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June 13, 2017

RESS & COURIER

Ontario Energy Board
P.O. Box 2319
27th Floor, 2300 Yonge Street
Toronto, ON M4P 1E4

Attention: Ms. K. Walli, Board Secretary

Dear Ms. Walli:

Re: Wataynikaneyap Power LP - Electricity Distribution Licence Application

We are counsel to 2472883 Ontario Limited ("Wataynikaneyap Power GP" or "WPGP") and Wataynikaneyap Power LP ("WPLP"). WPGP on behalf of WPLP (the "Applicant") hereby applies to the Ontario Energy Board (the "Board") for an Electricity Distribution Licence pursuant to ss. 57(a) and 60 of the *Ontario Energy Board Act, 1998* (the "OEB Act").

The Applicant is seeking an order of the Board granting an Electricity Distribution Licence because it is developing, and intends to construct, own and operate, a distribution system in northwestern Ontario, between Red Lake and the Pikangikum First Nation Reserve (the "Distribution System"). The Distribution System is being developed to address an urgent need for grid connection of the Pikangikum First Nation on an interim basis until the Pikangikum First Nation can be served by the Wataynikaneyap Power Transmission Project (the "Transmission Project"). At a future date and subject to obtaining approval under s. 92 of the OEB Act, most of the Distribution System will be converted to form part of the Transmission Project.

Attached as **Appendix 'A'** is the Applicant's completed application form, together with all schedules (the "Application"), as well as payment of the applicable filing fee. In connection with the Application, the Applicant is seeking exemptions from certain standard licence conditions as set out below. The Applicant, the Transmission Project, the Distribution System and other aspects relevant to this Application are discussed below.

1. The Applicant

WPGP is an Ontario company and the general partner of WPLP, an Ontario limited partnership. WPGP is held 51% by 2472881 Ontario Limited ("First Nation GP") and 49% by Fortis (WP) GP Inc. The limited partnership interests in WPLP are held 51% by First Nation LP and 49% by Fortis (WP) LP. The Applicant's corporate structure is shown in Schedule 'C' of Appendix 'A'.

First Nation GP / First Nation LP

First Nation GP is an Ontario company and is the general partner of First Nation LP, an Ontario limited partnership. The shares of First Nation GP, as well as the limited partnership interests in First Nation LP, are held directly by 22 First Nations (the "Participating First Nations") in equal shares. The Participating First Nations are as follows:

- Bearskin Lake First Nation
- Cat Lake First Nation
- Deer Lake First Nation
- Kasabonika Lake First Nation
- Keewaywin First Nation
- Kingfisher Lake First Nation
- Kitchenuhmaykoosib Inninuwug First Nation
- Lac des Mille Lacs First Nation
- Lac Seul First Nation
- McDowell Lake First Nation
- Muskrat Dam First Nation
- North Caribou First Nation
- North Spirit Lake First Nation
- Pikangikum First Nation
- Poplar Hill First Nation
- Sachigo Lake First Nation
- Sandy Lake First Nation
- Slate Falls First Nation
- Wabigoon Lake Ojibway Nation
- Wapekeka First Nation
- Wawakapewin First Nation
- Wunnumin Lake First Nation

Fortis (WP) GP / Fortis (WP) LP

Fortis (WP) GP Inc. is an Ontario company and is the general partner of Fortis (WP) LP, an Ontario limited partnership. FortisOntario Inc. holds 100% of the shares of Fortis (WP) GP Inc. Fortis Inc., the parent company of FortisOntario Inc., holds a 99.99% limited partnership interest in Fortis (WP) LP and Fortis (WP) GP Inc. holds a 0.01% general partnership interest in Fortis (WP) LP. FortisOntario Inc. owns and operates generation, transmission and distribution businesses in Ontario and is an affiliate of Fortis Inc., which is a leader in the North American electricity and gas utility business.

2. The Transmission Project

WPGP, on behalf of WPLP, is a licensed Ontario electricity transmitter (ET-2015-0264). In accordance with its transmission licence, WPLP is developing the Transmission Project in northwestern Ontario. The Transmission Project will be comprised of (i) a new 300 km, 230 kV single circuit overhead transmission line originating at a point between Ignace and Dryden and terminating in Pickle Lake, including associated stations and ancillary facilities (the "Line to Pickle Lake"), and (ii) approximately 905 km of new 115 kV and 44 kV transmission lines extending north from Pickle Lake, and approximately 595 km of new 115 kV and 44 kV transmission lines extending north from Red Lake, each including associated stations, ancillary facilities and interconnections to existing distribution systems, as required to connect at least 16 remote First Nations communities (all of which are Participating First Nations) to the provincial electricity grid (the "Remote Connection Lines").

The Transmission Project is being developed to meet important and recognized needs. In the 2013 Long-Term Energy Plan, the provincial government identified that connecting remote northwestern First Nation communities is a priority for Ontario. The government also confirmed that a new line to Pickle Lake would, among other things, provide increased capacity to connect remote communities north of Pickle Lake and, for that reason, that line continues to be a key priority for Ontario.

In a July 29, 2016 letter, the Minister of Energy informed the Board that the Lieutenant Governor in Council made an order dated July 20, 2016, under the authority of section 96.1(1) of the OEB Act, declaring that construction of the Transmission Project is needed as a "priority project". In a separate letter dated July 29, 2016, the Minister of Energy issued a Directive to the Board under s. 28.6.1 of the OEB Act requiring the Board to amend WPLP's electricity transmission licence so as to require WPLP to develop and seek approvals for the Transmission Project. In accordance with the terms of its amended licence, WPLP is required to develop the Transmission Project in accordance with the scope recommended by the Independent Electricity System Operator ("IESO"). The IESO recommended scope was issued to the Board on October 13, 2016.

On March 23, 2017, the Board issued a Decision and Order in EB-2016-0262 granting WPLP's application for an accounting order to establish a deferral account to record costs incurred in relation to the development of the Transmission Project, as well as approving certain reporting requirements.

3. The Planned Distribution System

Background

The Pikangikum First Nation is the southernmost of the remote communities that will connect to the grid by means of WPLP's Remote Connection Line north of Red Lake. Pikangikum has been working for many years to develop a distribution line from Red Lake to provide electricity service to its community. Although WPLP has long recognized the potential for overlap with the Pikangikum project and the need for WPLP's transmission line north of Red Lake to cross Pikangikum's traditional lands (as well as the opportunity for integrating the two projects), Pikangikum was not one of the initial Participating First Nations.

Through meetings with the Chief, Council and Elders from Pikangikum, representatives of WPLP explored scenarios under which Pikangikum would be willing to support and/or join WPLP's Transmission Project. WPLP learned that, due to the severe capacity constraints and significant reliability issues with its existing diesel generation, Pikangikum's primary concern was with the timing for getting its community connected to the grid. It was anticipated that Pikangikum's distribution project would be able to connect the community approximately 3-4 years before they could be connected through the WPLP Transmission Project. WPLP also learned that prior development work on Pikangikum's distribution project included consideration of the use of 115 kV facilities, which would allow the future connection of additional communities to the north.

Regarding the urgency of Pikangikum's need for grid connection, a detailed account of the conditions in Pikangikum, including how those conditions are affected by the community's access to electricity, the urgency of the need for reliable electricity service, and the history of the community's efforts to secure reliable electricity service, is set out in an April 2, 2016 article by Eric Bombicino, published on www.tvo.org, entitled *How Energy Poverty Devastates Pikangikum First Nation.* A copy of the article is provided in Schedule 'H' of Appendix 'A'.

Distribution Project

As recently explained to the Board in EB-2016-0262, WPLP intends to construct one part of the planned transmission system, running approximately 117 km from Red Lake to the Pikangikum

First Nation Reserve, prior to commencing construction on the remainder of the Transmission Project. Although WPLP intends to construct this part of the planned transmission system using 115 kV transmission level conductors, WPLP will initially connect this line to Hydro One's distribution system and will operate it at a distribution voltage (44kV) for a period of approximately 3-4 years. This will enable WPLP to connect the Pikangikum First Nation to the grid by late 2018.

The facilities will be designed so as to be capable of being converted to transmission facilities in a manner that minimizes the need for additional cost or construction activity. Once WPLP's Remote Connection Line north of Red Lake is ready to serve additional communities, the facilities serving Pikangikum will be converted so as to instead be connected to Hydro One's transmission system and will operate at 115 kV. In doing so, these facilities will be incorporated into the Transmission Project and will serve as the first leg of the Remote Connection Line north of Red Lake. Through this innovative approach, the Pikangikum First Nation will be able to connect to the grid sooner and participate in the WPLP Transmission Project, while avoiding the duplication of electricity infrastructure in the region.

Regulatory Approach

When it seeks leave to construct the Transmission Project, the Applicant plans to seek approval to convert approximately 94 km of the Distribution System to operate at transmission voltages. In addition, as part of the leave to construct application, the Applicant will seek approval to deem approximately 18 km at the northern end of the Distribution System (which will continue to operate at voltages of 50 kV or less) to be part of the Applicant's planned transmission system. An approximately 5 km portion at the southern end of the Distribution System would not be required as part of WPLP's planned transmission system, nor does WPLP intend to operate it on an ongoing basis as a distribution system. As such, after converting the majority of the Distribution System to transmission, the Applicant does not expect to require the requested distribution licence for any purpose.

The capital costs of developing and constructing the distribution facilities from Red Lake to the Pikangikum First Nation are expected to be paid for primarily through funding provided by Indigenous and Northern Affairs Canada ("INAC"). However, as the funding application process with INAC is ongoing at the time of this Application, the full extent of the funding to be received is not yet certain. The Applicant plans to apply to the Board for approval of distribution rates, to take effect upon the Distribution System going into service, based on its relevant capital and forecast OM&A costs.

4. Technical and Financial Expertise, Experience and Resources

The experience and resources of the Applicant, through its partners and their affiliates, provides the Applicant with a very high level of technical and financial capability, expertise and experience with respect to the development, construction, ownership, operation and maintenance of electricity distribution facilities. This expertise is summarized below.

First Nation GP / First Nation LP

First Nation LP is indirectly owned by the Participating First Nations, which through a predecessor organization known as Wataynikaneyap Power Corporation undertook all aspects of the early development work for the Transmission Project. This included extensive engagement

within the affected communities, as well as with key regulators and governmental authorities. Through the Participating First Nations (which includes the Pikangikum First Nation itself), First Nation LP also has a very high level of experience and expertise with respect to the geographic area in which the Distribution System will be situated and the environmental attributes that will potentially be affected. In addition, the Participating First Nations possess a unique capability for working with potentially affected stakeholders.

FortisOntario

FortisOntario is an electric utility, which owns and operates Canadian Niagara Power Inc., Cornwall Street Railway Light & Power Company Ltd. and Algoma Power Inc., serving a combined 65,000 customers. In addition, FortisOntario owns minority interests in three additional local distribution companies that serve a total of nearly 40,000 customers. Through a project management partnership, FortisOntario manages various aspects of the Transmission Project. FortisOntario also owns regulated transmission assets with approximately 3,430 km of distribution and transmission lines. FortisOntario is a wholly-owned subsidiary of Fortis Inc., which has total assets of approximately $48 billion and fiscal 2016 revenue of $6.8 billion, and serves more than 3 million customers across Canada, the United States and the Caribbean.

5. Lexi Decision

On August 10, 2009, the Board issued a Decision denying an application by Lexi Transmission Corporation ("Lexi") for an electricity transmission licence (EB-2009-0164) (the "Lexi Decision"). In the Lexi Decision, the Board clarified how it considers licence applications for applicants that do not yet have facilities in Ontario.

In its application, Lexi stated that it had no active transmission business in Ontario but that its proposed business activities generally included the development, construction, ownership and operation of transmission assets. Lexi's intended business was to be province-wide and was to include all types of transmission reinforcements and enhancements that were referred to in the Integrated Power System Plan.

In the Lexi Decision, the Board identified two threshold tests for transmission licence applications: (1) whether there is a specific project which underpins the application, and (2) in the absence of a specific project, whether the applicant is engaged in transmission activity elsewhere and whether it has the necessary technical and financial expertise to undertake transmission activity in Ontario.

In the Applicant's view, this test should also apply in the distribution context. In the present Application, there is a specific and well-defined project underpinning WPLP's Application, as described above. The project that underpins the Application is a discrete portion of a larger project that has been identified as a "priority project" by the Government of Ontario and that the Applicant is required to develop as a condition of its transmission licence. The discrete portion that will comprise the planned distribution system is required on an urgent basis. Moreover, as demonstrated above, the Applicant through its partners and their affiliates has the necessary technical and financial expertise to undertake the relevant distribution activities. As such, the Applicant satisfies the threshold test.

6. Exemptions

Recognizing that certain requirements of the distribution licence will not be relevant until such time as WPLP has distribution assets, the Applicant relies upon the Board's findings (in the transmission context) at p. 6 of its August 31, 2011 Decision and Order in EB-2011-0126 that "those sections of the Board's regulatory instruments that cannot be complied with by a transmission licence holder without assets in the province are simply inapplicable, and no specific exemption is necessary." The Applicant is not otherwise seeking any exemptions from any code or standard distribution licence conditions, but does wish to clarify its understanding of how it will be characterized under the Distribution System Code (DSC) and Retail Settlement Code (RSC).

Under each of the DSC and the RSC, the Applicant would be an "embedded distributor", which is a distributor that is not a wholesale market participant and that is provided electricity by a host distributor. The Applicant's "host distributor", being the distributor who provides electricity to the Applicant's embedded distribution system, would be Hydro One Networks Inc. (HONI). What is perhaps unique is that the Applicant's sole customer, Hydro One Remote Communities Inc. (HORCI) in respect of the Pikangikum First Nation Reserve, will itself be an embedded distributor as it will be provided with electricity by the Applicant. However, the RSC specifies that a "host distributor" means the registered wholesale market participant that provides electricity to an embedded distributor. The Applicant, as an embedded distributor to HONI, will not be a wholesale market participant and will therefore not be a "host distributor" or be in a position to fulfill all of the responsibilities of a host distributor contemplated under the DSC and RSC. Instead, the Applicant expects that those responsibilities would flow through to HONI. The Applicant further expects that HORCI would effectively settle most of its charges directly with HONI and would only settle with the Applicant based on distribution rates to be determined by the Board.

7. Procedural Matters

The Applicant requests that the Board consider this Application by way of a written hearing. We further request that the Board direct all correspondence with respect to the Application to the Applicant and its counsel as follows:

Applicant:	Applicant's Counsel:
Wataynikaneyap Power LP c/o Shibogama First Nations Council P.O. Box 449 81 King St. Sioux Lookout, Ontario P8T 1A5	Torys LLP 79 Wellington St. W., 30th Floor Box 270 TD South Tower Toronto, Ontario M5K 1N2
Attention: Ms. Margaret Kenequanash, Director and Chair Tel: (807) 737-2662 Fax: (807)737-1583 margaretk@shibogama.on.ca	Attention: Mr. Jonathan Myers Tel: 416-865-7532 Fax: 416-865-7380 jmyers@torys.com

Wataynikaneyap Power PM Inc. c/o FortisOntario Inc. PO Box 1218 1130 Bertie Street Fort Erie, Ontario L2A 5Y2 Attention: Mr. Tim Lavoie, Vice President Tel: (705) 256-3850 Fax: (705) 759-2218 tim.lavoie@fortisontario.com	Mr. Charles Keizer Tel: 416-865-7512 Fax: 416-865-7380 ckeizer@torys.com

Yours truly,

Jonathan Myers

cc: Ms. Margaret Kenequanash, WPLP
Mr. Tim Lavoie, Wataynikaneyap Power PM Inc.
Mr. Charles Keizer, Torys LLP

APPENDIX ‘A’

DISTRIBUTION LICENCE APPLICATION FORM

Ontario Energy Board
Commission de l'Énergie de l'Ontario
Application for Electricity Distribution Licence

Ontario Energy Board
2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4
Telephone: 1-888-632-6273
Facsimile: (416) 440-7656

Commission de l'Énergie de l'Ontario
2300 rue Yonge
C.P. 2319
Toronto, ON M4P 1E4
Téléphone: 1-888-632-6273
Télécopieur: (416) 440-7656

For Office Use Only	
Application Number	
Date Received	

A. General information

1. Type of Application

New licence	[x]
Renewal	[ ]
Amendment to an existing Licence	[ ]

2. Ownership/Operation

Please indicate whether the Application is for:

[x] Ownership and Operation of a distribution system

[ ] Ownership of a distribution system only. Please provide the name and licence no., if any, of the operator of the distribution system?

[ ] Operation of a distribution system only. Please provide the name and licence no., if any, of the owner of the distribution system?

3. Applicant

Please provide the following information about the Applicant:			
Full Legal Name of Applicant 2472883 Ontario Limited on behalf of Wataynikaneyap Power LP (WPLP")	Ontario Corporation Number, Canadian Corporation Number or Business Registration Number 250676426		Date of Formation or Incorporation July 6, 2015
Business Address: c/o Shibogama First Nations Council 81 King Street, P.O. Box 449			
City Sioux Lookout	Province Ontario	Country Canada	Postal/Zip Code P8T 1A8
Phone Number 807-737-2662	FAX Number 807-737-1583	E-Mail Address (if applicable)	

4. Primary Contact for this Application

Please provide the following information about the Primary Contact for this Application:			
Mr. ☒ Mrs. ☐ Miss ☐ Ms. ☐ Other: _____	Last Name: Myers	Full First Name: Jonathan	Initial:
	Position Held: Counsel		
Contact Address (if R.R., give Lot, Concession No. and Township) Torys LLP, 79 Wellington St. W., 30th Floor			
City Toronto	Province Ontario	Country Canada	Postal/Zip Code M5K 1N2
Phone Number 416-865-7532	FAX Number 416-865-7380	E-mail Address (if applicable) jmyers@torys.com	

5. Service Area

Please indicate the location (name of municipality or unorganized territory) of the Applicant's distribution facilities and provide a description of the extent (size, length, coverage) of the distribution facilities involved in this Application. This description will be used for the purpose of stating a service area in which the licensee would be authorized to distribute electricity:

WPLP's planned facilities will consist of a new 44 kV and 25 kV distribution line, of approximately 117 km in length, running from a point in the Municipality of Red Lake to the Pikangikum First Nation Reserve. The vast majority of the distribution facilities will therefore be situated in the Unorganized Kenora District. The Municipality of Red Lake is situated in northwest Ontario, approximately 150 km north of Dryden and approximately 90 km from the Manitoba border. The Pikangikum First Nation Reserve is located on the shore of Lake Pikangikum, approximately 90 km north of Red Lake. The distribution line will connect at its southern end to Hydro One's distribution system by means of a line tap on circuit M6 at a point north of Red Lake near the Red Lake Airport. From this point, the line will run north for approximately 99 km to a planned Transformer Station at Berens River, and a further approximately 18 km to the northwest until it reaches the Pikangikum First Nation Reserve. A map is provided in Schedule 'A'.

6. Facilities Use

Please indicate whether the distribution facilities are for exclusive use by the Applicant.	Yes	No
	☐	☒ x

B. Distribution Facilities Information

7. Facilities Type

Please indicate whether the Applicant's distribution facilities are:

[X] New assets to be constructed? Proposed In-service date: November 2018

If Applicant is to be the owner, please attach a statement explaining the financing arrangements.

The capital costs of developing and constructing the distribution facilities from Red Lake to the Pikangikum First Nation are expected to be paid for primarily through funding provided by Indigenous and Northern Affairs Canada ("INAC"). However, as the funding application process with INAC is ongoing at the time of this Application, the full extent of the funding to be received is not yet certain.

[ ] Existing assets presently owned and/or operated by the Applicant?

[ ] Existing assets not presently owned and/or operated by the Applicant (ie to be purchased)?

If Applicant is to be the owner please indicate:

a) from whom assets will be purchased:

b) when application for sale has/will be filed with the Board?

[ ] Other (please describe):

8. Facilities Purpose

Please indicate the intended purpose(s) of the Applicant's distribution facilities:

☐	To provide a connection between a generator and a transmission/distribution system.
☒	To provide a connection between a transmission/distribution system and a load customer or customers.
☐	To provide a connection between a generator and a load customer or customers.
☐	To provide distribution services to the general public.
☐	Other (please describe):

9. Description of Facilities

Please describe the Applicant's distribution facilities indicating operating voltage(s) (kV), length of distribution line (km), number of substations and approximate total supply capacity (MW):

The distribution facilities will provide a connection between Hydro One's distribution system in Red Lake and the distribution system that is currently owned and operated by Eshkotay Wayab, an independent power authority operated as a business by the Pikangikum First Nation. The Pikangikum First Nation has formally requested, through the Minister of Energy, that Hydro One Remote Communities Inc. ("HORCI") provide distribution service within its community as a result of the pending grid-connection. Further to this request, Pikangikum has engaged with INAC and HORCI and is in the process of transferring ownership and operation of its distribution assets to HORCI. Concurrently with WPLP's distribution line going into service, it is anticipated that ownership and operation of the distribution system on the Pikangikum First Nation Reserve will be transferred to HORCI. Upon the Applicant's distribution facilities going into service, the Pikangikum First Nation will become grid-connected. The Applicant's distribution facilities will be operated at 44 kV and 25 kV and will have a total length of approximately 117 km. These facilities will be connected to Hydro One's distribution system by means of a line tap. There will be one transformer station located outside of the Reserve. The planned distribution line would, absent any constraints, have an approximate total supply capacity of 30-45 MW, depending on distance and configuration. However, supply capacity to end-use customers is limited by the size of and number of transformers and lower voltage distribution feeders. For the planned distribution facilities, supply capacity is limited by upstream constraints with respect to the transmission supply to the Red Lake area. The System Impact Assessment for the connection of WPLP's planned facilities concludes that 5.8 MW of incremental load can be connected, which exceeds the expected requirements of the Pikangikum First Nation during the relevant 3-4 year period.

10. Location of Facilities

	Yes	No
Please indicate whether the distribution facilities will be located on, over or under public streets or highways.	☒	☐

C. Supporting Information Organizational Information

11. Business Classification

Sole Proprietor	☐
Partnership	☐
Corporation	☐
Other - Limited Partnership	☒

12. Affiliates of the Applicant

a) Please provide the following information for all Affiliates of the Applicant (attach a copy of 12(a) for each affiliate).

Full Legal Name of Affiliate Company:

Business Address:

City	Province	Country	Postal/Zip Code

Tel. Number	FAX Number	E-Mail Address (if applicable)

Description of Business Activities:

Pursuant to the meaning of "affiliate" under Section 1 of the Ontario ***Business Corporations Act***, the Applicant has no energy sector affiliates. The Applicant is Wataynikaneyap Power GP on behalf of Wataynikaneyap Power LP. Wataynikaneyap Power GP is controlled by 2472881 Ontario Limited ("First Nation GP"). As such, the only affiliates of the Applicant are First Nation GP and Opiikapawiin Services GP Inc., which are not regulated entities in the energy sector.

Descriptions of First Nation GP and Opiikapawiin Services GP Inc. are provided in Schedule 'B'.

b) Please attach a Corporate organization chart describing the relationships between the Applicant and its Affiliates and, if applicable, the respective ownership percentages by the Applicant in each Affiliate.

A Corporate Organization Chart showing the relationships between the Applicant and its affiliates is provided in Schedule 'C'.

13. Energy Sector Activities

Has the Applicant or an Affiliate undertaken any energy sector activities in Ontario or any other jurisdiction? If yes, please provide the following information for each:	Yes [X] No [ ]
Full Legal Name of Company: 2472883 Ontario Limited on behalf of Wataynikaneyap Power LP	Licence/Registration Number: ET-2015-0264
Jurisdiction: Ontario	Type of Business Activity (e.g. Generation, Transmission, Distribution): Electricity Transmission Development

Technical Capability and Experience Information

14. Business Activities

Please provide a description of the Applicant's business activities:

See response in Schedule 'D'.

15. Technical Ability

a) Please describe the applicant's technical ability to carry out the activities applied for including the Applicant's specific experience in Ontario and in other jurisdictions.

See response in Schedule 'E'.

b) If the Applicant intends to utilize the capability of others by contracting distribution activities, please indicate below which activities and to whom they will be contracted:

[X] Design	Contracted to:	Qualified Contractor to be Determined.
[X] Construction	Contracted to:	Qualified Contractor to be Determined.
[X] Inspection & Maintenance	Contracted to:	Qualified Contractor to be Determined.
[X] Operation	Contracted to:	Qualified Contractor to be Determined.
[X] Customer Connection	Contracted to:	Qualified Contractor to be Determined.
[X] Standard Supply Service	Contracted to:	Qualified Contractor to be Determined.
[X] Metering & Metering Services	Contracted to:	Qualified Contractor to be Determined.
[X] Settlement & Billing	Contracted to:	Qualified Contractor to be Determined.
[X] Other (describe): Project Management	Contracted to:	Wataynikaneyap Power PM Inc.

16. Information About Each Key Individual

Mr. □ Mrs.□ Miss □ Ms. □x Other: _____	Last Name: Kenequanash	Full First Name: Margaret	Initial:
	Position Held: Director & Chair (until Aug. 15, 2017)/CEO (effective Aug. 15, 2017)		

Please explain the person's experience in the electrical distribution business and in the energy field in general.

[redacted]

a) Has this person been a proprietor, partner, officer or director of a business that was granted a licence under Part IV or Part V of the *Ontario Energy Board Act, 1998.* Yes [redacted] No

If yes, provide business names and licence number(s) and describe the individuals specific related experience.

[redacted]

b) Has this person been a proprietor, partner, officer, or director of a business that was registered or licenced under this or any other acts or legislation? Yes [redacted] No

If yes, identify the business name, the legislation, licence number(s), date of the licencing or registration and the individual's specific related experience.

c) Has this person been a proprietor, partner, officer or director of a business that had a registration or licence of any kind refused, suspended, revoked or cancelled? Yes [redacted] No

If yes, please provide company name and describe the situation, including the jurisdiction and type of licence.

Note:
Attach a copy of Item 16 for each Key Individual: Officer and Director, Partner or sole Proprietor.

16. Information About Each Key Individual

Mr. ☒ Mrs.☐ Miss ☐ Ms. ☐ Other: _____	Last Name: McKay	Full First Name: Frank	Initial:
	Position Held: Director and Vice-President - Government Relations		

Please explain the person's experience in the electrical distribution business and in the energy field in general.

[redacted]

a) Has this person been a proprietor, partner, officer or director of a business that was granted a licence under Part IV or Part V of the *Ontario Energy Board Act, 1998.* Yes [redacted] No

If yes, provide business names and licence number(s) and describe the individuals specific related experience.

[redacted]

b) Has this person been a proprietor, partner, officer, or director of a business that was registered or licenced under this or any other acts or legislation? Yes [redacted] No

If yes, identify the business name, the legislation, licence number(s), date of the licencing or registration and the individual's specific related experience.

c) Has this person been a proprietor, partner, officer or director of a business that had a registration or licence of any kind refused, suspended, revoked or cancelled? Yes [redacted] No

If yes, please provide company name and describe the situation, including the jurisdiction and type of licence.

Note:
Attach a copy of Item 16 for each Key Individual: Officer and Director, Partner or sole Proprietor.

16. Information About Each Key Individual

Mr. ☒ Mrs.☐ Miss ☐ Ms. ☐ Other: _____	Last Name: Hawkes	Full First Name: Scott	Initial:
	Position Held: Director and President		

Please explain the person's experience in the electrical distribution business and in the energy field in general.

[redacted]

a) Has this person been a proprietor, partner, officer or director of a business that was granted a licence under Part IV or Part V of the *Ontario Energy Board Act, 1998.* Yes [redacted] No

If yes, provide business names and licence number(s) and describe the individuals specific related experience.

b) Has this person been a proprietor, partner, officer, or director of a business that was registered or licenced under this or any other acts or legislation? Yes [redacted] No

If yes, identify the business name, the legislation, licence number(s), date of the licencing or registration and the individual's specific related experience.

[redacted]

c) Has this person been a proprietor, partner, officer or director of a business that had a registration or licence of any kind refused, suspended, revoked or cancelled? Yes [redacted] No

If yes, please provide company name and describe the situation, including the jurisdiction and type of licence.

Note:
Attach a copy of Item 16 for each Key Individual: Officer and Director, Partner or sole Proprietor.

16. Information About Each Key Individual

Mr. X □ Mrs.□ Miss □ Ms. □ Other: _____	Last Name: Cutfeet	Full First Name: John	Initial:
	Position Held: Vice President - Communications		

Please explain the person's experience in the electrical distribution business and in the energy field in general.

[redacted]

a) Has this person been a proprietor, partner, officer or director of a business that was granted a licence under Part IV or Part V of the *Ontario Energy Board Act, 1998.* Yes [redacted] No

If yes, provide business names and licence number(s) and describe the individuals specific related experience.

[redacted]

b) Has this person been a proprietor, partner, officer, or director of a business that was registered or licenced under this or any other acts or legislation? Yes [redacted] No

If yes, identify the business name, the legislation, licence number(s), date of the licencing or registration and the individual's specific related experience.

c) Has this person been a proprietor, partner, officer or director of a business that had a registration or licence of any kind refused, suspended, revoked or cancelled? Yes [redacted] No

If yes, please provide company name and describe the situation, including the jurisdiction and type of licence.

Note:
Attach a copy of Item 16 for each Key Individual: Officer and Director, Partner or sole Proprietor.

16. Information About Each Key Individual

Mr. ☒ Mrs.☐ Miss ☐ Ms. ☐ Other: _____	Last Name: Comerford	Full First Name: Michael	Initial:
	Position Held: Director		

Please explain the person's experience in the electrical distribution business and in the energy field in general.

[redacted]

a) Has this person been a proprietor, partner, officer or director of a business that was granted a licence under Part IV or Part V of the *Ontario Energy Board Act, 1998.* Yes [redacted] No

If yes, provide business names and licence number(s) and describe the individuals specific related experience.

[redacted]

b) Has this person been a proprietor, partner, officer, or director of a business that was registered or licenced under this or any other acts or legislation? Yes [redacted] No

If yes, identify the business name, the legislation, licence number(s), date of the licencing or registration and the individual's specific related experience.

c) Has this person been a proprietor, partner, officer or director of a business that had a registration or licence of any kind refused, suspended, revoked or cancelled? Yes [redacted] No

If yes, please provide company name and describe the situation, including the jurisdiction and type of licence.

Note:
Attach a copy of Item 16 for each Key Individual: Officer and Director, Partner or sole Proprietor.

16. Information About Each Key Individual

Mr. ☒ Mrs.☐ Miss ☐ Ms. ☐ Other: _____	Last Name: King	Full First Name: Glen	Initial:
	Position Held: Vice President - Finance & Chief Financial Officer		

Please explain the person's experience in the electrical distribution business and in the energy field in general.

[redacted]

a) Has this person been a proprietor, partner, officer or director of a business that was granted a licence under Part IV or Part V of the *Ontario Energy Board Act, 1998.* Yes [redacted] No

If yes, provide business names and licence number(s) and describe the individuals specific related experience.

[redacted]

b) Has this person been a proprietor, partner, officer, or director of a business that was registered or licenced under this or any other acts or legislation? Yes [redacted] No

If yes, identify the business name, the legislation, licence number(s), date of the licencing or registration and the individual's specific related experience.

c) Has this person been a proprietor, partner, officer or director of a business that had a registration or licence of any kind refused, suspended, revoked or cancelled? Yes [redacted] No

If yes, please provide company name and describe the situation, including the jurisdiction and type of licence.

Note:
Attach a copy of Item 16 for each Key Individual: Officer and Director, Partner or sole Proprietor.

16. Information About Each Key Individual

Mr. X Mrs. □ Miss □ Ms. □ Other: _____	Last Name: Lavoie	Full First Name: Tim	Initial:
	Position Held: Secretary		

Please explain the person's experience in the electrical distribution business and in the energy field in general.

[redacted]

a) Has this person been a proprietor, partner, officer or director of a business that was granted a licence under Part IV or Part V of the *Ontario Energy Board Act, 1998.* Yes [redacted] No

If yes, provide business names and licence number(s) and describe the individuals specific related experience.

[redacted]

b) Has this person been a proprietor, partner, officer, or director of a business that was registered or licenced under this or any other acts or legislation? Yes [redacted] No

If yes, identify the business name, the legislation, licence number(s), date of the licencing or registration and the individual's specific related experience.

c) Has this person been a proprietor, partner, officer or director of a business that had a registration or licence of any kind refused, suspended, revoked or cancelled? Yes [redacted] No

If yes, please provide company name and describe the situation, including the jurisdiction and type of licence.

Note:
Attach a copy of Item 16 for each Key Individual: Officer and Director, Partner or sole Proprietor.

Financial Information
17. Financial Statements

Please attach financial statements of the Applicant for each of the past two fiscal years. This may include audited financial statements, annual reports, prospectuses or other such information. Financial statements for the Applicant for 2015 and 2016 are not yet available because the audit, although nearing completion, continues to be in progress. See **Schedule 'F'** for the most recent financial statements currently available for the partners of WPLP and shareholders of WPGP.

Other Information
18. Delivery

Please indicate whether the Applicant's distribution facilities are to be used to deliver electricity to one or more parties other than the Applicant. If yes, please provide the following information:	Yes	No
	[x]	[ ]

a) if the purpose of the Applicant's distribution facilities is to provide distribution services to specific generators or load customers rather than the general public (see question #8) please indicate the names of these participants:

HORCI in respect of the distribution system it plans to own and operate for purposes of serving the Pikangikum First Nation Reserve.

b) a summary of the business plans relating to the Applicant's proposed distribution business for the next five years. This should include the following:

- a forecast of annual growth in terms of factors such as the amount of electricity distributed (MW and/or MWH), number of customers served, amount of distribution facilities (lines and/or stations), etc.
- annual pro forma financial statements including forecasts of costs, revenues and project financing indicating the underlying assumptions on which the forecasts are based.

See response in Schedule 'G'.

c) estimates of net annual cash flows for subsequent periods to demonstrate financial feasibility and security.

See response in Schedule 'G'.

d) indication of the Applicant's plans to seek Ontario Energy Board approval for electricity distribution rates.

See response in Schedule 'G'.

19. Proposed Business Transactions

Please provide a brief summary of the expected impact of the proposed business transactions on the Ontario electricity market under the following headings:

a) Facilitate competition and enhance access to transmission/distribution services:

The Applicant's planned Distribution System will enhance access to distribution services by providing, for the first time, a connection to the provincial electricity grid for the Pikangikum First Nation. In addition, as the Distribution System will later be converted to transmission and will form the first leg of the north of Red Lake portion of the Applicant's Transmission Project, the facilities will also have the effect of enhancing access to transmission services for those remote communities that are situated to the north of Pikangikum.

b) Improve reliability and quality of supply:

Reliability and quality of electricity supply for the Pikangikum First Nation are so poor at present that the community is in a constant state of energy crisis. The need for the Distribution System is briefly summarized in section 3 of the cover letter to this Application, and described in detail in the article entitled *How Energy Poverty Devastates Pikangikum First Nation*, a copy of which is provided in Schedule 'H'.

c) Promote economic and energy efficiency:

The updated draft *Remote Community Connection Plan* was issued by the former Ontario Power Authority on August 21, 2014 (the "2014 Plan"). The 2014 Plan states that "diesel generation that is used to supply electricity in remote communities is on average the highest cost electricity generation resource currently supplying Ontario customers. Typically, diesel generation costs are three to ten times higher than the average cost of the provincial generation supply mix." As a result of the high cost for diesel-generated electricity supply, the 2014 Plan concludes that (a) there is an economic case for connecting up to 21 of the 25 remote communities in northwestern Ontario to the provincial grid, (b) connecting these 21 communities would result in savings of about $1B over 40 years relative to their continued supply from diesel generation, and (c) that the $1B of savings only reflects the avoidable cost of diesel fuel and system expansion and not the additional economic, societal, developmental and environmental benefits that would also arise from connection of the remote communities. A proportionate share of these benefits would be expected to flow upon the connection of Pikangikum by means of the Distribution System.

20. Electricity Sector Activities

Please indicate whether the Applicant intends to be involved with electricity sector activities in the Ontario market other than distribution and provision of Standard Supply Service?

	Yes	No
Buy or Sell (Wholesale) electricity	☐	☒
Transmit electricity	☒	☐
Retail electricity	☐	☒
Generate electricity	☐	☒

If yes to any of the above:

a) If affiliates have not yet been established, please indicate when this is planned: _____

b) Has the Applicant or an affiliate applied for Ontario Energy Board Licences? If no, when planned? The Applicant holds a valid transmission licence for its Transmission Project (ET-2015-0264.)	Yes [X]	No [ ]

D. Notice and Consent for Ontario Board to Collect Additional Information

AS REQUIRED BY THE FREEDOM OF INFORMATION AND PROTECTION OF INDIVIDUAL PRIVACY ACT

In order to complete or verify the information provided on this form, it may be necessary for the Ontario Energy Board to collect additional information from some or all of the following sources: federal, provincial/state and municipal governments; licensing bodies; banks; professional and industry associations; and former and current employers. **Only information relevant to your application will be collected.**

The public official who can answer questions about the collection of information is:

Board Secretary
Ontario Energy Board
2300 Yonge Street, P.O. Box 2319
Toronto, Ontario M4P 1E4

Note: The issuance of an electricity distribution licence does not guarantee accreditation by the IESO, or connection to a transmission or distribution system.

NOTE: This application must be signed by the proprietor or by at least one partner, officer or director of the organization.

WARNING: It is an offence to knowingly provide false information on this application.

	Yes
I/We consent to the collection of this information as authorized under the *Ontario Energy Board Act, 1998*.	[X]
I/We understand that this information will be used to determine whether I am/we are and remain qualified for the licence for which I am/we are applying.	[X]

Print Name and Title	Signature of Applicant(s)	Date Signed
TIM LAVOIE CORPORATE SECRETARY		2017/06/13

E. Acknowledgement of Market Rules, Codes and Conditions

NOTE: This acknowledgement must be signed by the proprietor or by at least one partner, officer or director of the organization.

