Yukon Energy Corporation

Financial Statements

December 31, 2016

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Financial Statements

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Yukon Energy Corporation
Statement of Financial Position
(in thousands of Canadian dollars)

As at	December 31 2016	December 31 2015
Assets		
Current		
Cash	$ 551	$ 1,672
Accounts receivable (Note 4)	5,873	6,347
Inventories (Note 5)	3,597	3,614
Prepaid expenses	754	828
	10,775	12,461
Non-current		
Property, plant and equipment (Note 6)	444,919	443,194
Intangible assets (Note 7)	7,281	6,992
Total assets	**462,975**	462,647
Regulatory deferral account debit balances (Note 8)	27,880	21,241
Total assets and regulatory deferral account debit balances	**$ 490,855**	$ 483,888
Liabilities		
Current		
Accounts payable and accrued liabilities (Note 10)	$ 8,535	$ 7,310
Construction financing (Note 11)	22,385	23,280
Derivative related liability (Note 24)	409	553
Current portion of long-term debt (Note 12)	5,238	6,066
	36,567	37,209
Non-current		
Post-employment benefits (Note 13)	5,867	5,436
Contributions in aid of construction (Note 14)	172,770	176,540
Decommissioning fund (Note 15)	2,636	2,612
Long-term debt (Note 12)	147,771	140,874
Total liabilities	**365,611**	362,671
Equity		
Share capital		
Authorized: Unlimited number of a single class of shares with no par value		
Issued and fully paid: 3,900 shares	39,000	39,000
Contributed surplus	14,600	14,600
Retained earnings	51,599	46,303
Total equity	**105,199**	99,903
Total liabilities and equity	**470,810**	462,574
Regulatory deferral account credit balances (Note 8)	20,045	21,314
Total liabilities, equity and regulatory deferral account credit balances	**$ 490,855**	$ 483,888

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Commitments and contingencies (Notes 20, 21 and 22)

The accompanying notes are an integral part of these financial statements.

Approved by the Board

____________________________, Chair   ____________________________, Director

Yukon Energy Corporation
Statement of Operations and Other Comprehensive Income
(in thousands of Canadian dollars)

For the year ended December 31	2016	2015
Revenues		
Sales of power (Note 16)	$ 40,013	$ 40,948
Funding from parent (Note 19)	825	6,135
Other	287	383
	41,125	$ 47,466
Operating expenses		
Operations and maintenance (Note 17)	19,322	17,376
Administration (Note 18)	11,358	9,891
Depreciation and amortization (Notes 6 and 7)	11,262	10,438
	41,942	37,705
Income from operations	**(817)**	9,761
Other income		
Allowance for funds used during construction	819	714
Amortization of contributions in aid of construction (Note 14)	4,102	3,624
Interest income	(36)	-
	4,885	4,338
Other expenses		
Interest on borrowings	3,500	3,319
Unrealized loss (gain) on interest rate swap (Note 24)	(144)	340
	3,356	3,659
Net income for the year before net movements in regulatory deferral account balances	**712**	10,440
Net movement in regulatory deferral account balances related to net income (Note 8 (d))	7,908	**(2,725)**
Net income for the year and net movements in regulatory deferral account balances	**8,620**	**7,715**
Other Comprehensive Income (Note 3 (p))		
Item that will be reclassified to financial performance		
Remeasurement of defined benefit pension plans (Note 13)	(483)	512
Total comprehensive income for the year	**$ 8,137**	$ 8,227

The accompanying notes are an integral part of these financial statements.

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Yukon Energy Corporation
Statement of Changes in Equity
(in thousands of Canadian dollars)

	Share Capital Number of shares	Share Capital $	Contributed surplus	Retained earnings	Accumulated other comprehensive income (loss)	Total
Balance at January 1, 2015	**3,900**	**$ 39,000**	**$ 14,600**	**$ 38,076**	**-**	**$ 91,676**
Net income for the year and net movement in regulatory deferral account balances	-	-	-	7,715	-	7,715
Other comprehensive income	-	-	-	-	512	512
Transfer of remeasurement of defined benefit pension plans to retained earnings	-	-	-	512	(512)	-
Balance at December 31, 2015	**3,900**	**$ 39,000**	**$ 14,600**	**$ 46,303**	**-**	**$ 99,903**
Net income for the year and net movement in regulatory deferral account balances	-	-	-	8,620	-	8,620
Other comprehensive income	-	-	-	-	(483)	(431)
Transfer of remeasurement of defined benefit pension plans to retained earnings	-	-	-	(483)	483	-
Dividends	-	-	-	(2,841)	-	(2,841)
Balance at December 31, 2016	**3,900**	**$ 39,000**	**$ 14,600**	**$ 51,599**	**-**	**$ 105,251**

The accompanying notes are an integral part of these financial statements.

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Yukon Energy Corporation
Statement of Cash Flows
(in thousands of Canadian dollars)

For the year ended December 31	**2016**	**2015**
Operating activities		
Cash receipts from customers	$ 41,616	$ 42,072
Cash receipts from parent	-	2,000
Cash receipts from contributions in aid of construction	332	739
Cash paid to suppliers	(12,098)	(16,906)
Cash paid to employees	(11,632)	(11,341)
Interest paid	(3,122)	(3,319)
Cash provided by operating activities	**15,096**	13,245
Financing activities		
Receipt of construction financing	8,400	11,200
Repayment of construction financing	-	(8,400)
Issuance of long-term debt	-	20,984
Repayment of long-term debt	(6,066)	(5,455)
Cash provided by financing activities	**2,334**	18,329
Investing activities		
Additions to property, plant and equipment	(17,241)	(28,024)
Additions to intangible assets	(1,310)	(707)
Cash used in investment activities	**(18,551)**	(28,731)
Net increase (decrease) in cash	(1,121)	2,843
Cash, beginning of year	**1,672**	(1,171)
Cash, end of year	**$ 551**	$ 1,672

Cash includes:		
Cash	$ 551	$ 1,672
Bank indebtedness	-	-
Total	$ 551	$ 1,672

The accompanying notes are an integral part of these financial statements.

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1. NATURE OF OPERATIONS

a) General

Yukon Energy Corporation ("the Utility") is incorporated under the Yukon *Business Corporations Act* and is a wholly-owned subsidiary of Yukon Development Corporation ("YDC" or "the Parent"), a corporation owned by the Yukon Government ("YG" or "the Government"). The Utility generates, transmits, distributes and sells electrical energy in the Yukon. The Utility is not subject to income taxes.

The Utility is subject to overall regulation by the Yukon Utilities Board (YUB) and specific regulation by the Yukon Water Board. Both boards are consolidated by the Government and as such are considered to be related parties for accounting purposes. Management believes these boards operate independently from the Utility from a rate setting and operating perspective.

b) Rate regulation

The operations of the Utility are regulated by the YUB pursuant to the *Public Utilities Act*. There is no minimum requirement for the Utility to appear before the YUB to review rates. However, the Utility is not permitted to charge any rate for the supply of power that is not approved by an Order of the YUB. The Utility is subject to a cost of service regulatory mechanism under which the YUB establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment in rate base. As actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

The regulatory hearing process used to establish or change rates typically begins when the Utility files a General Rate Application (GRA) for its proposed electricity rate changes over the next one or two forecast years. The YUB must ensure that its decision, which fixes electricity rates, complies with appropriate principles of rate making, all relevant legislation including the *Public Utilities Act* and directives issued by the YG through Orders-In-Council ("OIC") that specify how the interests of the customer and Utility are to be balanced.

The YUB typically follows a two-stage decision process. In the first stage, the total costs that the Utility will incur to provide electricity to its customers over the immediate future are reviewed and approved. The approval of these costs determines the total revenues the Utility is allowed to collect from its customers. It is the responsibility of the YUB to examine the legitimacy of three classes of costs:

- the costs to the Utility to run its operations and maintain its equipment (personnel and materials);
- the cost associated with the depreciation of all capital equipment; and
- the return on rate base (the borrowing costs related to borrowing that portion of the rate base which is financed with debt plus the costs to provide a reasonable rate of return on that portion of the rate base which is financed with equity).

The YUB assesses the prudency of costs added to rate base, which includes an allowance for funds used during construction ("AFUDC") charged to capital projects. The YUB also reviews the appropriateness of property, plant and equipment depreciation rates, which are periodically updated by the Utility through depreciation studies.

In the second stage, the YUB approves how the revenue will be raised. This stage essentially determines the electricity rates for the various customer classes in the Yukon: residential, government, commercial and industrial. This process is guided mainly by requirements of OIC 1995/90 and can include a cost-of-service study which allocates the Utility's overall cost of service to the various customer classes on the basis of appropriate costing principles.

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1. NATURE OF OPERATIONS - continued

c) Water regulation
The Yukon Water Board pursuant to the Yukon *Waters Act* decides if and for how long the Utility will have a water license for the purposes of operating hydro generation stations in the Yukon. The licenses will also indicate terms and conditions for the operation of these facilities.

d) Capital structure
The Utility's policy which has been approved by the YUB is to maintain a capital structure of 60% debt and 40% equity (Note 24). Dividends are normally declared annually to the Parent and are typically loaned back in order to maintain this ratio during normal on-going operations. When large assets are purchased or constructed, the Parent may be required to make an equity or capital contribution.

