldwide economic conditions and related uncertainties; (xi) the effect and timing of changes in laws or in governmental regulations (including environmental laws and regulations); (xii) the timing and extent of changes in interest rates, commodity prices and demand and market prices for gas and electricity; and (xiii) other factors discussed or referred to in the “Risk Factors” or “Forward Looking Statements” sections of Empire’s most recent Annual Report on Form 10-K filed with the Securities and Exchange Commission (the SEC) and in subsequently filed Forms 10-Q and 8-K.

Additional risks and uncertainties will be discussed in the proxy statement and other materials that Empire will file with the SEC in connection with the proposed transaction. There can be no assurance that the proposed transaction will be completed, or if it is completed, that it will close within the anticipated time period. These factors should be considered carefully and undue reliance should not be placed on the forward-looking statements. Each forward-looking statement in this presentation speaks only as of the date of the particular statement. For additional information with respect to certain of the risks or factors, reference should be made to Empire’s filings with the SEC. Except as required by law, Empire disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

# Algonquin Power & Utilities Corp. to Acquire The Empire District Electric Company

*"Algonquin Power & Utilities Corp. ("APUC") and The Empire District Electric Company ("Empire") announced that a subsidiary of Liberty Utilities Co. ("Liberty Utilities"), APUC's wholly owned regulated utility business, has entered into an agreement and plan of merger pursuant to which Liberty Utilities will indirectly acquire Empire and its subsidiaries.*

*Under the terms of the all-cash transaction, which has been unanimously approved by the Board of Directors of each company, Empire's shareholders will receive $34.00 per common share, representing an aggregate purchase price of approximately $2.4 billion, including the assumption of approximately $0.9 billion of debt as of September 30, 2015. The purchase price represents a 21% premium to the closing price on February 8, 2016 and a 50% premium to Empire's unaffected share price on December 10, 2015." – Press Release dated February 11, 2016*



# *Transaction Highlights*

- $34.00 purchase price
  - Represents 50% premium to unaffected December 10, 2015 closing price of $22.65
- Joplin headquarters for Liberty Utilities Central Region (“Liberty Central”)
  - Subsidiary of Liberty Utilities
  - Liberty Central will serve approximately 338,000 customers on close
- Empire senior management team to lead Liberty Central
  - Brad Beecher to assume role of President and CEO of Liberty Central
- Empire branding maintained for no less than 5 years
- Commitment to retain Empire employees
- Current Empire customer rates remain unaffected
- Continuing level of community support and involvement

# Midwestern Utility Empire District Electric Said to Explore Sale

**Matthew Monks** **Mark Chediak**
**MattMonks123** **markchediak**
December 11, 2015 — 4:34 PM CST

Empire District Electric Co., a utility that supplies energy across the Midwestern U.S., is exploring a sale, according to people familiar with the matter.

The Joplin, Missouri-based company is working with an adviser as it seeks potential buyers, said the people, who asked not to be identified because the matter is private. The process is at an early stage, no final decision has been made, and the company may decide not to pursue a sale, they said.

Empire District's shares rose 8.3 percent on Friday, giving the company a market value of about $1.1 billion.

A spokeswoman for Empire District declined to comment, citing company policy regarding public statements on speculation about mergers and acquisitions.

Utilities have been consolidating to offset slow growth due to weak electricity demand. They have also been dealing with rising costs as they replace aging infrastructure to comply with environmental rules.

Empire District provides electricity, natural gas and water service to about 217,000 customers in Missouri, Kansas, Oklahoma and Arkansas, **according** to its website.

The Empire District Electric Company

Retained Earnings Balance at year-end*
($ in thousands)

| | |
|---|---|
| 2015 | 101,443 |
| 2014 | 90,276 |
| 2013 | 67,554 |
| 2012 | 47,115 |
| 2011 | 33,707 |
| 2010 | 5,468 |
| 2009 | 10,068 |
| 2008 | 13,579 |
| 2007 | 17,153 |
| 2006 | 22,619 |
| 2005 | 19,692 |

* from respective years Empire 10K on file with SEC

Exhibit WKW-11

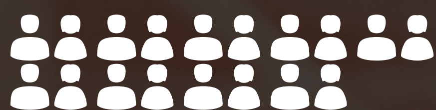
# RELATIONSHIPS

Southwest Power Pool
2015 Annual Report

SPP
75th Anniversary
75

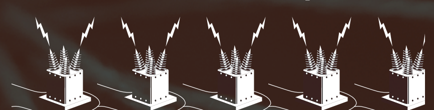
# OPERATIONS

**POPULATION SERVED:**
**18 million**



= 1 million people

**SUBSTATIONS: 4,757**



= 1,000 substations

**SERVICE TERRITORY:**
575,000 SQUARE MILES

The successful integration of the Integrated System (IS) was a significant milestone for SPP in 2015. The integration was the result of years of discussions and public involvement among the IS members, SPP, the Federal Energy Regulatory Commission (FERC) and customers. The IS is comprised of the Western Area Power Administration's (WAPA) Upper Great Plains in Billings, Mont., the Basin Electric Power Cooperative in Bismarck, N.D., and the Heartland Consumers Power District in Madison, S.D. In a historic milestone, WAPA became the first federal agency to join a regional transmission organization (RTO).