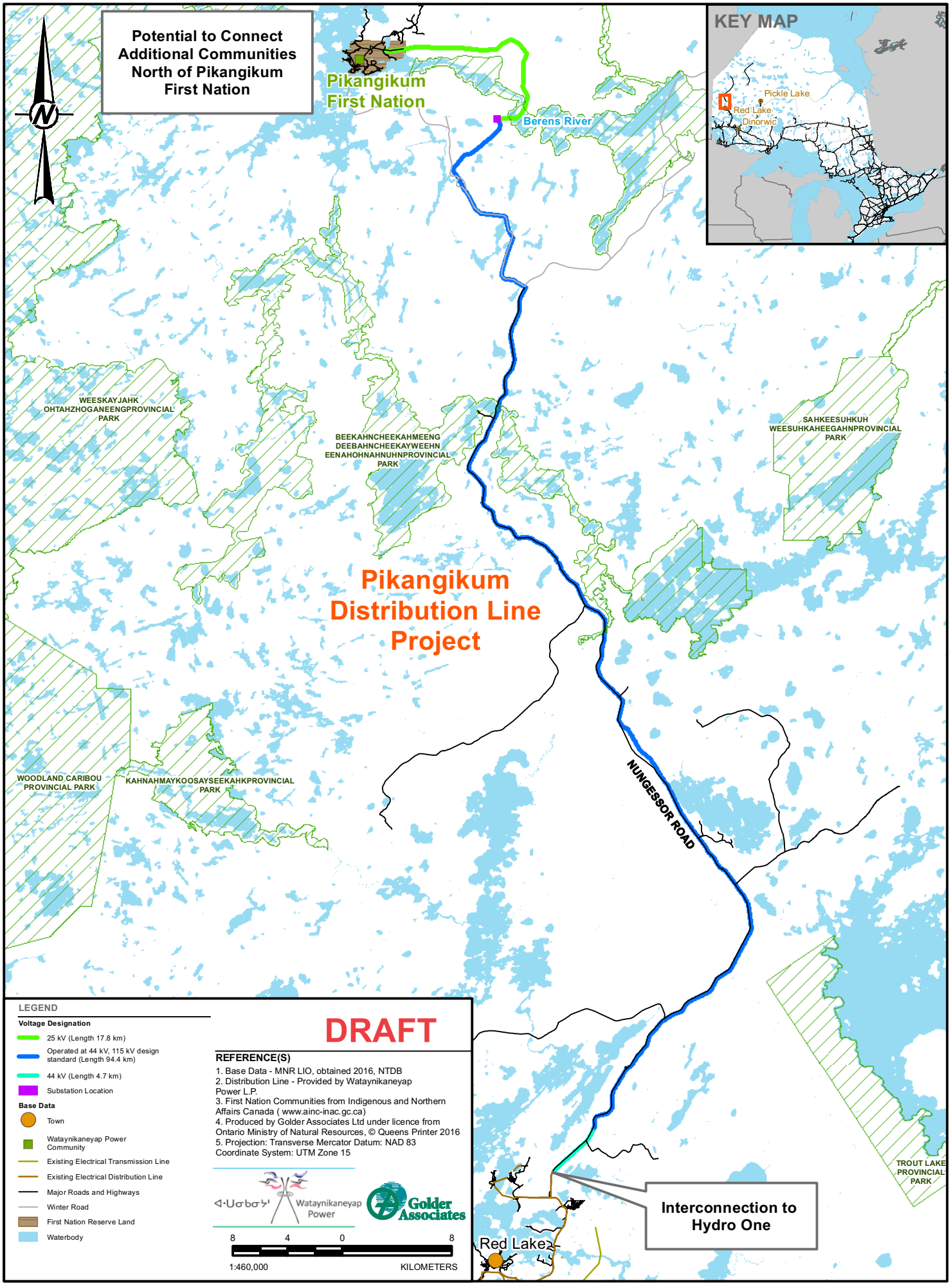
I understand and acknowledge that, as a licenced electricity distributor, I will be required, unless otherwise exempted:

- To provide non-discriminatory access to all persons wishing to connect to the distribution system.
- To comply with all licence conditions including the provisions of:
  - Affiliate Relationships Code for Electricity Distributors and Transmitters
  - Distribution System Code
  - Retail Settlement Code
  - Standard Supply Service Code
  - Retail Metering Code
  - Market Rules made under section 32 of the *Electricity Act, 1998.*

Print Name and Title	Signature of Applicant(s)	Date Signed
TIM LAVOIE CORPORATE SECRETARY		2017/06/13

Schedule ‘A’

Distribution System Map



S:\Clients\Wataynikaneyap_Power\Phase2_Transmission_Line\99_PROJ\16577738_PikangikumDist\40_PROD\0003_AboriginalEngagement\16577738-0003-HL-0005.mxd

SCHEDULE "B"

Response to #12(a)

Full Legal Name of Affiliate Company:

2472881 Ontario Limited ("First Nation GP")

Business Address:

c/o Shibogama First Nations Council, 81 King St., P.O. Box 449, Sioux Lookout, ON, P8T 1A8

Description of Business Activities:

First Nation GP is an Ontario company (2472881 Ontario Limited) and is the general partner of First Nation LP, an Ontario limited partnership. The shares of First Nation GP, as well as the limited partnership interests in First Nation LP, are held directly by 22 First Nations (the "Participating First Nations") in equal shares. The sole business activity of First Nation GP is holding the investments of the Participating First Nations, through First Nation LP, in WPLP. As indicated below, the Participating First Nations include 17 communities that currently rely on diesel generation, 4 communities that are grid-connected and 1 community that is a recently established reserve with no electricity generation whatsoever. Of the 17 communities that rely on diesel generation, 9 are currently served by Hydro One Remote Communities Inc. ("HORCI"), 7 are currently served by community-owned, non-regulated, independent power authorities ("IPAs") and 1 does not currently have any community-based electricity supply. These are the communities that are currently expected to connect to the Transmission System. The Participating First Nations are as follows:

Diesel Generation

Served by HORCI

- Bearskin Lake First Nation
- Deer Lake First Nation
- Kasabonika Lake First Nation
- Kingfisher Lake First Nation
- Kitchenuhmaykoosib Inninuwug First Nation
- North Caribou Lake First Nation
- Sachigo Lake First Nation
- Sandy Lake First Nation
- Wapekeka First Nation

Served by IPAs

- Keewaywin First Nation
- Muskrat Dam First Nation
- North Spirit Lake First Nation
- Pikangikum First Nation
- Poplar Hill First Nation
- Wawakapewin First Nation

- Wunnumin Lake First Nation

No Community Supply

- McDowell Lake First Nation

No Generation or Electricity Service

- Lac des Mille Lacs First Nation

Grid Connected

- Cat Lake First Nation
- Lac Seul First Nation
- Slate Falls First Nation.
- Wabigoon Lake First Nation

Full Legal Name of Affiliate Company:

Opiikapawiin Services GP Inc.

Business Address:

300 Anemki Place, Suite C, Fort William First Nation, Ontario P7J 1H9

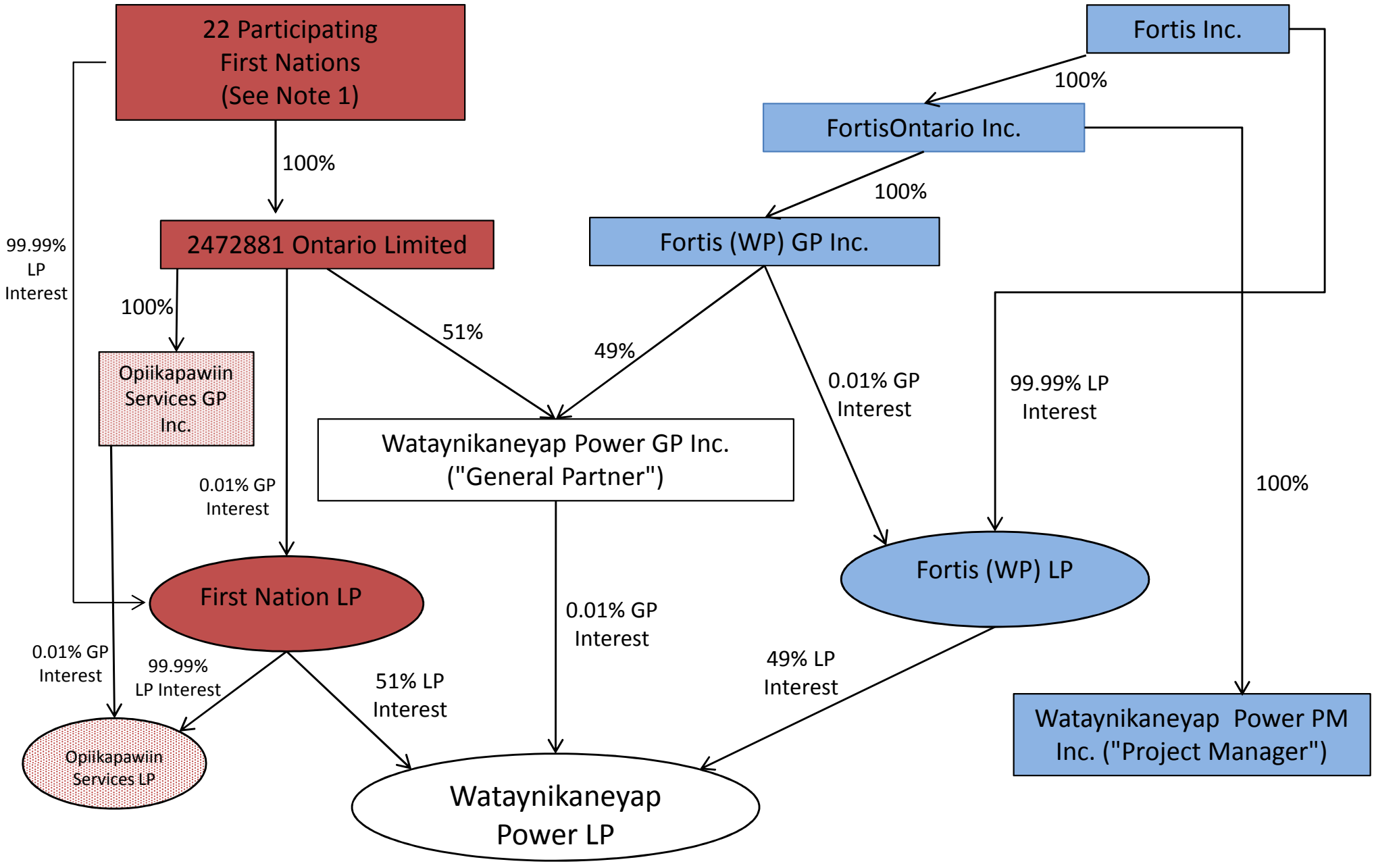
Description of Business Activities:

Opiikapawiin Services GP Inc. is the general partner of Opiikapawiin Services LP ("OSLP"), an Ontario Limited Partnership. As shown in Schedule 'C', the shares of Opiikapawiin Services GP Inc. are held by 2472881 Ontario Limited, which is wholly owned by the 22 Participating First Nations in equal shares. The limited partnership interests in OSLP are held by First Nation LP, which is also controlled by the 22 Participating First Nations. OSLP's business activities consist of administering projects and programs for WPLP in relation to community engagement, community readiness, education & training, business readiness, stakeholder engagement (including government relations), communications and capacity building. OSLP also provides support to First Nations LP in respect of managing its investment in WPLP, including seeking development funding and raising equity.

Schedule ‘C’

Corporate Organization Chart

Wataynikaneyap Power LP – Ownership Structure



Note 1: The Participating First Nations are Bearskin Lake, Cat Lake, Deer Lake, Kasabonika Lake, Keewaywin, Kingfisher Lake, Kitchenuhmaykoosib Inninuwug, Lac des Mille Lacs, Lac Seul, McDowell Lake, Muskrat Dam, North Caribou, North Spirit Lake, Pikangikum, Poplar Hill, Sachigo Lake, Sandy Lake, Slate Falls, Wabigoon Lake, Wapekeka, Wawakapewin and Wunnumin.

SCHEDULE "D"

Response to #14

As discussed in the cover letter accompanying this Application, the Applicant plans to construct, own and operate an approximately 117 km distribution line from Red Lake to the Pikangikum First Nation Reserve (the "Distribution System"). The Distribution System is being developed to address an urgent need for grid connection of the Pikangikum First Nation on an interim basis until the Pikangikum First Nation can be served by the Wataynikaneyap Power Transmission Project (the "Transmission Project"), which is currently being developed by the Applicant as a priority project pursuant to conditions of its transmission licence. The distribution line will go into service, thereby connecting the Pikangikum First Nation to the provincial electricity grid, by late 2018. Although WPLP intends to construct the majority of this line using 115 kV transmission level conductors, the line will initially be connected to Hydro One's distribution system and will operate at a distribution voltage (44kV) for a period of approximately 3-4 years. The facilities will be designed so that the majority of the line will be capable of being converted to transmission facilities in a manner that minimizes the need for additional cost or construction activity.

Once WPLP obtains leave to construct for its Transmission Project (including the conversion of the Distribution System to transmission) and the portion of the Transmission Project known as the Remote Connection Line north of Red Lake is ready to serve additional communities, the connection point of the Distribution System will be changed from Hydro One's distribution system to Hydro One's transmission system and will thereafter operate at 115 kV. These facilities will thereby be incorporated into the Transmission Project and will serve as the first leg of the Remote Connection Line north of Red Lake. The purpose of this unique sequencing is to enable the Pikangikum First Nation to connect to the grid sooner, participate in the WPLP Transmission Project, and avoid the duplication of electricity infrastructure in the region.

SCHEDULE "E"

Response to #15(a)

Background information about the Applicant and its partners is provided in Section 1 of the cover letter accompanying this Application. Each of the Applicant's partners, along with their respective affiliates, brings unique skills, resources and experience to WPLP, including with respect to technical and financial capabilities, project development capabilities and stakeholder relationship capabilities, as follows.

First Nation LP / First Nation GP

First Nation GP and First Nation LP hold controlling interests in WPGP and WPLP, as well as in Opiikapawiin Services GP and OSLP. The shares of First Nation GP, as well as the limited partnership interests in First Nation LP, are held directly by the 22 Participating First Nations, which are listed in section 1 of the cover letter. The Applicant's First Nation partners are experienced with electricity project development and bring considerable expertise with respect to stakeholdering with and within affected communities, as well as with key regulators and governmental authorities. Through their work on the Transmission Project, the First Nation partners also have experience with respect to transmission line routing and technical parameters, engagement of environmental and technical consultants and obtaining approvals from the Ministry of the Environment and Climate Change and other governmental authorities. In addition, the Participating First Nations, including in particular the Pikangikum First Nation, have a high level of experience and expertise with respect to the geographic area in which the Distribution System will be situated and the environmental attributes that will potentially be affected. Moreover, the Participating First Nations possess a unique capability for working with potentially affected stakeholders that may be affected by the project.

FortisOntario

FortisOntario Inc., an affiliate of Fortis Inc., owns and operates Canadian Niagara Power Inc. ("CNPI"), Cornwall Street Railway Light & Power Company Ltd. ("Cornwall Electric") and Algoma Power Inc. ("Algoma"). CNPI is a licensed and rate-regulated transmitter (ET-2003-0073) whose transmission facilities are interconnected with Hydro One Networks Inc. in Niagara Falls, Ontario, as well as with US National Grid in New York State. CNPI provides transmission service in and around Fort Erie, Ontario. CNPI is also a licensed distributor (ED-2002-0572) that provides electricity distribution service to the Town of Fort Erie, the City of Port Colborne and the Town of Gananoque. Algoma is a licensed distributor (ED-2009-0072) that serves customers in northern Ontario, north and east of the City of Sault Ste. Marie. Cornwall Electric is a licensed distributor (ED-2004-0405) that serves customers in Cornwall, Ontario. Together, these entities serve a combined 65,000 customers and operate approximately 3,430 km of transmission and distribution lines. FortisOntario also owns a 10 per cent strategic interest in each of Westario Power, Rideau St. Lawrence, and Grimsby Power, which collectively serve approximately 38,000 customers.

With respect to its significant recent development activity, Fortis Inc. has recently completed several key projects. For example, in 2015 through a partnership with Columbia Power

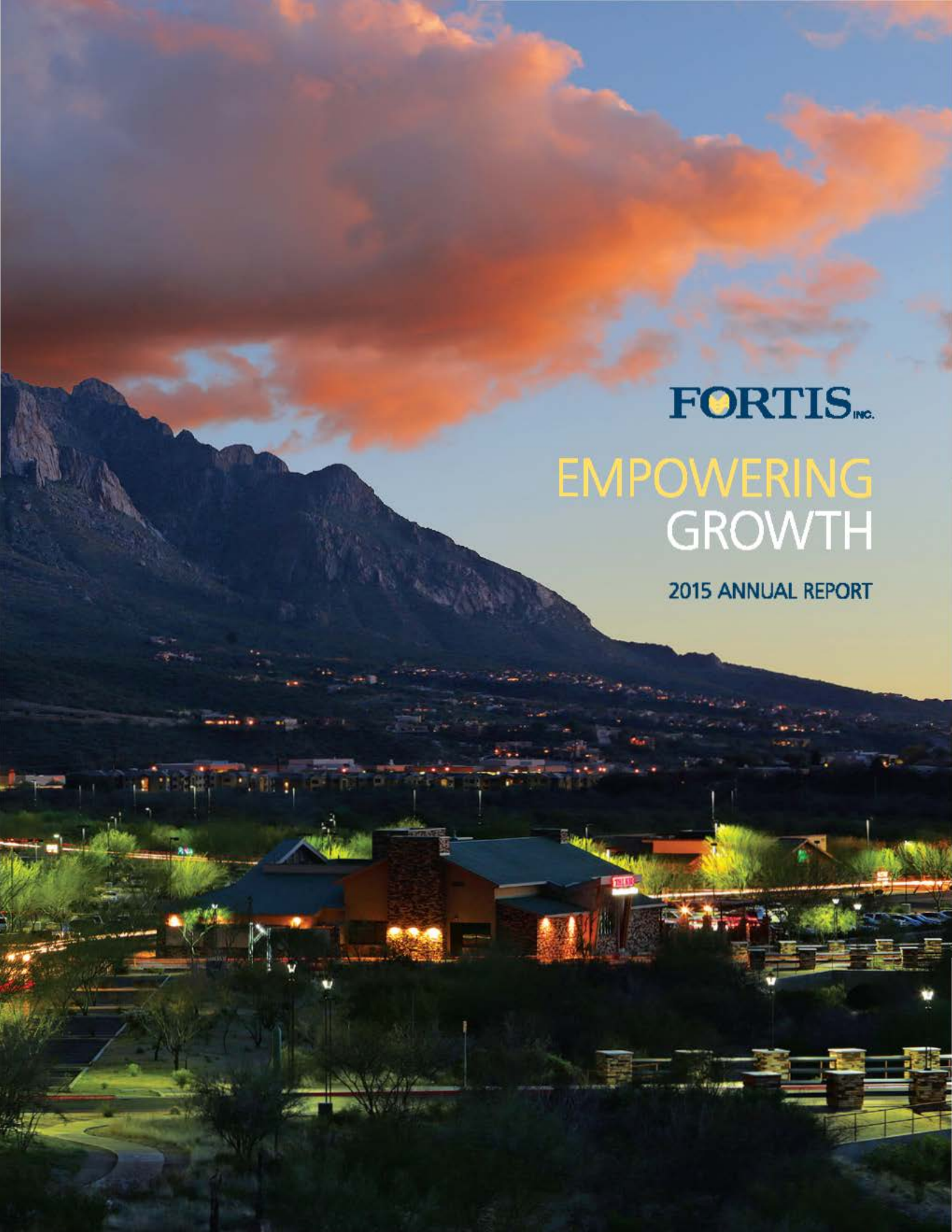
Corporation and Columbia Basin Trust, Fortis completed a 335 MW hydroelectric generating facility in British Columbia at an estimated cost of $900M. This project included construction of a 10 km, 230 kV transmission line. In 2011, Fortis Inc.'s subsidiary FortisBC completed its approximately 40 km, 230 kV Okanagan Transmission Reinforcement Project at a cost of approximately $100M. In 2011, FortisBC also completed the development of a liquefied natural gas facility and associated infrastructure, including a substation, 5 km 25kV power line and two 5 km natural gas transmission lines at an approximate cost of $200M. In addition, through its holdings in WPGP and WPLP, Fortis and FortisOntario are actively involved in developing the Wataynikaneyap Power Transmission Project in northwestern Ontario, as discussed in the cover letter to this Application.

Fortis Inc. is a leading North American electricity and gas utility company with total assets of approximately $48B and fiscal 2016 revenue of $6.8B. Its regulated utilities account for approximately 93% of its total assets and serve more than 3 million customers across Canada and in the United States and the Caribbean. Fortis Inc. currently operates a total of approximately 7,285 km of transmission lines and 182,233 km of distribution lines. It is a member of the Utilities Standards Forum, has dedicated engineering staff that has expertise with respect to a wide range of technical codes, standards and guidelines and has a sophisticated organization for material and equipment procurement. Fortis has significant experience with the acquisition and operation of rights-of-way. FortisOntario alone operates over 3,000 km of right-of-way, of which nearly 2,000 km is situated in northern Ontario. FortisOntario also has significant experience with respect to permitting, licensing and regulatory matters. FortisOntario has substantial construction experience as well, both in terms of its internal construction capabilities and in retaining and overseeing qualified construction contractors. Fortis Inc. owns and operates multiple operation centers across Canada, including six in Ontario. FortisOntario's day-to-day system operations are managed from two control rooms within Ontario. Through its distribution utilities, Fortis also has significant experience with the long-term assessment and management of distribution assets, including vegetation management, as well as with respect to environmental, health and safety compliance, regulatory compliance, community relations, human resources and finance.

The combined expertise, experience and resources of the Applicant, through its partners and their respective affiliates, provides the Applicant with a high level of technical and financial capability, expertise and experience with respect to the activities associated with this Application, including the development, construction, ownership and operation of distribution facilities.

Schedule ‘F’

Financial Information



FORTIS INC.

EMPOWERING GROWTH

2015 ANNUAL REPORT

FORTIS INC.

Quick Facts

BASED IN
ST. JOHN'S, NL

9 UTILITY OPERATIONS
IN CANADA, U.S. AND CARIBBEAN

7,700
EMPLOYEES **STRONG**

$29B
TOTAL **ASSETS**



- Regulated Gas
- Regulated Electric
- Long-Term Contracted Generation

NEWFOUNDLAND POWER
(NEWFOUNDLAND)

MARITIME ELECTRIC
(PRINCE EDWARD ISLAND)

FORTISONTARIO
(ONTARIO)

CENTRAL HUDSON
(NEW YORK STATE)

FORTIS TURKS AND CAICOS
(TURKS AND CAICOS ISLANDS)

CARIBBEAN UTILITIES
(GRAND CAYMAN)

BECOL
(BELIZE)

2 MILLION ELECTRIC
UTILITY CUSTOMERS

1.2 MILLION GAS
UTILITY CUSTOMERS

$10.5B
MARKET CAP
(as of December 31, 2015)

MEMBER OF THE
S&P/TSX 60







Regulated, Low Risk and Diversified

No jurisdiction accounts for more than one-third of total assets or operating earnings.

Business Segments

Regulated

Utility	Customers Electric (#)	Customers Gas (#)	Employees (#)	Peak Demand Electric (MW)	Peak Demand Gas (TJ)	Sales Electric (GWh)	Volumes Gas (PJ)	Earnings ($M)	Total Assets ($B)	2016F Midyear Rate Base ($B)	2016F Capital Program ($M)
UNS Energy	511,000	152,000	2,015	3,267	109	15,366	13	195	8.9	4.8	485
Central Hudson	300,000	79,000	966	1,059	140	5,132	24	58	3.2	1.6	228
FortisBC [1]	168,000	982,000	2,127	624	1,074	3,116	186	190	8.1	5.0	428
FortisAlberta	539,000	–	1,162	2,733	–	17,132	–	138	3.8	3.0	441
Eastern Canadian [2]	405,000	–	1,033	1,883	–	8,403	–	62	2.3	1.7	174
Caribbean Electric [3]	42,000	–	356	139	–	802	–	34	1.3	0.9	127
TOTAL	**1,965,000**	**1,213,000**	**7,659**	**9,705**	**1,323**	**49,951**	**223**	**677**	**27.6**	**17.0**	**1,883**

[1] *Includes FortisBC Energy and FortisBC Electric.*

[2] *Includes Newfoundland Power, Maritime Electric and FortisOntario.*

[3] *Includes Caribbean Utilities and Fortis Turks and Caicos. Data includes 100% of Caribbean Utilities' operations except for earnings, which represent Caribbean Utilities' contribution to consolidated earnings of Fortis based on the Corporation's approximate 60% ownership interest. Also includes the Corporation's 33% equity investment in Belize Electricity.*

Non-Regulated

	Generating Capacity (MW)	Employees (#)	Sales Energy (GWh)	Earnings [2] ($M)	Total Assets ($B)	2016F Capital Program ($M)
Fortis Generation [1]	407	34	844	77	1.0	18 [3]

[1] *Comprised of investments in British Columbia, Belize and Ontario.*

[2] *Earnings from non-utility operations were $114 million.*

[3] *Includes forecast capital expenditures of approximately $15 million at Fortis Generation and $3 million at FortisBC Alternative Energy Services Inc., which is reported in the Corporate and Other segment.*

All financial information is presented in Canadian dollars.
Information is for the fiscal year ended December 31, 2015 unless otherwise indicated.

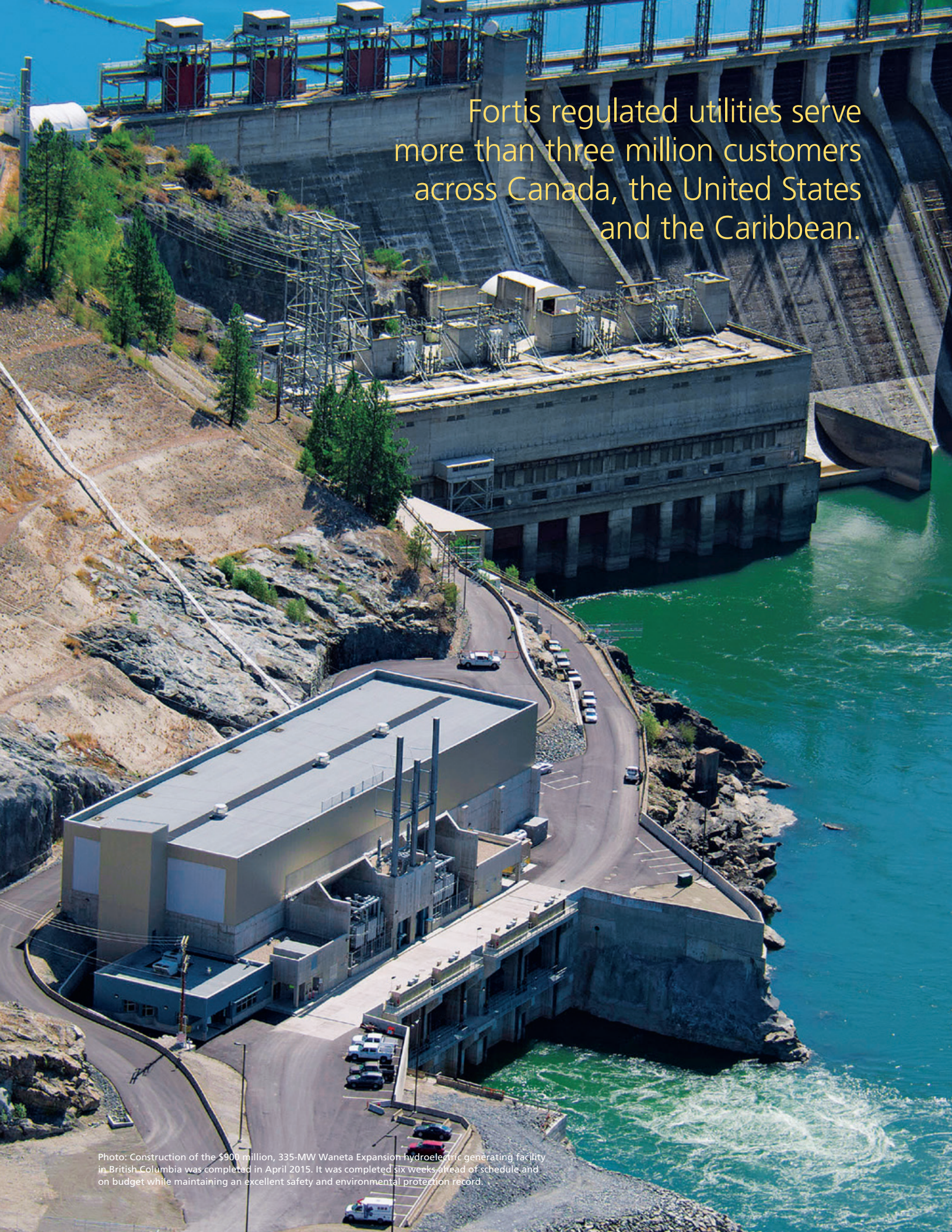


Photo: Construction of the $900 million, 335-MW Waneta Expansion hydroelectric generating facility in British Columbia was completed in April 2015. It was completed six weeks ahead of schedule and on budget while maintaining an excellent safety and environmental protection record.

Fortis is a leader in the North American electric and gas utility business with total assets of approximately $29B.

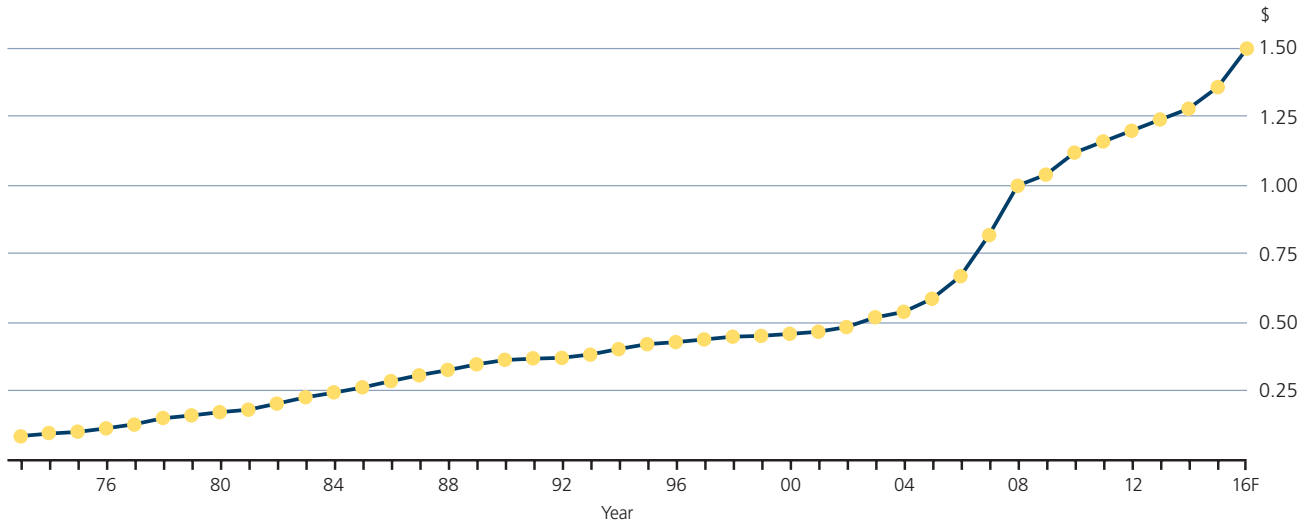


Photo: Fortis owns and/or operates more than 188,000 kilometres of transmission and distribution lines.

Strong Track Record of Total Shareholder Returns

2015 was the 42nd consecutive year of annual dividend increases and marked the introduction of dividend guidance for the first time, with an annual average dividend growth target of 6% through 2020.

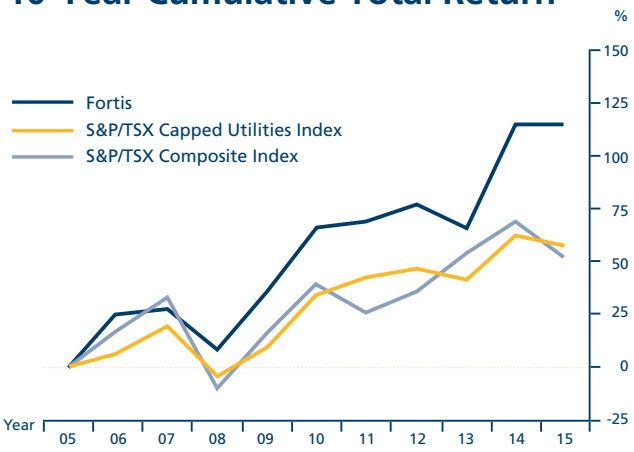
Dividends Paid Per Common Share



Achieved Average Annualized Total Shareholder Return of 8.2% Over the Last 10 Years

The 10-year cumulative total return of 116% for the period ended December 31, 2015 is approximately 60% higher than the performance of the S&P/TSX Capped Utilities and Composite indices.

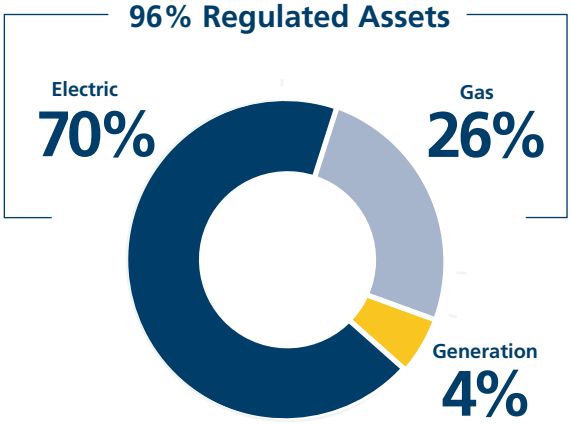
10-Year Cumulative Total Return



Total Assets Increased 9.9%

$29 Billion (as at December 31, 2015)

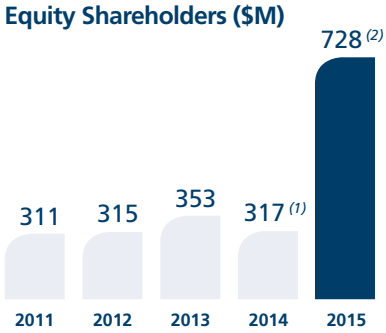
Total Assets



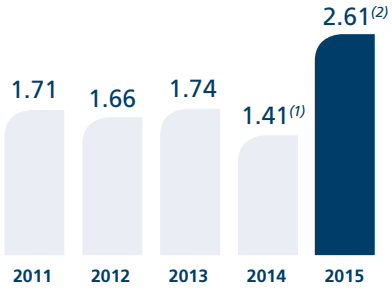
Financial Highlights

Fortis achieved record earnings in 2015, driven by its U.S. utility acquisitions, gains on non-core asset dispositions, completion of the Waneta hydroelectric generating facility (Waneta Expansion) and strong results from its Canadian utilities.

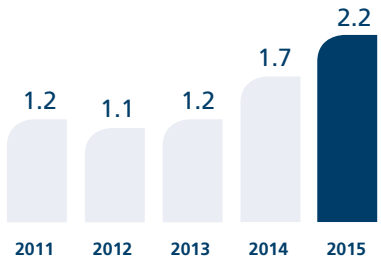
Earnings Attributable to Common Equity Shareholders ($M)



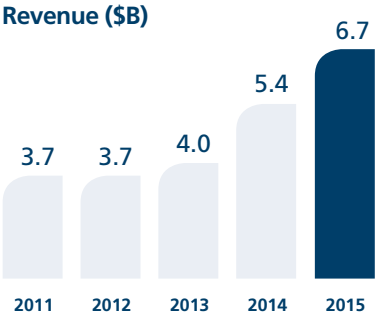
Basic Earnings per Common Share ($)



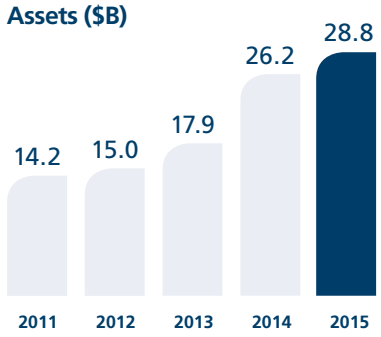
Capital Expenditures ($B)



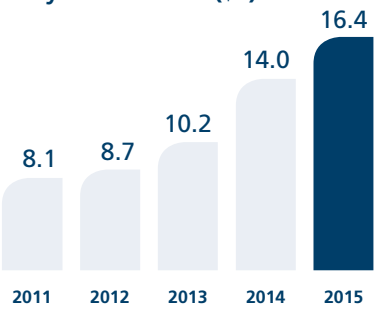
Revenue ($B)



Assets ($B)



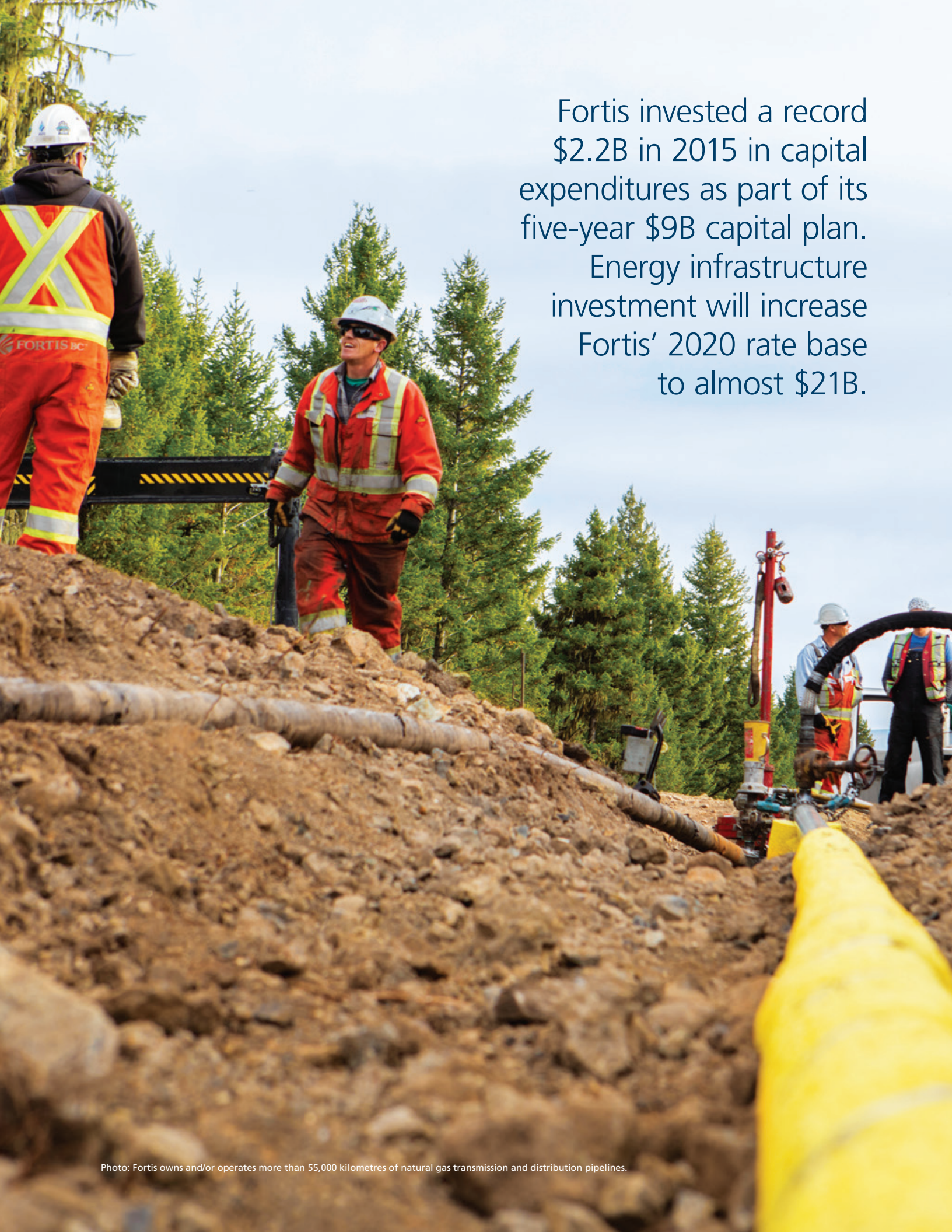
Midyear Rate Base ($B)



(1) *Results were impacted by non-recurring items, largely associated with the acquisition of UNS Energy in 2014.*

(2) *Results were impacted by a full year's contribution from UNS Energy, completion of the Waneta Expansion and non-recurring items, largely associated with gains on the sale of non-core assets.*

All financial information is presented in Canadian dollars.
Information is for the fiscal years ended December 31.