2. BASIS OF PRESENTATION

a) Statement of compliance
These financial statements have been prepared in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board ("IASB").

These financial statements were authorized for issue by the Board of Directors on May XX, 2017.

b) Basis of measurement
The financial information included in the financial statements for the year ended December 31, 2016, and for the related comparative periods, has been prepared under the historical cost basis, except for financial instruments which are measured at fair value. The Utility’s policy for these items is described in Note 3 below.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied to all periods presented in these financial statements.

a) Significant accounting judgments, estimates and assumptions
The preparation of financial statements requires the use of judgment in applying accounting policies and in making critical accounting estimates that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of any contingent assets and liabilities. These judgments and estimates are based on management’s best knowledge of the relevant facts and circumstances, having regard to previous experience, but actual results may differ from the amounts included in the financial statements. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which estimates are revised and in any future periods affected. Information about such judgments and estimates is contained in the accounting policies and/or the Notes to the financial statements, and the key areas are summarized below.

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3. SIGNIFICANT ACCOUNTING POLICIES - continued

a) Significant accounting judgments, estimates and assumptions - continued
The critical judgements made by management in preparing these financial statements include:

Impairment of long-lived assets - Note 3j
An evaluation of whether or not an asset is impaired involves consideration of whether indicators of impairment exist. Management continually monitors the Utility's operations and makes judgements and assessments about conditions and events in order to conclude whether possible impairment exists.

The critical estimates and assumptions utilized in preparing these financial statements include:

Revenue – Note 17
Estimate of the usage not yet billed at year end, which is included in revenues from sale of power. This accrual is based on an assessment of unbilled electricity supplied to customers between the date of the last meter reading and the year end. Management applies judgement to the measurement of the estimated consumption.

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Depreciation and amortization – Note 7 and 8
Significant components of property, plant and equipment are depreciated over their estimated useful lives. Useful lives are determined based on current facts and past experience and employment of experts to perform depreciation studies. While these useful life estimates are reviewed on a regular basis and depreciation calculations are revised accordingly, actual lives may differ from the estimates. As such, assets may continue in use after being fully depreciated, or may be retired or disposed of before being fully depreciated. The latter could result in additional depreciation expense in period of disposition.

Asset retirement obligations – Note 3l
In determining the present value of the obligation, the Utility must estimate the amount and timing of the future cash payments and then apply an appropriate risk-free interest rate. Any changes to the anticipated amounts or timing of future payments or risk-free interest rate can result in a change to the obligation.

Post-employment benefits – Note 14
The Utility accrues for its obligations under defined benefit pension plans using actuarial valuation methods and other assumptions to estimate the projected benefit obligation and the associated expense related to the current period, as well as the return on plan assets. The key assumptions utilized include the long-term rate of inflation, rates of future compensation, liability discount rates and the expected return on plan assets. The Utility consults with qualified actuaries when setting the assumptions used to estimate benefit obligations. Changes in these assumptions give rise to gains and losses which are recognized immediately in other comprehensive income and then are reclassified to retained earnings each year. The obligations are measured by discounting the Utility's future payments under these plans. In addition, actual payments may vary from the estimates used to project the obligations and the net expense.

b) Revenue recognition
All revenues are recognized in the period earned. Revenue from the sale of power is recognized based on cyclical meter readings. Sales of power includes an accrual for electricity deliveries not yet billed at year-end.

3. SIGNIFICANT ACCOUNTING POLICIES - continued

c) Translation of foreign currencies
The functional currency of the Utility is the Canadian Dollar. Revenue and expense items denominated in foreign currencies are translated at exchange rates prevailing during the period. Monetary assets and liabilities denominated in foreign currencies are translated at period-end exchange rates. Non-monetary assets and liabilities are translated at exchange rates in effect when the assets are acquired or the obligations are incurred. Foreign exchange gains and losses are reflected in net income for the period.

d) Allowance for funds used during construction
The cost of the Utility's property, plant and equipment and deferred charges includes an allowance for funds used during construction (AFUDC) as allowed by the regulator. The AFUDC rate is based on the Utility's weighted average cost of debt. The AFUDC capitalized for 2016 was $819,000 (2015 - $714,000). The AFUDC rate estimate was 2.40% for 2016 (2015 - 2.46%).

e) Cash
Cash is comprised of bank account balances (net of outstanding cheques).

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f) Inventories
Inventories consist of materials and supplies, diesel fuel and liquefied natural gas. Inventories are recorded at the lesser of weighted average cost and net realizable value. Cost includes all expenditures incurred in acquiring the items and bringing them to their existing condition and location. Critical spare parts are recorded in the Utility's books as property, plant and equipment.

The recoverable value of inventory considers its net realizable value, including required processing costs, and is impacted by estimates and assumptions on prices, quality, recovery and exchange rates. Obsolete materials and supplies are recorded at salvage value in the period when obsolescence is determined.

g) Financial instruments
Financial assets and financial liabilities are recognized on the Utility’s statement of financial position when the Utility becomes party to the contractual provisions of the instrument. Accounts receivable, classified as loans and receivables, are initially measured at fair value. Subsequent to initial recognition, accounts receivable are measured at amortized cost using the effective interest rate method less any impairment.

A provision for impairment of accounts receivable is established when there is objective evidence that the Utility will not be able to collect all amounts due according to the original terms of the receivables. Significant financial difficulties of the debtor, probability that the debtor will enter into bankruptcy or require financial reorganization, and default or delinquency in payments are considered indicators that the related accounts receivable are impaired. The accounts receivable carrying amount is reduced through the use of an allowance account and the loss is recognized in net income.

Bank indebtedness, accounts payable and accrued liabilities, construction financing and long term debt are classified as other financial liabilities and they are initially recognized at fair value. Subsequent to initial recognition, they are measured at amortized cost using the effective interest rate method (except for bank indebtedness which is measured at cost).

Transaction costs are presented as a reduction from the carrying value of the related debt and are amortized using the effective interest rate method over the terms of the debts to which they relate. Transaction costs include fees paid to agents, brokers and advisors but exclude debt discounts and lender financing costs.

(tabular amounts in thousands of Canadian dollars)

3. SIGNIFICANT ACCOUNTING POLICIES - continued

g) Financial instruments - continued

Derivative financial instruments are financial contracts that derive their value from changes in an underlying variable. The Utility has entered into an interest rate swap to manage interest rate risk. The Utility's interest rate swap is classified as held for trading and is thus recognized at fair value on the date the contract has been entered into with any subsequent realized and unrealized gains and losses recognized in net income during the period in which the fair value movement occurred.

h) Property, plant and equipment

Property, plant and equipment are carried at cost, less accumulated depreciation and any asset impairment charges. Cost includes the direct costs of acquisition and materials, direct labour, and, if applicable, an allocation of directly attributable overhead costs, AFUDC and any asset retirement costs associated with the property, plant and equipment.

AFUDC is based on the Utility's weighted average cost of borrowing and is applied to actual costs in work-in-progress less any contributions in aid of construction. For items of property, plant and equipment acquired prior to January 1, 2011, the AFUDC rate also included a regulatory cost of equity component as allowed by the YUB. Capitalization of AFUDC ceases when the asset being constructed is substantially ready for its intended purpose.

Assets under construction are recorded as in progress until they are operational and available for use, at which time they are transferred to property, plant and equipment.

Depreciation is recognized in net income based on the straight-line method over the estimated useful life of each major component of property, plant and equipment. The range of the estimated useful lives of the major classes and subclasses of property, plant and equipment is as follows:

Generation	
Hydroelectric plants	30 to 103 years
Thermal plants	12 to 72 years
Wind turbines	30 years
Transmission	20 to 65 years
Distribution	12 to 55 years
Buildings	20 to 55 years
Transportation	9 to 31 years
Other equipment	5 to 20 years

Depreciation commences when an asset is available for use. The estimated useful lives of the assets are based upon depreciation studies conducted periodically by the Utility and any changes in the estimated useful lives are accounted for prospectively.

Gains and losses on the disposal or retirement of property, plant and equipment, with the exception of land and vehicles, are deferred and amortized over the remaining expected useful life of the related assets under regulatory accounting (Note 8). These gains and losses are recognized immediately in net income under IFRS.

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3. SIGNIFICANT ACCOUNTING POLICIES - continued

h) Property, plant and equipment - continued

Major overhaul costs are capitalized and depreciated on a straight-line basis over the period of the expected useful life (until the next major overhaul) which varies from 5 to 10 years. However, major overhaul costs cannot be depreciated for regulatory purposes until the costs are approved by the YUB (Note 8). Repairs and maintenance costs of property plant and equipment are expensed as incurred unless they meet the criteria of a betterment.

i) Intangible assets

Intangible assets are carried at cost less accumulated amortization and any asset impairment charges. Cost includes the direct costs of acquisition and materials, direct labour, and, if applicable, an allocation of directly attributable overhead costs and AFUDC.

Amortization is recognized in net income on a straight-line basis over the estimated useful lives as follows:

Software	5 years
Financial software	10 years
Deferred customer service costs	12 years
Licencing costs	
Hydro generation	17 to 25 years
Diesel generation	3 years

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j) Impairment of non-financial and financial assets

Property, plant and equipment, regulatory deferral debit balances and intangible assets with finite lives are reviewed for impairment on an annual basis if there is an indication that the carrying amount may not be recoverable. Impairment is assessed at the level of cash-generating units, which are identified as the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or group of assets.