SPP began providing reliability coordination to the IS on June 1, 2015. Reliability coordination would allow SPP to monitor the power flow and take action to manage congestion and coordinate a regional response in emergency situations.

On Oct. 1, 2015, the IS successfully transferred functional control of the integrated transmission system to SPP and began operating in the RTO. This was the final step in achieving full membership.

With the inclusion of the IS, SPP's footprint expanded to almost 575,000 square miles in all or parts of 14 states in the central U.S., and includes more than 700 generating plants, nearly 5,000 substations and about 60,000 miles of high-voltage transmission lines. IS integration added more than 5,000 MW of peak demand and 9,500 miles of transmission infrastructure to the SPP region. The IS added 7,759 MW of overall new generation, including 1,014 MW of new wind generation. IS integration also added six new asset-owning market participants, one financial-only market participant, five market participants who were transitioning from financial-only to asset-owning, 21 new transmission customers and 11 new transmission owners.

SPP's winter peak load was 36,995 MW in January 2015, setting a new all-time peak. SPP's summer peak load was 45,873 in July 2015. The region expanded its system to reliably meet peak loads as well as other operating conditions, with 15 additional transmission lines energized during 2015. SPP brought online 2,326 MW of additional generation capacity, while 2,697 MW of capacity was registered in the Integrated Marketplace (IM) by multiple market participants. This expansion increased the opportunity for renewable and other economically efficient resources to reliably serve regional demand.

SPP saw increasing energy production from renewable energy resources, most notably wind generation. In 2015, SPP saw peak wind energy output of 9,949 MW, an increase over 2014's peak of 7,800 MW. SPP also saw a higher proportion of IM energy demand served by wind than ever before, with 38.3 percent wind penetration in November 2015. To ensure SPP reliably incorporates increasing levels of asynchronous renewable generation, SPP staff undertook an effort to study the impacts of increasing renewable resource penetration on operations throughout 2015, with the results of its analysis published in February 2016.

Throughout 2015, SPP spent substantial efforts working to improve the efficiency of the IM. SPP addressed 464 defects and enhancements and nine participant Revision Requests throughout a series of three planned software releases throughout the year.

Project Pinnacle replicated the IM's success by reaching its March 1, 2015, go-live date on time and under budget. Project Pinnacle was comprised of six enhancement projects to the Integrated Marketplace: Pseudo Tie-Out, Environment Build-Out, Long-Term Congestion Rights (LTCR), Market-to-Market (M2M), Regulation Compensation (Reg Comp) and Enhanced Combined Cycle.

LTCR went live in February 2015. LTCR implementation brought SPP in compliance with a FERC order that required long-term firm transmission rights to help ease congestion. LTCRs are an annual product covering all hours of a year; the allocated LTCRs are a guaranteed right that can be held as long as the firm Transmission Service Reservation exists (i.e., into perpetuity).

M2M and Reg Comp were implemented successfully and on schedule March 1, 2015. With the implementation of M2M coordination, SPP and Midcontinent Independent System Operator (MISO) worked together to manage congestion along seams more efficiently with financial settlement based on each RTO's respective impact on congestion. The Reg Comp project brought SPP in compliance with a FERC order that required regulation providers be compensated according to performance in response to SPP regulation-deployment signals. By dividing regulation service into distinct capacity and mileage components and paying resources based on their actual movement, resources can be rewarded for their specific characteristics.