Fortis invested a record $2.2B in 2015 in capital expenditures as part of its five-year $9B capital plan. Energy infrastructure investment will increase Fortis' 2020 rate base to almost $21B.

Photo: Fortis owns and/or operates more than 55,000 kilometres of natural gas transmission and distribution pipelines.

Report to Shareholders

2015 was a remarkable year for Fortis

We advanced our business operationally and strategically, delivered record earnings, raised our dividend for the 42nd consecutive year and introduced dividend growth guidance of 6%, on average, annually through 2020. We successfully executed our annual capital expenditure plan, investing a record $2.2 billion in energy infrastructure. Our 2015 results illustrate the underlying strength of our business model, the breadth and depth of the management team, and our ability to drive performance across the organization.

Ongoing focus – strength & growth in our core business

Our priority continues to be the provision of safe, reliable, cost-effective energy service to our customers and the profitable expansion of our existing operations. We remain focused on executing our capital program and pursuing additional investment opportunities within existing service territories. Our stand-alone operating model and financial strength, driven by a strong balance sheet and investment-grade credit ratings, positions us well for future expansion and leadership in the North American utility sector.

Rate base is expected to be almost $21 billion in 2020

Over the five-year period through 2020, excluding the acquisition of ITC Holdings Corp., our capital program related to our existing operations is expected to be approximately $9 billion. This investment in energy infrastructure is expected to increase rate base to almost $21 billion in 2020, exclusive of new acquisitions, and produce a five-year compound annual growth rate of approximately 5%.

Fortis remains focused on being a leader in the North American utility industry and its strategic vision is guided by the goals of delivering long-term profitable growth and building shareholder value.



Barry Perry, President and CEO, Fortis Inc. (left) and David Norris, Chair of the Board, Fortis Inc. (right).

Report to Shareholders

Strong financial performance

We achieved record net earnings of $728 million, or $2.61 per common share. A number of factors drove our strong financial results in 2015. We were successful in selling non-core assets and achieved significant gains on these sales. The acquisition of UNS Energy, which we completed in August 2014, clearly had an important impact on our results, contributing $195 million in earnings. We also benefitted from the completion of the Waneta hydroelectric generating facility (Waneta Expansion), the strength of the US dollar relative to the Canadian dollar, strong results from our Canadian utilities, and the resetting of customer rates at Central Hudson. Adjusted net earnings attributable to common equity shareholders for 2015 were $589 million, or $2.11 per common share, an increase of $195 million, or $0.36 per common share, over 2014. Cash flow from operations totalled $1.7 billion, 70% higher than last year, largely driven by higher cash earnings.

Record capital investment

Consolidated capital expenditures totalled $2.2 billion in 2015, representing the largest capital program in the history of Fortis. These investments fuel growth in our rate base, which midyear was $16.4 billion. The majority of our capital projects are small and highly executable, but in 2015 we did successfully complete our largest project to date: the $900 million, 335-megawatt (MW) Waneta Expansion. We also continued to advance other projects across our businesses, including the following key projects:

FortisBC Energy – Tilbury LNG Facility Expansion

Construction efforts in 2015 focused on building the storage tank and liquefaction process areas. We expect the project, which includes a second liquefied natural gas (LNG) tank and a new liquefier, to be in service around the end of 2016. Total project costs to the end of 2015 were approximately $326 million, with $181 million invested in 2015.

FortisAlberta – Pole-Management Program

During 2015 FortisAlberta continued with the replacement of vintage poles under its Pole-Management Program. The total capital cost of the program through 2020 is expected to be approximately $336 million, with $41 million invested in 2015, for a total of $200 million to date.

UNS Energy – Residential Solar Program and Pinal Transmission Project

UNS Energy, which ranks among the top 10 utilities in the United States for installing new solar capacity and per-capita additions to its solar energy portfolio, advanced its Residential Solar Program in partnership with local solar companies. This partnership allows UNS Energy to own and install rooftop solar systems for residential customers. The total capital cost of the program through 2020 is expected to be approximately US$82 million, with US$16 million to be invested in 2016. UNS Energy also completed the Pinal Transmission Project in 2015 at a total project cost of US$79 million. The project consisted of the construction of a 500-kilovolt (kV) transmission line in Pinal County that will increase UNS Energy's import capacity from Gila River Unit 3 and the Palo Verde trading hub.

Significant progress in renewable energy

In partnership with Columbia Power Corporation and Columbia Basin Trust, Fortis completed the 335-MW Waneta Expansion near Trail, British Columbia. The output of the Waneta Expansion is being sold to BC Hydro and FortisBC under 40-year contracts. The Waneta Expansion has added a second powerhouse that shares the existing hydraulic head and generates clean, renewable, cost-efficient power from water that would otherwise be spilled. The project included construction of a 10-kilometre, 230-kV transmission line and provides enough energy to power approximately 60,000 homes per year. It was completed six weeks ahead of schedule and on budget while maintaining an excellent safety and environmental protection record.

Solid credit metrics

Maintaining solid investment-grade credit ratings through a strong balance sheet and ample liquidity is a priority for us. As of year-end, we had unused consolidated credit facilities that totalled approximately $2.4 billion.

Underlying confidence in our business allows us to initiate dividend guidance

The strength of our business and the confidence in our future allowed us in 2015 to raise our dividend twice as well as initiate dividend guidance. We ended the year with a quarterly dividend that translates into an annualized dividend of $1.50 per share, and we are targeting average annualized dividend growth of 6% through 2020. We are proud of our 42-year track record of annual dividend increases, and believe that our low-risk, predictable and diversified business will allow us to meet our dividend growth targets.

Sharpening our focus on our core regulated utility businesses

After two major acquisitions in the previous two years, we spent 2015 focusing on our base business and integrating our Arizona utility, UNS Energy. As part of sharpening our focus on our core utility business in 2015, we divested our commercial real estate and hotel business, as well as some small non-regulated generation assets. We realized proceeds of almost $900 million from these sales, which were used primarily to repay credit facility borrowings – largely associated with the acquisition of UNS Energy.

We continue to look for investment opportunities in energy-related infrastructure

While Fortis expects long-term sustainable growth in rate base, earnings, and shareholder returns from investment in its existing utility operations, it is also committed to identifying and executing on opportunities for additional growth through investments in existing service territories.

We delivered on this commitment with the announcement in December of the acquisition of the Aitken Creek Gas Storage Facility (Aitken Creek) for approximately US$266 million. Aitken Creek is the largest gas storage facility in British Columbia with a total working gas capacity of 77 billion cubic feet and is an integral part of Western Canada's natural gas transmission network. We anticipate that this transaction will close in the first half of 2016.

Active regulatory calendar

Fortis focuses on maintaining constructive regulatory relationships and outcomes across its utilities. Our regulatory calendar remains active. There were some important decisions and advancements in 2015, including a three-year rate settlement that saw a resetting of customer rates effective July 1 at Central Hudson; as well as decisions on Capital Tracker Applications and a Generic Cost of Capital Proceeding at FortisAlberta.

We expect 2016 to also be an active year, with the advancement of the general rate applications at Tucson Electric Power for new retail rates effective January 1, 2017 and at Newfoundland Power for new rates effective July 1, 2016; Reforming the Energy Vision proceeding progressing in New York State; Generic Cost of Capital Proceedings in British Columbia and Alberta; and a Capital Tracker application at FortisAlberta.

Empowering leaders to grow the business

We continue to empower the leaders of our utilities to drive performance, discover new investment opportunities and foster talent. Enterprise-wide talent management and development has been elevated to a strategic priority as we prepare for the next stage of growth at Fortis. As part of this initiative we have appointed Nora Duke, Executive Vice President, Corporate Services and Chief Human Resource Officer. Nora is a veteran of Fortis, having spent almost 30 years with the organization, most recently as President and Chief Executive Officer of Fortis Properties.

Environmental sustainability – Fortis at the forefront of industry change

The North American electric utility industry continues to evolve and change. The most notable changes include a continued focus on clean energy and energy conservation initiatives, while balancing technology advancements and changes in customer needs. With increasing levels of solar usage and plans for a significant shift away from coal generation in Arizona, as well as major regulatory reform ongoing in New York, Fortis subsidiaries in the United States are at the centre of many of the key trends within the industry.

Our strategy is to ensure that we are well positioned to embrace these opportunities, facilitate public policy objectives, and collaborate with customers and regulators on outcomes that preserve the strength of the grid and role of the incumbent utilities. This, in turn, will allow us to deliver on our growth objectives.

Report to Shareholders

Acquisition of ITC Holdings Corp.

Fortis has grown its business through strategic acquisitions that have contributed to the strong organic growth of the Corporation over the past decade. On February 9, 2016, Fortis announced it would be acquiring ITC Holdings Corp. (ITC) in a transaction valued at approximately US$11.3 billion. We expect this accretive acquisition will support our growth strategy, as well as further strengthen and diversify our business.

ITC is the largest independent pure-play electric transmission company in the United States. The Michigan-based company owns and operates high-voltage transmission facilities, serving a combined peak load exceeding 26,000 MW along approximately 15,600 circuit miles of transmission line. ITC's rate base is expected to grow at a compound annual rate of approximately 7.5% through 2018, and its rates are regulated by the Federal Energy Regulatory Commission (FERC), which has been one of the most consistently supportive regulators in North America, providing reasonable returns and equity ratios.

The combined company will be one of the largest investor-owned North American utilities, with an expected consolidated 2016 midyear rate base of $26 billion. Following the completion of the acquisition, our utilities in the United States will represent approximately 60% of our regulated earnings and assets. As part of the ITC transaction, Fortis expects to list its common shares on the New York Stock Exchange (NYSE) under the ticker symbol FTS. Listing on the NYSE will provide access to larger pools of capital and likely increase trading of our shares.

Shareholders can expect to hear more from us in 2016 as we move through key milestones leading up to closing, including shareholder approval for both companies and various regulatory approvals. Closing is expected to occur in late 2016.

Looking forward

Fortis is continuing on its sound and successful, time-tested strategy: a well-managed, low-risk, highly diversified utility that has a measured and disciplined approach to growth.

Fortis remains focused on being a leader in the North American utility industry and its strategic vision is guided by the goals of delivering long-term profitable growth and building shareholder value. We measure our financial and operational performance primarily through growth in earnings per common share and total shareholder return.

Over the 10-year period ended December 31, 2015, earnings per common share of Fortis grew at a compound annual growth rate of 4.6%, on an adjusted basis. Over the same period, Fortis delivered an average annualized total return to shareholders of 8.2%, exceeding the S&P/TSX Capped Utilities and S&P/TSX Composite indices, which delivered average annualized performance of 4.6% and 4.2%, respectively, over the same period.

Clearly, we are confident about the future of Fortis. Our success to date and our future prospects have, and will always be, the result of the hard work of our talented and dedicated people, and to the strong corporate culture of Fortis. To each and every one of our employees, your hard work and commitment to customers underpins the success of Fortis. Thank you for your ongoing contribution.

It is with regret that we acknowledge the resignation of Paul Bonavia from our Board in February 2016. Paul withdrew from the Fortis Board in order to remain in compliance with the rules of another entity of which he is a director. We wish to express our genuine gratitude to Paul for his insight and valuable contribution to the Board and extend our best wishes to him for the future. Finally, we also extend our sincerest appreciation to all of our colleagues on the Board of Directors for your continuing dedication, insight and support.

On behalf of the Board of Directors,



David G. Norris
Chair of the Board,
Fortis Inc.



Barry V. Perry
President and Chief Executive Officer,
Fortis Inc.

Fortis Inc. – H. Stanley Marshall Memorial Scholarship



H. Stanley Marshall retired as President and CEO from Fortis in 2014, after building a formidable legacy at Fortis. He has left an indelible imprint on our culture, vision and values.

During 2015 Fortis established an endowed scholarship in recognition of his contribution to the Corporation's success. The *Fortis Inc. – H. Stanley Marshall Memorial Scholarship* will support undergraduate students from a Caribbean country entering a professional school or faculty at Memorial University of Newfoundland. Fortis has a strong link to the Caribbean through its operations there, beginning in 1999 with the acquisition of an electric utility in Belize.

Honouring Our Past

In keeping with Fortis' proud Newfoundland history and roots, and honouring its provincial heritage, Fortis became a Centennial Leader with a $3.25 million donation to the *Where Once They Stood We Stand* capital campaign.

With this donation, Fortis became the lead corporate supporter to commemorate Newfoundland's contribution to the First World War and the Battle of Beaumont-Hamel. Both the First World War Exhibition and The Rooms Site Courtyard area will serve as a perpetual monument to Newfoundland's contribution to the First World War, and will be dedicated by the Centennial Lead Donors on July 1, 2016 to all those who served overseas and on the home front.

We encourage those of you living here in Newfoundland or visiting to join us and other supporters to open this important monument and honour those who served Newfoundland and the British Empire.



Photo Credit: The Rooms: NA 3106. Opening of the Newfoundland Memorial Park, Beaumont-Hamel, France. 7 June 1925.

Management Discussion and Analysis

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Dated February 17, 2016

FORWARD-LOOKING INFORMATION

The following Fortis Inc. ("Fortis" or the "Corporation") Management Discussion and Analysis ("MD&A") has been prepared in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations*. The MD&A should be read in conjunction with the Audited Consolidated Financial Statements and notes thereto for the year ended December 31, 2015. Financial information for 2015 and comparative periods contained in the MD&A has been prepared in accordance with accounting principles generally accepted in the United States ("US GAAP") and is presented in Canadian dollars unless otherwise specified.

Fortis includes forward-looking information in the MD&A within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the safe harbour provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "target", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs based on information currently available. The forward-looking information in the MD&A includes, but is not limited to, statements related to the acquisition of ITC Holdings Corp. ("ITC"), the expected timing and conditions precedent to the closing of the acquisition of ITC, including shareholder approvals of both ITC and Fortis, regulatory approvals, governmental approvals and other customary closing conditions; the expectation that Fortis will borrow funds to satisfy its obligation to pay the cash portion of the purchase price and will issue securities to pay the balance of the purchase price; the assumption of ITC debt and expected maintenance of investment-grade credit ratings; the impact of the acquisition on the Corporation's earnings, midyear rate base, credit rating, estimated enterprise value and compound annual growth rate; the expectation that the acquisition of ITC will be accretive in the first full year following closing and that the acquisition will support the average annual dividend growth target of Fortis; the expectation that the Corporation will become a U.S. Securities and Exchange Commission registrant and have its common shares listed on the New York Stock Exchange in connection with the acquisition; the expectation that Fortis will identify one or more minority investors to invest in ITC; the annualized 2016 common share dividend; targeted annual dividend growth through 2020; the expectation that there will be a significant reduction in the use of coal in certain of UNS Energy's generating facilities by 2022; the acquisition of a share of Aitken Creek Gas Storage facility, the expected timing, total expected consideration and conditions precedent to the closing of such acquisition, including regulatory approval; the expected timing of filing of regulatory applications and receipt and outcome of regulatory decisions; the expectation that midyear rate base will increase from 2016 to 2020; the Corporation's forecast gross consolidated capital expenditures for 2016 and total capital spending over the five-year period from 2016 through 2020; the nature, timing and expected costs of certain capital projects including, without limitation, the Tilbury liquefied natural gas ("LNG") facility expansion, the pipeline expansion to the Woodfibre LNG site, the development of a diesel power plant in Grand Cayman, the Residential Solar Program, the Gas Main Replacement Program, the Lower Mainland System Upgrade, the Pole Management Program, and

additional opportunities including electric transmission, LNG and renewable related infrastructure and generation; the expectation that the Corporation's significant capital expenditure program will support continuing growth in earnings and dividends; the expectation that cash required to complete subsidiary capital expenditure programs will be sourced from a combination of cash from operations, borrowings under credit facilities, equity injections from Fortis and long-term debt offerings; the expectation that the Corporation's subsidiaries will be able to source the cash required to fund their 2016 capital expenditure programs, operating and interest costs, and dividend payments; the expected consolidated fixed-term debt maturities and repayments in 2016 and on average annually over the next five years; the expectation that long-term debt will not be settled prior to maturity; the expectation that the Corporation and its subsidiaries will continue to have reasonable access to capital in the near to long terms; the expectation that the combination of available credit facilities and relatively low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets; the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants during 2016; the intent of management to hedge future exchange rate fluctuations and monitor its foreign currency exposure; the expectation that economic conditions in Arizona will improve; the expectation that any liability from current legal proceedings will not have a material adverse effect on the Corporation's consolidated financial position and results of operations; and the expectation that the adoption of future accounting pronouncements will not have a material impact on the Corporation's consolidated financial statements.

The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders, no material adverse regulatory decisions being received, and the expectation of regulatory stability; no material capital project and financing cost overrun related to any of the Corporation's capital projects; the realization of additional opportunities including natural gas related infrastructure and generation; the Board of Directors exercising its discretion to declare dividends, taking into account the business performance and financial conditions of the Corporation; no significant variability in interest rates; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the continued ability to maintain the electricity and gas systems to ensure their continued performance; no severe and prolonged downturn in economic conditions; no significant decline in capital spending; sufficient liquidity and capital resources; the continuation of regulator-approved mechanisms to flow through the cost of natural gas and energy supply costs in customer rates; the ability to hedge exposures to fluctuations in foreign exchange rates, natural gas prices and electricity prices; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas, fuel, coal and electricity supply; continuation and regulatory approval of power supply and capacity purchase contracts; the ability to fund defined benefit pension plans, earn the assumed long-term rates of return on the related assets and recover net pension costs in customer rates; no significant changes in government energy plans and environmental laws that may materially negatively affect the operations and cash flows of the Corporation and its subsidiaries; no material change in public policies and directions by governments that could materially negatively affect the Corporation and its subsidiaries; new or revised environmental laws and regulations will not severely affect the results of operations; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; the ability to report under US GAAP beyond 2018 or the adoption of International Financial Reporting Standards after 2018 that allows for the recognition of regulatory assets and liabilities; the continued tax-deferred treatment of earnings from the Corporation's Caribbean operations; continued maintenance of information technology infrastructure; continued favourable relations with First Nations; favourable labour relations; that the Corporation can reasonably assess the merit of and potential liability attributable to ongoing legal proceedings; and sufficient human resources to deliver service and execute the capital program.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Risk factors which could cause results or events to differ from current expectations are detailed under the heading "Business Risk Management" in this MD&A and in continuous disclosure materials filed from time to time with Canadian securities regulatory authorities. Key risk factors for 2016 include, but are not limited to: uncertainty regarding the completion of the acquisition of ITC including but not limited to the receipt of shareholder approvals of ITC and Fortis, the receipt of regulatory and other governmental approvals, the availability of financing sources at the desired time or at all, on cost-efficient or commercially reasonable terms and the satisfaction or waiver of certain other conditions to closing; uncertainty related to the realization of some or all of the expected benefits of the acquisition of ITC; uncertainty regarding the outcome of regulatory proceedings of the Corporation's utilities; uncertainty of the impact a continuation of a low interest rate environment may have on the allowed rate of return on common shareholders' equity at the Corporation's regulated utilities; the impact of fluctuations in foreign exchange rates; and risk associated with the impact of less favorable economic conditions on the Corporation's results of operations.

All forward-looking information in the MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.


Karl Smith, *EVP, CFO, Fortis Inc.*

CORPORATE OVERVIEW

Fortis is a leader in the North American electric and gas utility business, with total assets of approximately $29 billion and fiscal 2015 revenue of $6.7 billion. The Corporation's asset mix is approximately 96% regulated (70% electric, 26% gas), with the remaining 4% comprised of long-term contracted hydroelectric operations. The Corporation's regulated utilities serve more than 3 million customers across Canada and in the United States and the Caribbean. In 2015 the Corporation's electricity distribution systems met a combined peak demand of 9,705 megawatts ("MW") and its gas distribution systems met a peak day demand of 1,323 terajoules.

The Corporation's main business, utility operations, is highly regulated and the earnings of the Corporation's regulated utilities are primarily determined under cost of service ("COS") regulation and, in certain jurisdictions, performance-based rate-setting ("PBR") mechanisms. Generally, under COS regulation the respective regulatory authority sets customer electricity and/or gas rates to permit a reasonable opportunity for the utility to recover, on a timely basis, estimated costs of providing service to customers, including a fair rate of return on a regulatory deemed or targeted capital structure applied to an approved regulatory asset value ("rate base"). The ability of a regulated utility to recover prudently incurred costs of providing service and earn the regulator-approved rate of return on common shareholders' equity ("ROE") and/or rate of return on rate base assets ("ROA") depends on the utility achieving the forecasts established in the rate-setting processes. If a historical test year is used to set customer rates, there may be regulatory lag between when costs are incurred and when they are reflected in customer rates. When PBR mechanisms are utilized in determining annual revenue requirements and resulting customer rates, a formula is generally applied that incorporates inflation and assumed productivity improvements. The use of PBR mechanisms should allow a utility a reasonable opportunity to recover prudently incurred costs and earn its allowed ROE or ROA.

Earnings of regulated utilities may be impacted by: (i) changes in the regulator-approved allowed ROE and/or ROA and common equity component of capital structure; (ii) changes in rate base; (iii) changes in energy sales or gas delivery volumes; (iv) changes in the number and composition of customers; (v) variances between actual expenses incurred and forecast expenses used to determine revenue requirements and set customer rates; and (vi) regulatory lag in the case of a historical test year. When future test years are used to establish revenue requirements and set base customer rates, these rates are not adjusted as a result of the actual COS being different from that which is estimated, other than for certain prescribed costs that are eligible to be deferred on the balance sheet. In addition, the Corporation's regulated utilities, where applicable, are permitted by their respective regulatory authority to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms.

Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation assets, which are treated as a separate segment. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each entity within the reporting segments operates with substantial autonomy, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following summary describes the operations included in each of the Corporation's reportable segments.

Regulated Utilities

The Corporation's interests in regulated electric and gas utilities are as follows.

Regulated Electric & Gas Utilities – United States

a. *UNS Energy:* Primarily comprised of Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas"), (collectively, the "UNS Utilities"), acquired by Fortis in August 2014.

   TEP, UNS Energy's largest operating subsidiary, is a vertically integrated regulated electric utility. TEP generates, transmits and distributes electricity to approximately 417,000 retail customers in southeastern Arizona, including the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP also sells wholesale electricity to other entities in the western United States.

   UNS Electric is a vertically integrated regulated electric utility, which generates, transmits and distributes electricity to approximately 94,000 retail customers in Arizona's Mohave and Santa Cruz counties.

TEP and UNS Electric currently own generation resources with an aggregate capacity of 2,799 MW, including 54 MW of solar capacity. Several of the generating assets in which TEP and UNS Electric have an interest are jointly owned. As at December 31, 2015, approximately 43% of the generating capacity was fuelled by coal.

UNS Gas is a regulated gas distribution utility, serving approximately 152,000 retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties.

b. *Central Hudson:* Central Hudson Gas & Electric Corporation ("Central Hudson") is a regulated transmission and distribution ("T&D") utility, serving approximately 300,000 electricity customers and 79,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. The Company owns gas-fired and hydroelectric generating capacity totalling 64 MW.

Regulated Gas Utility – Canadian

FortisBC Energy: Primarily includes FortisBC Energy Inc. ("FortisBC Energy" or "FEI") and, prior to December 31, 2014, FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy (Whistler) Inc. ("FEWI"). On December 31, 2014, FEI, FEVI and FEWI were amalgamated and FEI is the resulting Company. FEI is the largest distributor of natural gas in British Columbia, serving approximately 982,000 customers in more than 135 communities. Major areas served by the Company are the Lower Mainland, Vancouver Island and Whistler regions of British Columbia. FEI provides T&D services to customers, and obtains natural gas supplies on behalf of most residential, commercial and industrial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through FEI's Southern Crossing pipeline, from Alberta.

Regulated Electric Utilities – Canadian

a. *FortisAlberta:* FortisAlberta Inc. ("FortisAlberta") owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, serving approximately 539,000 customers. The Company does not own or operate generation or transmission assets and is not involved in the direct sale of electricity.

b. *FortisBC Electric:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia, serving approximately 168,000 customers directly and indirectly. FortisBC Inc. owns four hydroelectric generating facilities with a combined capacity of 225 MW. Also included in the FortisBC Electric segment are the operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generating facility owned by Teck Metals Ltd. and BC Hydro; the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion"), owned by Fortis and Columbia Power Corporation and Columbia Basin Trust ("CPC/CBT"); the 149-MW Brilliant hydroelectric plant and the 120-MW Brilliant hydroelectric expansion plant, both owned by CPC/CBT; and the 185-MW Arrow Lakes hydroelectric plant owned by CPC/CBT.

c. *Eastern Canadian:* Comprised of Newfoundland Power Inc. ("Newfoundland Power"), Maritime Electric Company, Limited ("Maritime Electric") and FortisOntario Inc. ("FortisOntario"). Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador, serving approximately 262,000 customers. Newfoundland Power has an installed generating capacity of 139 MW, of which 97 MW is hydroelectric generation. Maritime Electric is an integrated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI"), serving approximately 78,000 customers. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to approximately 65,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario's operations are primarily comprised of Canadian Niagara Power Inc. ("Canadian Niagara Power"), Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric") and Algoma Power Inc. ("Algoma Power").

Regulated Electric Utilities – Caribbean

The Regulated Electric Utilities – Caribbean segment includes the Corporation's approximate 60% controlling ownership interest in Caribbean Utilities Company, Ltd. ("Caribbean Utilities") (December 31, 2014 – 60%), Fortis Turks and Caicos, and the Corporation's 33% equity investment in Belize Electricity Limited ("Belize Electricity"). Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands, serving approximately 28,000 customers. The Company has an installed diesel-powered generating capacity of 132 MW. Caribbean Utilities is a public company traded on the Toronto Stock Exchange ("TSX") (TSX:CUP.U). Fortis Turks and Caicos is comprised of two integrated electric utilities serving approximately 14,000 customers on certain islands in Turks and Caicos. The utilities have a combined diesel-powered generating capacity of 82 MW. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize.

Non-Regulated – Fortis Generation

Fortis Generation is primarily comprised of long-term contracted generation assets in British Columbia and Belize. Generating assets in British Columbia include the Corporation's 51% controlling ownership interest in the 335-MW Waneta Expansion. Construction of the Waneta Expansion was completed in April 2015 and the output is sold to BC Hydro and FortisBC Electric under 40-year contracts. The Corporation's 51% controlling ownership interest in the Waneta Expansion is conducted through the Waneta Expansion Limited Partnership ("Waneta Partnership"), with CPC/CBT holding the remaining 49% interest.

Generating assets in Belize are comprised of three hydroelectric generating facilities with a combined capacity of 51 MW. All of the output of these facilities is sold to Belize Electricity under 50-year power purchase agreements ("PPAs") expiring in 2055 and 2060. The hydroelectric generation operations in Belize are conducted through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the Government of Belize ("GOB").

As at December 31, 2015, the 16-MW run-of-river Walden hydroelectric generating facility has been classified as held for sale.

In June 2015 and July 2015 the Corporation sold its non-regulated generation assets in Upstate New York and Ontario, respectively.

Non-Regulated – Non-Utility

The Non-Utility segment previously included Fortis Properties Corporation ("Fortis Properties") and Griffith Energy Services, Inc. ("Griffith"). Fortis Properties completed the sale of its commercial real estate assets in June 2015 and its hotel assets in October 2015. For further information, refer to the "Significant Items" section of this MD&A. Griffith was sold in March 2014.

Corporate and Other

The Corporate and Other segment captures expense and revenue items not specifically related to any reportable segment and those business operations that are below the required threshold for reporting as separate segments. The Corporate and Other segment includes net corporate expenses of Fortis and non-regulated holding company expenses of FortisBC Holdings Inc. ("FHI"), CH Energy Group, Inc. and UNS Energy Corporation. Also included in the Corporate and Other segment are the financial results of FortisBC Alternative Energy Services Inc. ("FAES"). FAES is a wholly owned subsidiary of FHI that provides alternative energy solutions, including thermal-energy and geo-exchange systems.

CORPORATE STRATEGY

The principal business of Fortis is the ownership and operation of regulated electric and gas utilities. The Corporation remains focused on being a leader in the North American utility industry and its strategic vision is guided by the goals of delivering long-term profitable growth and building shareholder value. Earnings per common share and total shareholder return are the primary measures of financial performance.

Over the 10-year period ended December 31, 2015, earnings per common share of Fortis grew at a compound annual growth rate of 4.6%, on an adjusted basis. Over the same period, Fortis delivered an average annualized total return to shareholders of 8.2%, exceeding the S&P/TSX Capped Utilities and S&P/TSX Composite Indices, which delivered average annualized performance of 4.6% and 4.2%, respectively, over the same period.

The Corporation's first priority remains the continued profitable expansion of existing operations. Management remains focused on executing the consolidated capital program and pursuing additional investment opportunities within existing service territories. Fortis has also demonstrated its ability to acquire additional regulated utilities in Canada and the United States. The Corporation's standalone operating model and financial strength, driven by a strong balance sheet and investment-grade credit ratings, positions it well for future investment opportunities in existing and new franchise areas.

KEY TRENDS, RISKS AND OPPORTUNITIES

Pending Acquisition of ITC Holdings Corp.: On February 9, 2016, Fortis and ITC Holdings Corp. ("ITC") (NYSE:ITC) entered into an agreement and plan of merger pursuant to which Fortis will acquire ITC in a transaction (the "Acquisition") valued at approximately US$11.3 billion, based on the closing price for Fortis common shares and the foreign exchange rate on February 8, 2016. For details on the Acquisition, including transaction details, strategic rationale and acquisition financing, refer to the "Subsequent Event" section of this MD&A, and for a discussion of risks associated with the Acquisition, refer to the "Business Risk Management – Risks Associated with the Acquisition of ITC" section of this MD&A.

Electric Utility Industry Developments: The North American electric utility industry has changed significantly over the past several years. The most notable changes include a continued focus on clean energy and energy conservation initiatives, while balancing technology advancements and changes in customer needs. At the same time, the continued low interest rate environment and decrease in world oil and gas prices are having significant impacts on the North American economy. Notwithstanding the changes occurring in the utility industry, safety, reliability and serving customers at the lowest reasonable cost remain at the forefront of the utility industry's focus.

Government and regulatory policy in Canada and the United States is being directed at environmental protection and energy efficiency. The increasing availability of cleaner sources of power generation are driving new environmental regulation designed to eliminate or reduce dependence on traditional sources of electricity power generation, such as coal. The availability of cheaper, cleaner burning natural gas, as well as growing accessibility of renewable or alternative energy sources like solar are encouraging governments to deploy aggressive targets for the removal of high carbon emission sources of energy. Reaching these targets will require the shutdown of certain high carbon emission generating plants earlier than planned, which is an issue that utilities and regulators need to address. These environmental regulations are, however, expected to create additional investment opportunities in renewable power generation and related energy infrastructure. Fortis' regulated utilities are actively involved in pursuing these opportunities.

Technological development, particularly in the area of distributed generation, is playing a significant role in the transformation of the utility industry. Although distributed generation customers remain connected to the electrical system and benefit from that connection, they avoid paying much of the fixed operating and maintenance costs because they can offset a portion of their volumetric energy usage with their own systems. This results in an increasing amount of utility costs that are ultimately shifted to other customers. The declining cost of certain types of distributed generation technologies, together with government subsidization, is encouraging increased adoption by customers. Not only does this expose the utility to declining revenue because of a decrease in energy sales, the rate structure serves to shift an increasing burden for these costs on those customers that do not have distributed generation, such as rooftop solar. Traditional rate designs have not been structured to ensure fairness among all customers, which is a focus for utilities and regulators. Fortis, through its subsidiaries, is working with its regulators to address these rate design issues for its customers.

Despite the challenges facing the utility industry, Fortis is well positioned to meet these headwinds and capitalize on any resulting opportunities. Its decentralized structure and customer focused business culture will support the efforts required to both meet evolving customer expectations and to work with policy makers and regulators on solutions that are financially sustainable for the utilities. Leveraging those relationships to get out in front of these evolving challenges will be essential to meeting the industry challenges.

Natural Gas Opportunities: FortisBC Energy continues to pursue opportunities in British Columbia related to gas infrastructure. The combination of an abundant supply of natural gas, low costs for natural gas and supportive government policy are generating new interest for large industrial customers and niche liquefied natural gas ("LNG") producers to utilize FortisBC Energy's gas system.

In 2013 the Government of British Columbia issued an Order in Council announcing the exemption of FEI's Tilbury LNG facility expansion ("Tilbury Expansion") from regulatory review. The Tilbury Expansion is well underway and will increase LNG production and storage capabilities, and is expected to be in service around the end of 2016. Since this announcement, there has been considerable interest for LNG supply from the Pacific Northwest, Hawaii, Alaska and international markets. In 2014 the Government of British Columbia issued a second Order in Council amending directions to the regulator regarding the Tilbury Expansion. The revisions set out a number of requirements for the regulator, including the consideration of a further expansion of the Tilbury site that would include additional liquefaction.

Traditionally, the majority of natural gas production in northern British Columbia has served the provincial and Pacific Northwest markets via the Westcoast (Spectra) system. However, to realize the full potential of British Columbia shale gas opportunities, additional capacity to connect to markets will have to be developed. FortisBC Energy continues to explore pipeline investment opportunities that include expansion of their existing distribution system to supply natural gas to a prospective LNG export facility, as well as to expand capacity on their Southern Crossing transmission pipeline. Specifically, FortisBC Energy is pursuing a potential pipeline expansion to the proposed Woodfibre LNG site in British Columbia. The Woodfibre LNG site is a former paper mill site located near Squamish, British Columbia. The Company has an opportunity to expand its gas pipeline and increase compression to deliver natural gas to this site.

For further information on the Corporation's natural gas investment opportunities, refer to the "Liquidity and Capital Resources – Additional Investment Opportunities" section of this MD&A.

Regulation: The Corporation's key business risk is regulation. Each of the Corporation's nine utilities is subject to regulation by the regulatory body in its respective operating jurisdiction. Relationships with the regulatory authorities are managed at the local utility level.

Commitment by the Corporation's utilities to provide safe and reliable service, operational excellence and promote positive customer and regulatory relations is important to ensure supportive regulatory relationships and obtain full cost recovery and competitive returns for the Corporation's shareholders.

Central Hudson began operating under a new three-year rate order in mid-2015. In November 2015 TEP filed a general rate application ("GRA") with the Arizona Corporation Commission ("ACC") requesting new retail rates to be effective January 1, 2017, using the year ended June 30, 2015 as a historical test year. Since its last approved rate order in 2013, which used a 2011 historical test year, TEP's total rate base has increased by approximately US$0.6 billion and the common equity component of capital structure increased from 43.5% to approximately 50%. The application also addresses rate design changes that would reduce the reliance on volumetric sales to recover fixed costs, and a new net metering tariff that would ensure that customers who install distributed generation pay an equitable price for their electric service. In May 2015 UNS Electric filed a similar GRA requesting new retail rates effective May 1, 2016, using 2014 as a historical test year. The nature of UNS Electric's application was similar to that of TEP.

The Corporation's regulatory calendar for its utilities in Canada continues to be extensive. Newfoundland Power recently filed a GRA for 2016 and FortisBC Energy, the benchmark utility in British Columbia, filed its application to review cost of capital for 2016. In Alberta, while the regulator issued decisions on outstanding generic cost of capital proceedings and capital tracker applications early in 2015, it has initiated a generic cost of capital proceeding for 2016 and 2017, which includes FortisAlberta.

For a further discussion of the nature of regulation and material regulatory decisions and applications and regulatory risk, refer to the "Regulatory Highlights" and "Business Risk Management" sections of this MD&A.

Capital Expenditure Program and Rate Base Growth: The Corporation's regulated midyear rate base for 2015 was $16.4 billion. Over the five-year period through 2020, excluding the pending acquisition of ITC, the Corporation's capital program is expected to be approximately $9 billion. This investment in energy infrastructure is expected to increase rate base to almost $21 billion in 2020 and produce a five-year compound annual growth rate in rate base of approximately 5%. Fortis expects this capital investment to support growth in earnings and dividends.

For further information on the Corporation's consolidated capital expenditure program and rate base of its regulated utilities, refer to the "Liquidity and Capital Resources – Capital Expenditure Program" section of this MD&A.

Access to Capital and Liquidity: The Corporation's regulated utilities require ongoing access to long-term capital to fund investments in infrastructure necessary to provide service to customers. Long-term capital required to carry out the utility capital expenditure programs is mostly obtained at the regulated utility level. The regulated utilities usually issue debt at terms ranging between 5 and 40 years. As at December 31, 2015, almost 90% of the Corporation's consolidated long-term debt, excluding borrowings under long-term committed credit facilities, had maturities beyond five years. Management expects consolidated fixed-term debt maturities and repayments to average approximately $260 million annually over the next five years.

To help ensure uninterrupted access to capital and sufficient liquidity to fund capital programs and working capital requirements, the Corporation and its subsidiaries have approximately $3.6 billion in credit facilities, of which approximately $2.4 billion was unused as at December 31, 2015. Based on current credit ratings and conservative capital structures, the Corporation and its regulated utilities expect to continue to have reasonable access to long-term capital in 2016.

The Corporation has significant financing requirements associated with the pending acquisition of ITC. Refer to the "Business Risk Management – Risks Associated with the Acquisition of ITC" and "Subsequent Event" sections of this MD&A.

Dividend Increases: Dividends paid per common share increased to $1.40 in 2015. During 2015 Fortis increased its quarterly dividend per common share over 17% to $0.375 per quarter, or $1.50 on an annualized basis. This continues the Corporation's record of raising its annualized dividend to common shareholders for 42 consecutive years, the record for a public corporation in Canada.