When an impairment review is undertaken, the recoverable amount is assessed by reference to the higher of value in use and fair value less costs to sell ("FVLCS") for non-financial assets and objective evidence of impairment in the case of financial assets. Value in use is the net present value of expected future cash flows of the relevant cash-generating unit in its current condition. The best evidence of FVLCS is the value obtained from an active market or binding sale agreement. Where neither exists, FVLCS is based on the best information available to reflect the amount the Utility could receive for the cash generating unit in an arm's length transaction. This is often estimated using discounted cash flow techniques and where unobservable inputs are material to the measurement of the recoverable amount, the measurement is classified as level 3 in the fair value hierarchy. The cash flow forecasts for FVLCS purposes are based on management's best estimates of expected future revenues and costs, including the future cash costs of production, capital expenditure, closure, restoration and environmental cleanup. For regulatory deferral debit balances the impairment review focuses on whether the amount is considered collectible based on the expected cash flows from the rates approved by the YUB.

These determinations and their individual assumptions require that management make a decision based on the best available information at each reporting period. Changes in these assumptions may alter the results of non-financial asset and financial asset impairment testing, impairment charges recognized in net income and the resulting carrying amounts of the assets.

3. SIGNIFICANT ACCOUNTING POLICIES - continued

k) Rate regulated accounting policies
Regulatory deferral accounts
Regulatory deferral accounts in these financial statements are accounted for differently than they would be in the absence of rate regulation. Where regulatory decisions dictate, the Utility defers certain costs or revenues as regulatory deferral account debit balances or regulatory deferral account credit balances on the statement of financial position and recognizes them in the net movement in regulatory deferral account balances in the statement of operations and other comprehensive income as it collects or refunds amounts through future customer rates. Any adjustments to these regulatory deferral accounts are recognized in the net movement in regulatory deferral account balances in the period that the YUB renders a subsequent decision. All amounts maintained as regulatory deferral account debit balances and regulatory deferral account credit balances are expected to be recovered or settled and are assessed on a yearly basis by comparing the rates approved by the YUB to the current balances. The recovery or settlement of regulatory deferral account balances through future rates is impacted by demand risk and regulatory risks (e.g. potential future decisions of the YUB which could result in material adjustments to these regulatory deferral account debit balances and regulatory deferral account credit balances as described in Note 1(b)).

i) Regulatory deferral account debit balances
Regulatory deferral account debit balances represent incurred costs which have been deferred and are recognized or being amortized over various periods as approved by the YUB. Regulatory deferral account debit balances represent costs which are expected to be recovered from customers in future periods through the rate-setting process. In the absence of rate regulation and the Utility's adoption of IFRS 14 (see Note 2(c)), such costs would be expensed as incurred.

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ii) Regulatory deferral account credit balances
Regulatory deferral account credit balances represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers as a result of the rate setting process. In the absence of rate regulation and the Utility's adoption of IFRS 14, such amounts would be recorded in income as earned.

Note 8 describes the individual regulatory deferral accounts, the Utility's related regulatory deferral and amortization policies and describes the related account activity in the relevant periods.

l) Provision for asset retirement obligations
The Utility has legal obligations related to the closure and restoration of property, plant and equipment, which includes the costs of dismantling, demolition of infrastructure and the removal of residual materials and remediation of the disturbed areas.

Where a reliable estimate of the present value of these obligations can be determined, the total retirement costs are recorded as a provision in the accounting period when the obligation arises. There is also a corresponding increase to property, plant and equipment upon recognition of the obligation. Management estimates its costs based on feasibility and engineering studies and assessments using current restoration standards and techniques.

3. SIGNIFICANT ACCOUNTING POLICIES - continued

m) Provision for environmental liabilities
Environmental liabilities consist of the estimated costs related to the remediation of environmentally contaminated sites. The Utility will accrue a provision when it has a present obligation as a result of a past event to remediate the contaminated site, it is expected that future economic benefits will be given up to settle the obligation, and a reliable estimate of the amount of the obligation can be made.

If the likelihood of the Utility's obligation to incur these costs is either not determinable or the amount of the obligation cannot be reliably estimated, the contingency is disclosed in the notes to the financial statements.

The Utility reviews its provision for environmental liabilities on an ongoing basis and any changes are recognized in net income for the current period.

The Utility does not have a provision for environmental liabilities as there is no present obligation to remediate.

n) Contributions in aid of construction
Certain property, plant and equipment additions are made with the assistance of cash contributions from customers or capital assistance from the Utility's Parent, the YG, or the Government of Canada. These contributions are deferred upon receipt and amortized to income on the same basis as the assets to which they relate.

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o) Decommissioning fund
The decommissioning fund represents monies paid in advance by an industrial customer to decommission the spur line that connects their operation to the Utility's grid. Under a power purchase agreement, the customer has the financial responsibility for decommissioning expenses to be performed by the Utility on its behalf. Any amounts not required for decommissioning will be refunded to the customer. This money accrues interest at the rate equal to the three month Canadian Dealer Offered Rate ("CDOR").

p) Post-employment benefits and other comprehensive income
The Utility sponsors an employee defined benefit pension plan which provides benefits based on the length of service and average salaries for the five highest paid consecutive years of service. Effective January 1, 2011, the Utility also sponsors an executive defined benefit pension plan and supplemental executive retirement plan. The Utility contributes amounts to the pension plans as recommended by an independent actuary.

For the defined benefit plan the cost of pension benefits is actuarially determined using the projected benefits method, prorated on service, and reflects management's best estimates of investment returns, wage and salary increases, and age at retirement. Remeasurements of the net defined benefit liability, including actuarial gains and losses and return on plan assets, are recognized in other comprehensive income ("OCI") and are not reclassified to net income in a subsequent period. The Utility's policy is to immediately transfer actuarial gains and losses recognized in OCI to retained earnings. The expected return on plan assets is based on the fair value of these assets.

3. SIGNIFICANT ACCOUNTING POLICIES - continued

p) Post-employment benefits and other comprehensive income - continued
Employees joining the Utility after January 1, 2002 are eligible for a defined contribution retirement plan and are not eligible to participate in the defined benefit pension plan. Contributions are required by both employees and the Utility to cover the current service cost of this defined contribution retirement plan. The Utility has no legal or constructive obligation to pay further contributions with respect to this plan. Consequently, contributions are recognized as an expense in the year when employees have rendered service and represents the obligation of the Utility.

q) New standards and interpretations not yet adopted
A number of new standards, and amendments to standards and interpretations, are not yet effective for the period ended December 31, 2015, and have not been applied in preparing these financial statements. None of these is expected to have a significant effect on the financial statements of the Utility, except for:

i) IFRS 9, *Financial Instruments,* which will replace IAS 39, Financial Instruments: Recognition and Measurement and IFRIC 9, Reassessment of Embedded Derivatives. The new standard is effective for fiscal years beginning on or after January 1, 2018 and is available for early adoption. The standard is expected to impact the classification and measurement of financial assets, introduce changes to financial liabilities and includes new hedge accounting requirements. The Utility intends to adopt IFRS 9 in its financial statements for the annual period beginning on January 1, 2018. The extent of the impact of adoption of the standard has not yet been determined.

ii) On May 28, 2014, the IASB issued IFRS 15, *Revenue from Contracts with Customers*, which will replace IAS 18, *Revenue*. The new standard is effective for fiscal years beginning on or after January 1, 2018 and is available for early adoption. The standard contains a single model that applies to contracts with customers and two approaches to recognising revenue: at a point in time or over time. The model features a contract based five step analysis of transactions to determine whether, how much and when revenue is recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and/or timing of revenue recognized. The Utility intends to adopt IFRS 15 in its financial statements for the annual period beginning on January 1, 2018. The extent of the impact of adoption of the standard has not yet been determined.

iii) IFRS 16, Leases, specifies how to recognize, measure, present and disclose leases. The standard provides a single lessee model, requiring lessees to recognize assets and liabilities for all leases unless the lease term is 12 months or less or the underlying asset has a low value. Lessors continue to classify leases as operating or finance, with IFRS 16's approach to lessor accounting substantially unchanged from its predecessor, IAS 17. This standard will become effective for annual periods beginning on or after January 1, 2019. The Utility is currently assessing the potential impact on its financial statements.