## THE INTEGRATED MARKETPLACE IN 2015

**Generating Resources:** 703

**Market Participants:** 166

**Market Settlement Dollars:**
$14.638 billion

**Peak Load (Coincident):**
45,873 MW (July 24, 2015)*

**Wind in Service:**
12,397 MW

** Occurred prior to integration of the Integrated System on Oct. 1, 2015*

## ENERGY CONSUMPTION

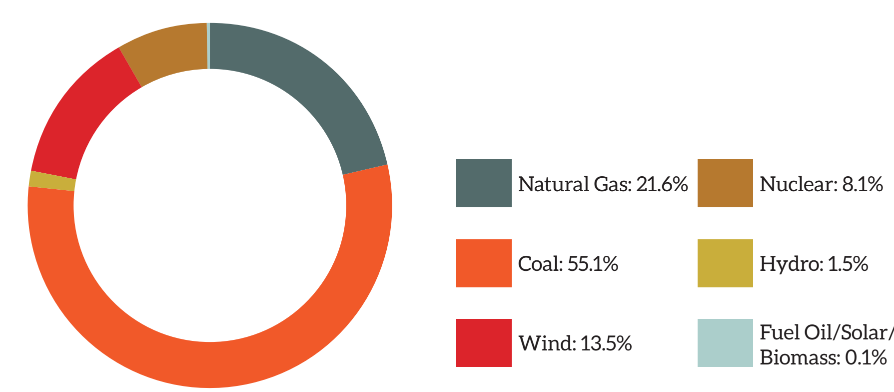


Exhibit WKW-12



# S&P Affirms Rationgs on Empire District Electric (EDE) Amid Merger Deal; Outlook to Negative

February 10, 2016 11:05 AM

Standard & Poor's Ratings Services said it revised its rating outlook on Empire District Electric Co. (NYSE: EDE) to negative from developing. At the same time, we affirmed our ratings on the company, including the 'BBB' issuer credit rating.

We base the negative outlook on Empire's announcement that it has entered into an agreement to be acquired by Algonquin Power & Utilities Corp.

"When the transaction closes, we would view Empire as a core subsidiary of Algonquin, leading to an issuer credit rating for Empire that is aligned with that of Algonquin," said Standard & Poor's credit analyst Dimitri Nikas.

We base this assessment on the following factors:

- We project that Empire will form a meaningful part of the merged entity, contributing about 40% of Algonquin's total EBITDA.
- Empire operates in lines of business that are integral to the overall group strategy (regulated utility operations).
- We expect Algonquin's management will be strongly committed to Empire given Algonquin's emphasis on maintaining the size and scope of its regulated utility operations relative to nonutility operations.
- Empire will enhance Algonquin's presence in common service territories, especially Missouri, facilitating growth and cost-reduction opportunities.

Because of our view of Empire's core group status, the negative outlook on Empire is in line with the negative outlook on Algonquin, which reflects the risk of weaker near-term credit measures associated with the transaction's timing and financing.

The ratings on Empire are based on the company's strong business and significant financial risk profiles.

The negative outlook on Empire reflects the prospect for lower ratings due to the company's agreement to be acquired by Algonquin. The negative outlook on Algonquin reflects our expectation that the company's credit measures will materially weaken in 2016 due to the issuance of convertible debentures to partly finance the cash purchase of Empire. Although we expect that the debentures will have a very high likelihood of conversion in 2017 when the transaction closes, in the meantime we expect that credit measures will be weak for the rating, eliminating any financial cushion at the current rating level. The negative outlook also reflects the execution risk associated with the additional equity and debt necessary to support the transaction and to fund the company's ongoing development plans.

S&P Global Ratings

# Ratings on UtiliCorp United Inc. and Subsidiaries Affirmed



## About This Report

677 words — Published Oct 19, 2001
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S&P Global Ratings

**Ratings on UtiliCorp United Inc. and Subsidiaries Affirmed**

Published Oct 19, 2001

**Abstract:**

NEW YORK (Standard&Poor's) Oct. 19, 2001--Standard&Poor's today affirmed the ratings of UtiliCorp United Inc. (BBB/Stable/A-2) and its affiliates (A complete list of ratings is available on RatingsDirect, Standard&Poor's on-line credit research service, or by calling the Standard&Poor's ratings desk at (212) 438-2400.) The outlook is stable. The ratings affirmation follows the firm's announced deal to purchase Midlands Electricity PLC with a financial partner for about $2.1 billion. UtiliCorp and its partner plan to keep the existing $1.7 billion of debt in the Midlands entity, with the remaining $360 million representing the partners' equity stake. The affirmation of the UtiliCorp ratings is based on Standard&Poor's conclusion that the company will offer

**Brief Excerpt:**

RESEARCH Ratings on UtiliCorp United Inc. and Subsidiaries Affirmed Publication date: 19-Oct-2001 NEW YORK (Standard & Poor's) Oct. 19, 2001--Standard & Poor's today affirmed the ratings of UtiliCorp United Inc. (###/Stable/A-2) and...

| | |
|---|---|
| **Report Type:** | Ratings Action |
| **Ticker** | ILA |
| **Issuer** | KCP&L Greater Missouri Operations Co. |
| **GICS** | Multi-Utilities (55103010) |
| **Sector** | Global Issuers |
| **Country** | United States |
| **Region** | United States |
| **Format:** | HTML |

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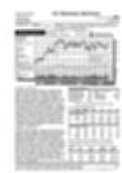
Example Report



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Summary: Aquila Inc – 2002/05/14 – US$ 225.00

Bulletin: Aquila Inc.'s Strategic Changes May Help Credit Quality – 2002/06/17 – Free

Summary: UtiliCorp United Inc. – 2001/10/19 – US$ 225.00

Summary: UtiliCorp United Inc. – 2001/01/04 – US$ 225.00

UtiliCorp United Inc.'s Ratings Affirmed After Acquisition Announcement – 2000/02/07 – US$ 150.00

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Energy in the News

Energy News

# Aquila's credit rating reduced

**06/24/2004**

Aquila Inc. on Wednesday faced a credit rating cut amid new concerns about its financial condition following a legal setback.