Fortis also announced dividend guidance, targeting annual dividend per common share growth through 2020 of 6% based on a 2016 dividend of $1.50. This guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at its utilities, the successful execution of its $9 billion five-year capital expenditure plan, and management's continued confidence in the strength of the Corporation's diversified portfolio of assets and record of operational excellence. The pending acquisition of ITC further supports this dividend guidance.

SIGNIFICANT ITEMS IN 2015

Pending Acquisition of Aitken Creek Gas Storage Facility: In December 2015 Fortis, through an indirect wholly owned subsidiary, entered into a definitive share purchase and sale agreement with Chevron Canada Properties Ltd. to acquire its share of the Aitken Creek Gas Storage Facility ("Aitken Creek") for approximately US$266 million, subject to customary closing conditions and adjustments. Aitken Creek is the largest gas storage facility in British Columbia with a total working gas capacity of 77 billion cubic feet and is an integral part of Western Canada's natural gas transmission network. The acquisition is subject to regulatory approval and is expected to close in the first half of 2016. The net cash purchase price is expected to be initially financed with borrowings under the Corporation's credit facility. In December 2015 the Corporation paid a deposit of US$29 million related to the transaction.

Sale of Commercial Real Estate and Hotel Assets: In June 2015 the Corporation completed the sale of the commercial real estate assets of Fortis Properties for gross proceeds of $430 million. As a result of the sale, the Corporation recognized an after-tax gain of approximately $109 million, net of expenses. As part of the transaction, Fortis subscribed to $35 million in trust units of Slate Office REIT in conjunction with the REIT's public offering.

In October 2015 the Corporation completed the sale of the hotel assets of Fortis Properties for gross proceeds of $365 million. As a result of the sale, the Corporation recognized an after-tax loss of approximately $8 million, which reflects an impairment loss and expenses associated with the sale transaction.

Net proceeds from the sales were used by the Corporation to repay credit facility borrowings, the majority of which were used to finance a portion of the acquisition of UNS Energy.

Sale of Non-Regulated Generation Assets in New York and Ontario: In June 2015 the Corporation sold its non-regulated generation assets in Upstate New York for gross proceeds of approximately $77 million (US$63 million). As a result of the sale, the Corporation recognized an after-tax gain of approximately $27 million (US$22 million), net of expenses and foreign exchange impacts.

In July 2015 the Corporation sold its non-regulated generation assets in Ontario for gross proceeds of approximately $16 million. As a result of the sale, the Corporation recognized an after-tax gain of approximately $5 million.

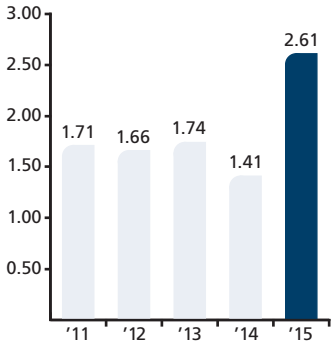
Settlement of Belize Electricity Expropriation Matters: In August 2015 the Corporation agreed to terms of a settlement with the GOB regarding the expropriation of the Corporation's approximate 70% interest in Belize Electricity in June 2011. The terms of the settlement included a one-time US$35 million cash payment to Fortis from the GOB and an approximate 33% equity investment in Belize Electricity. As a result of the settlement, the Corporation recognized an approximate $9 million loss.

SUMMARY FINANCIAL HIGHLIGHTS

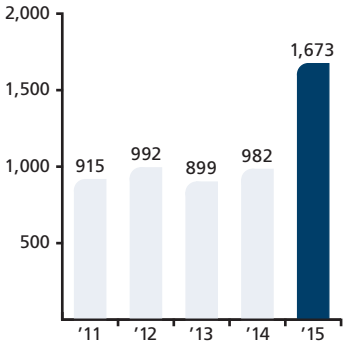
For the Years Ended December 31	2015	2014	Variance
Net Earnings Attributable to Common Equity Shareholders *($ millions)*	**728**	317	411
Basic Earnings per Common Share *($)*	**2.61**	1.41	1.20
Diluted Earnings per Common Share *($)*	**2.59**	1.40	1.19
Weighted Average Number of Common Shares Outstanding *(millions)*	**278.6**	225.6	53.0
Cash Flow from Operating Activities *($ millions)*	**1,673**	982	691
Dividends Paid per Common Share *($)*	**1.40**	1.28	0.12
Dividend Payout Ratio *(%)*	**53.6**	90.8	(37.2)
Return on Average Book Common Shareholders' Equity *(%)* [1]	**9.8**	5.4	4.4
Total Assets *($ billions)*	**28.8**	26.2	2.6
Gross Capital Expenditures *($ billions)*	**2.2**	1.7	0.5
Public Preference Share Offering *($ billions)*	**–**	0.6	(0.6)
Convertible Debenture Offering *($ billions)*	**–**	1.8	(1.8)
Long-Term Debt Offerings *($ billions)*	**1.0**	1.2	(0.2)

[1] Return on average book common shareholders' equity is a non-US GAAP measure and is defined as net earnings attributable to common equity shareholders divided by the average of opening and closing consolidated shareholders' equity, excluding preference shares and non-controlling interests. Return on average book common shareholders' equity is referred to by users of the Corporation's consolidated financial statements in evaluating the results of operations.

Basic Earnings per Common Share *($)*



Cash Flow from Operating Activities *($ millions)*



Net Earnings Attributable to Common Equity Shareholders: Fortis achieved net earnings attributable to common equity shareholders of $728 million in 2015 compared to $317 million in 2014. On an adjusted basis, net earnings attributable to common equity shareholders for 2015 were $589 million, an increase of $195 million, or almost 50%, over 2014. Results for both years were impacted by non-recurring or adjusting items, which are detailed in the "Consolidated Results of Operations" section of this MD&A. The increase in adjusted net earnings attributable to common equity shareholders was driven by a full year's contribution from UNS Energy, which was acquired in mid-August 2014, earnings contribution from the Waneta Expansion, which came online in early April 2015, rate base growth associated with capital expenditures and growth in the number of customers at FortisAlberta, a higher allowance for funds used during construction ("AFUDC") at FortisBC Energy, the resetting of customer rates at Central Hudson, effective July 1, 2015, and the continued strength of the US dollar relative to the Canadian dollar. Earnings growth was tempered by an increase in Corporate expenses and lower earnings contribution due to the sale of the commercial real estate and hotel assets.

Basic Earnings per Common Share: Basic earnings per common share were $2.61 in 2015 compared to $1.41 in 2014. On an adjusted basis, as noted above, basic earnings per common share were $2.11 for 2015, an increase of $0.36 over 2014. The increase was driven by higher adjusted earnings per common share, as discussed above, partially offset by an increase in the weighted average number of common shares outstanding.

Cash Flow from Operating Activities: Cash flow from operating activities was $1,673 million for 2015, an increase of $691 million, or 70%, over 2014. The increase was driven by higher cash earnings, mainly due to the factors noted above, and favourable changes in working capital.

Dividends: Dividends paid per common share increased to $1.40 in 2015, 9.0% higher than $1.28 in 2014. During 2015 Fortis increased its quarterly dividend per common share over 17% to $0.375 per quarter. The Corporation's dividend payout ratio was 53.6% in 2015 compared to 90.8% in 2014. On an adjusted basis, the dividend payout ratio was 66.4% in 2015 compared to 73.1% in 2014.

Return on Average Book Common Shareholders' Equity: The return on average book common shareholders' equity for 2015 was 9.8% compared to 5.4% for 2014. On an adjusted basis, the return on average book common shareholders' equity for 2015 was 7.9%, compared to 6.8% for 2014.

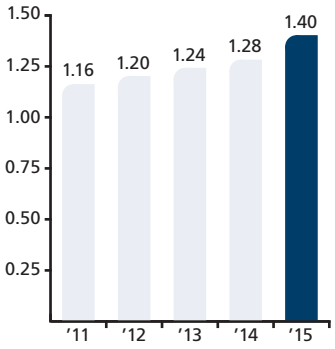
Total Assets: Total assets increased 9.9% to approximately $28.8 billion at the end of 2015 compared to approximately $26.2 billion at the end of 2014. The increase reflects favourable foreign exchange on the translation of US dollar-denominated assets and continued investment in energy infrastructure, driven by capital spending at the regulated utilities, partially offset by the sale of commercial real estate and hotel assets in 2015.

Gross Capital Expenditures: Consolidated capital expenditures, before customer contributions, were $2.2 billion in 2015 compared to $1.7 billion in 2014. The increase was driven by a full year contribution from UNS Energy and higher capital spending at most of the Corporation's regulated utilities, partially offset by lower non-regulated capital expenditures due to the completion of the Waneta Expansion and the sale of commercial real estate and hotel assets. For a detailed discussion of the Corporation's consolidated capital expenditure program, refer to the "Liquidity and Capital Resources – Capital Expenditure Program" section of this MD&A.

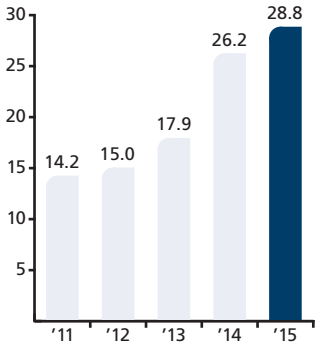
Long-Term Capital: The Corporation's regulated utilities raised approximately $1 billion in long-term debt in 2015, largely in support of energy infrastructure investment and regularly scheduled debt repayments.

Fortis completed the sale of $1.8 billion convertible debentures in 2014 to finance a portion of the acquisition of UNS Energy. In October 2014 approximately 58.2 million common shares of Fortis were issued on conversion of the debentures. In September 2014 Fortis issued 24 million First Preference Shares, Series M for gross proceeds of $600 million. The net proceeds were also used to finance a portion of the acquisition of UNS Energy. The Corporation and its regulated utilities raised approximately $1.2 billion in long-term debt in 2014.

Dividends Paid per Common Share *($)*



Total Assets *($ billions)*
(as at December 31)



For further information, refer to the "Liquidity and Capital Resources – Summary of Consolidated Cash Flows" section of this MD&A.

CONSOLIDATED RESULTS OF OPERATIONS

Years Ended December 31

($ millions)	**2015**	2014	Variance
Revenue	**6,727**	5,401	1,326
Energy Supply Costs	**2,561**	2,197	364
Operating Expenses	**1,864**	1,493	371
Depreciation and Amortization	**873**	688	185
Other Income (Expenses), Net	**187**	(25)	212
Finance Charges	**553**	547	6
Income Tax Expense	**223**	66	157
Earnings From Continuing Operations	**840**	385	455
Earnings From Discontinued Operations, Net of Tax	**–**	5	(5)
Net Earnings	**840**	390	450
Net Earnings Attributable to:			
Non-Controlling Interests	**35**	11	24
Preference Equity Shareholders	**77**	62	15
Common Equity Shareholders	**728**	317	411
Net Earnings	**840**	390	450

Revenue

The increase in revenue was driven by the acquisition of UNS Energy in August 2014. Favourable foreign exchange associated with the translation of US dollar-denominated revenue, contribution from the Waneta Expansion and higher base electricity rates at the Canadian Regulated Electric Utilities also contributed to the increase. The increase was partially offset by the flow through in customer rates of lower energy supply costs at FortisBC Energy, Central Hudson and the Caribbean Regulated Electric Utilities, and a decrease in non-utility revenue due to the sale of commercial real estate and hotel assets in June 2015 and October 2015, respectively.

Energy Supply Costs

The increase in energy supply costs was primarily due to the acquisition of UNS Energy and unfavourable foreign exchange associated with the translation of US dollar-denominated energy supply costs. The increase was partially offset by lower commodity costs at FortisBC Energy, Central Hudson and the Caribbean Regulated Electric Utilities.

Operating Expenses

The increase in operating expenses was primarily due to the acquisition of UNS Energy, unfavourable foreign exchange associated with the translation of US dollar-denominated operating expenses and general inflationary and employee-related cost increases. The increase was partially offset by a decrease in non-utility operating expenses due to the sale of commercial real estate and hotel assets, and lower Corporate retirement expenses.

Depreciation and Amortization

The increase in depreciation and amortization was primarily due to the acquisition of UNS Energy and continued investment in energy infrastructure at the Corporation's regulated utilities.

Other Income (Expenses), Net

The increase in other income, net of expenses, was driven by gains on the sale of commercial real estate and non-regulated generation assets in 2015, compared to acquisition-related expenses associated with UNS Energy in 2014. The increase was partially offset by a loss associated with the sale of hotel assets in 2015.

Finance Charges

The increase in finance charges was primarily due to the acquisition of UNS Energy, including interest expense on debt issued to complete the financing of the acquisition, and unfavourable foreign exchange associated with the translation of US dollar-denominated interest expense. The increase was partially offset by lower interest on convertible debentures. Approximately $72 million ($51 million after tax) in interest expense was recognized in 2014 associated with convertible debentures issued to finance a portion of the acquisition of UNS Energy. In October 2014 the convertible debentures were substantially all converted into common shares of the Corporation.

Income Tax Expense

The increase in income tax expense was primarily due to higher earnings before income taxes, driven by the acquisition of UNS Energy and gains on the sale of commercial real estate and non-regulated generation assets in 2015, and a higher effective income tax rate, mainly due to the combined federal and state income tax rate at UNS Energy.

Net Earnings Attributable to Common Equity Shareholders and Basic Earnings Per Common Share

Net earnings attributable to common equity shareholders were impacted by a number of non-recurring or non-operating items. These items, referred to as adjusting items, are reconciled below and discussed in the segmented results of operations for the respective reporting segments. Management believes that adjusted net earnings attributable to common equity shareholders and adjusted basic earnings per common share provide useful information to investors and shareholders as they provide increased transparency and predictive value. The adjusting items do not have a standardized meaning as prescribed under US GAAP and are not considered US GAAP measures. Therefore, these adjusting items may not be comparable with similar measures presented by other companies.

Non-US GAAP Reconciliation

Years Ended December 31 *($ millions, except for common share data)*	**2015**	2014	Variance
Net Earnings Attributable to Common Equity Shareholders	**728**	317	411
Adjusting Items:			
FortisAlberta –			
Capital tracker revenue adjustment for 2013 and 2014	**(9)**	–	(9)
Non-Regulated – Fortis Generation –			
Gain on sale of generation assets	**(32)**	–	(32)
Non-Utility –			
Gain on sale of commercial real estate assets	**(109)**	–	(109)
Loss on sale of hotel assets	**8**	–	8
Earnings from discontinued operations	**–**	(5)	5
Corporate and Other –			
Foreign exchange gain	**(13)**	(8)	(5)
Loss on settlement of expropriation matters	**9**	–	9
Interest expense on convertible debentures	**–**	51	(51)
Acquisition-related expenses	**7**	39	(32)
Adjusted Net Earnings Attributable to Common Equity Shareholders	**589**	394	195
Adjusted Basic Earnings Per Common Share *($)*	**2.11**	1.75	0.36

Adjusted Net Earnings Attributable to Common Equity Shareholders

The increase in adjusted net earnings attributable to common equity shareholders was driven by earnings contribution of $195 million at UNS Energy compared to $60 million for 2014. Earnings contribution of $22 million from the Waneta Expansion, which represents the Corporation's 51% controlling ownership interest, also contributed to the increase. Performance was driven by all of the Corporation's other regulated utilities, including rate base growth associated with capital expenditures and growth in the number of customers at FortisAlberta; a higher AFUDC at FortisBC Energy; and improved performance at Central Hudson under a new three-year rate order. Favourable foreign exchange impacts associated with US dollar-denominated earnings also increased earnings year over year. The increase in adjusted earnings was partially offset by higher preference share dividends and finance charges in the Corporate and Other segment, largely associated with the acquisition of UNS Energy, and lower earnings contribution from non-utility assets due to the sale of commercial real estate and hotel assets.

Adjusted Basic Earnings Per Common Share

The increase in adjusted earnings per common share was driven by accretion associated with the acquisition of UNS Energy, after considering the finance charges associated with the acquisition and the increase in the weighted average number of common shares outstanding, and contribution from the Waneta Expansion. Performance at all of the Corporation's other regulated utilities, as discussed above, and the impact of favourable foreign exchange also contributed to the increase. The increase was partially offset by an increase in Corporate expenses and lower earnings contribution from non-utility assets due to the sale of commercial real estate and hotel assets.

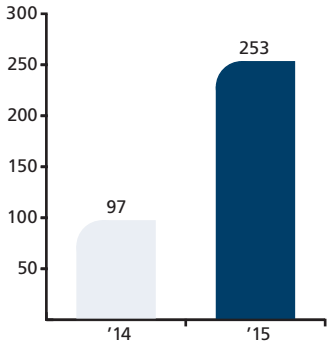
SEGMENTED RESULTS OF OPERATIONS

Segmented Net Earnings Attributable to Common Equity Shareholders

Years Ended December 31 *($ millions)*	**2015**	2014	Variance
Regulated Electric & Gas Utilities – United States			
UNS Energy	**195**	60	135
Central Hudson	**58**	37	21
	253	97	156
Regulated Gas Utility – Canadian			
FortisBC Energy	**140**	127	13
Regulated Electric Utilities – Canadian			
FortisAlberta	**138**	103	35
FortisBC Electric	**50**	46	4
Eastern Canadian	**62**	60	2
	250	209	41
Regulated Electric Utilities – Caribbean	**34**	27	7
Non-Regulated – Fortis Generation	**77**	20	57
Non-Regulated – Non-Utility	**114**	28	86
Corporate and Other	**(140)**	(191)	51
Net Earnings Attributable to Common Equity Shareholders	**728**	317	411

The following is a discussion of the financial results of the Corporation's reporting segments. A discussion of the nature of regulation and material regulatory decisions and applications pertaining to the Corporation's regulated utilities is provided in the "Regulatory Highlights" section of this MD&A.

Regulated Electric & Gas Utilities – United States Earnings *($ millions)*



REGULATED UTILITIES

The Corporation's primary business is the ownership and operation of regulated utilities. In 2015 earnings from regulated assets represented approximately 92% (2014 – 91%) of the Corporation's earnings from its operating segments (excluding Corporate and Other segment expenses), excluding the gains on sale of non-core assets. Total regulated assets represented 96% of the Corporation's total assets as at December 31, 2015 (December 31, 2014 – 93%).

Regulated Electric & Gas Utilities – United States

Regulated Electric & Gas Utilities – United States earnings for 2015 were $253 million (2014 – $97 million), which represented approximately 37% (2014 – 21%) of the Corporation's total regulated earnings. Total segment assets were approximately $12.1 billion as at December 31, 2015 (December 31, 2014 – $9.9 billion), which represented approximately 44% of the Corporation's total regulated assets as at December 31, 2015 (December 31, 2014 – 40%).

UNS Energy

Financial Highlights [1]

Years Ended December 31	**2015**	2014
Average US:CAD Exchange Rate [2]	**1.28**	1.12
Electricity Sales *(gigawatt hours ("GWh"))*	**15,366**	5,646
Gas Volumes *(petajoules ("PJ"))*	**13**	5
Revenue *($ millions)*	**2,034**	684
Earnings *($ millions)*	**195**	60

[1] Financial results of UNS Energy are from August 15, 2014, the date of acquisition.

[2] The reporting currency of UNS Energy is the US dollar. The average US:CAD exchange rate for 2014 is from the date of acquisition.

Electricity Sales & Gas Volumes

Electricity sales were 15,366 gigawatt hours ("GWh") for 2015 compared to 14,560 GWh for the full year in 2014. The increase was primarily due to higher short-term wholesale electricity sales. The majority of short-term wholesale electricity sales is flowed through to customers and has no impact on earnings. Retail sales were comparable year over year.

Gas volumes of 13 petajoules ("PJ") for 2015 were comparable with the full year in 2014.

Revenue

Revenue was US$1,588 million for 2015 compared to US$1,560 million for the full year in 2014. The increase was primarily due to the flow through to customers of higher purchased power and fuel supply costs, higher transmission revenue, and higher wholesale electricity sales. On a Canadian dollar basis, revenue was also impacted by favourable foreign exchange.

Earnings

Earnings were US$152 million for 2015 compared to US$144 million for the full year in 2014, excluding the impact of acquisition-related expenses. The increase was primarily due to higher transmission revenue and a decrease in interest expense due to the expiry of leasing arrangements. The increase was partially offset by higher operating expenses. On a Canadian dollar basis, earnings were also impacted by favourable foreign exchange.

Central Hudson

Financial Highlights

Years Ended December 31	**2015**	2014	Variance
Average US:CAD Exchange Rate [1]	**1.28**	1.10	0.18
Electricity Sales *(GWh)*	**5,132**	5,075	57
Gas Volumes *(PJ)*	**24**	23	1
Revenue *($ millions)*	**880**	821	59
Earnings *($ millions)*	**58**	37	21

[1] The reporting currency of Central Hudson is the US dollar.

Electricity Sales & Gas Volumes

The increase in electricity sales was mainly due to higher average consumption as a result of warmer temperatures in the summer, which increased the use of air conditioning and other cooling equipment. Gas volumes for 2015 were comparable with last year.

Changes in electricity sales and gas volumes at Central Hudson are subject to regulatory revenue decoupling mechanisms and, as a result, do not have a material impact on revenue and earnings.

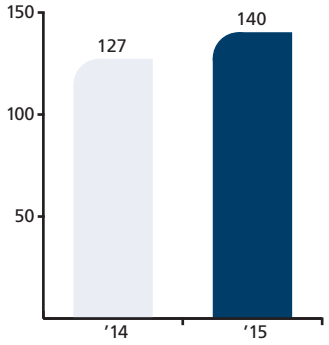
Revenue

The increase in revenue was driven by approximately $111 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue. An increase in base electricity rates effective July 1, 2015 and the recovery from customers of previously deferred electricity costs also contributed to the increase in revenue. Additionally, revenue for the first half of 2015 was favourably impacted by energy efficiency incentives and higher gas revenue associated with a new gas delivery contract in late 2014. The increase was partially offset by the recovery from customers of lower commodity costs, which were mainly due to lower wholesale prices.

Earnings

The increase in earnings was primarily due to approximately $9 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings, an increase in base electricity rates effective July 1, 2015, a new gas delivery contract implemented in late 2014, and energy efficiency incentives earned during the first half of 2015. The increase was partially offset by the impact of higher expenses during the two-year rate freeze period post acquisition, which ended on June 30, 2015.

Regulated Gas Utility – Canadian Earnings *($ millions)*



Regulated Gas Utility – Canadian

Regulated Gas Utility – Canadian earnings for 2015 were $140 million (2014 – $127 million), which represented approximately 21% of the Corporation's total regulated earnings (2014 – 28%). Total segment assets were approximately $6.0 billion as at December 31, 2015 (December 31, 2014 – $5.8 billion), which represented approximately 22% of the Corporation's total regulated assets as at December 31, 2015 (December 31, 2014 – 24%).

FortisBC Energy

Financial Highlights

Years Ended December 31	**2015**	2014	Variance
Gas Volumes *(PJ)*	**186**	195	(9)
Revenue *($ millions)*	**1,295**	1,435	(140)
Earnings *($ millions)*	**140**	127	13

Gas Volumes

The decrease in gas volumes was primarily due to lower average consumption in the first quarter as a result of warmer temperatures.

FortisBC Energy earns approximately the same margin regardless of whether a customer contracts for the purchase and delivery of natural gas or only for the delivery of natural gas. As a result of the operation of regulatory deferral mechanisms, changes in consumption levels and the cost of natural gas from those forecast to set customer gas rates do not materially affect earnings.

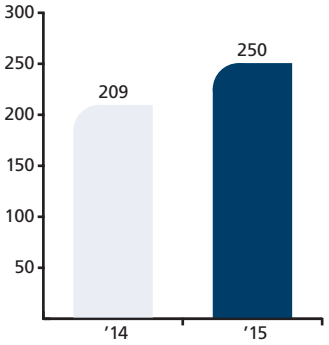
Revenue

The decrease in revenue was primarily due to a lower commodity cost of natural gas charged to customers and lower gas volumes. The decrease was partially offset by higher regulatory flow-through deferral amounts.

Earnings

The increase in earnings was mainly due to higher AFUDC, regulatory flow-through deferral amounts and operating cost savings, net of the earnings sharing mechanism. The increase was partially offset by a decrease in the allowed ROE and equity component of capital structure as a result of the amalgamation of FEVI and FEWI with FEI, effective December 31, 2014. For further details on the amalgamation, refer to the "Material Regulatory Decisions and Applications" section of this MD&A.

Regulated Electric Utilities – Canadian Earnings *($ millions)*



Regulated Electric Utilities – Canadian

Regulated Electric Utilities – Canadian earnings for 2015 were $250 million (2014 – $209 million), which represented approximately 37% of the Corporation's total regulated earnings (2014 – 45%). Total segment assets were approximately $8.2 billion as at December 31, 2015 (December 31, 2014 – $7.7 billion), which represented approximately 30% of the Corporation's total regulated assets as at December 31, 2015 (December 31, 2014 – 32%).

FortisAlberta

Financial Highlights

Years Ended December 31	**2015**	2014	Variance
Energy Deliveries *(GWh)*	**17,132**	17,372	(240)
Revenue *($ millions)*	**563**	518	45
Earnings *($ millions)*	**138**	103	35

Energy Deliveries

The decrease in energy deliveries was primarily due to lower average consumption by oil and gas customers as a result of low commodity prices for oil and gas, partially offset by higher average consumption by farm and irrigation, residential and commercial customers. Lower levels of precipitation, particularly in the third quarter, and warmer temperatures had a favorable impact on energy deliveries to farm and irrigation customers. Higher energy deliveries to residential and commercial customers due to customer growth were partially offset by lower average consumption due to warmer temperatures.

Revenue

As a significant portion of FortisAlberta's distribution revenue is derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered are not entirely correlated with changes in revenue. Revenue is a function of numerous variables, many of which are independent of actual energy deliveries.

The increase in revenue was primarily due to the operation of the PBR formula, including an increase in customer rates based on a combined inflation and productivity factor of 1.49%, higher capital tracker revenue, growth in the number of customers, and higher revenue related to flow-through costs to customers. Revenue was also favourably impacted by a $9 million capital tracker revenue adjustment recognized in 2015 associated with 2013 and 2014, as a result of regulatory decisions. For further details on regulatory decisions, refer to the "Material Regulatory Decisions and Applications" section of this MD&A.

Earnings

The increase in earnings was primarily due to rate base growth associated with capital expenditures, growth in the number of customers, and the impact of a technical update on depreciation and amortization. Also contributing to the increase in earnings was capital tracker revenue of approximately $9 million recognized in 2015 associated with 2013 and 2014, as discussed above.

FortisBC Electric

Financial Highlights

Years Ended December 31	**2015**	2014	Variance
Electricity Sales *(GWh)*	**3,116**	3,179	(63)
Revenue *($ millions)*	**360**	334	26
Earnings *($ millions)*	**50**	46	4

Electricity Sales

The decrease in electricity sales was primarily due to lower average consumption in the first and fourth quarters as a result of warmer temperatures.

Revenue

The increase in revenue was driven by increases in base electricity rates, mainly established to recover higher power purchase costs, and surplus capacity sales. Revenue was also favourably impacted by higher contribution from non-regulated operating, maintenance and management services associated with the Waneta Expansion. The increase was partially offset by lower electricity sales.

Earnings

The increase in earnings was primarily due to higher earnings from non-regulated operating, maintenance and management services, and rate base growth.

Eastern Canadian Electric Utilities

Financial Highlights

Years Ended December 31	**2015**	2014	Variance
Electricity Sales *(GWh)*	**8,403**	8,376	27
Revenue *($ millions)*	**1,033**	1,008	25
Earnings *($ millions)*	**62**	60	2

Electricity Sales

The increase in electricity sales was primarily due to customer growth in Newfoundland, as well as higher average consumption in PEI, mainly due to an increase in the number of customers using electricity for home heating. The increase was partially offset by lower electricity sales in Ontario, largely due to the loss of a commercial customer and lower average consumption by residential customers due to changes in temperatures.

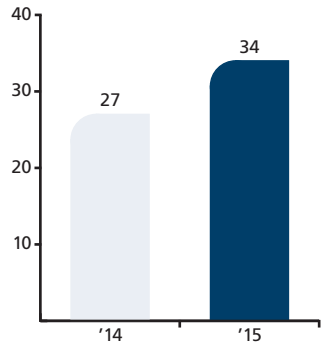
Revenue

The increase in revenue was mainly due to the flow through in customer electricity rates of overall higher energy supply costs and electricity sales growth.

Earnings

The increase in earnings was primarily due to electricity sales growth and lower operating costs, mainly due to restoration efforts at Newfoundland Power following the loss of energy supply from Newfoundland and Labrador Hydro ("Newfoundland Hydro") and related power interruptions in January 2014, partially offset by higher depreciation expense.

Regulated Electric Utilities – Caribbean Earnings *($ millions)*



Regulated Electric Utilities – Caribbean

Regulated Electric Utilities – Caribbean earnings for 2015 were $34 million (2014 – $27 million), which represented approximately 5% of the Corporation's total regulated earnings (2014 – 6%). Total segment assets were approximately $1.3 billion as at December 31, 2015 (December 31, 2014 – $1.1 billion), which represented approximately 4% of the Corporation's total regulated assets as at December 31, 2015 (December 31, 2014 – 4%).

Financial Highlights

Years Ended December 31	**2015**	2014	Variance
Average US:CAD Exchange Rate [1]	**1.28**	1.10	0.18
Electricity Sales *(GWh)*	**802**	771	31
Revenue *($ millions)*	**321**	321	–
Earnings *($ millions)*	**34**	27	7

[1] The reporting currency of Caribbean Utilities and Fortis Turks and Caicos is the US dollar. The reporting currency of Belize Electricity is the Belizean dollar, which is pegged to the US dollar at BZ$2.00=US$1.00.

Electricity Sales

The increase in electricity sales was primarily due to growth in the number of customers as a result of increased economic activity and overall warmer temperatures, which increased air conditioning load.

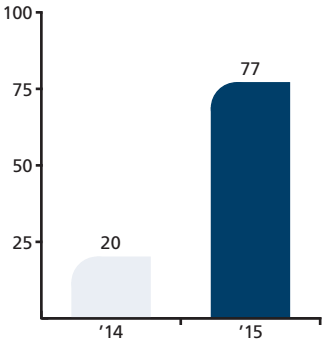
Revenue

Revenue was impacted by approximately $39 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue, and electricity sales growth. The increase was largely offset by the flow through in customer electricity rates of lower fuel costs at Caribbean Utilities.

Earnings

The increase in earnings was due to approximately $5 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings, electricity sales growth and higher capitalized interest at Caribbean Utilities. The increase was partially offset by higher depreciation. Equity income from Belize Electricity from the date of settlement in August 2015 was less than $1 million.

Non-Regulated – Fortis Generation Earnings *($ millions)*



NON-REGULATED

Non-Regulated – Fortis Generation

Financial Highlights

Years Ended December 31	**2015**	2014	Variance
Energy Sales *(GWh)*	**844**	407	437
Revenue *($ millions)*	**107**	38	69
Earnings *($ millions)*	**77**	20	57

Energy Sales

The increase in energy sales was driven by the Waneta Expansion, which commenced production in early April 2015 and reported energy sales of 517 GWh in 2015. The increase was partially offset by decreased production in Belize due to lower rainfall and in Upstate New York and Ontario due to the sale of generation assets in mid 2015, lower rainfall, and generating units taken out of service for repairs.

Revenue

The increase in revenue was driven by the Waneta Expansion, which recognized revenue of $70 million in 2015, and approximately $4 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue. The increase was partially offset by decreased production in Belize, Upstate New York and Ontario.

Earnings

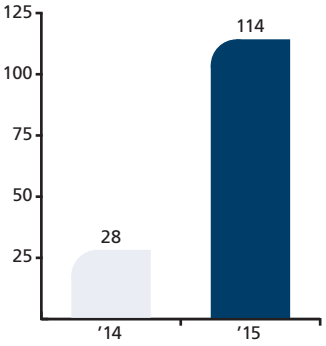
The increase in earnings was driven by the recognition of after-tax gains totalling approximately $32 million on the sale of generation assets in Upstate New York and Ontario in mid 2015, and earnings contribution of $22 million from the Waneta Expansion. Approximately $3 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings and lower business development costs were partially offset by decreased production in Belize, Upstate New York and Ontario.

Non-Regulated – Non-Utility

Financial Highlights

Years Ended December 31 ($ millions)	2015	2014	Variance
Revenue	**171**	249	(78)
Earnings	**114**	28	86

Non-Regulated – Non-Utility Earnings
($ millions)



Revenue

The decrease in revenue was primarily due to the sale of commercial real estate and hotel assets in June 2015 and October 2015, respectively.

Earnings

The increase in earnings was driven by a net after-tax gain of approximately $101 million on the sale of commercial real estate and hotel assets. The increase was partially offset by lower earnings contribution from the commercial real estate and hotel assets as a result of the sale and $5 million in earnings in 2014 associated with Griffith from normal operations to the date of sale in March 2014.

Corporate and Other

Financial Highlights

Years Ended December 31 ($ millions)	2015	2014	Variance
Revenue	**24**	31	(7)
Operating Expenses	**26**	38	(12)
Depreciation and Amortization	**2**	2	–
Other Income (Expenses), Net	**(8)**	(45)	37
Finance Charges	**94**	154	(60)
Income Tax Recovery	**(43)**	(79)	36
	(63)	(129)	66
Preference Share Dividends	**77**	62	15
Net Corporate and Other Expenses	**(140)**	(191)	51

Net Corporate and Other expenses were impacted by the following items.

(i) A foreign exchange gain of $13 million in 2015 compared to $8 million in 2014, associated with the Corporation's previous US-dollar denominated long-term other asset that represented the book value of its expropriated investment in Belize Electricity, which was included in other income;
(ii) A loss of approximately $9 million in 2015 on settlement of expropriation matters related to the Corporation's investment in Belize Electricity, which was included in other income, net of expenses;
(iii) Acquisition-related expenses of $10 million ($7 million after tax) in 2015 associated with the pending acquisition of ITC, which were included in other income;
(iv) Finance charges of $72 million ($51 million after tax) in 2014 associated with the convertible debentures issued to finance a portion of the acquisition of UNS Energy; and
(v) Other expenses of approximately $58 million ($39 million after tax) in 2014 related to the acquisition of UNS Energy.

Excluding the above-noted items, net Corporate and Other expenses were $137 million for 2015 compared to approximately $109 million for 2014. The increase in net Corporate and Other expenses was primarily due to higher preference share dividends and finance charges, and a decrease in revenue. The increase was partially offset by lower operating expenses.

The increase in preference share dividends and finance charges was primarily due to the acquisition of UNS Energy. Finance charges were also impacted by no longer capitalizing interest upon completion of the Waneta Expansion and unfavourable foreign exchange associated with the translation of US dollar-denominated interest expense.

The decrease in revenue was primarily due to a decrease in related-party interest income, mainly due to the sale of commercial real estate and hotel assets in June 2015 and October 2015, respectively.

The decrease in operating expenses was primarily due to lower retirement expenses. Retirement expenses of approximately $13 million ($11 million after tax) were recognized in 2014 compared to approximately $2 million ($1 million after tax) in 2015. The decrease in operating expenses was partially offset by a $3 million ($2 million after tax) corporate donation recognized in 2015.

REGULATORY HIGHLIGHTS

The nature of regulation and material regulatory decisions and applications associated with each of the Corporation's regulated electric and gas utilities are summarized as follows.

Nature of Regulation

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed Returns (%)			Significant Features
			2014	2015	2016	Future or Historical Test Year Used to Set Customer Rates
			ROE			
TEP	ACC	43.5	10.00	10.00	10.00	COS/ROE [1]
UNS Electric	ACC	52.6 [2]	9.50	9.50	9.50 [2]	ROEs established by the ACC
UNS Gas	ACC	50.8	9.75	9.75	9.75	Historical Test Year
Central Hudson	New York State Public Service Commission ("PSC")	48	10.00	10.00/ 9.00 [3]	9.00	COS/ROE Earnings sharing mechanism ROE established by the PSC Future Test Year
FEI	British Columbia Utilities Commission ("BCUC")	38.5 [2]	8.75	8.75	8.75 [2]	COS/ROE PBR mechanism for 2014 through 2019 ROEs established by the BCUC 2013 test year with 2014 through 2019 rates set using PBR mechanism
FEVI	BCUC	41.5 [4]	9.25	n/a [4]	n/a [4]	
FEWI	BCUC	41.5 [4]	9.50	n/a [4]	n/a [4]	
FortisBC Electric	BCUC	40 [2]	9.15	9.15	9.15 [2]	COS/ROE PBR mechanism for 2014 through 2019 ROE established by the BCUC 2013 test year with 2014 through 2019 rates set using PBR mechanism
FortisAlberta	Alberta Utilities Commission ("AUC")	40 [2]	8.30	8.30	8.30 [2]	COS/ROE PBR mechanism for 2013 through 2017 with capital tracker account and other supportive features ROE established by the AUC 2012 test year with 2013 through 2017 rates set using PBR mechanism
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB")	45 [2]	8.80 +/– 50 bps	8.80 +/– 50 bps	8.80 [2] +/– 50 bps	COS/ROE ROE established by the PUB Future Test Year
Maritime Electric	Island Regulatory and Appeals Commission ("IRAC")	40 [2]	9.75	9.75	9.35 [2]	COS/ROE ROE established by the *PEI Energy Accord* in 2014 and 2015. ROE in 2016 to be established by IRAC Future Test Year
FortisOntario	Ontario Energy Board	40	8.93 – 9.85	8.93 – 9.30	8.93 – 9.30	COS/ROE [5] Future test year and incentive regulation rate-setting mechanism
Caribbean Utilities	Electricity Regulatory Authority	N/A	ROA 7.00 – 9.00	7.25 – 9.25	6.75 – 8.75	COS/ROA Rate-cap adjustment mechanism based on published consumer price indices Historical Test Year
Fortis Turks and Caicos	Government of the Turks and Caicos Islands	N/A	15.00 – 17.50 [6]	15.00 – 17.50 [6]	15.00 – 17.50 [6]	COS/ROA Historical Test Year

[1] Additionally, allowed ROEs are adjusted for the fair value of rate base as required under the laws of the State of Arizona.
[2] Interim and subject to change pending the outcome of regulatory proceedings effective January 1, 2016 for FortisAlberta, FEI and FortisBC Electric; May 1, 2016 for UNS Electric; July 1, 2016 for Newfoundland Power; and March 1, 2016 for Maritime Electric.
[3] Allowed ROE of 10.0% with a 48% common equity component of capital structure to June 30, 2015. Allowed ROE of 9.00% with a 48% common equity component of capital structure effective July 1, 2015 through June 30, 2018.
[4] As approved by the BCUC, effective December 31, 2014, FEVI and FEWI were amalgamated with FEI and, as a result, the allowed ROE and common equity component of capital structure for 2015 reverted to those of FEI.
[5] Cornwall Electric is subject to a rate-setting mechanism under a Franchise Agreement with the City of Cornwall, based on a price cap with commodity cost flow through.
[6] Achieved ROAs at the utilities are significantly lower than those allowed under licences as a result of the inability, due to economic and political factors, to increase base customer electricity rates.