(tabular amounts in thousands of Canadian dollars)

4. ACCOUNTS RECEIVABLE

	December 31 2016	December 31 2015
Wholesale energy sales	$ 3,734	$ 3,549
Retail energy sales	1,494	1,321
Due from related parties (Note 19)	112	850
Other	533	627
	$ 5,873	$ 6,347

At December 31, 2016, the aging of accounts receivable is as follows:

	Current	31 - 90 Days	Over 90 Days	Total
Accounts receivable	$ 5,616	$ 232	$ 35	$ 5,883
Allowance for doubtful accounts			(10)	(10)
	$ 5,616	$ 232	$ 25	$ 5,873

At December 31, 2015, the aging of accounts receivable is as follows:

	Current	31 - 90 Days	Over 90 Days	Total
Accounts receivable	$ 5,680	$ 192	$ 485	$ 6,357
Allowance for doubtful accounts			(10)	(10)
	$ 5,680	$ 192	$ 475	$ 6,347

A reconciliation of the beginning and ending amount of allowance for doubtful accounts is as follows:

	December 31 2016	December 31 2015
Allowance for doubtful accounts at beginning of year	$ (10)	$ (10)
Amounts written off as uncollectable	-	-
Allowance for doubtful accounts at end of year	$ (10)	$ (10)

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(tabular amounts in thousands of Canadian dollars)

5. INVENTORIES

	December 31 2016	December 31 2015
Materials and supplies	$ 3,087	$ 3,105
Diesel fuel	299	333
Liquefied natural gas	211	176
	$ 3,597	$ 3,614

The amount of inventory expensed during the year is $667,000 (2015 - $781,000) for fuel as disclosed in note 17 and $75,000 (2015 - $75,000) for materials and supplies.

6. PROPERTY, PLANT AND EQUIPMENT

A reconciliation of the changes in the carrying amount of property, plant and equipment is as follows:

	Generation	Transmission & Distribution	Land & Buildings	Transportation & Other	Construction Work-in Progress	Total
Cost:						
At January 1, 2015	230,695	144,586	13,939	3,234	47,951	440,405
Additions	-	-	-	-	22,255	22,255
Transfers	44,519	15,908	1,913	359	(62,699)	-
Disposals	(22)	-	-	(112)	-	(134)
At December 31, 2015	$ 275,192	$ 160,494	$ 15,852	$ 3,481	$ 7,507	$ 462,526
Additions	-	-	-	-	12,834	12,834
Transfers	2,823	3,076	1,020	784	(7,703)	-
Disposals	-	-	(635)	(311)	-	(946)
At December 31, 2016	$ 278,015	$ 163,570	$ 16,237	$ 3,954	$ 12,638	$ 474,414
Accumulated depreciation:						
At January 1, 2015	4,112	3,962	776	269	-	9,119
Depreciation*	4,903	4,248	812	290	-	10,253
Disposals	(1)	-	-	(39)	-	(40)
At December 31, 2015	$ 9,014	$ 8,210	$ 1,588	$ 520	$ -	$ 19,332
Depreciation	5,283	4,628	847	285	-	11,043
Disposals	-	-	(635)	(245)	-	(880)
At December 31, 2016	$ 14,297	$ 12,838	$ 1,800	$ 560	$ -	$ 29,495
Net book value:						
At December 31, 2015	$ 266,178	$ 152,284	$ 14,264	$ 2,961	$ 7,507	$ 443,194
At December 31, 2016	$ 263,718	$ 150,732	$ 14,437	$ 3,394	$ 12,638	$ 444,919

* Included in generation depreciation is the annual depreciation for overhauls of $805,000 (2015 - $778,000) which is recorded in regulatory account expenses in Note 17.

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(tabular amounts in thousands of Canadian dollars)

7. INTANGIBLE ASSETS

A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Software	Deferred Customer Service Costs	Financial Software	Aishihik Licensing	Other Licensing	Total
Cost:						
At January 1, 2015	112	443	2,406	2,991	2,210	8,162
Additions	281	-	-	51	306	638
Acquisitions	69	-	-	-	-	69
Disposals	-	-	-	(10)	-	(10)
At December 31, 2015	$ 462	$ 443	$ 2,406	3,032	$ 2,516	$ 8,859
Additions	66	-	-	955	297	1,318
Acquisitions	-	-	-	-	-	-
Amortization	-	-	-	-	-	-
Disposals	(8)	-	-	-	-	(8)
At December 31, 2016	520	443	2,406	3,987	2,813	10,169
Accumulated amortization:						
At January 1, 2015	28	64	284	524	14	914
Amortization	33	64	284	524	58	963
Disposals	-	-	-	(10)	-	(10)
At December 31, 2015	$ 61	$ 128	$ 568	$ 1,038	$ 72	$ 1,867
Amortization	92	64	283	524	58	1,021
Disposals	-	-	-	-	-	-
At December 31, 2016	153	192	851	1,562	130	2,888
Net book value:						
At December 31, 2015	401	315	1,838	1,994	2,444	6,992
At December 31, 2016	367	251	1,555	2,425	2,683	7,281

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The internally generated costs and externally purchased costs included in these categories software, deferred customer service costs, financial software, Aishihik licensing and other licensing are approximately 50% internal and 50% external at December 31, 2016 and December 31, 2015.

(tabular amounts in thousands of Canadian dollars)

8. REGULATORY ACCOUNTS

Regulatory deferral account debit balances

	Feasibility Studies (i)	IFRS Planning (ii)	Regulatory Costs (iii)	Vegetation Management (iv)	Dam Safety (v)	Uninsured Losses (vi)	Total
Cost:							
At January 1, 2015	20,794	566	4,144	917	332	300	27,053
Costs incurred	4,110	-	343	1,229	144	193	6,019
Regulatory provision	-	-	-	(502)	-	(226)	(728)
Disposals	(183)	-	-	-	(332)	-	(515)
Contribution received	(6,166)	-	(127)	-	-	-	(6,293)
At December 31, 2015	18,555	566	4,360	1,644	144	267	25,536
Costs incurred	4,872	-	695	1,074	4	1,018	7,663
Regulatory provision	-	-	-	(502)	-	(226)	(728)
Disposals	-	-	(794)	-	-	-	(794)
Contributions received	(828)	-	(1)	-	-	-	(829)
At December 31, 2016	22,599	566	4,260	2,216	148	1,059	30,848
Accumulated amortization:							
At January 1, 2015	3,342	339	1,099	-	308	-	5,088
Amortization	1,185	114	246	-	24	-	1,569
Disposals	(183)	-	-	-	(332)	-	(515)
At December 31, 2015	4,344	453	1,345	-	-	-	6,142
Amortization	25	113	248	-	-	-	386
Disposals/Retirement	-	-	(794)	-	-	-	(794)
At December 31, 2016	4,369	566	799	-	-	-	5,734
Net book value:							
At December 31, 2015	14,211	113	3,015	1,644	144	267	19,394
At December 31, 2016	18,230	-	3,461	2,216	148	1,059	25,114

Net increase (decrease) in regulatory deferral account debit balances (which are recognized in the net movement of regulatory deferral account balances related to net income on the statement of operations and other comprehensive income):

	Feasibility Studies (i)	IFRS Planning (ii)	Regulatory Costs (iii)	Vegetation Management (iv)	Dam Safety (v)	Uninsured Losses (vi)	Total
December 31, 2015	(3,241)	(114)	(30)	727	120	(33)	(2,571)
December 31, 2016	4,019	(113)	446	572	4	792	5,720
Remaining recovery years							
At December 31, 2015	5 to 10 years	1 year	10 to 45 years	Indeterminate	5 years	Indeterminate	-
At December 31, 2016	5 to 10 years	0 years	10 to 45 years	Indeterminate	4 years	Indeterminate	
Absent rate regulation, net income would increase (decrease) by:							
December 31, 2015	3,241	114	30	(727)	(120)	33	2,571
December 31, 2016	(4,019)	113	(446)	(572)	(4)	(792)	(5,720)

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(tabular amounts in thousands of Canadian dollars)

8. REGULATORY ACCOUNTS - continued

	Carry Forward	Deferred Overhauls (vii)	Fuel Price Adjustment (viii)	Deferred Gains And losses (ix)	Total
Cost:					
At January 1, 2015	27,053	943	19	-	28,015
Cost incurred	6,019	900	-	-	6,919
Regulatory provision	(728)	-	-	-	(728)
Disposals	(515)	-	-	-	(515)
Contributions received	(6,293)	-	(15)	-	(6,308)
At December 31, 2015	25,536	1,843	4	-	27,383
Cost incurred	7,663	925	-	-	8,588
Regulatory provision	(728)	-	-	-	(728)
Disposals	(794)	-	-	-	-
Contributions received	(829)	-	(6)	-	(835)
At December 31, 2016	30,848	2,768	(2)	-	34,408
Accumulated amortization:					
At January 1, 2015	5,088	-	-	-	5,088
Amortization	1,569	-	-	-	1,569
Disposals	(515)	-	-	-	(515)
At December 31, 2015	6,142	-	-	-	6,142
Amortization	386	-	-	-	386
Disposals	(794)	-	-	-	-
At December 31, 2016	5,734	-	-	-	6,528
Net book value:					
At December 31, 2015	19,394	1,843	4	-	21,241
At December 31, 2016	25,114	2,768	(2)	-	27,880
Net increase (decrease) in regulatory deferral account debit balances (which are recognized in the net movement of regulatory deferral account balances on the statement of operations and other comprehensive income):					
December 31, 2015	(2,571)	900	(15)	-	(1,686)
December 31. 2016	5,720	925	(6)	-	6,639
Remaining recovery years					
At December 31, 2015		Indeterminate	1 year		
At December 31, 2016		Indeterminate	1 year		
Absent rate regulation, Net Income would increase (decrease) by:					
December 31, 2015	2,571	(900)	15	-	1,686
December 31, 2016	(5,720)	(925)	6	-	(6,639)

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(a) Regulatory deferral account debit balances

(i) Feasibility studies and infrastructure planning

The Utility undertakes certain studies to determine the feasibility of a range of projects and infrastructure proposals. While in progress, the costs of these studies are deferred within this account. Once the study is completed, the costs are amortized over a prescribed number of years ranging between five and ten years under regulatory reporting. In absence of rate regulation, IFRS would require these costs to be expensed as incurred.