A preliminary injunction on Tuesday by the U.S. District Court in Kansas City will keep Aquila from using $504 million in proceeds from the recent sale of its Canadian utilities. A top Aquila executive testifying at the hearing said that not having access to the cash could put the company "at risk," especially in the upcoming winter heating season, and that liquidity would be tight.

Standard and Poor's Ratings said Wednesday that it was downgrading Aquila's credit rating another notch in the junk category and that it could be knocked down again, depending on the results of a meeting it plans to have with Aquila's management. Fitch Ratings, though not downgrading the company's rating from its current junk status, warned that there would be little financial flexibility to meet unexpected expenses, such as higher natural gas costs.

"There will be almost no cushion," said Sharon Bonelli, an analyst for Fitch.

Rick Dobson, Aquila's chief financial officer, testified Tuesday that the company's liquidity could become so tight that in December and January it might be unable to supply natural gas to its utility customers, depending on the volatility of gas prices. It has about 890,000 gas customers in seven states.

George Minter, an Aquila spokesman, said Wednesday that the company was disappointed in the credit downgrade but was continuing its restructuring efforts and pursuing "liability management" plans that would provide long-term stability to meet its gas supply operations.

"Even though a very cold winter season could cause higher gas prices, we will be working on various financial approaches in gas purchasing that would mitigate issues in continuing to provide reliable gas supplies for customers," he said.

The dispute leading to the preliminary injunction involved $504 million in prepaid contracts under which Aquila must deliver gas to several Nebraska municipal utilities through 2012. Two units of Chubb Corp. issued surety bonds on the contracts and in December 2001 told Aquila that Chubb wanted to be discharged from the liability or have collateral posted. Aquila refused, and the issue went to court.

U.S. District Judge Gary Fenner said Tuesday that the contract Chubb signed with Aquila clearly gave Chubb, at its discretion, the right to be discharged from the liability or have Aquila post collateral. As a result, it had a right to the preliminary injunction.

There will be a hearing on a permanent injunction to settle some legal issues, but no date for that hearing was set.

The S&P action reduces Aquila's debt rating from B-, which is junk level, to CCC+. S&P defines a CCC rating as reserved for companies that are "currently vulnerable and dependent on favorable business, financial and economic conditions to meet financial commitments."

S&P noted Aquila's assurance that it will be able to pay $400 million in debt due this year, but the rating service was nevertheless concerned about the amount of working capital Aquila would be left with to cover expenses, especially if there are volatile gas prices. Aquila has about $728 million of cash on hand, not counting the amount set aside by the injunction.

"Moreover, uncertainty associated with continuing unwinding of the company's (energy) trading book, volatility associated with commodity prices, and further restructuring actions could adversely affect liquidity," said Rajeev Sharma, an analyst for S&P Ratings, in a prepared statement.

Bonelli, of Fitch Ratings, said there is concern about Aquila's long-term business and financial prospects. Critical to financial recovery is renegotiating the prepaid gas contracts, which are a drain on cash, as well as renegotiating "tolling" agreements on unregulated power plants. In the tolling agreements, Aquila makes payments for power that it then needs to resell.

The preliminary injunction "deepens their problems," Bonelli said.

Aquila's stock closed Wednesday at $3.14, down 23 cents a share.

To reach Steve Everly, call

(816) 234-4455 or send e-mail to severly@kcstar.com.

First glance

Aquila's debt rating, already at junk status, is cut further by Standard and Poor's Ratings.

The company's financial picture has been clouded by an injunction keeping it from spending $504 million in proceeds from the sale of its Canadian utilities.

For more news or to subscribe, please visit http://www.kansascity.com

**Back to News**

Archive for Friday, November 22, 2002

# Aquila announces pay cuts for executives



By The Associated Press
November 22, 2002

KANSAS CITY, MO — The head of Aquila Inc. has told employees that he and other executives will have their pay cut as the company struggles to deal with its growing financial problems.

The latest setback for the former UtiliCorp United came on Tuesday when Standard & Poor's Corp. downgraded its credit rating to junk bond status, which could require it to come up with $238 million in cash.

On Tuesday, CEO Richard Green Jr. told employees about the executive pay cuts and other new steps being taken to reduce expenses.

"Aquila executives will not receive annual or long-term incentives, merit increases or stock options for 2002 performance," Green said.

That means that Green, who got $10 million in salary and bonuses for 2001, will earn about 10 percent of that amount this year. His salary last year was $972,000 and this year is around $990,000, according to company documents.

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