Material Regulatory Decisions and Applications

The following summarizes the significant regulatory decisions and applications for the Corporation's regulated utilities for 2015.

UNS Energy

In November 2015 TEP, UNS Energy's largest utility, filed a GRA with the ACC requesting new retail rates to be effective January 1, 2017, using the year ended June 30, 2015 as a historical test year. The key provisions of the rate request include: (i) a base retail rate increase of US$110 million, or 12.0%, compared with adjusted test year revenue; (ii) a 7.34% return on original cost rate base of US$2.1 billion; (iii) a common equity component of capital structure of approximately 50%; (iv) a cost of equity of 10.35% and an average cost of debt of 4.32%; and (v) rate design changes that would reduce the reliance on volumetric sales to recover fixed costs, and a new net metering tariff that would ensure that customers who install distributed generation pay an equitable price for their electric service. Since its last approved rate order in 2013, which used a 2011 historical test year, TEP's total rate base has increased by approximately US$0.6 billion and the common equity component of capital structure increased from 43.5% to approximately 50%. In May 2015 UNS Electric filed a GRA requesting new retail rates to be effective May 1, 2016, using 2014 as a historical test year. The nature of UNS Electric's GRA was similar to that of TEP. A decision on UNS Electric's application is expected in the third quarter of 2016 and TEP's application is expected in the fourth quarter of 2016.

Central Hudson

Three-Year Rate Order

In June 2015 the PSC issued a Rate Order for Central Hudson covering a three-year period, with new electricity and natural gas delivery rates effective July 1, 2015. A delivery rate freeze was implemented for electricity and natural gas delivery rates through June 30, 2015 as part of the regulatory approval of the acquisition of Central Hudson by Fortis. Central Hudson invested approximately US$225 million in energy infrastructure during the two-year delivery rate freeze period ended June 30, 2015. The approved Rate Order reflects an allowed ROE of 9.0% and a 48% common equity component of capital structure. The Rate Order includes capital investments of approximately US$490 million during the three-year period targeted at making the electric and gas systems stronger.

The approved Rate Order includes full cost recovery of electric and natural gas commodity costs and continuation of certain mechanisms, including revenue decoupling and earnings sharing mechanisms. In the approved earnings sharing mechanism, the Company and customers share equally earnings in excess of 50 basis points above the allowed ROE up to an achieved ROE that is 100 basis points above the allowed ROE. Earnings in excess of 100 basis points above the allowed ROE are shared primarily with the customer. In addition, the Rate Order includes a major storm reserve for electric operations and provides for continuation of recovery of various operating expenses, including environmental site investigation and remediation costs. To the extent that Central Hudson receives gas delivery revenue associated with a new contract implemented in late 2014, associated revenue is being used to mitigate future gas customer rate increases, effective July 1, 2015.

Reforming the Energy Vision

In 2014 the PSC issued an order instituting a proceeding to reform New York State's electricity industry and regulatory practices ("Reforming the Energy Vision"). The initiative seeks to further a number of policy objectives and seeks to determine the appropriate role of electric distribution utilities in furthering these objectives, as well as considering regulatory changes to better align utility interest with energy policy objectives. In 2015 Central Hudson continued to fully participate in this proceeding. The outcome of Reforming the Energy Vision cannot be determined at this time and it could impact the scope of regulated utilities in New York State.

FortisBC Energy and FortisBC Electric

Multi-Year PBR Plans

In September 2014 the BCUC issued its decisions on FEI and FortisBC Electric's Multi-Year PBR Plans for 2014 through 2019. The approved PBR Plans incorporate incentive mechanisms for improving operating and capital expenditure efficiencies. Operation and maintenance expenses and base capital expenditures during the PBR period are subject to an incentive formula reflecting incremental costs for inflation and half of customer growth, less a fixed productivity adjustment factor of 1.1% for FEI and 1.03% for FortisBC Electric each year. The approved PBR Plans also include a 50%/50% sharing of variances from the formula-driven operation and maintenance expenses and capital expenditures over the PBR period, and a number of service quality measures designed to ensure FEI and FortisBC Electric maintain service levels. It also sets out the requirements for an annual review process which will provide a forum for discussion between the utilities and interested parties regarding current performance and future activities.

In May 2015 and June 2015, the BCUC issued its decisions on FEI and FortisBC Electric's 2015 rates in compliance with the PBR decisions issued in September 2014. The decisions approved 2015 midyear rate base of approximately $3,661 million and $1,249 million for FEI and FortisBC Electric, respectively, and approved customer rate increases for 2015 of 0.7% and 4.2% over 2014 rates, respectively.

In December 2015 the BCUC issued its decisions on FEI and FortisBC Electric's 2016 rates. The decisions approved 2016 midyear rate base of approximately $3,693 million and $1,286 million for FEI and FortisBC Electric, respectively, and approved customer rate increases for 2016 of 1.79% and 2.96% over 2015 rates, respectively.

Generic Cost of Capital Proceedings

A Generic Cost of Capital ("GCOC") Proceeding to establish the allowed ROE and capital structures for regulated utilities in British Columbia occurred from 2012 through 2014. FEI was designated as the benchmark utility and a BCUC decision established that the ROE for the benchmark utility would be set at 8.75% with a 38.5% common equity component of capital structure, both effective January 1, 2013 through December 31, 2015. The GCOC Proceeding reaffirmed for FortisBC Electric a risk premium over the benchmark utility of 40 basis points, resulting in an allowed ROE of 9.15% effective January 1, 2013 through December 31, 2015, and a common equity component of capital structure at 40%.

The BCUC decision directed FEI to file an application to review the 2016 benchmark utility ROE and common equity component of capital structure. In October 2015, as required by the regulator, FEI filed its application to review the 2016 benchmark allowed ROE and common equity component of capital structure. As FEI is the benchmark utility, the review of the application could also have an impact on FortisBC Electric. A decision on the application is expected in the second quarter of 2016.

FortisAlberta

Generic Cost of Capital Proceedings

In March 2015 the AUC issued its decision on the GCOC Proceeding in Alberta. The GCOC Proceeding set FortisAlberta's allowed ROE for 2013 through 2015 at 8.30%, down from the interim allowed ROE of 8.75%, and set the common equity component of capital structure at 40%, down from 41%. The AUC also determined that it would not re-establish a formula-based approach to setting the allowed ROE at this time. Instead, the allowed ROE of 8.30% and common equity component of capital structure of 40% will remain in effect on an interim basis for 2016 and beyond. For regulated utilities in Alberta under PBR mechanisms, including FortisAlberta, the impact of the changes to the allowed ROE and common equity component of capital structure resulting from the GCOC Proceeding applies to the portion of rate base that is funded by capital tracker revenue only. For assets not being funded by capital tracker revenue, no revenue adjustment is required for the change in the allowed ROE and common equity component of capital structure, from that set in an earlier GCOC decision.

In April 2015 the AUC initiated a GCOC Proceeding to set the allowed ROE and capital structure for 2016 and 2017. While the AUC approved a request by utilities in Alberta to negotiate matters at issue in the GCOC Proceeding for 2016, a negotiated settlement was not reached and a 2016 and 2017 GCOC Proceeding commenced. A hearing is scheduled for June 2016 and a decision is expected before the end of 2016.

Capital Tracker Applications

The funding of capital expenditures during the PBR term is a material aspect of the PBR plan for FortisAlberta. The PBR plan provides a capital tracker mechanism to fund the recovery of costs associated with certain qualifying capital expenditures.

In March 2015 the AUC issued its decision related to FortisAlberta's 2013, 2014 and 2015 Capital Tracker Applications. The decision: (i) indicated that the majority of the Company's applied for capital trackers met the established criteria and were, therefore, approved for collection from customers; (ii) approved FortisAlberta's accounting test to determine qualifying K factor amounts; and (iii) confirmed certain inputs to be used in the accounting test, including the conclusion that the weighted average cost of capital be based on actual debt rates and the allowed ROE and capital structure approved in the GCOC Proceeding.

In September 2015 the AUC approved FortisAlberta's compliance filing related to the 2015 Capital Tracker Decision, substantially as filed. Capital tracker revenue of $17 million was approved for 2013 on an actual basis and capital tracker revenue of $42 million and $62 million was approved on a forecast basis for 2014 and 2015, respectively. FortisAlberta collected $15 million, $29 million and $62 million in 2013, 2014 and 2015, respectively, related to capital tracker expenditures.

In May 2015 FortisAlberta filed an application with the AUC seeking: (i) capital tracker revenue of $72 million for 2016 and $90 million for 2017; (ii) a reduction of $5 million to the 2014 capital tracker revenue to reflect actual capital expenditures; and (iii) approval of additional revenue related to capital tracker amounts that had not been fully approved in the 2015 Capital Tracker Decision. A hearing related to this proceeding concluded in October 2015, with a decision from the regulator expected in the first quarter of 2016.

FortisAlberta recognized capital tracker revenue of approximately $59 million in 2015, of which $9 million was related to updates to the 2013 and 2014 capital tracker approved amounts. The capital tracker revenue for 2015 of approximately $50 million incorporates an update for related 2015 capital expenditures as compared to the approved forecast reflected in current rates. This resulted in a deferral of $12 million of 2015 capital tracker revenue as a regulatory liability.

2016 Annual Rates Application

In December 2015 the regulator approved FortisAlberta's 2016 Annual Rates Application substantially as filed. The rates and riders, effective January 1, 2016, include an increase of approximately 4.6% to the distribution component of customer rates. This increase reflects: (i) a combined inflation and productivity factor of 0.9%; (ii) a K factor placeholder of $64 million, which is 90% of the depreciation and return associated with the 2016 forecast capital tracker expenditures as filed in the capital tracker applications, as discussed previously; and (iii) $17 million for adjustments to 2013, 2014 and 2015 capital tracker revenue as filed in the capital tracker compliance filing related to the 2015 capital tracker decision.

Utility Asset Disposition Matters

In previous decisions, the AUC made statements regarding cost responsibility for stranded assets and gains or losses related to extraordinary retirement of utility assets, which FortisAlberta and other Alberta utilities challenged as being incorrectly made. Stranded assets are generally understood to be utility assets no longer used to provide utility service as a result of extraordinary circumstances. The AUC's statements implied that the shareholder is responsible for the cost of stranded assets in a broader sense than that generally understood by regulated utilities and also conflicted with the *Electric Utilities Act* (Alberta). As a result, the utilities in Alberta had filed leave to appeal motions with the Court of Appeal of Alberta.

In September 2015 the Court of Appeal of Alberta issued a decision that dismissed the appeals of the utilities. The basis for the decision was that the AUC should be accorded deference for its conclusions in utility asset disposition matters. The decision by the Court of Appeal of Alberta has no immediate impact on FortisAlberta's financial position. However, the Company is exposed to the risk that unrecovered costs associated with utility assets subsequently deemed by the AUC to have been subject to an extraordinary retirement will not be recoverable from customers. In November 2015 the utilities in Alberta filed a leave to appeal motion with the Supreme Court of Canada, the outcome and timing of which is unknown.

Eastern Canadian Electric Utilities

In October 2015 Newfoundland Power filed a 2016/2017 GRA with the PUB to set customer rates effective July 1, 2016. The Company is proposing an overall average increase in electricity rates of 3.1%. The GRA will include a full review of Newfoundland Power's costs, including cost of capital. The application is currently under review by the PUB. A public hearing is scheduled to begin at the end of the first quarter of 2016 and a decision on the application is expected by the end of the second quarter of 2016.

In October 2015 Maritime Electric filed a GRA with the IRAC to set customer rates effective March 1, 2016, on expiry of the *Prince Edward Island Energy Accord*. In January 2016 Maritime Electric and the Government of PEI entered into a 2016 General Rate Agreement covering the three-year period from March 1, 2016 through February 28, 2019. The agreement, which is subject to regulatory approval, is generally consistent with the GRA filed in October 2015, however, reflects an allowed ROE capped at 9.35% on a maximum average common equity component of capital structure of 40%. Under the agreement, the typical customer electricity cost increase will be limited to a maximum of 2.3% annually.

Significant Regulatory Proceedings

The following table summarizes significant ongoing regulatory proceedings, including filing dates and expected timing of decisions for the Corporation's regulated utilities.

Regulated Utility	Application/Proceeding	Filing Date	Expected Decision
TEP	GRA for 2017	November 2015	Fourth quarter of 2016
UNS Electric	GRA for 2016	May 2015	Third quarter of 2016
Central Hudson	Reforming the Energy Vision	Not applicable	To be determined
FEI	2016 Cost of Capital Application	October 2015	Second quarter of 2016
FortisAlberta	2016/2017 Capital Tracker Application	May 2015	First quarter of 2016
	2016/2017 GCOC Proceeding	Not applicable	Second half of 2016
Newfoundland Power	GRA for 2016/2017	October 2015	Second quarter of 2016

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets between December 31, 2015 and December 31, 2014.

Significant Changes in the Consolidated Balance Sheets between December 31, 2015 and December 31, 2014

Balance Sheet Account	Increase/ (Decrease) *($ millions)*	Explanation
Regulatory assets – current and long-term	117	The increase was mainly due to: (i) an increase in regulatory deferred income taxes, mainly at FortisAlberta; (ii) the impact of foreign exchange on the translation of US dollar-denominated regulatory assets; and (iii) the deferral of various other costs as permitted by the regulators. The above-noted increases were partially offset by a reduction in regulatory assets at Central Hudson due to the offsetting of certain regulatory account balances, as approved by the regulator, and a decrease in the deferral for employee future benefits.
Utility capital assets	2,416	The increase primarily related to utility capital expenditures and the impact of foreign exchange on the translation of US dollar-denominated utility capital assets, partially offset by depreciation and customer contributions.
Non-utility capital assets	(664)	The decrease was due to the sale of commercial real estate and hotel assets in June 2015 and October 2015, respectively.
Goodwill	441	The increase was due to the impact of foreign exchange on the translation of US dollar-denominated goodwill.
Short-term borrowings	181	The increase was mainly due to higher short-term borrowings at FortisBC Energy and FortisBC Electric, largely to finance utility capital expenditures.
Regulatory liabilities – current and long-term	193	The increase was mainly due to the impact of foreign exchange on the translation of US dollar-denominated regulatory liabilities and higher rate stabilization accounts at FortisBC Energy, partially offset by a reduction in regulatory liabilities at Central Hudson due to the offsetting of certain regulatory account balances, as approved by the regulator.
Long-term debt (including current portion)	732	The increase was primarily due to the issuance of long-term debt at the Corporation's regulated utilities, largely in support of energy infrastructure investment, and the impact of foreign exchange on the translation of US dollar-denominated debt. The increase was partially offset by regularly scheduled debt repayments and net repayments under committed credit facilities, mainly at the Corporation, using net proceeds from the sale of commercial real estate and hotel assets.
Capital lease and finance obligations (including current portion)	(190)	The decrease was mainly due to the purchase of an additional ownership interest in the Springerville Unit 1 generating facility and the Springerville coal handling facilities at UNS Energy following the expiry of lease arrangements.
Deferred income tax liabilities	424	The increase was primarily due to tax timing differences mainly related to capital expenditures at the regulated utilities and the impact of foreign exchange on the translation of US dollar-denominated deferred income tax liabilities.
Shareholders' equity (before non-controlling interests)	1,189	The increase primarily related to: (i) an increase in accumulated other comprehensive income associated with the translation of the Corporation's US dollar-denominated investments in subsidiaries, net of hedging activities and tax; (ii) net earnings attributable to common equity shareholders for 2015, less dividends declared on common shares; and (iii) the issuance of common shares under the Corporation's dividend reinvestment, employee share purchase and stock option plans.

LIQUIDITY AND CAPITAL RESOURCES

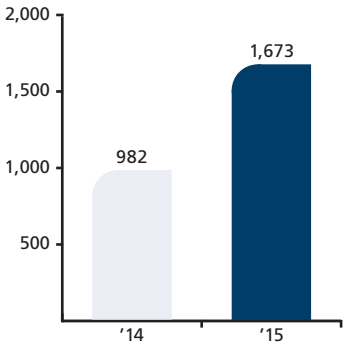
Summary of Consolidated Cash Flows

The table below outlines the Corporation's sources and uses of cash in 2015 compared to 2014, followed by a discussion of the nature of the variances in cash flows.

Summary of Consolidated Cash Flows

Years Ended December 31 *($ millions)*	**2015**	2014	Variance
Cash, Beginning of Year	**230**	72	158
Cash Provided by (Used in):			
Operating Activities	**1,673**	982	691
Investing Activities	**(1,368)**	(4,199)	2,831
Financing Activities	**(346)**	3,361	(3,707)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**53**	14	39
Cash, End of Year	**242**	230	12

Cash Flow from Operating Activities *($ millions)*



Operating Activities: Cash flow from operating activities in 2015 was $691 million higher than in 2014. The increase was driven by higher cash earnings and favourable changes in working capital. The increase in cash earnings was driven by the acquisition of UNS Energy in August 2014. Earnings contribution from the Waneta Expansion and higher cash earnings at FortisAlberta also contributed to the increase. Favourable changes in working capital at FortisBC Energy and UNS Energy were partially offset by unfavourable changes at FortisAlberta.

Investing Activities: Cash used in investing activities in 2015 was $2,831 million lower than in 2014. The decrease was due to the acquisition of UNS Energy in August 2014 for a net cash purchase price of $2,745 million. Also contributing to the decrease were proceeds received from the sale of commercial real estate assets in June 2015 for $430 million, hotel assets in October 2015 for $365 million, and generation assets in Upstate New York in June 2015 for $77 million (US$63 million), compared to proceeds of $105 million (US$95 million) on the sale of Griffith in March 2014. The decrease was partially offset by an increase in capital expenditures of $518 million, driven by a full year contribution from UNS Energy and higher capital spending at most of the Corporation's regulated utilities, partially offset by lower non-regulated capital expenditures due to the completion of the Waneta Expansion and the sale of commercial real estate and hotel assets.

Financing Activities: Cash provided by financing activities in 2015 was $3,707 million lower than in 2014. The decrease was primarily due to financing associated with the acquisition of UNS Energy in August 2014 and the repayment of credit facility borrowings in 2015 using proceeds from the sale of commercial real estate and hotel assets. The acquisition of UNS Energy was financed from proceeds of $1,800 million, or $1,725 million net of issue costs, from the issue of convertible debentures, proceeds from the issuance of preference shares and credit facility borrowings. In October 2014 substantially all of the convertible debentures were converted into 58.2 million common shares of Fortis.

Proceeds from long-term debt, net of issue costs, repayments of long-term debt and capital lease and finance obligations, and net (repayments) borrowings under committed credit facilities for 2015 and 2014 are summarized in the following tables.

Proceeds from Long-Term Debt, Net of Issue Costs

Years Ended December 31

($ millions)	**2015**	2014	Variance
UNS Energy [1]	**591**	–	591
Central Hudson [2]	**25**	33	(8)
FortisBC Energy [3]	**150**	–	150
FortisAlberta [4]	**149**	274	(125)
FortisBC Electric [5]	**–**	198	(198)
Newfoundland Power [6]	**75**	–	75
Caribbean Utilities [7]	**–**	57	(57)
Fortis Turks and Caicos [8]	**12**	92	(80)
Corporate [9]	**–**	539	(539)
Total	**1,002**	1,193	(191)

[1] In February 2015 TEP issued 10-year US$300 million 3.05% senior unsecured notes. Net proceeds were used to repay long-term debt and credit facility borrowings and to finance capital expenditures. In April 2015 UNS Electric issued 30-year US$50 million 3.95% unsecured notes. The net proceeds were primarily used for general corporate purposes. In August 2015 UNS Electric issued 12-year US$80 million 3.22% unsecured notes and UNS Gas issued 30-year US$45 million 4.00% unsecured notes. The net proceeds were used to repay maturing long-term debt.

[2] In March 2015 Central Hudson issued 10-year US$20 million 2.98% unsecured notes. The net proceeds were used to finance capital expenditures and for general corporate purposes. In March 2014 Central Hudson issued 10-year US$30 million unsecured notes with a floating interest rate of 3-month LIBOR plus 1%. The net proceeds were used to repay maturing long-term debt and for other general corporate purposes.

[3] In April 2015 FortisBC Energy issued 30-year $150 million 3.38% unsecured debentures. The net proceeds were used to repay short-term borrowings and for general corporate purposes.

[4] In September 2015 FortisAlberta issued 30-year $150 million 4.27% senior unsecured debentures. The net proceeds were used to repay credit facility borrowings and for general corporate purposes. In September 2014 FortisAlberta issued $275 million senior unsecured debentures in a dual tranche of 10-year $150 million at 3.30% and 30-year $125 million at 4.11%. The net proceeds were used to repay maturing long-term debt, finance capital expenditures and for general corporate purposes.

[5] In October 2014 FortisBC Electric issued 30-year $200 million 4.00% senior unsecured debentures. The net proceeds were used to repay long-term debt and credit facility borrowings.

[6] In September 2015 Newfoundland Power issued 30-year $75 million 4.446% secured first mortgage sinking fund bonds. The net proceeds were used to repay credit facility borrowings and for general corporate purposes.

[7] In November 2014 Caribbean Utilities issued a total of US$50 million unsecured notes with terms to maturity ranging from 15 to 32 years and coupon rates ranging from 3.65% to 4.53%. The net proceeds were used to finance capital expenditures.

[8] In January 2015 Fortis Turks and Caicos issued 15-year US$10 million 4.75% unsecured notes. The net proceeds were used to finance capital expenditures and for general corporate purposes. In December 2014 Fortis Turks and Caicos issued 15-year US$80 million 4.75% unsecured notes. The net proceeds were used to repay inter-company loans with a direct subsidiary of Fortis.

[9] In June 2014 the Corporation issued US$213 million unsecured notes with terms to maturity ranging from 5 to 30 years and coupon rates ranging from 2.92% to 4.88%. The weighted average term to maturity was approximately 9 years and the weighted average coupon rate was 3.51%. Net proceeds were used to repay US dollar-denominated borrowings on the Corporation's committed credit facility and for general corporate purposes. In September 2014 the Corporation issued US$287 million unsecured notes with terms to maturity ranging from 7 to 30 years and coupon rates ranging from 3.64% to 5.03%. The weighted average term to maturity was approximately 12 years and the weighted average coupon rate was 4.11%. Net proceeds were used to repay long-term debt and for general corporate purposes.

Repayments of Long-Term Debt and Capital Lease and Finance Obligations

Years Ended December 31 *($ millions)*	**2015**	2014	Variance
UNS Energy	**(449)**	–	(449)
Central Hudson	**–**	(24)	24
FortisBC Energy	**(92)**	(6)	(86)
FortisAlberta	**–**	(200)	200
FortisBC Electric	**–**	(140)	140
Newfoundland Power	**(6)**	(35)	29
Caribbean Utilities	**(17)**	(19)	2
Fortis Turks and Caicos	**(4)**	(4)	–
Fortis Properties	**(34)**	(22)	(12)
Corporate	**–**	(293)	293
Total	**(602)**	(743)	141

Net (Repayments) Borrowings Under Committed Credit Facilities

Years Ended December 31 *($ millions)*	**2015**	2014	Variance
UNS Energy	**(199)**	61	(260)
FortisAlberta	**30**	3	27
FortisBC Electric	**–**	(54)	54
Newfoundland Power	**(47)**	65	(112)
Corporate	**(406)**	535	(941)
Total	**(622)**	610	(1,232)

Borrowings under credit facilities by the utilities are primarily in support of their respective capital expenditure programs and/or for working capital requirements. Repayments are primarily financed through the issuance of long-term debt, cash from operations and/or equity injections from Fortis. From time to time, proceeds from preference share, common share and long-term debt offerings are used to repay borrowings under the Corporation's committed credit facility.

In September 2014 Fortis issued 24 million First Preference Shares, Series M for gross proceeds of $600 million. The net proceeds were used to repay a portion of credit facility borrowings used to initially finance a portion of the acquisition of UNS Energy.

Common share dividends paid in 2015 totalled $232 million, net of $156 million of dividends reinvested, compared to $194 million, net of $81 million of dividends reinvested, paid in 2014. The increase in dividends paid was due to a higher annual dividend paid per common share and an increase in the number of common shares outstanding. The dividend paid per common share was $1.40 in 2015 compared to $1.28 in 2014. The weighted average number of common shares outstanding was 278.6 million for 2015 compared to 225.6 million for 2014.

Contractual Obligations

The Corporation's consolidated contractual obligations with external third parties in each of the next five years and for periods thereafter, as at December 31, 2015, are outlined in the following table.

Contractual Obligations

As at December 31, 2015 ($ millions)	Total	Due within 1 year	Due in year 2	Due in year 3	Due in year 4	Due in year 5	Due after 5 years
Long-term debt	**11,240**	384	71	283	239	857	9,406
Interest obligations on long-term debt	**9,435**	536	512	507	495	488	6,897
Capital lease and finance obligations [1]	**2,478**	72	74	93	77	75	2,087
Renewable power purchase obligations [2]	**1,589**	93	93	92	92	92	1,127
Gas purchase obligations [3]	**1,449**	366	253	222	153	131	324
Power purchase obligations [4]	**1,440**	281	209	180	102	36	632
Long-term contracts – UNS Energy [5]	**1,057**	146	141	105	102	82	481
Capital cost [6]	**488**	19	19	19	19	19	393
Operating lease obligations [7]	**181**	12	11	11	11	8	128
Renewable energy credit purchase agreements [8]	**162**	13	13	13	13	13	97
Purchase of Springerville Common Facilities [9]	**147**	–	53	–	–	–	94
Employee future benefits funding contributions	**139**	49	12	8	9	9	52
Waneta Partnership promissory note	**72**	–	–	–	–	72	–
Joint-use asset and shared service agreements	**53**	3	3	3	3	3	38
Other [10]	**71**	15	12	16	3	–	25
Total	**30,001**	1,989	1,476	1,552	1,318	1,885	21,781

[1] Includes principal payments, imputed interest and executory costs, mainly related to FortisBC Electric's capital lease obligations.

[2] TEP and UNS Electric are party to 20-year long-term renewable PPAs totalling approximately US$1,148 million as at December 31, 2015, which require TEP and UNS Electric to purchase 100% of the output of certain renewable energy generating facilities that have achieved commercial operation. While TEP and UNS Electric are not required to make payments under these contracts if power is not delivered, the table above includes estimated future payments based on expected power deliveries. These agreements have various expiry dates through 2035. TEP has entered into additional long-term renewable PPAs to comply with renewable energy standards of the State of Arizona; however, the Company's obligation to purchase power under these agreements does not begin until the facilities are operational. In February 2016 one of the generating facilities achieved commercial operation, increasing estimated future payments of renewable PPAs by US$58 million, which is not included in the table above.

[3] Certain of the Corporation's subsidiaries, mainly FortisBC Energy and Central Hudson, enter into contracts for the purchase of gas, gas transportation and storage services. FortisBC Energy's gas purchase obligations are based on gas commodity indices that vary with market prices and the obligations are based on index prices as at December 31, 2015. At Central Hudson, the obligations are based on tariff rates, negotiated rates and market prices as at December 31, 2015.

[4] Power purchase obligations include various power purchase contracts held by certain of the Corporation's subsidiaries, as described below.

FortisBC Energy

In March 2015 FortisBC Energy entered into an Electricity Supply Agreement with BC Hydro for the purchase of electricity supply to the Tilbury Expansion Project, with purchase obligations totalling $513 million as at December 31, 2015.

FortisBC Electric

Power purchase obligations for FortisBC Electric, totalling $292 million as at December 31, 2015, mainly include a PPA with BC Hydro to purchase up to 200 MW of capacity and 1,752 GWh of associated energy annually for a 20-year term, as approved by the BCUC. The capacity and energy to be purchased under this agreement do not relate to a specific plant.

In addition, in November 2011 FortisBC Electric executed the Waneta Expansion Capacity Agreement ("WECA"), allowing FortisBC Electric to purchase 234 MW of capacity for 40 years, effective April 2015, as approved by the BCUC. Amounts associated with the WECA have not been included in the Contractual Obligations table as they are to be paid by FortisBC Electric to a related party and such a related-party transaction would be eliminated upon consolidation with Fortis.

FortisOntario

Power purchase obligations for FortisOntario, totalling $208 million as at December 31, 2015, primarily include two long-term take-or-pay contracts between Cornwall Electric and Hydro-Quebec Energy Marketing for the supply of electricity and capacity, both expiring in December 2019. The first contract provides approximately 237 GWh of energy per year and up to 45 MW of capacity at any one time. The second contract provides 100 MW of capacity and provides a minimum of 300 GWh of electricity per contract year.

Maritime Electric

Power purchase obligations for Maritime Electric, totalling $194 million as at December 31, 2015, primarily include two take-or-pay contracts for the purchase of either capacity or energy, expiring in February 2019 and November 2032, as well as an Energy Purchase Agreement with New Brunswick Power ("NB Power") expiring in February 2019.

Central Hudson

Central Hudson's power purchase obligations totalled US$124 million as at December 31, 2015. In June 2014 Central Hudson entered into a contract to purchase available installed capacity from the Danskammer Generating Facility from October 2014 through August 2018 with approximately US$76 million in purchase commitments remaining as at December 31, 2015. During 2015, Central Hudson entered into agreements to purchase electricity on a unit-contingent basis at defined prices during peak load periods from June 2015 through August 2016, replacing existing contracts which expired in March 2015.

(5) UNS Energy has entered into various long-term contracts for the purchase and delivery of coal to fuel its generating facilities, the purchase of gas transportation services to meet its load requirements, and the purchase of transmission services for purchased power, with obligations totalling US$440 million, US$261 million and US$63 million, respectively, as at December 31, 2015. Amounts paid under contracts for the purchase and delivery of coal depend on actual quantities purchased and delivered. Certain of these contracts also have price adjustment clauses that will affect future costs under the contracts. As a result of the restructuring of the ownership of the San Juan generating station in January 2016, a new coal supply agreement came into effect under which TEP's minimum purchase obligations are US$137 million, which is not included in the previous table.

(6) Maritime Electric has entitlement to approximately 4.55% of the output from NB Power's Point Lepreau nuclear generating station for the life of the unit. As part of its entitlement, Maritime Electric is required to pay its share of the capital and operating costs of the unit.

(7) Operating lease obligations include certain office, warehouse, natural gas T&D asset, rail car, land easement and rights-of-way, and vehicle and equipment leases.

(8) UNS Energy is party to renewable energy credit purchase agreements, totalling approximately US$117 million as at December 31, 2015, to purchase the environmental attributions from retail customers with solar installations. Payments for the renewable energy credit purchase agreements are paid in contractually agreed-upon intervals based on metered renewable energy production.

(9) UNS Energy has entered into a commitment to exercise its fixed-price purchase provision to purchase an undivided 50% leased interest in the Springerville Common Facilities if the lease is not renewed, for a purchase price of US$106 million, with one facility to be acquired in 2017 and the remaining two facilities to be acquired in 2021.

(10) Other contractual obligations include various other commitments entered into by the Corporation and its subsidiaries, including Performance Share Unit, Restricted Share Unit and Directors' Deferred Share Unit Plan obligations and asset retirement obligations.

Other Contractual Obligations

Capital Expenditures: The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by the need to ensure continued and enhanced performance, reliability and safety of the electricity and gas systems and to meet customer growth. The Corporation's consolidated capital expenditure program, including capital spending at its non-regulated operations, is forecast to be approximately $1.9 billion for 2016. Over the five years 2016 through 2020, the Corporation's consolidated capital expenditure program is expected to be approximately $9 billion, which has not been included in the Contractual Obligations table.

Other: CH Energy Group is party to an investment to develop, own and operate electric transmission projects in New York State. In December 2014 an application was filed with the U.S. Federal Energy Regulatory Commission ("FERC") for the recovery of the cost of and return on five high-voltage transmission projects totalling US$1.7 billion, of which CH Energy Group's maximum commitment is US$182 million. CH Energy Group issued a parental guarantee to assure the payment of a maximum commitment of US$182 million. As at December 31, 2015, no payment obligation is expected under this guarantee.

FortisBC Energy issued commitment letters to customers, totalling $33 million as at December 31, 2015, to provide Energy Efficiency and Conservation ("EEC") funding under the EEC program approved by the BCUC.

Caribbean Utilities is party to primary and secondary fuel supply contracts and is committed to purchasing approximately 60% and 40%, respectively, of the Company's diesel fuel requirements under the contracts for the operation of its diesel-powered generating plant. The approximate combined quantity under the contracts for 2016 is 20 million imperial gallons. Fortis Turks and Caicos has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

The Corporation's long-term regulatory liabilities of $1,340 million as at December 31, 2015 have been excluded from the Contractual Obligations table, as the final timing of settlement of many of the liabilities is subject to further regulatory determination or the settlement periods are not currently known. The nature and amount of the long-term regulatory liabilities are detailed in Note 8 to the Corporation's 2015 Audited Consolidated Financial Statements.

Capital Structure

The Corporation's principal businesses of regulated electric and gas utilities require ongoing access to capital to enable the utilities to fund maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. Fortis generally finances a significant portion of acquisitions at the corporate level with proceeds from common share, preference share and long-term debt offerings. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 35% common equity, 65% debt and preferred equity, as well as investment-grade credit ratings. Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in each of the utility's customer rates.

The consolidated capital structure of Fortis is presented in the following table.

Capital Structure

	2015		2014	
As at December 31	*($ millions)*	*(%)*	*($ millions)*	*(%)*
Total debt and capital lease and finance obligations (net of cash) [1]	**11,950**	**54.8**	11,239	56.4
Preference shares	**1,820**	**8.3**	1,820	9.1
Common shareholders' equity	**8,060**	**36.9**	6,871	34.5
Total [2]	**21,830**	**100.0**	19,930	100.0

[1] Includes long-term debt and capital lease and finance obligations, including current portions, and short-term borrowings, net of cash

[2] Excludes amounts related to non-controlling interests

Excluding capital lease and finance obligations, the Corporation's capital structure as at December 31, 2015 was 53.7% debt, 8.5% preference shares and 37.8% common shareholders' equity (December 31, 2014 – 54.8% debt, 9.5% preference shares and 35.7% common shareholders' equity).

The improvement in the Corporation's capital structure was due to an increase in common shareholders' equity as a result of: (i) an increase in accumulated other comprehensive income associated with the translation of the Corporation's US dollar-denominated investments in subsidiaries, net of hedging activities and tax; (ii) net earnings attributable to common equity shareholders for the year ended December 31, 2015, less dividends declared on common shares; and (iii) the issuance of common shares under the Corporation's dividend reinvestment, employee share purchase and stock option plans. The capital structure was also impacted by an increase in total debt due to the impact of foreign exchange on the translation of US dollar-denominated debt and new debt in support of energy infrastructure investment, partially offset by regular scheduled debt repayments and net repayments under committed credit facilities.

Credit Ratings

As at December 31, 2015, the Corporation's credit ratings were as follows:

Standard & Poor's ("S&P")	A– / Stable (long-term corporate and unsecured debt credit rating)
DBRS	A (low) / Stable (unsecured debt credit rating)

The above-noted credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, and management's commitment to maintaining reasonable levels of debt at the holding company level. In February 2016, after the announcement by Fortis that it had entered into an agreement to acquire ITC, S&P affirmed the Corporation's long-term corporate credit rating at A–, revised its unsecured debt credit rating to BBB+ from A–, and revised its outlook on the Corporation to negative from stable. Similarly, in February 2016 DBRS placed the Corporation's credit rating under review with negative implications.

Capital Expenditure Program

Capital investment in energy infrastructure is required to ensure continued and enhanced performance, reliability and safety of the electricity and gas systems, and to meet customer growth. All costs considered to be maintenance and repairs are expensed as incurred. Costs related to replacements, upgrades and betterments of capital assets are capitalized as incurred. Approximately $276 million in maintenance and repairs was expensed in 2015 compared to approximately $203 million in 2014. The increase was largely due to a full year of expense for UNS Energy in 2015.

Gross consolidated capital expenditures for 2015 were approximately $2.2 billion. A breakdown of these capital expenditures by segment and asset category for 2015 is provided in the following table.

Gross Consolidated Capital Expenditures [1]

Year Ended December 31, 2015

	Regulated Utilities								Non-Regulated		
($ millions)	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Eastern Canadian	Caribbean Electric	**Total Regulated Utilities**	**Fortis Generation**	**Non-Utility** [2]	**Total**
Generation	321	1	–	–	3	9	107	**441**	**38**	**–**	**479**
Transmission	131	37	57	–	19	23	2	**269**	**–**	**–**	**269**
Distribution	135	102	134	358	38	121	16	**904**	**–**	**–**	**904**
Facilities, equipment, vehicles and other [3]	39	27	254	73	35	14	9	**451**	**–**	**28**	**479**
Information technology	43	14	15	21	8	8	3	**112**	**–**	**–**	**112**
Total	669	181	460	452	103	175	137	**2,177**	**38**	**28**	**2,243**

[1] Represents cash payments to construct utility capital assets, non-utility capital assets and intangible assets, as reflected on the consolidated statement of cash flows. Excludes the non-cash equity component of AFUDC.

[2] Includes capital expenditures of approximately $14 million at FAES, which is reported in the Corporate and Other segment

[3] Includes capital expenditures associated with the Tilbury Expansion at FortisBC Energy and Alberta Electric System Operator ("AESO") transmission-related capital expenditures at FortisAlberta

Planned capital expenditures are based on detailed forecasts of energy demand, cost of labour and materials, as well as other factors, including economic conditions and foreign exchange rates, which could change and cause actual expenditures to differ from those forecast. Gross consolidated capital expenditures of $2,243 million for 2015 were $91 million higher than $2,152 million forecast for 2015, as disclosed in the MD&A for the year ended December 31, 2014. The increase was driven by higher capital spending at FortisBC Energy primarily due to the timing of payments associated with the Tilbury Expansion and at FortisAlberta primarily due to the purchase of two Rural Electrification Associations ("REAs") for approximately $21 million in 2015, and due to the impact of foreign exchange associated with the translation of US dollar-denominated capital expenditures. The increase was partially offset by lower-than-forecast capital spending at the Waneta Expansion, due to the timing of payments, and at FAES.

Gross consolidated capital expenditures for 2016 are expected to be approximately $1.9 billion. A breakdown of forecast gross consolidated capital expenditures by segment and asset category for 2016 is provided in the following table.