(ii) IFRS planning

These deferred costs are associated with the conversion from previous GAAP to IFRS and are amortized over a term of 5 years. In absence of rate regulation, IFRS would require these costs to be expensed as incurred.

8. **REGULATORY ACCOUNTS - continued**

(iii) Regulatory costs
These costs are associated with the YUB regulatory proceedings. The costs consist primarily of various rate and project review proceedings but also include resource plans, hearing costs from before 2012 and demand side management costs. The Utility is directed to defer and amortize the costs over terms at the discretion of the YUB. In the absence of rate regulation, IFRS would require these costs to be expensed as incurred.

(iv) Vegetation management
These deferred costs are annual brushing costs in excess of the maximum annual amount approved by the YUB. Amortization of these costs has not yet been approved. In the absence of rate regulation, IFRS would require these costs to be expensed as incurred.

(v) Dam safety review
The Utility has a program of conducting safety reviews of its dams in accordance with standards set by the Canadian Dam Association. External consultants are hired every five years with intermittent costs incurred in the interim periods. These costs are being amortized over five years as approved by the YUB. In the absence of rate regulation, IFRS would require these costs to be expensed as incurred.

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(vi) Uninsured losses
The YUB has approved the use of a deferral account for uninsured damages and injuries as a means of self-insurance. The account is maintained through an annual provision approved by the YUB and collected through customer rates. Variances between the approved annual provision and actual costs incurred are deferred until the following GRA or until a specific application is made to the YUB requesting recovery from or refund to customers. In the absence of rate regulation, IFRS would require these costs to be expensed as incurred.

vii) Deferred overhauls
Overhauls represent costs incurred to overhaul engines that are used in operations and these overhauls are recorded as property, plant and equipment. The Utility was directed by YUB Order 2013-01 to defer all overhaul costs incurred after 2011 until the Utility comes before the YUB for a prudence review and the costs are approved to be depreciated. IFRS requires these completed overhauls to be considered in service and they should be depreciated through net income. In addition, IFRS also requires that AFUDC would cease when the overhaul is substantially ready for its intended purpose. As a result the AFUDC capitalized on these completed overhauls of $119,000 (2015 - $122,000) and the associated depreciation on these overhauls of $805,000 (2015 - $778,000) are shown as a regulatory deferral account debit balance. The opening balance on transition was $259,000 at January 1, 2014,

(viii) Fuel price adjustment
OIC 1995/90 directs the YUB to permit the Utility to adjust electricity rates to reflect fluctuations in the price of diesel fuel. The amount by which actual fuel prices vary from the YUB approved rates is deferred and recovered from or refunded to customers in a future period. In the absence of rate regulation, IFRS would require these costs to be expensed as incurred.

(ix) Deferred gains and losses
Deferred gains and losses represent amounts from disposals of property plant and equipment. There are no deferred gains or losses during any of the reporting years.

(tabular amounts in thousands of Canadian dollars)

8. REGULATORY ACCOUNTS - continued

Regulatory deferral account credit balances

	Deferred Insurance Proceeds (i)	Hearing reserve (ii)	Diesel Contingency Fund (iii)	Future removal and site Restoration (iv)	Total
Cost:					
At January 1, 2015	11,602	224	9,627	4,671	26,124
Cost incurred	-	(213)	-	(304)	(517)
Regulatory provision	-	550	-	-	550
Cash received	-	-	2,027	-	2,027
Cash refunded	-	-	(759)	-	(759)
At December 31, 2015	11,602	561	10,895	4,367	27,425
Cost incurred	-	(138)	-	(8)	(146)
Regulatory provision	-	550	-	-	550
Cash received	-	-	-	-	-
Cash refunded	-	-	(1,410)	-	(1,410)
At December 31, 2016	11,602	973	9,485	4,359	26,419
Accumulated amortization:					
At January 1, 2015	5,849	-	-	-	5,849
Amortization	262	-	-	-	262
Disposals	-	-	-	-	-
At December 31, 2015	6,111	-	-	-	6,111
Amortization	263	-	-	-	263
Disposals	-	-	-	-	-
At December 31, 2016	6,374	-	-	-	6,374
Net book value					
At December 31, 2015	5,491	561	10,895	4,367	21,314
At December 31, 2016	5,228	973	9,485	4,359	20,045

Net (increase) decrease in regulatory deferral account credit balances (which are recognized in the net movement of regulatory deferral account balances related to net income on the statement of operations and other comprehensive income):

	Deferred Insurance Proceeds (i)	Hearing reserve (ii)	Diesel Contingency Fund (iii)	Future removal and site Restoration (iv)	Total
December 31, 2015	262	(337)	(1,268)	304	(1,039)
December 31, 2016	263	(412)	1,410	8	1,269
Remaining recovery years					
At December 31, 2015	21 years	Indeterminate	Indeterminate	Indeterminate	
At December 31, 2016		Indeterminate	Indeterminate	Indeterminate	
Absent rate regulation, net income would increase (decrease) by:					
December 31, 2015	(262)	337	1,268	(304)	1,039
December 31. 2016	(263)	412	(1,410)	(8)	(1,269)

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8. REGULATORY ACCOUNTS - continued

(b) Regulatory deferral account credit balances

(i) Deferred insurance proceeds
The deferred insurance proceeds represents a gain on fire insurance proceeds related to a fire at the Whitehorse Rapids Generating Station in 1997 which, pursuant to YUB Order 2000-3, is being amortized to income at the same rate as depreciation of the related replacement assets. In the absence of rate regulation, IFRS would have required the gain to have been fully recognized as income in the year received.

(ii) Hearing reserve
Pursuant to YUB Order 2013-01, the Utility has established a deferral account for future regulatory hearing costs. A provision is made for $550,000 of hearing costs each year. Actual hearing costs will be applied to this regulatory deferral account. Variances between the annual provision and actual costs are deferred until the following GRA or until a specific application is make to the YUB requesting recover or a refund to customers. In the absence of rate regulation, IFRS would require hearing costs to be expensed as incurred.

(iii) Diesel Contingency Fund and Energy Reconciliation Adjustment
The Diesel Contingency Fund ("DCF") was established by YUB Order 1996-6 through the negotiated settlement process. The DCF is used to reimburse the Utility for costs associated with diesel generation required when there is a diesel cost variance due solely to water-related hydro and wind generation variances from YUB approved GRA forecasts. The DCF attracts interest based upon short/intermediate term bond rates. Any negative balance attracts interest at the lowest short-term bond rates available to the Utility through its line of credit. The Utility is required to file quarterly reports with the YUB on the DCF's activity.

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As part of the 2012/13 GRA, the Utility filed for changes to the DCF and Energy Reconciliation Adjustment ("ERA") provisions of the Wholesale Primary Rate Schedule. The YUB deferred a decision on these two issues pending further consultation with affected utilities and a separate proceeding to review the impacts of proposed changes. In January 2014, the Utility filed an application to revise the DCF and ERA with the YUB. A decision was delivered February 6, 2015. In accordance with YUB Order 2015-01, the Utility defers recognition of the additional amounts collected from rate payers when the cost of diesel consumed in the period is less than the long-term average diesel requirements estimated for the actual annual generation load. These deferred revenues are recognized as revenue in the period when the cost of diesel fuel incurred for the period is greater than the long-term average diesel requirements and the reason for the shortfall is a shortage of water in the hydro system. The YUB has set a cap of +/- $8 million for the DCF. If the balance falls outside of this range, the Utility is to make an application to the YUB requesting recovery or a refund to customers. In accordance with YUB Order 2015-06, the Utility is providing a refund to the customers of 0.68 cents/kWh effective September 1, 2015.

In the 2012/13 GRA, the Utility applied to reactivate the Energy Reconciliation Adjustment provision in the Wholesale Primary Rate Schedule. In YUB Order 2015-06, the YUB rejected the proposal and as a result the Utility eliminated the ERA balances in accounts receivable and accounts payable for the years ended December 31, 2015 and 2014.

In the absence of rate regulation, IFRS would require any amounts earned or incurred related to the DCF to be included in the Utility's net income in the year incurred.

8. REGULATORY ACCOUNTS - continued

(iv) Future removal and site restoration costs

The Utility maintains a regulatory provision for future removal and site restoration related to property plant and equipment, which is incremental to that required to be recognized as an asset retirement provision under IAS 37. The reserve has been established through amortization rates approved by the YUB. The amortization rates supporting the provision are based upon depreciation studies conducted periodically by the Utility. As a result of the YUB Order 2005-12, effective January 1, 2005, the provision is not to exceed the cumulative value of the provision at December 31, 2004 of $5,757,000. YUB Order 2005-12 also directs the Utility to notify interveners and interested parties when the balance of the provision reaches $2,000,000.