Forecast Gross Consolidated Capital Expenditures [1]

Year Ending December 31, 2016

	Regulated Utilities								Non-Regulated		
($ millions)	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Eastern Canadian	Caribbean Electric	**Total Regulated Utilities**	**Fortis Generation**	**Non-Utility [2]**	**Total**
Generation	162	2	–	–	2	24	73	**263**	**15**	**–**	**278**
Transmission	66	30	84	–	21	19	6	**226**	**–**	**–**	**226**
Distribution	168	142	129	311	29	110	23	**912**	**–**	**–**	**912**
Facilities, equipment, vehicles and other [3]	40	25	118	109	16	9	20	**337**	**–**	**3**	**340**
Information technology	49	29	18	21	11	12	5	**145**	**–**	**–**	**145**
Total	485	228	349	441	79	174	127	**1,883**	**15**	**3**	**1,901**

[1] Represents forecast cash payments to construct utility capital assets and intangible assets, as would be reflected on the consolidated statement of cash flows. Excludes the non-cash equity component of AFUDC. Forecast capital expenditures for 2016 are based on a forecast exchange rate of US$1.00=CAD$1.38.
[2] Includes forecast capital expenditures of approximately $3 million at FAES, which is reported in the Corporate and Other segment
[3] Includes forecast capital expenditures associated with the Tilbury Expansion at FortisBC Energy and AESO transmission-related capital expenditures at FortisAlberta

The percentage breakdown of 2015 actual and 2016 forecast gross consolidated capital expenditures among growth, sustaining and other is as follows.

Gross Consolidated Capital Expenditures

Year Ending December 31	**Actual**	Forecast
(%)	**2015**	2016
Growth [1]	**40**	36
Sustaining [2]	**44**	48
Other [3]	**16**	16
Total	**100**	100

[1] Includes capital expenditures associated with the Tilbury Expansion at FortisBC Energy and AESO transmission-related capital expenditures at FortisAlberta
[2] Capital expenditures required to ensure continued and enhanced performance, reliability and safety of generation and T&D assets
[3] Relates to facilities, equipment, vehicles, information technology systems and other assets

Over the five-year period 2016 through 2020, excluding the pending acquisition of ITC, gross consolidated capital expenditures are expected to be approximately $9 billion. The approximate breakdown of the capital spending expected to be incurred is as follows: 40% at Regulated Electric & Gas Utilities in the United States; 37% at Canadian Regulated Electric Utilities, driven by FortisAlberta; 17% at Canadian Regulated Gas Utility; 5% at Caribbean Regulated Electric Utilities; and the remaining 1% at non-regulated operations. Capital expenditures at the regulated utilities are subject to regulatory approval. Over the five-year period, on average annually, the approximate breakdown of the total capital spending to be incurred is as follows: 35% to meet customer growth; 50% to ensure continued and enhanced performance, reliability and safety of generation and T&D assets, i.e., sustaining capital expenditures; and 15% for facilities, equipment, vehicles, information technology and other assets.

Actual 2015 and forecast 2016 midyear rate base for the Corporation's regulated utilities and the Waneta Expansion is provided in the following table.

Midyear Rate Base

	Actual	Forecast
($ billions)	**2015**	2016
UNS Energy [1]	**4.1**	4.8
Central Hudson [1]	**1.4**	1.6
FortisBC Energy	**3.7**	3.7
FortisAlberta	**2.7**	3.0
FortisBC Electric	**1.3**	1.3
Eastern Canadian Electric Utilities	**1.6**	1.7
Regulated Electric Utilities – Caribbean [1]	**0.8**	0.9
Waneta Expansion	**0.8**	0.8
Total	**16.4**	17.8

[1] Actual midyear rate base for 2015 is based on the actual average exchange rate of US$1.00=CAD$1.28 and forecast midyear rate base for 2016 is based on a forecast exchange rate of US$1.00=CAD$1.38.

The most significant capital projects that are included in the Corporation's base consolidated capital expenditures for 2015 and 2016 are summarized in the table below.

Significant Capital Projects [1]

($ millions)		Pre-	**Actual**	Forecast	Forecast	Expected Year of
Company	**Nature of Project**	2015	**2015**	2016	2017–2020	Completion
UNS Energy [2]	Interest in Springerville Unit 1	23	**57**	–	–	2015
	Springerville Coal Handling Facilities Lease Buyout	–	**91**	–	–	2015
	Pinal Transmission Project	9	**84**	–	–	2015
	Residential Solar Program	–	**1**	22	90	Ongoing
Central Hudson [2]	Gas Main Replacement Program	7	**19**	29	135	Post-2020
FortisBC Energy	Tilbury LNG Facility Expansion [3]	145	**181**	105	15	2016
	Lower Mainland System Upgrade	4	**11**	50	362	2018
FortisAlberta	Pole-Management Program	159	**41**	42	94	Post-2020
Caribbean Utilities [2]	Generation Expansion	12	**61**	35	–	2016
Waneta Partnership	Waneta Expansion [4]	679	**36**	13	97	2015

[1] Represents utility capital asset and intangible asset expenditures, including both the capitalized interest and equity components of AFUDC, where applicable

[2] Forecast capital expenditures are based on a forecast exchange rate of US$1.00=CAD$1.38 for 2016 through 2020

[3] Total project investment as at December 31, 2014 and 2015 includes approximately $43 million and $11 million, respectively, in non-cash capital accruals

[4] Includes the $72 million payment expected to be made in 2020 and excludes forecast capitalized interest of the minority partners, CPC/CBT, in the Waneta Partnership

UNS Energy completed three significant capital investments in 2015. In January 2015, upon expiration of the Springerville Unit 1 lease, UNS Energy purchased an additional ownership interest in Springerville Unit 1 for US$46 million. This purchase increased the ownership interest to 49.5%. Additionally, upon expiration of the Springerville Coal Handling Facilities lease in April 2015, UNS Energy purchased an ownership interest in the coal-handling assets for US$72 million. The Pinal Transmission Project at UNS Energy was also completed in 2015 at a total project cost of US$79 million. The project consisted of the construction of a 500-kilovolt transmission line in Pinal County that will increase the Company's import capacity from Gila River Unit 3 and the Palo Verde trading hub.

The Residential Solar Program at UNS Energy is a partnership with local solar companies for UNS Energy to own and install rooftop solar systems for residential customers. The total capital cost of the program through 2020 is expected to be approximately US$82 million, with approximately US$16 million expected to be spent in 2016.

The Gas Main Replacement Program at Central Hudson is a 15-year replacement program to eliminate and replace leakage-prone pipes throughout the gas distribution system. The proposed replacement program increases the rate of annual expenditures on pipe replacements to approximately US$20 million to expedite the replacement plan. Approximately US$15 million was spent on this program in 2015 and an additional US$21 million is expected to be spent in 2016. The majority of spending is expected post 2020.

FortisBC Energy's ongoing Tilbury LNG Facility Expansion, at an estimated total project cost of $440 million, will include a second LNG tank and a new liquefier, both to be in service around the end of 2016. FortisBC Energy received an Order in Council from the Government of British Columbia exempting the Tilbury LNG Facility project from further regulatory review. Key construction activities in 2015 were focused on construction of the storage tank and liquefaction process areas. Total project costs to the end of 2015 were approximately $326 million.

The Lower Mainland System Upgrade project at FortisBC Energy is in place to address system capacity and pipeline condition issues for the gas supply system in the Lower Mainland area of British Columbia. The project will be completed in two phases: (i) the Lower Mainland Intermediate Pressure System Upgrade project phase, which is focused on addressing pipeline condition issues; and (ii) the Coastal Transmission System phase, which is intended to increase security of supply by reducing the number of single points of failure. The project has an estimated capital cost of $427 million, with approximately $50 million forecast to be spent in 2016, and is expected to be completed in 2018. The BCUC approved the application to replace certain sections of intermediate pressure pipeline segments within the Greater Vancouver area in October 2015. The Coastal Transmission System phase was approved by a Special Direction by the Government of British Columbia in 2014 and will not be subject to further regulatory review.

During 2015 FortisAlberta continued with the replacement of vintage poles under its Pole-Management Program to extend the service life of existing poles and to replace poles when deterioration is beyond repair. The total capital cost of the program through 2020 is expected to be approximately $336 million. Approximately $41 million was spent on this program in 2015, for a total of $200 million spent to date.

Caribbean Utilities was the successful bidder for new generation capacity and entered into a design-build contract agreement to cover the purchase and turnkey installation of two 18.5 MW diesel-generating units, one 2.7 MW waste heat recovery steam turbine and associated auxiliary equipment. Approximately US$48 million was spent on the project in 2015, with approximately US$25 million forecast to be spent in 2016. The project cost is estimated to be US$85 million and the plant is expected to be commissioned in mid-2016.

Construction of the $900 million, 335-MW Waneta Expansion was completed on April 1, 2015, ahead of schedule and on budget. Construction of the Waneta Expansion, which is adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia, commenced late in 2010. The expansion added a second powerhouse, immediately downstream of the Waneta Dam on the Pend d'Oreille River, that shares the existing hydraulic head and generates clean, renewable, cost-effective power from water that would otherwise be spilled. The project also included construction of a 10-kilometre, 230-kilovolt transmission line. On April 2, 2015, the Waneta Expansion began generating power, all of which is being sold to BC Hydro and FortisBC Electric under 40-year contracts. Fortis owns a 51% interest in the Waneta Partnership and operates and maintains the non-regulated investment. The capital cost of the Waneta Expansion, as reported in the Significant Capital Projects table, includes capitalized interest by Fortis during construction, as well as other eligible capitalized expenses, and a $72 million payment expected to be made in 2020 related to accrued development costs previously incurred by CPC/CBT. The table excludes approximately $50 million of forecast capitalized interest of the minority partners in the Waneta Partnership.

Additional Investment Opportunities

In addition to the Corporation's base consolidated capital expenditure forecast, management is pursuing additional investment opportunities within existing service territories. These additional investment opportunities, as discussed below, are not included in the Corporation's base capital expenditure forecast and also exclude the acquisition of ITC.

FortisBC Energy is pursuing additional LNG infrastructure investment opportunities, including a pipeline expansion to the proposed Woodfibre LNG site in Squamish, British Columbia and a further expansion of Tilbury. In December 2014 FortisBC Energy received an Order in Council from the Government of British Columbia effectively exempting these projects from further regulatory approval by the BCUC.

The pipeline expansion is conditional on Woodfibre LNG proceeding with its LNG export facility. The Woodfibre LNG plant has passed the British Columbia Environmental Assessment Office review and the Squamish First Nation approved an environmental certificate for the project in October 2015. These approvals are significant milestones; however, the project is pending a Federal Environmental Assessment. In addition, FortisBC Energy's pipeline expansion, at an estimated total project cost of up to $600 million, is also subject to various environmental approvals. A final investment decision by Woodfibre LNG is expected in 2016.

A further expansion of Tilbury is conditional upon having long-term contracts in place for the offtake of 70% of the additional liquefaction capacity, on average, for the first 15 years of operation. FortisBC Energy has a conditional agreement with Hawaiian Electric Company that would meet this requirement, subject to the regulatory approval process in Hawaii. The Corporation continues to have discussions with Hawaiian Electric Company, which is expected to be the primary offtaker, regarding the viability and scope of the project. Any resulting agreement would be subject to the approval of the Hawaii Public Utilities Commission.

The Corporation also has other significant opportunities that have not yet been included in the Corporation's capital expenditure forecast including, but not limited to, the New York Transco, LLC at Central Hudson to address transmission constraints in New York; renewable energy alternatives at UNS Energy; Wataynikaneyap transmission line to connect remote First Nations communities at FortisOntario; further gas infrastructure opportunities at FortisBC Energy; and consolidation of Rural Electrification Associations at FortisAlberta.

Cash Flow Requirements

At the subsidiary level, it is expected that operating expenses and interest costs will generally be paid out of subsidiary operating cash flows, with varying levels of residual cash flows available for subsidiary capital expenditures and/or dividend payments to Fortis. Borrowings under credit facilities may be required from time to time to support seasonal working capital requirements. Cash required to complete subsidiary capital expenditure programs is also expected to be financed from a combination of borrowings under credit facilities, equity injections from Fortis and long-term debt offerings.

The Corporation's ability to service its debt obligations and pay dividends on its common shares and preference shares is dependent on the financial results of the operating subsidiaries and the related cash payments from these subsidiaries. Certain regulated subsidiaries may be subject to restrictions that may limit their ability to distribute cash to Fortis.

Cash required of Fortis to support subsidiary capital expenditure programs and finance acquisitions is expected to be derived from a combination of borrowings under the Corporation's committed corporate credit facility and proceeds from the issuance of common shares, preference shares and long-term debt. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed corporate credit facility may be required from time to time to support the servicing of debt and payment of dividends. For a discussion of the Corporation's cash flow requirements associated with the pending acquisition of ITC, refer to the "Business Risk Management – Risks Associated with the Acquisition of ITC" and "Subsequent Event" sections of this MD&A.

In April 2015 FortisBC Energy filed a short-form base shelf prospectus to establish a Medium-Term Note Debenture Program, under which the Company may issue debentures in an aggregate principal amount of up to $1 billion during the 25-month life of the shelf prospectus. In April 2015 FortisBC Energy issued 30-year $150 million 3.38% unsecured debentures under the base shelf prospectus.

In June 2015 Fortis injected US$180 million of equity into TEP. Proceeds were used to repay credit facility borrowings in June 2015 and the balance was used to redeem bonds in August 2015 and provide additional liquidity to TEP. This equity injection fulfilled one of the commitments made by Fortis in order to receive regulatory approval for the acquisition of UNS Energy, and increased TEP's common equity component of capital structure to almost 50%, which is comparable with other regulated utilities in Arizona.

In May 2015 Caribbean Utilities completed a rights offering in which it raised gross proceeds of US$32 million through the issue of 2.9 million common shares. Fortis invested US$23 million in approximately 2.2 million common shares of Caribbean Utilities. The net proceeds from the rights offering were used by Caribbean Utilities to finance capital expenditures.

In October 2015 FortisAlberta filed a short-form base shelf prospectus to establish a Medium-Term Note Debenture Program, under which the Company may issue debentures in an aggregate principal amount of up to $500 million during the 25-month life of the shelf prospectus.

As at December 31, 2015, management expects consolidated fixed-term debt maturities and repayments to be $313 million in 2016 and to average approximately $260 million annually over the next five years. The combination of available credit facilities and relatively low annual debt maturities and repayments provides the Corporation and its subsidiaries with flexibility in the timing of access to capital markets. For a discussion of capital resources and liquidity risk, refer to the "Business Risk Management – Capital Resources and Liquidity Risk" section of this MD&A.

Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2015 and are expected to remain compliant in 2016.

Credit Facilities

As at December 31, 2015, the Corporation and its subsidiaries had consolidated credit facilities of approximately $3.6 billion, of which approximately $2.4 billion was unused, including $570 million unused under the Corporation's committed revolving corporate credit facility. The credit facilities are syndicated mostly with the seven largest Canadian banks, as well as large banks in the United States, with no one bank holding more than 20% of these facilities. Approximately $3.3 billion of the total credit facilities are committed facilities with maturities ranging from 2016 through 2020.

The following summary outlines the credit facilities of the Corporation and its subsidiaries.

Credit Facilities

($ millions)	Regulated Utilities	Corporate and Other	**Total as at December 31, 2015**	Total as at December 31, 2014
Total credit facilities [1]	2,211	1,354	**3,565**	3,854
Credit facilities utilized:				
Short-term borrowings	(511)	–	**(511)**	(330)
Long-term debt (including current portion) [2]	(71)	(480)	**(551)**	(1,096)
Letters of credit outstanding	(68)	(36)	**(104)**	(192)
Credit facilities unused	1,561	838	**2,399**	2,236

[1] Total credit facilities exclude a $300 million option to increase the Corporation's committed corporate credit facility, as discussed below.

[2] As at December 31, 2015, credit facility borrowings classified as long-term debt included $71 million in current installments of long-term debt on the consolidated balance sheet (December 31, 2014 – $257 million).

As at December 31, 2015 and 2014, certain borrowings under the Corporation's and subsidiaries' long-term committed credit facilities were classified as long-term debt. It is management's intention to refinance these borrowings with long-term permanent financing during future periods.

Regulated Utilities

The UNS Utilities have a total of US$350 million ($484 million) in unsecured committed revolving credit facilities maturing in October 2020, with the option of two one-year extensions.

Central Hudson has a US$200 million ($277 million) unsecured committed revolving credit facility, maturing in October 2020, that is utilized to finance capital expenditures and for general corporate purposes. Central Hudson also has an uncommitted credit facility totalling US$25 million ($34 million).

FEI has a $700 million unsecured committed revolving credit facility, maturing in August 2018, that is utilized to finance working capital requirements, capital expenditures and for general corporate purposes.

FortisAlberta has a $250 million unsecured committed revolving credit facility, maturing in August 2020, that is utilized to finance capital expenditures and for general corporate purposes.

FortisBC Electric has a $150 million unsecured committed revolving credit facility, maturing in May 2018. This facility is utilized to finance capital expenditures and for general corporate purposes. FortisBC Electric also has a $10 million unsecured demand overdraft facility.

Newfoundland Power has a $100 million unsecured committed revolving credit facility, maturing in August 2019, and a $20 million demand credit facility. Maritime Electric has a $50 million unsecured committed revolving credit facility, maturing in February 2019, and a $5 million unsecured demand credit facility. FortisOntario has a $30 million unsecured committed revolving credit facility, maturing in June 2016.

Caribbean Utilities has unsecured credit facilities totalling approximately US$47 million ($65 million). Fortis Turks and Caicos has short-term unsecured demand credit facilities of US$26 million ($36 million), maturing in September 2016.

Corporate and Other

Fortis has a $1 billion unsecured committed revolving credit facility, maturing in July 2020, that is available for general corporate purposes. The Corporation has the ability to increase this facility to $1.3 billion. As at December 31, 2015, the Corporation has not yet exercised its option for the additional $300 million. The Corporation also has a $35 million letter of credit facility, maturing in January 2017.

UNS Energy Corporation has a US$150 million ($208 million) unsecured committed revolving credit facility, maturing in October 2020, with the option of two one-year extensions.

CH Energy Group has a US$50 million ($69 million) unsecured committed revolving credit facility, maturing in July 2020, that can be utilized for general corporate purposes.

FHI has a $30 million unsecured committed revolving credit facility, maturing in April 2018, that is available for general corporate purposes.

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $104 million as at December 31, 2015 (December 31, 2014 – $192 million), the Corporation had no off-balance sheet arrangements that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources.

BUSINESS RISK MANAGEMENT

The following is a summary of the Corporation's significant business risks.

Regulatory Risk: The Corporation's key business risk is regulation. Regulated utility assets comprised approximately 96% of total assets of Fortis as at December 31, 2015 (December 31, 2014 – 93%). Approximately 96% of the Corporation's operating revenue[(1)] was derived from regulated utility operations in 2015 (2014 – 95%), and approximately 92% of the Corporation's operating earnings[(1)], excluding the gains on sale of non-core assets, were derived from regulated utility operations in 2015 (2014 – 91%). The Corporation operates nine utilities in different jurisdictions in Canada, the United States and the Caribbean, with no more than one-third of total assets located in any one regulatory jurisdiction.

Each of the Corporation's regulated utilities is subject to normal regulation that can affect future revenue and earnings. As a result, the utilities are subject to uncertainties faced by regulated entities, including approval by the respective regulatory authorities of electricity and gas rates that permit a reasonable opportunity to recover, on a timely basis, the estimated COS, including a fair rate of return on rate base and, in the case of utilities in the Caribbean, the continuation of licences. Generally, the ability of a utility to recover the actual COS and earn the approved ROE and/or ROA depends on achieving the forecasts established in the rate-setting processes. When PBR mechanisms are utilized in determining annual revenue requirements and resulting customer rates, a formula is generally applied that incorporates inflation and assumed productivity improvements. The use of PBR mechanisms should allow a utility a reasonable opportunity to recover prudent cost of service and earn its allowed ROE, however, a utility is exposed to risks that inflationary increases may exceed the inflationary factor set by the regulator and that the utility may be unable to achieve productivity improvements. In the case of FortisAlberta's current PBR mechanism, there is a risk that capital expenditures may not qualify, or be approved, as a capital tracker where necessary.

Regulators approve the allowed ROEs and deemed capital structures of the utilities. Fair regulatory treatment that allows a utility to earn a fair risk-adjusted rate of return, comparable to that available on alternative investments of similar risk, is essential for maintaining service quality, as well as ongoing capital attraction and growth. Rate applications establishing revenue requirements may be subject to negotiated settlement procedures. Failing a negotiated settlement, rate applications may be pursued through a litigated public hearing process. There can be no assurance that resulting rate orders issued by the regulators will permit the regulated utilities to recover all costs actually incurred and to earn the expected or fair rates of return on an appropriate capitalization.

Electricity and gas infrastructure investments require the approval of the regulatory authorities, either through the approval of capital expenditure plans or revenue requirements for the purpose of setting electricity and gas rates, which include the impact of capital expenditures on rate base and/or COS. There is no assurance that capital projects perceived as required or completed by the Corporation's regulated utilities will be approved. Capital cost overruns may not be recoverable in customer rates.

A failure to obtain acceptable rate orders, appropriate ROEs or capital structures as applied for may adversely affect the business carried on by the regulated utilities, the undertaking or timing of capital expenditures, ratings assigned by credit rating agencies, the issuance of long-term debt and other matters, which may, in turn, have a material adverse effect on the results of operations and financial position of the Corporation's regulated utilities. In addition, there is no assurance that the regulated utilities will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement.

As an owner of an electricity distribution network under the *Electric Utilities Act (Alberta)*, FortisAlberta is required to act, or to authorize a substitute party to act, as a provider of electricity services, including the sale of electricity, to eligible customers under a regulated rate and to appoint a retailer as a default supplier to provide electricity services to customers otherwise unable to obtain electricity services. In order to remain solely a distribution utility, FortisAlberta appointed EPCOR Energy Services (Alberta) Inc. ("EPCOR") as its regulated-rate provider. As a result of this appointment, EPCOR assumed all of FortisAlberta's rights and obligations in respect of these services. In the unlikely event that EPCOR is unable or unwilling to act as a regulated-rate provider or default supplier, and no other party is willing to act in this capacity, FortisAlberta would be required to act as a provider of electricity services to eligible customers under a regulated rate or to provide electricity services to customers otherwise unable to obtain electricity services. If FortisAlberta could not secure outsourcing for these functions, it would need to administer these retail responsibilities by adding necessary staff, facilities and/or equipment.

For additional information on the nature of regulation and various regulatory matters pertaining to the Corporation's utilities, refer to the "Regulatory Highlights" section of this MD&A.

[(1)] Operating revenue and operating earnings are non-US GAAP measures and refer to total revenue, excluding Corporate and Other segment revenue and inter-segment eliminations, and net earnings attributable to common equity shareholders, excluding Corporate and Other segment expenses, respectively. Operating revenue and operating earnings are referred to by users of the consolidated financial statements in evaluating the performance of the Corporation's operating subsidiaries.

Risks Associated with the Pending Acquisition of ITC: ITC is a public company and its directors have fiduciary duties which may require them to consider competing offers to purchase the common stock of ITC as an alternative to the Acquisition. The agreement and plan of merger preserves the ability of the directors of ITC to accept a competing offer, in certain circumstances. Fortis may exercise its right to match such offer and, as a result, the purchase price could increase and other key transaction terms could change.

The closing of the acquisition of ITC, which is expected to occur in late 2016, is subject to normal commercial risks that the Acquisition will not close on the terms negotiated, or at all. Completion of the Acquisition remains subject to receipt of ITC and Fortis shareholder approvals, certain regulatory, state and federal approvals, and the satisfaction or waiver of other customary closing conditions contained in the agreement and plan of merger. The failure to obtain the required approvals or to satisfy or waive the conditions to closing may result in the termination of the agreement and plan of merger. Fortis intends to complete the Acquisition as soon as practicable after obtaining the required shareholder, regulatory and governmental approvals, and satisfying the other required closing conditions. A substantial delay in obtaining regulatory approvals or the imposition of unfavourable terms and/or conditions in such approvals could have a material adverse effect on the Corporation's ability to complete the Acquisition and on the Corporation's business, financial condition or results of operations. If the closing of the acquisition of ITC does not take place as contemplated, the Corporation could suffer material adverse consequences. Failure to complete the Acquisition would, in certain circumstances, result in the Corporation being required to pay a termination fee of up to US$280 million and other potential costs.

Fortis expects that the Acquisition will provide benefits to the Corporation, including approximately 5% accretion to earnings per common share in the first full year following closing, excluding one-time acquisition-related expenses and assuming a stable currency exchange environment. There is a risk that some or all of the expected benefits of the Acquisition may fail to materialize, or may not occur within the time periods anticipated by the Corporation. The realization of such benefits may be affected by a number of factors, many of which are beyond the control of the Corporation. Failure to realize the anticipated benefits of the acquisition of ITC may impact the financial performance of the Corporation, the price of its common shares and the ability of Fortis to continue to pay dividends on its common shares at rates consistent with the Corporation's dividend guidance, at current rates or at all.

Financing of the cash portion of the Acquisition is expected to be achieved primarily through the issuance of approximately US$2 billion of Fortis debt and the sale of up to 19.9% of ITC to one or more infrastructure-focused minority investors. There can be no assurance that such financing sources will be available to Fortis at the desired time or at all, or on cost-efficient or commercially acceptable terms. As a result, there is no certainty that Fortis will reach a binding agreement with minority investors to complete the minority investment prior to closing of the Acquisition or at all. The Acquisition is not conditional upon Fortis securing one or more minority investors. Consummation of the Acquisition without completion of the contemplated minority investment could increase the consolidated indebtedness of the Corporation or result in the requirement for additional common equity and may have a negative impact on the Corporation's credit ratings and outlook and could result in additional financing costs and the failure to realize some, or all, of the expected benefits of the acquisition, including the extent to which the Acquisition is accretive. The Corporation obtained commitments for an aggregate of US$3.7 billion non-revolving term credit facilities. The commitments of the lenders to enter into these credit facilities is subject to certain customary conditions, which may result in such facilities becoming unavailable to Fortis in certain circumstances. If these credit facilities become unavailable, Fortis may not be able to complete the Acquisition.

While Fortis intends to become a U.S. Securities and Exchange Commission ("SEC") registrant and list its common shares on the New York Stock Exchange, there is no guarantee that it will be successful in this regard. If the Corporation is successful in this regard, it will be subject to increased regulatory compliance and may be subject to a greater risk of litigation.

The operations of ITC are conducted in US dollars and, following the Acquisition, the consolidated earnings and cash flows of Fortis will be impacted to a greater extent by fluctuations in the US dollar-to-Canadian dollar exchange rate. In particular, any decrease in the value of the US dollar relative to the Canadian dollar following the Acquisition could negatively impact the Corporation's net income as reported in Canadian dollars. Fortis may enter into forward foreign exchange contracts and utilize certain other derivatives as cash flow hedges of its exposure to foreign currency risk to a greater extent than in the past. There is no guarantee that such hedging strategies, if adopted, will be effective.

Fortis expects to incur a variety of costs in 2016 associated with completing the Acquisition. The majority of these costs will be non-recurring expenses related to financing and obtaining shareholder and regulatory approvals. Certain of these costs have already been incurred and other such costs will be incurred even if the Acquisition is ultimately not completed. Additional unanticipated acquisition-related costs may also be incurred in 2016.

Interest Rate Risk: Generally, allowed ROEs for regulated utilities in North America are exposed to changes in long-term interest rates. Such rates affect allowed ROEs directly when they are applied in formulaic ROE automatic adjustment mechanisms or indirectly through a regulatory process of what constitutes an appropriate rate of return on investment, which may consider the general level of interest rates as a factor for setting allowed ROEs. Uncertainty exists regarding the duration of the current environment of low interest rates and the effect it may have on allowed ROEs of the Corporation's regulated utilities. If interest rates continue to remain at historically low levels, allowed ROEs could decrease. The continuation of a low interest rate environment could adversely affect the Corporation's ability to earn a reasonable ROE, which could have a negative effect on the financial condition and results of operations of the Corporation's regulated utilities. Also, if interest rates begin to climb, regulatory lag may cause a delay in any resulting increase in cost of capital and the regulatory allowed ROEs.

The Corporation and its subsidiaries may also be exposed to interest rate risk associated with borrowings under variable-rate credit facilities, variable-rate long-term debt and refinancing of long-term debt. Central Hudson, FortisBC Energy and FortisBC Electric, however, have regulatory approval to defer any increase or decrease in interest expense resulting from fluctuations in interest rates associated with variable-rate credit facilities for recovery from, or refund to, customers in future rates. There can be no assurance that such deferral mechanisms will exist in the future, as they are dependent on future regulatory decisions. UNS Energy and Central Hudson use interest rate swaps and interest rate caps on variable-rate long-term debt to reduce risk associated with interest rates, as permitted by the regulators. At the Corporation's other regulated utilities, if the timing of issuance of, and the interest rates on, long-term debt are different from those forecast and approved in customer rates, the additional or lower interest costs incurred on the new long-term debt are not recovered from, or refunded to, customers in rates during the period that was covered by the approved customer rates. An inability to flow through interest costs to customers could have a material adverse effect on the results of operations and financial position of the utilities.

Excluding borrowings under long-term committed credit facilities, almost 90% of the Corporation's consolidated long-term debt as at December 31, 2015 had maturities beyond five years. With a significant portion of the Corporation's consolidated debt having long-term maturities, interest rate risk on debt refinancing has been reduced for the near and medium terms.

The following table outlines the nature of the Corporation's consolidated debt as at December 31, 2015.

Total Debt

As at December 31, 2015	*($ millions)*	*(%)*
Short-term borrowings	**511**	**4.4**
Utilized variable-rate credit facilities classified as long term	**551**	**4.7**
Variable-rate long-term debt (including current portion)	**333**	**2.8**
Fixed-rate long-term debt (including current portion)	**10,284**	**88.1**
Total	**11,679**	**100.0**

In 2015 the Corporation's regulated subsidiaries issued approximately $1 billion in long-term debt, all of which was at fixed interest rates ranging from 2.98% to 4.75%, with terms ranging from 10 to 30 years. The terms negotiated on new long-term debt demonstrate the ability of the Corporation and its utilities to raise long-term capital at attractive rates. Further information on the Corporation's consolidated long-term debt issuances is provided in the "Liquidity and Capital Resources" section of this MD&A.

A change in the level of interest rates could materially affect the measurement and disclosure of the fair value of long-term debt. The fair value of the Corporation's consolidated long-term debt, as at December 31, 2015, is provided in the "Financial Instruments" section of this MD&A.

Operating and Maintenance Risks: Storms and severe weather conditions, natural disasters, wars, terrorist acts, failure of critical equipment and other catastrophic events occurring both within and outside the service territories of the Corporation's utilities could result in service disruptions, leading to lower earnings and/or cash flows if the situation is not resolved in a timely manner or the financial impacts of restoration are not alleviated through insurance policies or regulated rate recovery. UNS Energy, Central Hudson and FortisBC Energy are exposed to various operational risks, associated with natural gas, such as: pipeline leaks, accidental damage to mains and service lines, corrosion in pipes, pipeline or equipment failure, other issues that can lead to outages and/or leaks, and any other accidents involving natural gas that could result in significant operational disruptions and/or environmental liability.

The operation of UNS Energy's electric generating stations involves certain risks, including equipment breakdown or failure, interruption of fuel supply and lower-than-expected levels of efficiency or operational performance. Unplanned outages, including extensions of planned outages due to equipment failure or other complications, occur from time to time and are an inherent risk of the generation business. There can be no assurance that the generation facilities of UNS Energy will continue to operate in accordance with expectations.

The operation of electricity T&D assets is also subject to risks, including the potential to cause fires, mainly as a result of equipment failure, falling trees and lightning strikes to lines or equipment. In addition, a significant portion of the utilities' infrastructure is located in remote areas, which may make access to perform maintenance and repairs difficult if such assets become damaged. The FortisBC utilities operate in remote and mountainous terrain with a risk of loss or damage from forest fires, floods, washouts, landslides, avalanches and other acts of nature. UNS Energy, FortisBC Energy, FortisBC Electric and the Corporation's operations in the Caribbean region are subject to risk of loss from earthquakes.

The Corporation and its subsidiaries have limited insurance that provides coverage for business interruption, liability and property damage. In the event of a large uninsured loss caused by severe weather conditions, natural disasters and certain other events beyond the control of the utility, an application would be made to the respective regulatory authority for the recovery of these costs through customer rates to offset any loss. However, there can be no assurance that the regulatory authorities would approve any such application in whole or in part. Refer to the "Business Risk Management – Insurance Coverage Risk" section of this MD&A for a further discussion on insurance.

The Corporation's electricity and gas systems require ongoing maintenance, improvement and replacement. The utilities could experience service disruptions and increased costs if they are unable to maintain their asset base. The inability to recover, through approved customer rates, the expenditures the utilities believe are necessary to maintain, improve, replace and remove assets; the failure by the utilities to properly implement or complete approved capital expenditure programs; or the occurrence of significant unforeseen equipment failures, despite maintenance programs, could have a material adverse effect on the financial position and results of operations of the Corporation's utilities.

Generally, the Corporation's utilities have designed their electricity and natural gas systems to service customers under various contingencies in accordance with good utility practice. The utilities are responsible for operating and maintaining their assets in a safe manner, including the development and application of appropriate standards, processes and/or procedures to ensure the safety of employees and contractors, as well as the general public. Failure to do so may disrupt the ability of the utilities to safely distribute electricity and gas, which could have a material adverse effect on the operations of the utilities.

Economic Conditions: Typical of utilities, economic conditions, such as changes in employment levels, personal disposable income, energy prices and housing starts, in the Corporation's service territories influence energy sales. Declines in energy sales could adversely impact the respective utilities' results of operations, net earnings and cash flows.

The business of UNS Energy is concentrated in the State of Arizona. In recent years economic conditions in Arizona have contributed significantly to a reduction in retail customer growth and lower energy usage by the Company's residential, commercial and industrial customers. While it is expected that economic conditions in Arizona will improve in the future, if they do not or if they should worsen, retail customer growth rates may stagnate or decline and customers' energy usage may further decline.

FortisBC Energy is affected by the trend in housing starts from single family dwellings to multi-family dwellings, for which natural gas has a lower penetration rate. The growth in new multi-family housing starts continues to significantly outpace that of new single-family homes, which may temper growth in gas distribution volumes.

Alberta's economy is impacted by a number of factors, including the level of oil and gas activity in the province, which is influenced by the market prices of oil and gas. A general and extended decline in economic conditions in Alberta or in other jurisdictions where the Corporation's utilities operate would be expected to have the effect of reducing demand for electricity over time. The regulated nature of utility operations, including various mitigating measures approved by certain regulators, helps reduce the impact that lower energy demand associated with poor economic conditions may have on the utilities' earnings. Significantly reduced electricity demand in the Corporation's service areas could materially reduce capital spending forecasts, and specifically capital spending related to new customer growth. A reduction in capital spending would, in turn, affect the Corporation's rate base and earnings growth. A severe and prolonged downturn in economic conditions could have a material adverse effect on the Corporation's results of operations, net earnings and cash flows despite regulatory measures, where applicable, available to compensate for reduced demand. In addition to the impact of reduced energy demand, an extended decline in economic conditions could also impair the ability of customers to pay for the electricity and gas they consume, thereby affecting the aging and collection of the utilities' trade receivables.

The Corporation's service territory in the Caribbean region has been impacted by challenging economic conditions over the past number of years. Activity in the tourism, real estate and construction sectors is closely tied to economic conditions in the region and changes in such activity affect customer electricity demand. Assets of Caribbean Regulated Electric Utilities comprise approximately 4% of the Corporation's total assets as at December 31, 2015.

Capital Resources and Liquidity Risk: The Corporation's financial position could be adversely affected if it and/or one of its larger subsidiaries fail to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures, acquisitions and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and financial position of the Corporation and its subsidiaries, the regulatory environment in which the utilities operate and the nature and outcome of regulatory decisions regarding capital structure and allowed ROEs, conditions in the capital and bank credit markets, ratings assigned by credit rating agencies, and general economic conditions. Funds generated from operations after payment of expected expenses, including interest payments on any outstanding debt, may not be sufficient to fund the repayment of all outstanding liabilities when due and anticipated capital expenditures. There can be no assurance that sufficient capital will continue to be available on acceptable terms to fund capital expenditures and repay existing debt.

Consolidated fixed-term debt maturities in 2016 are expected to total $313 million. The ability to meet long-term debt repayments when due will be dependent on the Corporation and its subsidiaries obtaining sufficient and cost-effective financing. The Corporation and its utilities have been successful at raising long-term capital at reasonable rates. Activity in the global capital markets may impact the cost and timing of issuance of long-term capital by the Corporation and its subsidiaries. While the future cost of raising capital could increase, the Corporation and its subsidiaries expect to continue to have reasonable access to capital in the near to medium terms.

The cost of renewed and extended credit facilities could increase going forward. Due to their regulated nature, any forecast changes in the cost of borrowing at the utilities are eligible to be reflected in customer rates.

Generally, the Corporation and its currently rated regulated utilities are subject to financial risk associated with changes in the credit ratings assigned to them by credit rating agencies. Credit ratings affect the level of credit risk spreads on new long-term debt and credit facilities. A change in the credit ratings could potentially affect access to various sources of capital and increase or decrease finance charges of the Corporation and its utilities.

In 2015 the following changes were made to debt credit ratings of the Corporation's utilities: (i) in February 2015 Moody's Investor Service ("Moody's") upgraded the debt credit ratings of UNS Energy to 'Baa1' from 'Baa2' and TEP, UNS Electric and UNS Gas to 'A3' from 'Baa1', and (ii) in July 2015 Fitch Ratings ("Fitch") downgraded Central Hudson's debt credit rating to 'A–' from 'A' and changed the rating outlook to stable from negative. Central Hudson's debt continues to be rated 'A' by S&P and 'A2' by Moody's, both with stable outlooks. In December 2015 DBRS confirmed FortisAlberta's debt credit rating of A(low) but revised its outlook to stable from positive. Also, in August 2015 Fitch confirmed TEP's credit rating of BBB+ but revised its outlook to positive from stable and in February 2016 Fitch withdrew its rating on TEP for commercial reasons at TEP's request. In February 2016, after the announcement by Fortis that it had entered into an agreement to acquire ITC, S&P revised its outlook on TEP, Central Hudson, FortisAlberta, Maritime Electric and Caribbean Utilities to negative from stable. For details on the Corporation's credit ratings, see the "Credit Ratings" section of this MD&A.

Additional information on the Corporation's consolidated credit facilities, contractual obligations, including long-term debt maturities and repayments, and consolidated cash flow requirements is provided in the "Liquidity and Capital Resources" section of this MD&A.

Political Risk: The regulatory framework under which utilities operate is impacted by significant shifts in government policy and/or changes in governments, which create uncertainty about public policy priorities and directions, particularly around energy and environmental issues. For details related to environmental issues, refer to the "Business Risk Management – Environmental Risks" section of this MD&A.

Information Technology and Cyber-Security Risks: As operators of critical energy infrastructure, the Corporation's utilities may face a heightened risk of cyber attacks. Information technology systems may be vulnerable to unauthorized access due to hacking, viruses, acts of war or terrorism, and other causes that can result in service disruptions, system failures, and the disclosure, deliberate or inadvertent, of confidential business and customer information. The ability of the Corporation's utilities to operate effectively is dependent upon developing and maintaining complex information systems and infrastructure that support the operation of generation and T&D facilities; provide customers with billing, consumption and load settlement information, where applicable; and support the financial and general operating aspects of the business.

The Corporation's subsidiaries have security measures, policies and controls designed to protect and secure the integrity of its information technology systems, and safeguard the confidentiality of corporate and customer information; however, cyber-security threats frequently change and require ongoing monitoring and detection capabilities. In the event the Corporation's utilities' information technology systems are breached, it could experience service disruptions, property damage, corruption or unavailability of critical data or confidential employee or customer information. If the breach is material in nature, it could adversely affect the financial performance of the Corporation, its reputation and standing with customers and regulators and expose it to claims of third-party damage. All of these factors could adversely affect the Corporation if not resolved in a timely manner, or if the financial impact of such adverse effects is not alleviated through insurance policies or, in the case of regulated utilities, through regulatory recovery.

Weather and Seasonality Risk: Fluctuations in the amount of electricity used by customers can vary significantly in response to seasonal changes in weather and could materially impact the operations, financial condition and results of operations of the electric utilities. In Canada, Arizona and New York State, cool summers may reduce air conditioning demand, while less severe winters may reduce electric heating load.

At FortisBC Energy and the gas operations of UNS Energy and Central Hudson, weather has a significant impact on gas distribution volumes as a major portion of the gas distributed is ultimately used for space heating for residential customers. Because of gas consumption patterns, the gas utilities normally generate quarterly earnings that vary by season and may not be an indicator of annual earnings. The earnings associated with regulated gas utilities are highest in the first and fourth quarters.

Regulatory deferral mechanisms are in place at certain of the Corporation's regulated utilities, including Central Hudson, FortisBC Energy, FortisBC Electric and Newfoundland Power, to minimize the volatility in earnings that would otherwise be caused by variations in weather conditions. The absence of the above-noted regulatory deferral mechanisms could have a material adverse effect on the results of operations and financial position of the utilities.

Natural gas and coal-fired generating plants require continuous water flow for their operation. Shifts in weather or climate patterns, seasonal precipitation, the timing and rate of melting, run off, and other factors beyond the control of the Corporation, may reduce the water flow to UNS Energy's generation facilities. Any material reduction in the water flow to UNS Energy's generation facilities would limit the ability of the Company to produce and market electricity from those respective facilities and could have a material adverse effect on the results of operations and financial position of the Corporation. Any change in regulations or the level of regulation respecting the use, treatment and discharge of water, or respecting the licensing of water rights in the jurisdictions where UNS Energy operates could result in a material adverse effect on the results of operations and financial position of the Company.

Extreme climatic factors could potentially cause government authorities to adjust water flows on the Kootenay River, where FortisBC Electric's dams and related facilities are located, in order to protect the environment. This adjustment could affect the amount of water available for generation at FortisBC Electric's plants or at plants operated by parties contracted to supply energy to FortisBC Electric. Prolonged adverse weather conditions could lead to a significant and sustained loss of precipitation over the headwaters of the Kootenay River system, which could reduce the Company's entitlement to capacity and energy under the Canal Plant Agreement.

Despite preparations for severe weather, hurricanes and other natural disasters will always remain a risk to the physical assets of utilities. Climate change, however, may have the effect of increasing the severity and frequency of weather-related natural disasters that could affect the Corporation's service territories. Although physical utility assets have been constructed and are operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances.

The assets and earnings of Caribbean Utilities, Fortis Turks and Caicos and, to a lesser extent, Central Hudson, Newfoundland Power and Maritime Electric, are subject to hurricane risk. Certain of the Corporation's utilities may also be subject to severe weather events, including ice, wind and snow storms. Weather risks are managed through insurance on generation assets, business-interruption insurance and self-insurance on T&D assets. Under its T&D licence, Caribbean Utilities may apply for a special additional customer rate in the event of a disaster such as a hurricane. Fortis Turks and Caicos does not have a specific hurricane cost-recovery mechanism; however, the Company may apply for an increase in customer rates in the following year if the actual ROA is lower than the allowed ROA due to additional costs resulting from a hurricane or other significant weather event. Central Hudson is authorized to request, and the PSC has typically approved, deferral account treatment for incremental storm restoration costs. To qualify for deferral, storm costs must meet certain criteria as stipulated by the PSC. In most cases, the Corporation's other regulated utilities can apply to their respective regulators for relief from major uncontrollable expenses, including those related to significant weather-related events.

Earnings from non-regulated generation assets in Belize are sensitive to rainfall levels. The Waneta Expansion is included in the Canal Plant Agreement and will receive fixed energy and capacity entitlements based upon long-term average water flows, thereby significantly reducing the hydrologic risk associated with hydroelectric generation. Prolonged adverse weather conditions, however, could lead to a significant and sustained loss of precipitation over the headwaters of the Kootenay River system, which could reduce the Waneta Expansion's entitlement to capacity and energy under the Canal Plant Agreement.

Commodity Price Risk: UNS Energy is exposed to commodity price risk associated with changes in the market price of gas, purchased power and coal. Central Hudson is exposed to commodity price risk associated with changes in the market prices of electricity and natural gas. FortisBC Energy is exposed to commodity price risk associated with changes in the market price of natural gas. The operation of regulator-approved deferral mechanisms to flow through in customer rates the cost of natural gas, purchased power and coal serves to mitigate the impact on earnings of commodity price volatility. The risks have also been reduced by entering into various price-risk management strategies to reduce exposure to commodity rates, including the use of derivative contracts that effectively fix the price of natural gas, power and electricity purchases. The absence of such hedging mechanism in the future could result in increased exposure to market price volatility.

Certain of the Corporation's regulated electric utilities are exposed to commodity price risk associated with changes in world oil prices, which affect the cost of fuel and purchased power. The risk is substantially mitigated by the utilities' ability to flow through to customers the cost of fuel and purchased power through base rates and/or the use of rate-stabilization and other mechanisms, as approved by the various regulatory authorities. The ability to flow through to customers the cost of fuel and purchased power alleviates the effect on earnings of the variability in the cost of fuel and purchased power.

There can be no assurance that the current regulator-approved mechanisms allowing for the flow through of the cost of natural gas, fuel, coal and purchased power will continue to exist in the future. Also, a severe and prolonged increase in such costs could materially affect FortisBC Energy, UNS Energy and Central Hudson, despite regulatory measures available to compensate for changes in these costs. The inability of the regulated utilities to flow through the full cost of natural gas, fuel and/or purchased power could have a material adverse effect on the utilities' results of operations and financial position.

Foreign Exchange Risk: The Corporation's earnings from, and net investments in, foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has decreased the above-noted exposure through the use of US dollar-denominated borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange gain or loss on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars. The reporting currency of UNS Energy, Central Hudson, Caribbean Utilities, Fortis Turks and Caicos and BECOL is the US dollar.

As at December 31, 2015, the Corporation's corporately issued US$1,535 million (December 31, 2014 – US$1,496 million) long-term debt had been designated as an effective hedge of a portion of the Corporation's foreign net investments. As at December 31, 2015, the Corporation had approximately US$3,137 million (December 31, 2014 – US$2,762 million) in foreign net investments remaining to be hedged. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar-denominated borrowings designated as effective hedges are recorded on the balance sheet in accumulated other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the net investments in foreign subsidiaries, which gains and losses are also recorded on the balance sheet in accumulated other comprehensive income.

On an annual basis, it is estimated that a 5 cent, or 5%, increase or decrease in the US dollar relative to the Canadian dollar exchange rate of US$1.00=CAD$1.38 as at December 31, 2015 would increase or decrease earnings per common share of Fortis by approximately 4 cents, before considering the impact of the pending acquisition of ITC. Management will continue to hedge future exchange rate fluctuations related to the Corporation's foreign net investments and US dollar-denominated earnings streams, where possible, through future US dollar-denominated borrowings, and will continue to monitor the Corporation's exposure to foreign currency fluctuations on a regular basis.

Counterparty Risk: UNS Energy, Central Hudson and FortisBC Energy may be exposed to credit risk in the event of non-performance by counterparties to derivative instruments. The above-noted utilities deal with credit quality institutions in accordance with established credit approval practices. These utilities did not experience any counterparty defaults in 2015 and do not expect any counterparties to fail to meet their obligations.

FortisAlberta has a concentration of credit risk as a result of its distribution service billings being to a relatively small group of retailers. As required under regulation, FortisAlberta minimizes its gross exposure associated with retailer billings by obtaining from the retailer either a cash deposit, bond, letter of credit or an investment-grade credit rating from a major rating agency, or a financial guarantee from an entity with an investment-grade credit rating.

Competitiveness of Natural Gas in British Columbia: In FortisBC Energy's service territory, natural gas primarily competes with electricity for space and hot water heating load. Recently, there has been upward pressure on electricity rates in British Columbia, largely due to new investment required in the electricity generation and transmission sectors. In addition, the growth in North American natural gas supply, primarily from shale gas production, has resulted in a lower natural gas price environment. These factors have helped to improve natural gas competitiveness on an operating basis. Nevertheless, differences in upfront capital costs between electric and natural gas equipment for hot water and space heating applications continue to present challenges for the competitiveness of natural gas on a full-cost basis.

Government policy has also impacted the competitiveness of natural gas in British Columbia. The Government of British Columbia has introduced changes to energy policy, including greenhouse gas emission reduction targets and a consumption tax on carbon-based fuels. The Government of British Columbia has yet to introduce a carbon tax on imported electricity generated through the combustion of carbon-based fuels. The impact of these changes in energy policy may have a material impact on the competitiveness of natural gas relative to non-carbon-based energy sources or other energy sources.

There are other competitive challenges impacting the penetration of natural gas in new housing supply, such as the green attributes of the energy source and the type of housing being built. In recent years, FortisBC Energy has experienced a decline in the percentage of new homes installing natural gas compared with the total number of dwellings being built throughout British Columbia.

In the future, if natural gas becomes less competitive due to pricing or other factors, the ability of FortisBC Energy to add new customers could be impaired, and existing customers could reduce their consumption of natural gas or eliminate its usage altogether as furnaces, water heaters and other appliances are replaced. The above conditions may result in higher customer rates and, in an extreme case, could ultimately lead to an inability of FortisBC Energy to fully recover COS in rates charged to customers.

Natural Gas, Fuel and Electricity Supply: FortisBC Energy is dependent on a limited selection of pipeline and storage providers, particularly in the Lower Mainland, Interior and Vancouver Island service areas. Regional market prices, particularly at the Sumas market hub, have been higher than prices elsewhere in North America during peak winter periods, when regional pipeline and storage resources become constrained in serving the demand for natural gas in British Columbia and the U.S. Pacific Northwest. In addition, FortisBC Energy is highly dependent on a single-source transmission pipeline. In the event of a prolonged service disruption of the Spectra Pipeline System, residential customers of FortisBC Energy could experience outages, thereby affecting revenue and also resulting in costs to safely relight customers. The LNG storage facility on Vancouver Island helps to reduce this risk by providing short-term on-system supply during cold weather conditions or emergency situations.

Developments are occurring in the region that may increase the demand for gas supply from British Columbia. These include an increase in pipeline capacity to deliver gas from British Columbia to markets outside of British Columbia and the potential development of large-scale LNG facilities to export gas. British Columbia has significant natural gas resources that are expected to be sufficient to meet incremental demand requirements and to continue to supply existing markets. It is uncertain at this time, however, how the pace and location of infrastructure development to connect production to new and existing markets could impact the Corporation's access to supply at fair market prices.

The UNS Utilities are dependent on third parties to supply fuel, including natural gas and coal. Disruption of fuel supply could impair the ability of the Companies to deliver electricity or gas or generate electricity and could adversely affect operations. In addition, a loss of coal suppliers or the inability to renew existing coal or natural gas contracts at favorable terms could significantly affect the ability to serve customers and adversely affect the financial condition and the results of operations of the UNS Utilities.

Newfoundland Power is dependent on Newfoundland Hydro for approximately 93% of its customers' energy requirements and Maritime Electric is dependent on NB Power for approximately 75% of its customers' energy requirements. The Corporation's utilities in the Caribbean are dependent on third parties for the supply of all of their fuel requirements in the operation of their diesel-powered generating facilities. A shortage or interruption of the supply of electricity or fuel for the above utilities could have a material impact on their operations.

Newfoundland Power experienced losses of electricity supply from Newfoundland Hydro in January 2013 and January 2014, which disabled it from meeting all of its customers' requirements. The PUB is conducting an inquiry and hearing into these system supply issues and related power interruptions. To the extent it is able, Newfoundland Power intends to participate in these reviews in 2016. As well, the Government of Newfoundland and Labrador engaged consultants to complete an independent review of the current electricity system in the province.

Future changes in energy supply costs at Newfoundland Power, including costs associated with Nalcor Energy's Muskrat Falls hydroelectric generation development and associated transmission assets, may affect electricity prices in a manner that affects Newfoundland Power's sales. The recovery of Muskrat Falls development costs are expected to materially increase customer electricity rates.

Power Purchase and Capacity Sale Contracts: FortisBC Electric's indirect customers are served by the Company's wholesale customers, who themselves are municipal utilities. The municipal utilities may be able to obtain alternate sources of energy supply, which would result in decreased demand, higher customer rates and, in extreme cases, could ultimately lead to an inability by FortisBC Electric to fully recover its COS in customer rates.

Additionally, the Corporation's regulated electric utilities periodically enter into various power purchase contracts and resale contracts for excess capacity with third parties. Upon expiry of the contracts, there is a risk that the utilities may not be able to secure extensions of such contracts. If the contracts are not extended, there is a risk of the utilities not being able to obtain alternate supplies of similarly priced electricity or not being able to secure additional capacity resale contracts. The utilities are also exposed to risk in the event of non-performance by counterparties to the various power purchase and resale contracts.

Employee Future Benefit Plan Performance and Funding Requirements: Fortis and the majority of its subsidiaries maintain a combination of defined benefit pension and/or OPEB plans for certain of their employees. Approximately 63% of the Corporation's total employees are members of defined benefit pension plans and approximately 72% of employees are members of OPEB plans.

The employee future benefit plans are subject to judgments utilized in the actuarial determination of the projected benefit obligation and related net benefit cost. The primary assumptions utilized by management are the expected long-term rate of return on assets, the discount rate and the health care trend rate used to value the projected benefit obligation. For a discussion of the critical accounting estimates associated with employee future benefit plans, refer to the "Critical Accounting Estimates – Employee Future Benefits" section of this MD&A.

The projected benefit obligation and related net benefit cost can be affected by changes in the global financial and capital markets. There is no assurance that the employee future benefit plan assets will earn the assumed long-term rates of return. Market-driven changes impacting the performance of the employee future benefit plan assets may result in material variations from the assumed long-term rates of return on the assets, which may cause material changes in future plan funding requirements from current estimates and future net benefit cost. Market-driven changes impacting the discount rates or the health care trend rate may also result in material changes in future plan funding requirements from current estimates and future net benefit cost.

There is also risk associated with measurement uncertainty inherent in the actuarial valuation process, as it affects the measurement of net benefit cost, future funding requirements and the projected benefit obligation.

Jointly Owned and Operated Generating Units: Certain of the generating stations from which TEP receives power are jointly owned with, or are operated by, third parties. TEP may not have the sole discretion or any ability to affect the management or operations at such facilities and, therefore, may not be able to ensure the proper management of the operations and maintenance of the plants. Further, TEP may have limited or no discretion in managing the changing regulations which may affect such facilities. In addition, TEP will not have sole discretion as to how to proceed with environmental compliance requirements which could require significant capital expenditures or the closure of such generating stations. A divergence in the interests of TEP and the co-owners or operators, as applicable, of such generating facilities could negatively impact the business and operations of TEP. In particular, TEP is subject to disagreement and litigation by third-party owners with respect to the existing agreements for Springerville Unit 1. As a result of these disagreements and pending litigation, the third-party owners have and may continue to refuse to pay some or all of their pro rata share of Springerville Unit 1 costs and expenses. For further details, refer to the "Critical Accounting Estimates – Contingencies" section of this MD&A.

Technology Developments and Energy Efficiency: New technology developments in distributed generation, particularly solar, and energy efficiency products and services, as well as the implementation of renewable energy and energy efficiency standards, will continue to have a significant impact on retail sales, which could negatively impact various utilities' results of operations, net earnings and cash flows. Heightened awareness of energy costs and environmental concerns have increased demand for products intended to reduce consumers' use of electricity. Utilities are promoting demand-side management programs designed to help customers reduce their energy usage.

Research and development activities are ongoing for new technologies that produce power, enable more efficient storage of energy, or reduce power consumption. These technologies include renewable energy, customer-owned generation, appliances, battery storage, equipment and control systems. Advances in these, or other technologies, could have a significant impact on retail sales which could negatively impact the results of operations, net earnings and cash flows of utilities.

Environmental Risks: The Corporation's electric and gas utilities are subject to inherent environmental risks, as well as environmental laws and regulations, as discussed below.

Inherent Environmental Risks

The Corporation's electric and gas utilities are subject to inherent risks, including fires, contamination of air, soil or water from hazardous substances, natural gas emissions and emissions from the combustion of fuel required in the generation of electricity. Risks associated with fire damage are related to weather, the extent of forestation, habitation and third-party facilities located on or near the land on which the utilities' facilities are situated. The utilities may become liable for fire-suppression costs, regeneration and timber value costs, and third-party claims in connection with fires on land on which its facilities are located if it is found that such facilities were the cause of a fire, and such claims, if successful, could be material. Inherent risks also include the responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the property owner. The risk of contamination of air, soil and water at the electric utilities primarily relates to the transportation, handling and storage of large volumes of fuel, the use and/or disposal of petroleum-based products, mainly transformer and lubricating oil, in the utilities' day-to-day operating and maintenance activities, and emissions from the combustion of fuel required in the generation of electricity. The risk of contamination of air, soil or water at the natural gas utilities primarily relates to natural gas and propane leaks and other accidents involving these substances. Additional risks include environmental reclamation associated with coal mines that supply generating stations in which the Corporation has an ownership interest.

The key environmental hazards related to hydroelectric generation operations include the creation of artificial water flows that may disrupt natural habitats and the storage of large volumes of water for the purpose of electricity generation.

While the Corporation and its subsidiaries maintain insurance, there can be no assurance that all possible types of liabilities that may arise related to environmental matters will be covered by insurance. For further information, refer to the "Business Risk Management – Insurance Coverage Risk" section of this MD&A.

Environmental Laws and Regulations

The Corporation's electric and gas utilities are subject to numerous federal, state and provincial environmental laws and regulations that may increase its cost of operations or expose it to environmental litigation and liabilities. Existing environmental laws and regulations may be revised or new environmental laws and regulations may be adopted or become applicable to the Corporation's operations. Increased compliance costs or additional operating restrictions from revised or additional regulation could have an adverse effect on the results of operations of the Corporation. The utilities would request that additional costs resulting from environmental laws and regulations be recovered from customers in future rates. In addition, the process of obtaining environmental permits and approvals, including any necessary environmental assessments, can be lengthy, contentious and expensive.

The trend in environmental regulation has been to impose more restrictions and limitations on activities that may impact the environment, including the generation and disposal of wastes, the use and handling of chemical substances, and the requirement for environmental impact assessments and remediation work. It is possible that other developments may lead to increasingly strict environmental laws and enforcement policies, and claims for damages to property or persons resulting from the operations of the Corporation's subsidiaries, any one of which could result in substantial costs or liabilities to the subsidiaries.

The management of greenhouse gas emissions is a specific environmental concern of the Corporation's regulated utilities in Canada and the United States, primarily due to new and emerging federal, provincial and state greenhouse gas laws, regulations and guidelines. In British Columbia, the Government of British Columbia's Energy Plan, *Carbon Tax Act*, *Clean Energy Act*, *Greenhouse Gas Reduction (Cap and Trade) Act* and *Greenhouse Gas Reduction Targets Act* affect, or may potentially affect, the operations of FortisBC Energy and FortisBC Electric. The utilities continue to assess and monitor the impact that the Government's Energy Plan and the *Clean Energy Act* may have on future operations.

In August 2015 the United States Environmental Protection Agency ("EPA") issued the Clean Power Plan ("CPP") limiting carbon emissions from existing and new fossil fuelled power plants. The CPP establishes state-level carbon emission rates and mass-based goals that apply to fossil fuel-fired generation. The plan targets carbon emissions reductions for existing facilities by 2030 and establishes interim goals that begin in 2022. The CPP will require a shift in generation from coal to natural gas and renewables and could lead to the early retirement of coal generation in Arizona within the 2022 to 2030 compliance time-frame. UNS Energy is currently in the process of transitioning its generation resource mix, as appropriate, in order to reduce carbon emissions. The Company will continue to work with the other Arizona and New Mexico utilities, as well as the appropriate regulatory agencies, to develop compliance strategies. UNS Energy is unable to determine how the final CPP rule will impact its facilities until state plans are developed and approved by the EPA. The Company cannot predict the ultimate outcome of these matters.

The EPA incorporated the compliance obligations for existing power plants located on Indian nations, including the Navajo Nation, in the existing sources rule and a newly proposed Federal Plan using a compliance method similar to that of the states. The proposed Federal Plan would be implemented for any Indian nation and/or state that does not submit a plan or that does not have an EPA or approved state plan. UNS Energy will work with the participants at Four Corners and Navajo to determine how this revision may impact compliance and operations at the facilities. The Company has submitted comments on the proposed Federal Plan impacting its facilities, including Four Corners and Navajo stating, among other things, that the EPA should not regulate the greenhouse gases on the Navajo Nation because it is not appropriate or necessary. The reduction of greenhouse gases achieved due to the shutdowns resulting from Regional Haze compliance will be equivalent to those required under the CPP rule. UNS Energy cannot predict the ultimate outcome of these matters.

The Company's compliance requirements under the CPP are subject to the outcomes of potential proceedings and litigation challenging the rule. In February 2016 the United States Supreme Court granted a stay effectively ordering the EPA to stop CPP implementation efforts until legal challenges to the regulation have been resolved. The ruling introduces uncertainty as to whether and when the states and utilities will have to comply with the CPP. UNS Energy will continue to work with the Arizona Department of Environmental Quality to determine what, if any, actions need to be taken in light of the ruling. UNS Energy anticipates that the ruling will likely delay the requirement to submit a plan or request an extension under the CPP by September 2016.

If any of the coal-fired generation plants, or coal-handling facilities, from which UNS Energy obtains power are closed prior to the end of their useful life in response to recent or future changes in environmental regulation, the Company could be required to recognize a material impairment of its assets and incur added expenses relating to accelerated depreciation and amortization, decommissioning and cancellation of long-term coal contracts of such generating plants and facilities. Closure of any such generating stations may force UNS Energy to incur higher costs for replacement capacity and energy. The Company may not be permitted recovery of these costs in customer rates.

In addition, early closures of certain generating units could require UNS Energy to redeem some or all tax-exempt bonds associated with the respective generating units. As at December 31, 2015, approximately 43% of UNS Energy's generating capacity was fuelled by coal.

Environmental laws and regulations have given rise to environmental liabilities at certain of the Corporation's utilities. TEP is contractually obligated to pay a portion of the environmental reclamation costs incurred at generating stations in which it has an ownership interest and is obligated to pay similar costs at the coal mines that supply these generating stations. As at December 31, 2015, TEP has recognized approximately US$25 million in mine reclamation obligations, representing the present value of the estimated future liability. While TEP has recorded the portion of its obligations for such reclamation costs that can be determined at this time, the total costs and timing of final reclamation at these sites are unknown and could be substantial. TEP currently recovers final mine reclamation costs through regulator-approved mechanisms as costs are paid to the coal suppliers.

Central Hudson is exposed to environmental contingencies associated with manufactured gas plants ("MGPs") that it and its predecessors owned and operated to serve their customers' heating and lighting needs from the mid to late 1800s to the 1950s. The New York State Department of Environmental Conservation ("DEC") regulates the timing and extent of remediation of MGP sites in New York State. As at December 31, 2015, Central Hudson has recognized approximately US$92 million in associated MGP environmental remediation liabilities. As approved by the PSC, the Company is currently permitted to recover MGP site investigation and remediation costs in customer rates.

The Corporation believes that it and its subsidiaries are materially compliant with the environmental laws, regulations and guidelines applicable to them in the various jurisdictions in which they operate. With the exception of the mine reclamation costs at TEP and the MGP remediation liabilities at Central Hudson, as noted above, as at December 31, 2015, there were no material environmental liabilities recognized in the Corporation's 2015 Audited Consolidated Financial Statements. The regulated utilities would seek to recover in customer rates the costs associated with environmental protection, compliance or damages; however, there is no assurance that the regulators would agree with the utilities' requests and, therefore, unrecovered costs, if substantial, could have a material adverse effect on the results of operations and financial position of the utilities.

Insurance Coverage Risk: The Corporation and its subsidiaries maintain insurance with respect to potential liabilities and the accidental loss of value of certain of their assets, for amounts and with such insurers as is considered appropriate, taking into account all relevant factors, including practices of owners of similar assets and operations. However, a significant portion of the Corporation's regulated electric utilities' T&D assets is not covered under insurance, as is customary in North America, as the cost of coverage is not considered economically viable. Insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions and there can be no assurance that the types of liabilities that may be incurred by the Corporation and its subsidiaries will be covered by insurance. The Corporation's regulated utilities would likely apply to their respective regulatory authority to recover any loss or liability through increased customer rates. However, there can be no assurance that a regulatory authority would approve any such application in whole, or in part. Any major damage to the physical assets of the Corporation and its subsidiaries could result in repair costs, lost revenue and customer claims that are substantial in amount and which could have a material adverse effect on the Corporation's results of operations, cash flows and financial position. In addition, the occurrence of significant uninsured claims, claims in excess of the insurance coverage limits maintained by the Corporation and its subsidiaries, or claims that fall within a significant self-insured retention could have a material adverse effect on the Corporation's results of operations, cash flows and financial position.

It is anticipated that insurance coverage will be maintained. However, there can be no assurance that the Corporation and its subsidiaries will be able to obtain or maintain adequate insurance in the future at rates considered reasonable, or that insurance will continue to be available on terms as favourable as the existing arrangements, or that the insurance companies will meet their obligations to pay claims.

Loss of Licences and Permits: The acquisition, ownership and operation of electric and gas utilities and assets require numerous licences, permits, agreements, orders, approvals and certificates ("Approvals") from various levels of government, government agencies and third parties. For various reasons, including increased stakeholder participation, the Corporation's regulated utilities and non-regulated generation operations may not be able to obtain or maintain all required Approvals. If there is a delay in obtaining any required Approvals, or if there is a failure to obtain or maintain any required Approvals or to comply with any applicable law, regulation or condition of an approval, or there is a material change to any required Approval, the operation of the assets and the sale of electricity and gas could be prevented or become subject to additional costs, any of which could have a material adverse effect on the Corporation's subsidiaries.

Loss of Service Area: FortisAlberta serves customers residing within various municipalities throughout its service areas. From time to time, municipal governments in Alberta give consideration to creating their own electric distribution utilities by purchasing the assets of FortisAlberta located within their municipal boundaries. Upon the termination, or in the absence, of a franchise agreement, a municipality has the right, subject to AUC approval, to purchase FortisAlberta's assets within its municipal boundaries pursuant to the *Municipal Government Act* (Alberta), with the price to be as agreed by the Company and the municipality, failing which it is to be determined by the AUC. Additionally, under the *Hydro and Electric Energy Act* (Alberta), if a municipality that owns an electric distribution system expands its boundaries, it can acquire FortisAlberta's assets in the annexed area. In such circumstances, the *Hydro and Electric Energy Act* (Alberta) provides that the AUC may determine that the municipality should pay compensation to the Company for any facilities transferred on the basis of replacement cost less depreciation. Given the historical population and economic growth of Alberta and its municipalities, FortisAlberta is affected by transactions of this type from time to time.

Within certain portions of FortisAlberta's service territory, REAs have been granted by the AUC the right to provide electric distribution service to their eligible members. Members eligible to receive electric distribution service from an REA are those who meet the specific eligibility criteria defined in the integrated operating agreements between the Company and REA. In general, this eligibility criteria has limited the provision of service to customers whose land is used for agricultural activity or as a rural estate property. This historical arrangement has been challenged by some self-operating REAs that are seeking to expand their services to a broader range of customers within the service area that overlaps that of the Company. FortisAlberta is actively resisting these efforts on the part of these self-operated REAs, as it believes the legislative scheme in Alberta does not support this type of competition between the regulated utility and these small rural electricity cooperatives. There is a risk that the efforts of these self-operating REAs to expand their services to a broader range of customers could increase their ability to serve customers in competition with the Company.

The consequence to FortisAlberta of a municipality purchasing its distribution assets or an REA serving more customers in its service territory would be an erosion of the Company's rate base, which would reduce the capital upon which FortisAlberta could earn a regulated return. A significant reduction of rate base could have a material adverse effect on the results of operations and financial position of FortisAlberta.

Continued Reporting in Accordance with US GAAP: In January 2014 the Ontario Securities Commission ("OSC") issued a relief order which permits the Corporation and its reporting issuer subsidiaries in Canada to continue to prepare their financial statements in accordance with US GAAP until the earliest of: (i) January 1, 2019; (ii) the first day of the financial year that commences after the Corporation or its reporting issuer subsidiaries ceases to have activities subject to rate regulation; or (iii) the effective date prescribed by the International Accounting Standards Board ("IASB") for the mandatory application of a standard within International Financial Reporting Standards ("IFRS") specific to entities with activities subject to rate regulation.

If the OSC relief does not continue as detailed above, the Corporation and its reporting issuer subsidiaries would then be required to become SEC registrants in order to continue reporting under US GAAP, or adopt IFRS. The IASB has released an interim, optional standard on Regulatory Deferral Accounts and continues to work on a project focusing on accounting specific to rate-regulated activities. It is not yet known when this project will be completed or whether IFRS will, as a result, include a permanent, mandatory standard to be applied by entities with activities subject to rate regulation. In the absence of a permanent standard for rate-regulated activities, the application of IFRS could result in volatility in the Corporation's earnings and earnings per common share as compared to those which would otherwise be recognized under US GAAP. In connection with the pending acquisition of ITC, Fortis expects to become a registrant with the SEC. As an SEC registrant, Fortis would be entitled under applicable Canadian laws to continue to prepare its consolidated financial statements in accordance with US GAAP.

Changes in Tax Legislation: The Corporation and its subsidiaries are subject to changes in tax legislation in Canada, the United States and other international jurisdictions.

Canadian Tax Legislation

During 2015 there were elections at the federal level and several provincial jurisdictions in Canada. A change in government can result in the passing of new tax legislation, including a change in rates of taxation. The new federal and provincial budgets are expected to be delivered in early 2016 and any resulting changes could have an impact on the Corporation and its Canadian subsidiaries. Any changes in tax legislation could affect the Corporation's results of operations, cash flows and financial position.

U.S. Tax Legislation

In 2015 the U.S. Congress enacted legislation approving the use of bonus depreciation through to 2019, subject to a phase out schedule reducing allowable rates to 50% in 2015 through 2017, 40% in 2018 and 30% in 2019. While this legislation provides greater certainty for planning purposes and reduces the cash tax burden of the Corporation's subsidiaries in the United States, any changes in this or other tax legislation in the United States could affect the Corporation's results of operations, cash flows and financial position.

International Tax Legislation

Fortis conducts business in certain tax-free jurisdictions, including certain countries in the Caribbean and Belize. Canada requires the governments of certain tax-free jurisdictions to enter a Tax Information Exchange Agreement ("TIEA"), which permits dividends paid from those jurisdictions to be exempt from tax when received in Canada. This legislation allows Fortis to receive a tax-free return of capital from the Caribbean. Certain legislation also provides a mechanism for the repayment of upstream loans that were previously used as a tax-deferred repatriation of earnings. The Corporation has approximately $79 million of upstream loans from its Caribbean subsidiaries, which are required to be repaid by August 2016. The Corporation expects to repay these loans, as required.

A TIEA has not yet been negotiated between Canada and Belize and there are no indications that Canada will conclude negotiations with the GOB in the near future. Until a TIEA is in place, active business earnings in Belize cannot be repatriated to Canada on a tax-free basis; however, the GOB has signed on to the Convention on Mutual Administrative Assistance in Tax Matter, which excludes Belize as a "non-qualifying country". As a result, the Corporation is not required to accrue tax on its active business income from Belize, whether or not repatriated to Canada.

In October 2015 the Organization for Economic Co-operation and Development ("OECD") released its final reports in connection with its action plan to address Base Erosion and Profit Sharing ("BEPS Action Plan"). The basis of the BEPS Action Plan is to identify and curb aggressive tax planning and practices, as well as monitor the international tax systems. Canada has not yet implemented the recommendations of the OECD report into tax treaties and domestic law; however, if it were to be enacted under Canadian tax legislation the Corporation would be required to assess the impacts and determine whether any changes to existing tax practices are required.

Access to First Nations' Lands: FortisBC Energy and FortisBC Electric provide service to customers on First Nations' lands and maintain gas facilities and electric generation and T&D facilities on lands that are subject to land claims by various First Nations. A treaty negotiation process involving various First Nations and the governments of British Columbia and Canada is underway, but the basis upon which settlements might be reached in the service areas of FortisBC Energy and FortisBC Electric is not clear. Furthermore, not all First Nations are participating in the process. To date, the policy of the Government of British Columbia has been to endeavour to structure settlements without prejudicing existing rights held by third parties, such as FortisBC Energy and FortisBC Electric. However, there can be no certainty that the settlement process will not have a material adverse effect on FortisBC Energy and FortisBC Electric's results of operations and financial position.

The Supreme Court of Canada decided in 2010 that, before issuing regulatory approvals for the addition of new facilities, the BCUC must consider whether the Crown has a duty to consult and accommodate First Nations, if necessary, and if so, whether the consultation and accommodation by the Crown have been adequate. This may affect the timing, cost and likelihood of the BCUC's approval of certain capital projects of FortisBC Energy and FortisBC Electric.

FortisAlberta has distribution assets on First Nations' lands with access permits to these lands held by TransAlta Utilities Corporation ("TransAlta"). In order for FortisAlberta to acquire these access permits, both the Department of Aboriginal Affairs and Northern Development Canada and the individual First Nations band councils must grant approval. FortisAlberta may not be able to acquire the access permits from TransAlta and may be unable to negotiate land-use agreements with property owners or, if negotiated, such agreements may be on terms that are less than favourable to the Company and, therefore, may have a material adverse effect on FortisAlberta.

Labour Relations Risk: The Corporation's subsidiaries employ members of labour unions or associations that have entered into collective bargaining agreements with the subsidiaries. The Corporation considers the relationships of its subsidiaries with their labour unions and associations to be satisfactory but there can be no assurance that current relations will continue in the future or that the terms under the present collective bargaining agreements will be renewed. The inability to maintain or renew the collective bargaining agreements on acceptable terms could result in increased labour costs or service interruptions arising from labour disputes that are not provided for in approved rate orders at the regulated utilities and which could have a material adverse effect on the results of operations, cash flows and financial position of the utilities.

Human Resources Risk: The ability of Fortis to deliver service in a cost-effective manner is dependent on the ability of the Corporation's subsidiaries to attract, develop and retain skilled workforces. Like other utilities across Canada and in the United States and the Caribbean, the Corporation's utilities are faced with demographic challenges relating to trades, technical staff and engineers. The growing size of the Corporation and a competitive job market present ongoing recruitment challenges. The Corporation's significant consolidated capital expenditure program will present challenges to ensure the Corporation's utilities have the qualified workforce necessary to complete the capital work initiatives.

CHANGES IN ACCOUNTING POLICIES

The new US GAAP accounting policies that are applicable to, and were adopted by, Fortis, effective during 2015, are described as follows.

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity: The Corporation prospectively adopted Accounting Standards Update ("ASU") No. 2014-08 that changes the criteria and disclosures for reporting discontinued operations. As a result, the sale of commercial real estate and hotel assets and the sale of non-regulated generation assets in 2015 did not meet the criteria for discontinued operations. The sales are consistent with the Corporation's focus on its core utility business and, therefore, do not represent a strategic shift in operations.

Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved After the Requisite Service Period: The Corporation early adopted ASU No. 2014-12 that resolves diversity in practice for employee share-based payments with performance targets that can entitle an employee to benefit from an award regardless of if they are rendering services at the date the performance target is achieved. The adoption of this update was applied prospectively and did not have a material impact on the Corporation's 2015 Audited Consolidated Financial Statements.

Simplifying the Presentation of Debt Issuance Costs: The Corporation early adopted ASU No. 2015-03 that requires debt issuance costs to be presented on the consolidated balance sheet as a direct deduction from the carrying amount of debt liability, consistent with debt discounts or premiums. The adoption of this update was applied retrospectively and resulted in the reclassification of debt issuance costs of approximately $65 million from long-term other assets to long-term debt on the Corporation's consolidated balance sheet as at December 31, 2014. Additionally, the Corporation early adopted ASU No. 2015-15 that clarifies the presentation and subsequent measurement of debt issuance costs associated with line-of-credit arrangements. The update permits an entity to defer and present debt issuance costs as an asset and subsequently amortize the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. The adoption of this update was applied retrospectively and did not have a material impact on the Corporation's consolidated financial statements.

Balance Sheet Classification of Deferred Taxes: The Corporation early adopted ASU No. 2015-17 that requires deferred tax assets and liabilities to be classified and presented as long term on the consolidated balance sheet. The adoption of this update was applied retrospectively and resulted in the reclassification of current deferred income taxes assets of $158 million, long-term deferred income tax assets of $62 million, and current deferred income tax liabilities of $9 million to long-term deferred income tax liabilities on the consolidated balance sheet as at December 31, 2014. As a result, the Corporation also reclassified current regulatory assets of $18 million, current regulatory liabilities of $19 million, and long-term regulatory liabilities of $91 million, to long-term regulatory assets on the consolidated balance sheet as at December 31, 2014, all associated with regulatory deferred income taxes.

FUTURE ACCOUNTING PRONOUNCEMENTS

The Corporation considers the applicability and impact of all ASUs issued by the Financial Accounting Standards Board ("FASB"). The following updates have been issued by FASB, but have not yet been adopted by Fortis. Any ASUs not included below were assessed and determined to be either not applicable to the Corporation or are not expected to have a material impact on the consolidated financial statements.