Costs of dismantling capital assets, including site remediation, will be applied to this regulatory deferral account credit balance if they do not otherwise relate to an asset retirement provision. The period over which the provision will be reduced is dependent on the timing of future costs of demolishing, dismantling, tearing down, site restoration or otherwise disposing of the asset net of actual recoveries, and is therefore indeterminate. In the absence of rate regulation, IFRS would require these costs to be expensed or included in the gain or loss on disposal of the related property, plant and equipment, as applicable.

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(c) Regulatory account expenses

Regulatory account expenses represent costs incurred related to regulatory account debit balances of $8,588,000 (2015 - $6,919,000) and regulatory account credit balances of $146,000 (2015 - $517,000). Total regulatory expenses were $8,734,000 (2015 - $7,436,000) and all these amounts were paid during the year.

(d) Net movement in regulatory deferral account balances related to net income

Net movement in regulatory deferral account balances related to net income is $7,908,000 (2015 – $(2,725,000)) represents the adjustment to the net income for the year before net movement in regulatory deferral account balances for the effects of rate regulation in accordance with IFRS 14. The net movement figure of $7,904,000 is comprised of higher net income of $6,639,000 and $1,269,000 for both regulatory account debit balances and regulatory account credit balances for rate regulation compared to the amounts that would be recorded under IFRS. The net movement figure of $(2,725,000) for 2015 is comprised of lower net income of $(1,686,000) and $(1,039,000) for both regulatory account debit balances and regulatory account credit balances for rate regulation compared to the amounts that would be recorded under IFRS. The net movement figure of $1,456,000 for 2014 is comprised of the higher net income of $2,741,000 for the regulatory debit balances which is partially offset by lower net income of $(1,285,000) for regulatory account credit balances.

9. BANK INDEBTEDNESS

The Utility has a $10 million unsecured line of credit that accrues interest on withdrawals at prime minus 0.75%. No commitment fees are payable on the unused portion of the line. At December 31, 2016, the outstanding balance under the line of credit was $2,229,000 (2015 - $125,000).

(tabular amounts in thousands of Canadian dollars)

10. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	December 31 2016	December 31 2015
Trade payables	$ 6,870	$ 5,763
Employee compensation	994	885
Due to related parties (Note 19)	468	433
Other	209	229
	$ 8,541	$ 7,310

11. CONSTRUCTION FINANCING

	December 31 2016	December 31 2015
Construction financing due December 31, 2016, bearing interest at 1.03% approved to a maximum of $25 million	$ -	$ 14,880
Construction financing, due December 31, 2016 bearing interest at 1.03% approved to a maximum of $8.4 million	-	8,400
Construction financing, due December 31, 2017 bearing interest at 1.33% approved to a maximum of $8.4 million	8,400	-
Construction financing, due December 31, 2017 bearing interest at 1.40% approved to a maximum of $14 million	13,985	-
	$ 22,385	$ 23,280
Less current portion	22,385	23,280
	$ -	$ -

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Construction financing balances are monies advanced from the Parent to assist in the development of the Utility's infrastructure and generally are repayable within one year. Interest is payable annually at December 31 and at the maturity date.

On August 9, 2016, the Utility entered into an agreement with YDC for up to $8,400,000, bearing interest equal to the one-year Canadian Dealer Offered Rate set on July 31, 2016, plus 20 basis points, maturing December 31, 2017.

On December 31, 2016, the Utility entered into an agreement with YDC to convert $9,295,000 of existing construction financing with YDC into long-term debt (see Note 12). The $9,295,000 was converted from the $14,880,000 outstanding in the $25 million agreement.

On December 31, 2016, the Utility entered into an agreement with YDC for up to $14,000,000, bearing interest equal to the one-year Canadian Dealer Offered Rate set on December 31, 2016, plus 20 basis points, maturing December 31, 2017. The actual amount borrowed at December 31, 2016 was $13,985,000. The proceeds of the new agreement were from the remaining $5,585,000 of the $25 million agreement and the $8,400,000 of the $8.4 million agreement expiring December 31, 2016.

(tabular amounts in thousands of Canadian dollars)

12. LONG-TERM DEBT

The Utility's long-term debt is summarized as follows:

	December 31 2016	December 31 2015
Yukon Development Corporation		
$92,458,473 term note bearing interest at 2.40% repayable in annual installments of $3,683,800 principal, plus accrued interest with the balance of $77,726,473 due December 31, 2019 (i)	$ 85,091	$ 88,775
$21,900,000 flexible term note bearing interest up to 5.46% repayable in annual installments of $336,923 principal, plus accrued interest with the balance of $8,423,078 due December 31, 2051 (ii)	20,215	20,552
$5,505,000 term note bearing interest at 2.40% interest only payable annually, due December 31, 2039	5,505	5,505
$20,984,404 term note bearing interest at 2.21% repayable in annual installments of $839,376 principal, plus accrued interest with the balance due December 31, 2040	20,145	20,984
$12,136,000 term note bearing interest at 2.10% interest only payable annually, due December 31, 2041	12,136	-
TD Bank		
$12,400,000 term note bearing interest at 4.02% payable in monthly installments of $94,406 interest and principal, with the balance due September 30, 2016.The note is guaranteed by the Yukon Government.	-	837
The Utility entered into an interest rate swap to convert the interest rate on the Bankers' Acceptances amounts from a variable interest rate based on the Bankers' Acceptances rates to a fixed rate of 2.69% per annum. Payable in monthly installments of $50,407 interest and principal with the balance due on December 28, 2022 (iii)	9,697	10,036
Carmacks Stewart First Nation Liability		
Long-term liability payable to several First Nations related to the building of the Carmacks Stewart Transmission Line. These are non interest bearing, repayable in varying installments, due in 2028	221	251
	153,010	146,940
Less current portion	5,238	6,066
	$ 147,772	$ 140,874

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(tabular amounts in thousands of Canadian dollars)

12. LONG-TERM DEBT - continued

(i) Debt Refinancing
The Utility entered into an agreement with YDC on January 1, 2015 (approved April 16, 2015) to renegotiate terms of all outstanding debt, excluding the $20,889,000 term note related to the Mayo Hydro Enhancement Project due December 31, 2051 and the $5,505,000 term note due December 31, 2039. The amount of the new restructuring is $92,458,473. The term of the new loan is until December 31, 2019 with interest payable at 2.40%. Interest on the loan is payable on the last business day of each month. The Utility will pay $3,683,000 against the outstanding principal annually on December 31 starting on December 31, 2015. The Utility will repay the outstanding principal balance in full by December 31, 2019, unless the parties negotiate alternative repayment.

(ii) $21,900,000 Flexible Term Note
The terms of the flexible term note provide for a maximum amount of interest payable within a calendar year, calculated based on the actual grid generation on the electrical grid system connected with the Mayo Hydro Enhancement Project. The amount of interest payable as a result of the interest rate exceeding the maximum interest payable will abate forever. The actual interest rate on this flexible note was 0.81% (2015 - 0.61%).

(iii) TD Bank Loan and Interest Rate Swap
On December 28, 2012, the Utility entered into a loan and interest rate swap with TD Bank to arrange financing for the purpose of continuing to develop the electrical infrastructure in the Yukon. The interest rate swap matures December 28, 2022.

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Long-term debt repayment
Scheduled repayments for all long-term debt are as follows:

2017	$ 5,245
2018	5,255
2019	79,284
2020	1,571
2021	1,564
Thereafter	60,091
	$ 153,010

Fair value
The fair value of long-term debt at December 31, 2016 is $152 million (2015 - $149 million). The fair value for all long-term debt including current portions was estimated using discounted cash flows based on an estimate of the Utility's current borrowing rate for similar borrowing arrangements.

13. POST-EMPLOYMENT BENEFITS

Characteristics of benefit plans
The Utility sponsors a defined benefit plan for employees joining the Utility before January 1, 2002 and a pension plan for a former executive. Benefits provided are calculated based on length of pensionable service, pensionable salary at retirement age and negotiated rates.

Employees joining the Utility after January 1, 2002 are not eligible to participate in the employee defined benefit plan. The Utility makes contributions to a Registered Retirement Savings Plan (“RRSP”) on behalf of these employees and employees hired before January 1, 2002 who belonged to the employee defined benefit plan and elected to opt out of that plan. The RRSP is a defined contribution plan. The costs recognized for the period are equal to the Utility’s contribution to the plan. During 2016, these were $448,000 (2015 - $446,000).

The employee plan is regulated by the Office of the Superintendent of Financial Institutions through the *Pension Benefits Standards Act and regulations.* This Act and accompanying regulations impose, among other things, minimum funding requirements.

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These minimum funding requirements require the Utility make special payments as prescribed by the Office of the Superintendent of Financial Institutions to repay any unfunded liability or deficit that may exist. For the employee pension plan the Utility is required to pay $225,300 as a minimum annual payment in each of the next 12 years (2015 - $323,700 in each of the next 12 years).

A committee of the Utility's Board of Directors oversees these plans and is responsible for the investment policy with regard to the assets of these funds.

Risks associated with defined benefit plans
The pension plans expose the Utility to actuarial risk such as investment risk, interest rate risk, longevity risk and salary risk.

Investment risk is the risk that the assets invested will be insufficient to meet expected benefits.

Interest rate risk is the risk that bond interest will increase the plan liability; however, this will be partially offset by an increase in the return on the plan’s debt investments.

Longevity risk is the risk that the present value of the defined benefit plan liability is calculated by reference to the best estimate of the mortality of plan participants both during and after their employment. An increase in the life expectancy of the plan participants will increase the plan’s liability.

Salary risk is the risk that the present value of the defined benefit plan liability is calculated by reference to the future salaries of plan participants. As such, an increase in the salary of the plan participants will increase the plan's liability.

(tabular amounts in thousands of Canadian dollars)

13. POST-EMPLOYMENT BENEFITS - continued

Net defined benefit liability

	December 31 2016	December 31 2015
Present value of benefit obligations		
Balance, beginning of year	$ 20,793	$ 20,690
Employee Contributions	84	89
Current service cost	493	544
Interest cost	868	847
Benefits paid	(458)	(397)
Actuarial losses (gains) on experience	388	(657)
Actuarial losses (gains) on financial assumptions	812	(323)
Balance, end of year	$ 22,980	$ 20,793
Fair value of plan assets		
Balance, beginning of year	15,357	14,672
Interest income on plan assets	638	599
Gain (losses) on plan assets	716	(468)
Employee contributions	84	89
Employer contributions	781	905
Benefits paid	(421)	(360)
Administrative costs	(42)	(80)
Balance, end of year	17,113	15,357
Net defined benefit liability	$ 5,867	$ 5,436

Components of benefit plan cost:

	December 31 2016	December 31 2015
Current Service cost	493	544
Interest cost	868	847
Interest income on plan asset	(638)	(599)
Administrative costs	42	80
Defined benefit expense in Statement of Operations	765	872
Defined contribution expense	448	446
Total benefit expense in Statement of Operations	$ 1,213	$ 1,318

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(tabular amounts in thousands of Canadian dollars)

13. POST-EMPLOYMENT BENEFITS - continued

Actuarial (gains)/losses on obligation	1,148	(980)
Loss/(gains) on plan assets	(717)	468
Total re-measurements included in Other Comprehensive Income	431	(512)
Total benefit costs recognized in Statement of Operations and Other Comprehensive Income	1,644	806

The fair value of the plans assets is based on market values as reported by the plans' custodians as at each applicable statement of financial position date. The distribution of assets by major asset class is as follows:

	December 31, 2016	December 31, 2015
Equities	54.9%	52.8%
Fixed income securities	35.9%	36.7%
Real estate	9.2%	10.4%

Significant assumptions:

	December 31, 2016	December 31, 2015
Discount rate - accrued benefit obligation	3.90 - 4.00%	4.10 - 4.50%
Assumed rate of salary escalation	2.80 - 3.50%	3.00 - 3.50%
Pension growth	2.00 - 2.50%	2.00 - 2.50%

Sensitivity analysis:
The sensitivities of key assumptions used in measuring accrued benefit obligations at each statement of financial position date. The sensitivities of each key assumption have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously. The sensitivity analysis has been determined based on reasonably possible changes of the respective assumptions occurring at the end of the reporting period. The mortality assumptions are based on the 2014 Canadian Pensioner Mortality Private Table projected with full generational mortality improvements using scale B.

Assumptions and sensitivity as at December 31, 2016

Assumption	+1%	-1%	+1%	-1%
Discount rate	-14.10%	17.97%	$ (3,241)	$ 4,129
Salary growth	2.55%	-2.41%	550	(521)
Pension growth	14.22%	-11.74%	3,071	(2,537)
Life expectancy (1 year movement)	2.41%	-2.43%	555	(559)

Assumptions and sensitivity as at December 31, 2015

Assumption	+1%	-1%	+1%	-1%
Discount rate	-14.31%	18.27%	$ (2,976)	$ 3,799
Salary growth	3.16%	-2.97%	616	(579)
Pension growth	13.75%	-11.39%	2,678	(2,220)
Life expectancy (1 year movement)	2.15%	-2.16%	446	(450)

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(tabular amounts in thousands of Canadian dollars)

13. POST-EMPLOYMENT BENEFITS - continued

The sensitivity analysis presented above may not be representative of the actual change in the defined benefit obligation as it is unlikely that the change in assumptions would occur in isolation of one another as some of the assumptions may be correlated.

Furthermore, in presenting the above sensitivity analysis, the present value of the defined benefit obligation has been calculated using the projected unit credit method at the end of the reporting period, which is the same that is applied in calculating the defined benefit obligation liability recognized in the statement of financial position.

The Utility pays the balance of the cost of the Plan over the employee contributions, as determined by the actuary. Members are required to contribute 3.5% of earnings up to the Year's Maximum Pensionable Earnings (YMPE) plus 5% of earnings above the YMPE. Permanent part-time members will have required contributions as above multiplied by their permanent part-time service ratio. Employees can make additional contributions to purchase ancillary benefits. Members choose the ancillary benefit on termination of service or on retirement.

The average duration of the benefit obligation is 16.0 years (2015 - 16.6 years).

The Utility expects to make payments of $706,000 to the defined benefit plans during the next financial year.

14. CONTRIBUTIONS IN AID OF CONSTRUCTION

	Government of Canada	Parent since 1998	Customer since 1998	Yukon Government since 1998	Pre-1998 contributions	Total
Cost:						
At January 1, 2015	71,000	73,545	24,001	10,879	1,739	181,164
Additions	-	18,265	578	161	-	19,004
At December 31, 2015	71,000	91,810	24,579	11,040	1,739	200,168
Additions	-	-	274	58	-	332
Transfers	-	-	(354)	354	-	-
At December 31, 2016	71,000	91,810	24,499	11,452	1,739	200,500
Accumulated amortization:						
At January 1, 2015	3,048	6,694	7,588	1,425	1,249	20,004
Amortization	991	1,217	1,173	200	43	3,624
At December 31, 2015	4,039	7,911	8,761	1,625	1,292	23,628
Amortization	990	1,680	1,179	209	44	4,102
At December 31, 2016	5,029	9,591	9,940	1,834	1,336	27,730
Net book value:						
At December 31, 2015	66,961	83,899	15,818	9,415	447	176,540
At December 31, 2016	65,971	82,219	14,559	9,618	403	172,770

The sources of contributions received prior to 1998 were not recorded separately.

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(tabular amounts in thousands of Canadian dollars)

15. DECOMMISSIONING FUND

	December 31 2016	December 31 2015
Opening balance	$ 2,612	$ 2,586
Interest	24	26
Closing balance	$ 2,636	$ 2,612

16. SALES OF POWER

	2016	2015
Wholesale	$ 28,641	$ 29,794
Industrial	4,506	4,230
General service	4,359	4,265
Residential	2,040	2,015
Secondary sales	371	544
Sentinel and street lights	96	100
	$ 40,013	$ 40,948

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17. OPERATIONS AND MAINTENANCE EXPENSES

	2016	2015
Wages and benefits	$ 5,955	$ 5,553
Regulatory account expenses (Note 8 (c))	8,734	7,436
Contractors	1,692	1,826
Materials and consumables	1,169	1,143
Travel	311	341
Rent	234	234
Fuel	1,169	781
Communication	58	62
	$ 19,322	$ 17,376

(tabular amounts in thousands of Canadian dollars)

December 31 2016

18. ADMINISTRATION EXPENSES

	2016	2015
Wages and benefits	$ 5,737	$ 5,516
External labour	1,189	1,094
Insurance and taxes	1,812	1,593
Materials, consumables and general	1,708	849
Licences and fees	658	614
Travel	171	170
Board fees	83	55
	$ 11,358	$ 9,891

19. RELATED PARTY TRANSACTIONS

The Utility is related in terms of common ownership to all YG departments, agencies and Crown Corporations. Transactions are entered into in the normal course of operations with these entities. All sales transactions are recorded at the rates approved by the YUB.

Revenue from related parties is included in other revenue on the statement of operations and other comprehensive income. Interim Electrical Rebate program revenues are received from YDC in accordance with terms established by YG which established the program to protect certain ratepayers. These revenues are included in sales of power on the statement of operations and other comprehensive income.

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The following table summarizes the Utility's related party transactions for the year:

	2016	2015
Revenue		
Sales of service to YDC	$ 6	$ 14
Program cost reimbursement from YG	-	127
Rate subsidy received from YDC	299	274
Funding from YDC	825	6,135
Operating expenses		
Interest expense on borrowings from YDC	$ 3,220	$ 2,964
Other receipts		
Construction financing from YDC	13,985	11,200
Long-term debt from YDC	12,136	20,984
Other payments		
Repayment of principal on borrowings from YDC	$ 4,860	$ 4,021
Repayment of construction financing from YDC	-	8,400

During January 2015 the Utility received an additional $11,200,000 of construction financing relating to a 2014 agreement (included in the above table).

(tabular amounts in thousands of Canadian dollars)

19. RELATED PARTY TRANSACTIONS - continued

The Utility entered into an agreement with YDC, effective December 29, 2015 to convert $39,200,000 (Note 12) of the construction financing into a capital contribution - $18,265,000 recorded as contributions in aid of construction (Note 14), $4,135,000 funding for feasibility studies which is recorded as funding from YDC (which is included in the above table), $8,400,000 was converted to a short-term loan due December 31, 2016 and $8,400,000 was repaid (included in the above table).

At the end of the year, the amounts receivable from and due to related entities are as follows:

	December 31 2016	December 31 2015
YDC		
Accounts receivable	$ 28	$ 27
Accounts payable	167	128
Construction financing	22,385	23,280
Current portion of long-term debt	4,860	4,860
Long-term debt	138,233	130,957
YG		
Accounts receivable	$ 62	$ 823
Accounts payable	32	301

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These balances are non-interest bearing and payable on demand except for construction financing and long-term debt.

Transactions with Key Management Personnel

The Utility's key management personnel include members of the senior management team and the Board of Directors, a total of 18 individuals (2015 - 18 individuals). Key management personnel compensation is as follows:

Year ended December 31	2016	2015
Short-term employee benefits	$ 1,537	$ 1,606
Post-employment benefits	59	55
Retirement benefits	-	18
	$ 1,596	$ 1,679

20. COMMITMENTS

Aishihik water licence
The Yukon Water Board issued a water use licence in 2002, valid until December 31, 2019, for the Utility's Aishihik Lake facility. In addition to maintaining a minimum and maximum water level, this licence commits the Utility to meet a number of future requirements including annual fish monitoring programs.

Fish monitoring programs are also required under an authorization provided by the federal government Department of Fisheries and Oceans, which is valid until December 31, 2019. The costs of meeting these requirements are accounted for as water licence costs in the year they are paid.

Contractual obligations
The Utility has entered into contracts to purchase products or services for which the liability has not been incurred as at December 31, 2016 as the product or service had not been provided. The total commitments at year end are $1,754,000 (2015 - $5,712,000).

21. CONTINGENCIES

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Aishihik Third Turbine Project
This project was commissioned into service in December 2011. On March 2, 2012, the general contractor filed a claim with the Supreme Court of Yukon for $4,000,000 plus interest and costs alleging the Utility has not paid for work performed. During 2016 trial was held, the judge’s order were received and the Utility paid the damages ordered. The Utility has appealed the decision. The outcome of the appeal is not determinable at this time and the amount paid has been recognized in the financial statements.

Asset Retirement Obligations
The Utility has not recognized a provision for the closure and restoration obligations for certain generation, transmission and distribution assets which the Utility anticipates maintaining and operating these assets for an indefinite period, making the date of retirement of these assets indeterminate. These significant uncertainties around the timing of any potential future cash outflows are such that a reliable estimate of the liability is not possible at this time. A provision will be recognized when the timing of the retirement of these assets can be reasonably estimated.

22. PROVISION FOR ENVIRONMENTAL LIABILITIES

The Utility's activities are subject to various federal and territorial laws and regulations governing the protection of the environment or to minimize any adverse impact thereon. The Utility conducts its operations so as to protect public health and the environment and believes its operations are materially in compliance with all applicable laws and regulations.

The Utility has conducted environmental site assessments at all its diesel plant sites. At sites where environmental contamination was found and a legal obligation to remediate the site existed, the Utility has conducted a full remediation. As at December 31, 2016 no new provisions for environmental liabilities, for which a legal obligation exists to remediate, have been identified by the Utility. The Utility will continue to use its Environmental Management System to monitor and assess previous and potential existing environmental liabilities on an ongoing basis.

23. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

At December 31, 2016, the Utility's financial instruments included cash, accounts receivable, bank indebtedness, accounts payable and accrued liabilities, construction financing, long-term debt and interest rate swaps. The fair value of cash, accounts receivable, bank indebtedness, accounts payable and accrued liabilities and construction financing approximate their carrying value due to the immediate or short-term maturity of these financial instruments.

The long-term debt is accounted for at amortized cost using the effective interest rate method. The fair value of the long-term debt is estimated by discounting the future cash flows using current rates for debt instruments subject to similar risks and maturities as disclosed in Note 12.

The Utility has access to a $10 million line of credit. The account accrues interest on withdrawals at prime rate minus 0.75% per annum.

Interest rate swaps are financial contracts that derive their value from changes in an underlying variable. The Utility’s interest rate swaps are classified as held for trading and are recognized at their fair value on the date the contract has been entered into. Any subsequent unrealized and realized gains and losses are reported in net income during the period in which the fair value movement occurred. The fair value of the interest rate swaps is estimated using standard market valuation techniques and is provided to the Utility by the financial institution that is the counterparty to the transactions.

The Utility did not engage in any other hedging transactions.

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Interest rate risk
Interest rate risk is the risk that future cash flows or fair value of a financial instrument will fluctuate due to changes in market interest rates. The Utility's future cash flows are not exposed to significant interest rate risk due to its long-term debt having fixed interest rates, with the exception of the Bankers' Acceptances from the TD Bank. The Bankers' Acceptances have had the variable rate converted to a fixed rate using an interest rate swap to eliminate the interest rate risk.

As at December 31, 2016, the Utility had an interest rate swap agreement in place with a notional principal amount of $9.7 million (2015 - $10.0 million). The agreement effectively changes the Utility’s interest rate exposure on this notional amount from a floating rate to a fixed rate of 2.69%.

The fair value of the interest rate swap agreement on December 31, 2016 was a liability of $409,000 (2015 - liability of $553,000). The increase in the fair value in 2016 of $144,000 (2015 – decrease of $340,000) is recorded on the statement of operations and comprehensive income as an unrealized gain/loss. A 100 basis point increase/decrease in the interest rate assumption would have resulted in an increase/decrease in the interest rate swap agreements fair value of $498,000 (2015 - $593,000).

Credit risk
Credit risk is the risk of failure of a debtor or counterparty to honour its contractual obligations resulting in financial loss to the Utility.

(tabular amounts in thousands of Canadian dollars)

23. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS - continued

The following table illustrates the maximum credit exposure to the Utility if all counterparties defaulted:

	December 31 2016	December 31 2015
Cash	$ 551	$ 1,672
Accounts receivable	5,873	6,347
	$ 6,424	$ 8,019

Credit risk on cash is considered minimal as the Utility's cash deposits are held by a Canadian Schedule 1 Chartered bank.

Credit risk on accounts receivable is considered minimal as the Utility has experienced insignificant bad debt in prior years. In addition, its primary customer is a rate regulated utility that purchases power from the Utility for resale and as such these receivables are considered fully collectible. Included in the accounts receivable past due but not impaired at December 31, 2016 are $256,000 (2015 - $667,000) which management believes will be received in full.

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Liquidity risk
Liquidity risk is the risk that the Utility will not be able to meet its financial obligations as they fall due. The Utility manages liquidity risk through regular monitoring of cash and currency requirements by preparing cash flow forecasts to identify financing requirements. The Utility's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Utility's reputation.

The Utility's largest current liability is current portion long-term debt which is predominantly due to the parent, and the Utility has successfully renegotiated this debt in prior years. In addition, rate regulation assists the Utility with liquidity management by providing consistent revenues and a consistent debt to equity ratio.

Fair values
The following table illustrates the fair value hierarchy of the Utility's financial instruments as at December 31, 2016:

	Quoted prices in active markets (Level 1)	Other observable inputs (Level 2)	Unobservable inputs (Level 3)	Total
Derivative related liability	-	$409	-	$409
Long-term debt			$152,000	$152,000

(tabular amounts in thousands of Canadian dollars)

23. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS - continued

The following table illustrates the fair value hierarchy of the Utility's financial instruments as at December 31, 2015:

	Quoted prices in active markets (Level 1)	Other observable inputs (Level 2)	Unobservable inputs (Level 3)	Total
Derivative related liability	-	$553	-	$553
Long-term debt	-	-	$149,000	$149,000

24. CAPITAL MANAGEMENT

The Utility’s capital is its shareholder's equity which is comprised of share capital, contributed surplus and retained earnings. The Utility manages its equity by managing revenues, expenses, assets and liabilities to ensure the Utility effectively achieves its objectives while remaining a going concern.

The Utility monitors its capital on the basis of the ratio of total debt to total capitalization. Debt is calculated as total borrowings, which is comprised of long-term debt, including the portion of long-term debt due within one year. Short term debt related to assets under construction at the statement of financial position date is excluded from the calculation of total debt, as the assets are similarly excluded from the determination of rate base. In addition the provision for decommissioning of the Minto Mine spur line has been added (Note 16). Total capitalization is calculated as total debt plus total shareholder’s equity as shown on the statement of financial position. The Utility maintains a balance in retained earnings as an indicator of the Utility's equity position.

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The Utility has a policy which defines its capital structure at a ratio of 60% debt and 40% equity. This policy has been reviewed and accepted by the YUB.

(tabular amounts in thousands of Canadian dollars)

24. CAPITAL MANAGEMENT - continued

The table below summarizes the Utility’s total debt to total capitalization position:

	December 31 2016	2015
Long-term debt due within one year	$ 6,066	$ 6,066
Long-term debt	147,771	140,874
Total debt	153,837	146,940
Add provision for decommissioning of industrial customer spur line	2,636	2,612
Total debt to include in the calculation	$ 156,473	$ 149,552
Share capital	$ 39,000	$ 39,000
Contributed surplus	14,600	14,600
Retained earnings	51,599	46,303
Total shareholder's equity	105,199	99,903
Total capitalization	$ 261,672	$ 249,455
Total debt to total capitalization	60 %	60 %

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There were no changes in the Utility’s approach to capital management during the period.