Revenue from Contracts with Customers: ASU No. 2014-09 was issued in May 2014 and the amendments in this update create ASC Topic 606, *Revenue from Contracts with Customers*, and supersede the revenue recognition requirements in ASC Topic 605, *Revenue Recognition*, including most industry-specific revenue recognition guidance throughout the codification. This standard completes a joint effort by FASB and the IASB to improve financial reporting by creating common revenue recognition guidance for US GAAP and IFRS that clarifies the principles for recognizing revenue and that can be applied consistently across various transactions, industries and capital markets. This standard was originally effective for annual and interim periods beginning after December 15, 2016 and is to be applied on a full retrospective or modified retrospective basis. ASU No. 2015-14 was issued in August 2015 and the amendments in this update defer the effective date of ASU No. 2014-09 by one year to annual and interim periods beginning after December 15, 2017. Early adoption is permitted as of the original effective date. The majority of the Corporation's revenue is generated from energy sales to customers based on published tariff rates, as approved by the respective regulators, and is expected to be in the scope of ASU No. 2014-09. Fortis has not yet selected a transition method and is assessing the impact that the adoption of this standard will have on its consolidated financial statements and related disclosures. The Corporation plans to have this assessment substantially complete by the end of 2016.

Amendments to the Consolidation Analysis: ASU No. 2015-02 was issued in February 2015 and the amendments in this update change the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. Specifically, the amendments note the following with regard to limited partnerships: (i) modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities; and (ii) eliminate the presumption that a general partner should consolidate a limited partnership. This update is effective for annual and interim periods beginning after December 15, 2015 and may be applied using a modified retrospective approach or retrospectively. The adoption of this update is not expected to materially impact the Corporation's consolidated financial statements, however, it is expected to change the Corporation's 51% controlling ownership interest in Waneta Partnership from a voting interest entity to a variable interest entity, resulting in additional note disclosure.

FINANCIAL INSTRUMENTS

The carrying values of the Corporation's consolidated financial instruments approximate their fair values, reflecting the short-term maturity, normal trade credit terms and/or nature of these instruments, except as follows.

Financial Instruments

Liability as at December 31	2015		2014	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Waneta Partnership promissory note	**56**	**59**	53	56
Long-term debt, including current portion	**11,240**	**12,614**	10,501	12,237

The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, as is the case with the Waneta Partnership promissory note and certain long-term debt, the fair value is determined by either: (i) discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality; or (ii) obtaining from third parties indicative prices for the same or similarly rated issues of debt of the same remaining maturities. Since the Corporation does not intend to settle the long-term debt or promissory note prior to maturity, the excess of the estimated fair value above the carrying value does not represent an actual liability.

The following table presents, by level within the fair value hierarchy, the Corporation's assets and liabilities accounted for at fair value on a recurring basis. These assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement and there were no transfers between the levels in the periods presented. For derivative instruments, the Corporation has elected gross presentation for its derivative contracts under master netting agreements and collateral positions.

Financial Instruments Carried at Fair Value

As at December 31	Fair value		
($ millions)	hierarchy	**2015**	2014
Assets			
Energy contracts subject to regulatory deferral [1] [2] [3]	Levels 2/3	**7**	3
Energy contracts not subject to regulatory deferral [1] [2]	Level 3	**2**	1
Available-for-sale investment [4] [5]	Level 1	**33**	–
Assets held for sale	Level 2	**9**	–
Other investments [4]	Level 1	**12**	5
Total gross assets		**63**	9
Less: Counterparty netting not offset on the balance sheet [6]		**(6)**	(3)
Total net assets		**57**	6
Liabilities			
Energy contracts subject to regulatory deferral [1] [2] [7]	Levels 1/2/3	**78**	72
Energy contracts not subject to regulatory deferral [1] [2]	Level 3	**–**	1
Energy contracts – cash flow hedges [2] [8]	Level 3	**–**	1
Interest rate swaps – cash flow hedges [8]	Level 2	**5**	5
Total gross liabilities		**83**	79
Less: Counterparty netting not offset on the balance sheet [6]		**(6)**	(3)
Total net liabilities		**77**	76

[1] The fair value of the Corporation's energy contracts is recorded in accounts receivable and other current assets, long-term other assets, accounts payable and other current liabilities and long-term other liabilities. Unrealized gains and losses arising from changes in fair value of these contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in rates as permitted by the regulators, with the exception of long-term wholesale trading contracts.

[2] Changes in one or more of the unobservable inputs could have a significant impact on the fair value measurement depending on the magnitude and direction of the change for each input. The impacts of changes in fair value are subject to regulatory recovery, with the exception of long-term wholesale trading contracts and those that qualify as cash flow hedges.

[3] Includes $2 million – level 2 and $5 million – level 3 (2014 – $3 million – level 3)

[4] Included in long-term other assets on the consolidated balance sheet

[5] The cost of the available-for-sale investment was $35 million and unrealized gains and losses arising from changes in fair value are recorded in other comprehensive income until they become realized and are reclassified to earnings.

[6] Certain energy contracts are subject to legally enforceable master netting arrangements to mitigate credit risk and netted by counterparty where the intent and legal right to offset exists.

[7] Includes $1 million – level 1, $52 million – level 2 and $25 million – level 3 (2014 – $2 million – level 1, $35 million – level 2 and $35 million – level 3)

[8] The fair value of certain of the Corporation's energy contracts are recorded in accounts payable and other current liabilities and the fair value of the Corporation's interest rate swaps are recorded in accounts payable and other current liabilities and long-term other liabilities. Unrealized gains and losses arising from changes in fair value are recorded in other comprehensive income until they become realized and are reclassified to earnings.

Derivative Instruments

The Corporation generally limits the use of derivative instruments to those that qualify as accounting, economic or cash flow hedges, or those that are approved for regulatory recovery. The Corporation records all derivative instruments at fair value, with certain exceptions including those derivatives that qualify for the normal purchase and normal sale exception. The fair value of derivative instruments are estimates of the amounts that the utilities would receive or have to pay to terminate the outstanding contracts as at the balance sheet dates.

Energy Contracts Subject to Regulatory Deferral

UNS Energy holds electricity power purchase contracts and gas swap and option contracts to reduce its exposure to energy price risk associated with purchased power and gas requirements. UNS Energy primarily applies the market approach for fair value measurements using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships and transmission and line losses. The fair value of gas option contracts is estimated using a Black-Scholes option-pricing model, which includes inputs such as implied volatility, interest rates, and forward price curves. UNS Energy also considers the impact of counterparty credit risk using current and historical default and recovery rates, as well as its own credit risk using credit default swap data.

Central Hudson holds electricity swap contracts and gas swap and option contracts to minimize commodity price volatility for electricity and natural gas purchases by fixing the effective purchase price for the defined commodities. The fair value of the electricity swap contracts and gas swap and option contracts was calculated using forward pricing provided by independent third parties.

FortisBC Energy holds gas purchase contract premiums to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. The fair value of the natural gas derivatives was calculated using the present value of cash flows based on market prices and forward curves for the cost of natural gas.

As at December 31, 2015, these energy contract derivatives were not designated as hedges; however, any unrealized gains or losses associated with changes in the fair value of the derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. These unrealized losses and gains would otherwise be recorded in earnings. As at December 31, 2015, unrealized losses of $74 million (December 31, 2014 – $69 million) were recognized in regulatory assets and unrealized gains of $3 million were recognized in regulatory liabilities.

Energy Contracts Not Subject to Regulatory Deferral

In June 2015 UNS Energy entered into long-term wholesale trading contracts that qualify as derivative instruments. The unrealized gains and losses on these derivative instruments are recorded in earnings, as they do not qualify for regulatory deferral. Ten percent of any realized gains on these contracts are shared with the ratepayer through UNS Energy's rate stabilization accounts.

Cash Flow Hedges

UNS Energy holds an interest rate swap, expiring in 2020, to mitigate its exposure to volatility in variable interest rates on lease debt, and held a power purchase swap, that expired in September 2015, to hedge the cash flow risk associated with a long-term power supply agreement. The after-tax unrealized gains and losses on cash flow hedges are recorded in other comprehensive income and reclassified to earnings as they become realized. The loss expected to be reclassified to earnings within the next 12 months is estimated to be approximately $1 million.

Central Hudson holds interest rate cap contracts expiring in 2016 and 2017 on bonds with a total principal amount of US$64 million. Variations in the interest costs of the bonds, including any gains or losses associated with the interest rate cap contracts, are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator and do not impact earnings.

Cash flows associated with the settlement of all derivative instruments are included in operating activities on the Corporation's consolidated statement of cash flows.

Volume of Derivative Activity

As at December 31, 2015, the following notional volumes related to electricity and natural gas derivatives that are expected to be settled are outlined below.

Volume	Maturity *(year)*	Contracts *(#)*	2016	2017	2018	2019	2020	There-after
Energy contracts subject to regulatory deferral:								
Electricity swap contracts *(GWh)*	2019	8	1,043	730	438	219	–	–
Electricity power purchase contracts *(GWh)*	2017	28	1,027	145	–	–	–	–
Gas swap and option contracts *(PJ)*	2018	154	40	10	4	–	–	–
Gas purchase contract premiums *(PJ)*	2024	89	91	42	38	22	22	64
Energy contracts not subject to regulatory deferral:								
Long-term wholesale trading contracts *(GWh)*	2016	6	1,310	–	–	–	–	–

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's consolidated financial statements in accordance with US GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Due to changes in facts and circumstances, and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are recognized in earnings in the period in which they become known. The Corporation's critical accounting estimates are discussed as follows.

Regulation: Generally, the accounting policies of the Corporation's regulated utilities are subject to examination and approval by the respective regulatory authority. Regulatory assets and regulatory liabilities arise as a result of the rate-setting process at the regulated utilities and have been recognized based on previous, existing or expected regulatory orders or decisions. Certain estimates are necessary since the regulatory environments in which the Corporation's regulated utilities operate often require amounts to be recognized at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. The final amounts approved by the regulatory authorities for deferral as regulatory assets and regulatory liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are recognized in earnings in the period in which they become known. In the event that a regulatory decision is received after the balance sheet date but before the consolidated financial statements are issued, the facts and circumstances are reviewed to determine whether or not it is a recognized subsequent event.

As at December 31, 2015, Fortis recognized a total of $2,532 million in regulatory assets (December 31, 2014 – $2,415 million) and $1,638 million in regulatory liabilities (December 31, 2014 – $1,445 million).

For a further discussion of the nature of regulatory decisions, refer to the "Material Regulatory Decisions and Applications" section of this MD&A.

Depreciation and Amortization: Depreciation and amortization are estimates based primarily on the useful life of assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical life of the assets. As at December 31, 2015, the Corporation's consolidated capital assets and intangible assets were approximately $20.1 billion, or approximately 70%, of total consolidated assets compared to approximately $18.3 billion, or approximately 70%, of total consolidated assets as at December 31, 2014. Depreciation and amortization was $873 million for 2015 compared to $688 million for 2014.

As required by their respective regulator, UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, Newfoundland Power and Maritime Electric accrue estimated non-asset retirement obligation ("ARO") removal costs in depreciation, with the amount provided for in depreciation recorded as a long-term regulatory liability. Actual non-ARO removal costs are recorded against the regulatory liability when incurred. The estimate of non-ARO removal costs is based on historical experience and expected cost trends. The balance of this regulatory liability as at December 31, 2015 was $1,060 million, an increase of $109 million from $951 million as at December 31, 2014, mainly due to the impact of foreign exchange associated with the translation of US dollar-denominated non-ARO removal cost liabilities.

Changes in depreciation rates, resulting from a change in the estimated service life or removal costs, could have a significant impact on the Corporation's consolidated depreciation and amortization expense.

As part of the customer rate-setting process at the Corporation's regulated utilities, appropriate depreciation, amortization and removal cost rates, as applicable, are approved by the respective regulatory authority. The depreciation periods used and the associated rates are reviewed on an ongoing basis to ensure they continue to be appropriate. From time to time, third-party depreciation studies are performed at the regulated utilities. Based on the results of these depreciation studies, the impact of any over- or under-depreciation, as a result of actual experience differing from that expected and provided for in previous depreciation rates, is generally reflected in future depreciation rates and depreciation expense, when the differences are refunded or collected in customer rates, as approved by the regulator.

Effective January 1, 2015, FortisAlberta's depreciation and amortization rates were changed as a result of a technical update to its last depreciation study, which was completed as of December 31, 2010. A technical update adjusts depreciation and amortization rates based on current capital asset balances, while retaining the depreciation parameters established in the last approved depreciation study. As a result, FortisAlberta's depreciation and amortization expense were reduced by approximately $7 million in 2015.

Income Taxes: Income taxes are determined based on estimates of the Corporation's current income taxes and estimates of deferred income taxes resulting from temporary differences between the carrying values of assets and liabilities in the consolidated financial statements and their tax values. A deferred income tax asset or liability is determined for each temporary difference based on enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. Deferred income tax assets are assessed for the likelihood that they will be recovered from future taxable income. To the extent recovery is not considered more likely than not, a valuation allowance is recognized against earnings in the period when the allowance is created or revised. Estimates of the provision for current income taxes, deferred income tax assets and liabilities, and any related valuation allowance, might vary from actual amounts incurred.

Assessment for Impairment of Goodwill and Indefinite-Lived Intangible Assets: The Corporation is required to perform, at least on an annual basis, an impairment test for goodwill and indefinite-lived intangible assets, and any impairment provision is charged to earnings. The annual impairment test is performed as at October 1. In addition, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. No such event or change in circumstances occurred during 2015 or 2014.

As at December 31, 2015, consolidated goodwill totalled approximately $4.2 billion (December 31, 2014 – $3.7 billion). Indefinite-lived intangible assets, not subject to amortization, consist of certain land, transmission and water rights and totalled approximately $106 million as at December 31, 2015 (December 31, 2014 – $77 million).

Fortis performs an annual internal quantitative assessment for each reporting unit. For those reporting units where: (i) management's assessment of quantitative and qualitative factors indicates that fair value is not 50% or more likely to be greater than carrying value; or (ii) the excess of estimated fair value over carrying value, as determined by an external consultant as of the date of the immediately preceding impairment test, was not significant, then fair value of the reporting unit will be estimated by an external consultant in the current year. Irrespective of the above-noted approach, a reporting unit to which goodwill has been allocated may have its fair value estimated by an external consultant as at the annual impairment date, as Fortis will, at a minimum, have fair value for each material reporting unit estimated by an external consultant once every five years.

In calculating goodwill impairment, Fortis determines those reporting units that will have fair value estimated by an external consultant, as described above, and such estimated fair value is then compared to the book value of the applicable reporting units. If the fair value of the reporting unit is less than the book value, then a second measurement step is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill, and then comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of the goodwill over the implied fair value is the impairment amount recognized.

The primary method for estimating fair value of the reporting units is the income approach, whereby net cash flow projections for the reporting units are discounted using an enterprise value approach. Under the enterprise value approach, sustainable cash flow is determined on an after-tax basis, prior to the deduction of interest expense, and is then discounted at the weighted average cost of capital to yield the value of the enterprise. An enterprise value approach does not assess the appropriateness of the reporting unit's existing debt level. The estimated fair value of the reporting unit is then determined by subtracting the fair value of the reporting unit's interest-bearing debt from the enterprise value of the reporting unit. A secondary valuation method, the market approach, is also performed by an external consultant as a check on the conclusions reached under the income approach. The market approach includes comparing various valuation multiples underlying the discounted cash flow analysis of the applicable reporting units to trading multiples of guideline entities and recent transactions involving guideline entities, recognizing differences in growth expectations, product mix and risks of those guideline entities with the applicable reporting units.

No impairment provisions were required in either 2015 or 2014 with respect to goodwill or indefinite-lived intangible assets.

Employee Future Benefits:

Defined Benefit Pension Plans

The Corporation's and subsidiaries' defined benefit pension plans are subject to judgments utilized in the actuarial determination of the net benefit cost and related obligation. The main assumptions utilized by management in determining the net benefit cost and obligation are the discount rate for the benefit obligation and the expected long-term rate of return on plan assets.

The expected weighted average long-term rate of return on the defined benefit pension plan assets, for the purpose of estimating net pension cost for 2016, is 6.17%, which is down from 6.25% used for 2015. The decrease in the average long-term rate of return reflects shifting of plan assets from equities to fixed income assets. The defined benefit pension plan assets experienced total positive returns of approximately $30 million in 2015 compared to expected positive returns of $140 million. The expected long-term rates of return on pension plan assets are developed by management with assistance from independent actuaries using best estimates of expected returns, volatilities and correlations for each class of asset. The best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes.

The assumed weighted average discount rate used to measure the projected benefit obligations as at December 31, 2015, and to determine net pension cost for 2016, is 4.21%, compared to the assumed weighted average discount rate used to measure the projected benefit obligations as at December 31, 2014, and to determine net pension cost for 2015, of 4.00%. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments. The methodology in determining the discount rates was consistent with that used to determine the discount rates in the previous year, except as follows for UNS Energy. UNS Energy adopted the spot rate methodology for determining net pension cost for 2016.

There was a $26 million increase in consolidated defined benefit net pension cost for 2015 compared to 2014, mainly due to the acquisition of UNS Energy in August 2014, and foreign currency translation impacts. Any increases in defined benefit net pension cost at the regulated utilities for 2016 are expected to be recovered from customers in rates, subject to regulatory lag and forecast risk at certain of the utilities.

The following table provides the sensitivities associated with a 100 basis point change in the expected long-term rate of return on pension plan assets and the discount rate on 2015 net benefit pension cost, and the related projected benefit obligation recognized in the Corporation's 2015 Audited Consolidated Financial Statements.

Sensitivity Analysis of Changes in Rate of Return on Plan Assets and Discount Rate

Year Ended December 31, 2015

(Decrease) increase *($ millions)*	**Net pension benefit cost**	**Projected benefit obligation** [1]
Impact of increasing the rate of return assumption by 100 basis points	(24)	–
Impact of decreasing the rate of return assumption by 100 basis points	20	(44)
Impact of increasing the discount rate assumption by 100 basis points	(44)	(370)
Impact of decreasing the discount rate assumption by 100 basis points	51	469

[1] At FortisBC Energy and FortisBC Electric, certain defined benefit pension plans have pension indexing provisions which provide for a portion of investment returns to be allocated in order to provide for indexing of pension benefits. Therefore, a change in the expected long-term rate of return on pension plan assets has an impact on the projected benefit obligation. The direction of the impact of a change in the rate of return assumption at FortisBC Energy and FortisBC Electric is also the result of the methodology for determining the pension indexing assumption.

Other assumptions applied in measuring net benefit pension cost and/or the projected benefit obligation include the average rate of compensation increase, average remaining service life of the active employee group, and employee and retiree mortality rates.

As approved by the regulator, the cost of defined benefit pension plans at FortisAlberta is recovered in customer rates based on the cash payments made. Any difference between the cash payments made during the year and the cost incurred during the year is deferred as a regulatory asset or regulatory liability. Therefore, changes in assumptions result in changes in regulatory assets and regulatory liabilities for FortisAlberta. Central Hudson, FortisBC Energy, FortisBC Electric and Newfoundland Power have regulator-approved mechanisms to defer variations in net pension cost from forecast net pension cost, used to set customer rates, as a regulatory asset or regulatory liability. There can be no assurance, however, that the above-noted deferral mechanisms will continue in the future as they are dependent on future regulatory decisions and orders.

As at December 31, 2015, for all defined benefit pension plans, the Corporation had consolidated projected benefit obligations of $2,828 million (December 31, 2014 – $2,604 million) and consolidated plan assets of $2,466 million (December 31, 2014 – $2,216 million), for a consolidated funded status in a liability position of $362 million (December 31, 2014 – $388 million). During 2015, the Corporation recognized consolidated net pension benefit cost of $97 million (2014 – $71 million).

OPEB Plans

The OPEB plans of the Corporation and its subsidiaries are also subject to judgments utilized in the actuarial determination of the cost and the accumulated benefit obligation. Similar assumptions as described above, except for the assumption of the expected long-term rate of return on pension plan assets, which is applicable only to the OPEB plans at UNS Energy and Central Hudson, along with the health care cost trend rate, were also utilized by management in determining net OPEB cost and accumulated benefit obligation.

The OPEB plan assets at UNS Energy and Central Hudson experienced no returns in 2015 compared to expected positive returns of approximately $12 million.

The following table provides the sensitivities associated with a 100 basis point change in the health care cost trend rate and the discount rate on 2015 net OPEB cost, and the related consolidated accumulated benefit obligation recognized in the Corporation's 2015 Audited Consolidated Financial Statements.

Sensitivity Analysis of Changes in Health Care Cost Trend Rate and Discount Rate

Year Ended December 31, 2015

Increase (decrease) *($ millions)*	**Net OPEB cost**	**Accumulated benefit obligation**
Impact of increasing the health care cost trend rate assumption by 100 basis points	7	51
Impact of decreasing the health care cost trend rate assumption by 100 basis points	(5)	(43)
Impact of increasing the discount rate assumption by 100 basis points	(6)	(71)
Impact of decreasing the discount rate assumption by 100 basis points	9	85

Central Hudson, FortisBC Energy, FortisBC Electric and Newfoundland Power have regulator-approved mechanisms to defer variations in net OPEB cost from forecast net OPEB cost, used to set customer rates, as a regulatory asset or regulatory liability. There can be no assurance, however, that the above-noted deferral mechanisms will continue in the future as they are dependent on future regulatory decisions and orders.

As at December 31, 2015, for all OPEB plans, the Corporation had consolidated accumulated benefit obligations of $574 million (December 31, 2014 – $564 million) and consolidated plan assets of $181 million (December 31, 2014 – $154 million), for a consolidated funded status in a liability position of $393 million (December 31, 2014 – $410 million). During 2015, the Corporation recognized consolidated net OPEB benefit cost of $27 million (2014 – $21 million).

AROs: The measurement of the fair value of AROs requires making reasonable estimates concerning the method of settlement and settlement dates associated with the legally obligated asset retirement costs. There are also uncertainties in estimating future asset retirement costs due to potential external events, such as changing legislation or regulations and advances in remediation technologies. While the Corporation has AROs associated with hydroelectric generating facilities, interconnection facilities, removal of certain distribution system assets from rights-of-way at the end of the life of the systems and the remediation of certain land, no amounts were recognized as at December 31, 2015 and 2014, with the exception of AROs recognized by UNS Energy, Central Hudson and FortisBC Electric.

The nature, amount and timing of costs associated with land and environmental remediation and/or removal of assets cannot be reasonably estimated at this time as the hydroelectric generation and T&D assets are reasonably expected to operate in perpetuity due to the nature of their operation; applicable licences, permits and interconnection facilities agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the related assets and ensure the continued provision of service to customers; a land-lease agreement is expected to be renewed indefinitely; and the exact nature and amount of land remediation is indeterminable. In the event that environmental issues are known and identified, assets are decommissioned or the applicable licences, permits, agreements or leases are terminated, AROs will be recognized at that time provided the costs can be reasonably estimated and are material.

As at December 31, 2015, the Corporation's total AROs were $49 million (December 31, 2014 – $37 million). UNS Energy's AROs were primarily associated with TEP's generation and photovoltaic assets; Central Hudson's AROs were primarily associated with asbestos remediation; and FortisBC Electric's AROs were associated with the removal of polychlorinated biphenyl ("PCB")-contaminated oil from electrical equipment. The total ARO liability as at December 31, 2015 has been classified on the consolidated balance sheet as a long-term other liability with the offset to utility capital assets. All factors used in estimating the companies' AROs represent management's best estimate of the fair value of the costs required to meet existing legislation or regulations. It is reasonably possible that volumes of contaminated assets, inflation assumptions, cost estimates to perform the work and the assumed pattern of annual cash flows may differ significantly from the companies' current assumptions. The AROs may change from period to period because of changes in the estimation of these uncertainties. Other subsidiaries also affected by AROs associated with the removal of PCB-contaminated oil from electrical equipment include Central Hudson, FortisAlberta, Newfoundland Power, FortisOntario and Maritime Electric. As at December 31, 2015, the AROs related to PCBs for the above-noted utilities were not material and, therefore, were not recognized.

Revenue Recognition: Revenue at the Corporation's regulated utilities is generally recognized on an accrual basis. Electricity and gas consumption is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of each reporting period, a certain amount of consumed electricity and gas will not have been billed. Electricity and gas that is consumed but not yet billed to customers is estimated and accrued as revenue at each period end, as approved by the regulator. Effective July 1, 2015, Central Hudson is permitted by the regulator to accrue unbilled revenue for electricity consumed at each period end for all of its electricity customers. As at December 31, 2014, approximately $15 million (US$13 million) in unbilled revenue at Central Hudson, associated with certain electricity customers, was not accrued, as permitted by the regulator.

The unbilled revenue accrual for the period is based on estimated electricity and gas sales to customers for the period since the last meter reading at the rates approved by the respective regulatory authority. The development of the electricity and gas sales estimates generally requires analysis of consumption on a historical basis in relation to key inputs, such as the current price of electricity and gas, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled electricity and gas consumption will result in adjustments of electricity and gas revenue in the periods they become known, when actual results differ from the estimates. As at December 31, 2015, the amount of accrued unbilled revenue recognized in accounts receivable was approximately $404 million (December 31, 2014 – $365 million) on consolidated revenue of $6,727 million for 2015 (2014 – $5,401 million). The increase in accrued unbilled revenue from December 31, 2014 was primarily due to the impact of foreign exchange on the translation of US dollar-denominated unbilled revenue accruals.

Capitalized Overhead: As required by their respective regulator, UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Fortis Turks and Caicos capitalize overhead costs that are not directly attributable to specific utility capital assets but relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized general overhead costs to utility capital assets is established by the respective regulator. Any change in the methodology of calculating and allocating general overhead costs to utility capital assets could have a material impact on the amount recognized as operating expenses versus utility capital assets.

Contingencies: The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with the ordinary course of business operations. Management believes that the amount of liability, if any, from these actions would not have a material adverse effect on the Corporation's consolidated financial position or results of operations.

The following describes the nature of the Corporation's contingencies.

UNS Energy

Springerville Unit 1

In November 2014 the Springerville Unit 1 third-party owners filed a complaint ("FERC Action") against TEP with FERC, alleging that TEP had not agreed to wheel power and energy for the third-party owners in the manner specified in the existing Springerville Unit 1 facility support agreement between TEP and the third-party owners and for the cost specified by the third-party owners. The third-party owners requested an order from FERC requiring such wheeling of the third-party owners' energy from their Springerville Unit 1 interests beginning in January 2015 for the price specified by the third-party owners. In February 2015 FERC issued an order denying the third-party owners' complaint. In March 2015 the third-party owners filed a request for rehearing in the FERC Action, which FERC denied in October 2015. In December 2015 the third-party owners appealed FERC's order denying the third-party owners' complaint to the U.S. Court of Appeals for the Ninth Circuit. In December 2015 TEP filed an unopposed motion to intervene in the Ninth Circuit appeal.

In December 2014 the third-party owners filed a complaint ("New York Action") against TEP in the Supreme Court of the State of New York, New York County. In response to motions filed by TEP to dismiss various counts and compel arbitration of certain of the matters alleged and the court's subsequent ruling on the motions, the third-party owners have amended the complaint three times, dropping certain of the allegations and raising others in the New York Action and in the arbitration proceeding described below. As amended, the New York Action alleges, among other things, that TEP failed to properly operate, maintain and make capital investments in Springerville Unit 1 during the term of the leases; and that TEP breached the lease transaction documents by refusing to pay certain of the third party owners' claimed expenses. The third amended complaint seeks US$71 million in liquidated damages and direct and consequential damages in an amount to be determined at trial. The third-party owners have also agreed to stay their claim that TEP has not agreed to wheel power and energy as required pending the outcome of the FERC Action. In November 2015 the third-party owners filed a motion for summary judgment on their claim that TEP failed to pay certain of the third-party owners' claimed expenses.

In December 2014 and January 2015, Wilmington Trust Company, as owner trustees and lessors under the leases of the third-party owners, sent notices to TEP that alleged that TEP had defaulted under the third-party owners' leases. The notices demanded that TEP pay liquidated damages totalling approximately US$71 million. In letters to the owner trustees, TEP denied the allegations in the notices.

In April 2015 TEP filed a demand for arbitration with the American Arbitration Association ("AAA") seeking an award of the owner trustees and co-trustees' share of unreimbursed expenses and capital expenditures for Springerville Unit 1. In June 2015 the third-party owners filed a separate demand for arbitration with the AAA alleging, among other things, that TEP has failed to properly operate, maintain and make capital investments in Springerville Unit 1 since the leases have expired. The third-party owners' arbitration demand seeks declaratory judgments, damages in an amount to be determined by the arbitration panel and the third-party owners' fees and expenses. TEP and the third-party owners have since agreed to consolidate their arbitration demands into one proceeding. In August 2015 the third-party owners filed an amended arbitration demand adding claims that TEP has converted the third-party owners' water rights and certain emission reduction payments and that TEP is improperly dispatching the third-party owners' unscheduled Springerville Unit 1 power and capacity.

In October 2015 the arbitration panel granted TEP's motion for interim relief, ordering the owner trustees and co-trustees to pay TEP their pro-rata share of unreimbursed expenses and capital expenditures for Springerville Unit 1 during the pendency of the arbitration. The arbitration panel also denied the third-party owners' motion for interim relief, which had requested that TEP be enjoined from dispatching the third-party owners' unscheduled Springerville Unit 1 power and capacity. TEP has been scheduling the third-party owners' entitlement share of power from Springerville Unit 1, as permitted under the Springerville Unit 1 facility support agreement, since June 2015. The arbitration hearing is scheduled for July 2016.

In November 2015 TEP filed a petition to confirm the interim arbitration order in the Supreme Court of the State of New York naming owner trustee and co-trustee as respondents. The petition seeks an order from the court confirming the interim arbitration order under the *Federal Arbitration Act*. In December 2015 the owner trustees filed an answer to the petition and a cross-motion to vacate the interim arbitration order.

As at December 31, 2015, TEP billed the third-party owners approximately US$23 million for their pro-rata share of Springerville Unit 1 expenses and US$4 million for their pro-rata share of capital expenditures, none of which had been paid as of February 17, 2016.

TEP cannot predict the outcome of the claims relating to Springerville Unit 1 and, due to the general and non-specific scope and nature of the claims, the Company cannot determine estimates of the range of loss, if any, at this time and, accordingly, no amount has been accrued in the consolidated financial statements. TEP intends to vigorously defend itself against the claims asserted by the third-party owners and to vigorously pursue the claims it has asserted against the third-party owners.

TEP and the third-party owners have agreed to stay these litigation matters relating to Springerville Unit 1 in furtherance of settlement negotiations. However, there is no assurance that a settlement will be reached or that the litigation will not continue.

Mine Reclamation Costs

TEP pays ongoing reclamation costs related to coal mines that supply generating stations in which the Company has an ownership interest but does not operate. TEP is liable for a portion of final reclamation costs upon closure of the mines servicing the San Juan, Four Corners and Navajo generating stations. TEP's share of reclamation costs at all three mines is expected to be US$43 million upon expiration of the coal supply agreements, which expire between 2019 and 2031. The mine reclamation liability recorded as at December 31, 2015 was US$25 million (December 31, 2014 – US$22 million), and represents the present value of the estimated future liability.

Amounts recorded for final reclamation are subject to various assumptions, such as estimations of reclamation costs, the dates when final reclamation will occur, and the expected inflation rate. As these assumptions change, TEP will prospectively adjust the expense amounts for final reclamation over the remaining coal supply agreements' terms.

TEP is permitted to fully recover these costs from retail customers and, accordingly, these costs are deferred as a regulatory asset.

Central Hudson

Site Investigation and Remediation Program

Central Hudson and its predecessors owned and operated MGPs to serve their customers' heating and lighting needs. These plants manufactured gas from coal and oil beginning in the mid to late 1800s, with all sites ceasing operations by the 1950s. This process produced certain by-products that may pose risks to human health and the environment.

The New York State DEC, which regulates the timing and extent of remediation of MGP sites in New York State, has notified Central Hudson that it believes the Company or its predecessors at one time owned and/or operated MGPs at seven sites in Central Hudson's franchise territory. The DEC has further requested that the Company investigate and, if necessary, remediate these sites under a Consent Order, Voluntary Clean-up Agreement or Brownfield Clean-up Agreement. Central Hudson accrues for remediation costs based on the amounts that can be reasonably estimated. As at December 31, 2015, an obligation of US$92 million (December 31, 2014 – US$105 million) was recognized in respect of site investigation and remediation and, based upon cost model analysis completed in 2014, it is estimated, with a 90% confidence level, that total costs to remediate these sites over the next 30 years will not exceed US$169 million.

Central Hudson has notified its insurers and intends to seek reimbursement from insurers for remediation, where coverage exists. Further, as authorized by the PSC, Central Hudson is currently permitted to defer, for future recovery from customers, differences between actual costs for MGP site investigation and remediation and the associated rate allowances, with carrying charges to be accrued on the deferred balances at the authorized pre-tax rate of return. In the three-year rate order issued by the PSC in June 2015, Central Hudson's authorization to defer all site investigation and remediation costs was reaffirmed and extended through June 2018.

Asbestos Litigation

Prior to and after its acquisition by Fortis, various asbestos lawsuits have been brought against Central Hudson. While a total of 3,350 asbestos cases have been raised, 1,167 remained pending as at December 31, 2015. Of the cases no longer pending against Central Hudson, 2,027 have been dismissed or discontinued without payment by the Company, and Central Hudson has settled the remaining 156 cases. The Company is presently unable to assess the validity of the outstanding asbestos lawsuits; however, based on information known to Central Hudson at this time, including the Company's experience in the settlement and/or dismissal of asbestos cases, Central Hudson believes that the costs which may be incurred in connection with the remaining lawsuits will not have a material effect on its financial position, results of operations or cash flows and, accordingly, no amount has been accrued in the consolidated financial statements.

FortisBC Electric

The Government of British Columbia filed a claim in the British Columbia Supreme Court in June 2012 claiming on its behalf, and on behalf of approximately 17 homeowners, damages suffered as a result of a landslide caused by a dam failure in Oliver, British Columbia in 2010. The Government of British Columbia alleges in its claim that the dam failure was caused by the defendants', which include FortisBC Electric, use of a road on top of the dam. The Government of British Columbia estimates its damages and the damages of the homeowners, on whose behalf it is claiming, to be approximately $15 million. While FortisBC Electric has notified its insurers, it has been advised by the Government of British Columbia that a response to the claim is not required at this time. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

FHI

In April 2013 FHI and Fortis were named as defendants in an action in the B.C. Supreme Court by the Coldwater Indian Band ("Band"). The claim is in regard to interests in a pipeline right of way on reserve lands. The pipeline on the right of way was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in April 2007. The Band seeks orders cancelling the right of way and claims damages for wrongful interference with the Band's use and enjoyment of reserve lands. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

RELATED-PARTY TRANSACTIONS

Related-party transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The significant related-party transactions for the years ended December 31, 2015 and 2014 are discussed below.

Upon completion of the Waneta Expansion in early April 2015, FortisBC Electric commenced purchasing capacity from the Waneta Expansion under terms of the 40-year WECA, as approved by the BCUC. Power purchased by FortisBC Electric from the Waneta Expansion in 2015 totalled approximately $30 million. In addition, the Waneta Expansion pays FortisBC Electric for management services associated with the generating station, which totalled approximately $7 million in 2015.

From time to time, the Corporation provides short-term financing to certain of its subsidiaries to support capital expenditure programs, acquisitions and seasonal working capital requirements, bearing interest at rates that approximate the Corporation's cost of short-term borrowing. In addition, the Corporation provided long-term financing to certain of its subsidiaries, bearing interest at rates that approximate the Corporation's cost of long-term debt. The majority of this long-term financing was repaid in 2015 as a result of the sale of commercial real estate and hotel assets. As at December 31, 2015, inter-segment loans outstanding totalled $48 million (December 31, 2014 – $402 million) and total interest charged in 2015 was $17 million (2014 – $27 million).

SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth the annual financial information for the years ended December 31, 2015, 2014 and 2013.

Selected Annual Financial Information

Years Ended December 31 *($ millions, except per share amounts)*	**2015**	2014	2013
Revenue	**6,727**	5,401	4,047
Net earnings	**840**	390	420
Net earnings attributable to common equity shareholders	**728**	317	353
Basic earnings per common share	**2.61**	1.41	1.74
Diluted earnings per common share	**2.59**	1.40	1.73
Total assets	**28,804**	26,233	17,908
Long-term debt (excluding current portion)	**10,784**	9,911	6,424
Preference shares	**1,820**	1,820	1,229
Common shareholders' equity	**8,060**	6,871	4,772
Dividends declared per common share	**1.43**	1.30	1.25
Dividends declared per First Preference Share, Series C [(1)]	**–**	–	0.4862
Dividends declared per First Preference Share, Series E	**1.2250**	1.2250	1.2250
Dividends declared per First Preference Share, Series F	**1.2250**	1.2250	1.2250
Dividends declared per First Preference Share, Series G [(2)]	**0.9708**	0.9708	1.1416
Dividends declared per First Preference Share, Series H [(3)]	**0.7344**	1.0625	1.0625
Dividends declared per First Preference Share, Series I [(3)]	**0.3637**	–	–
Dividends declared per First Preference Share, Series J	**1.1875**	1.1875	1.1875
Dividends declared per First Preference Share, Series K [(4)]	**1.0000**	1.0000	0.6233
Dividends declared per First Preference Share, Series M [(5)]	**1.0250**	0.4613	–

[(1)] In July 2013 the Corporation redeemed all of the issued and outstanding First Preference Shares, Series C.

[(2)] The annual fixed dividend per share for the First Preference Shares, Series G was reset from $1.3125 to $0.9708 for the five-year period from and including September 1, 2013 to but excluding September 1, 2018.

[(3)] On June 1, 2015, 2,975,154 of the 10,000,000 First Preference Shares, Series H were converted on a one-for-one basis into First Preference Shares, Series I. The annual fixed dividend per share for the First Preference Shares, Series H was reset from $1.0625 to $0.6250 for the five-year period from and including June 1, 2015 to but excluding June 1, 2020. The First Preference Shares, Series I are entitled to receive floating rate cumulative dividends, which rate will be reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus 1.45%.

[(4)] The Fixed Rate Reset First Preference Shares, Series K were issued in July 2013 and are entitled to receive cumulative dividends in the amount of $1.0000 per share per annum for the first six years.

[(5)] The Fixed Rate Reset First Preference Shares, Series M were issued in September 2014 and are entitled to receive cumulative dividends in the amount of $1.0250 per share per annum for the first five years.

2015/2014: Revenue increased $1,326 million, or 24.6%, from 2014 and net earnings attributable to common equity shareholders were $728 million, or $2.61 per common share, compared to $317 million, or $1.41 per common share, in 2014. For a discussion of the reasons for the changes in revenue, net earnings attributable to common equity shareholders, and earnings per common share, refer to the "Consolidated Results of Operations" and "Summary Financial Highlights" sections of this MD&A.

The growth in total assets reflects favourable foreign exchange on the translation of US dollar-denominated assets and continued investment in energy infrastructure, driven by capital spending at the regulated utilities, partially offset by the sale of commercial real estate and hotel assets in 2015. The increase in long-term debt was primarily due to the issuance of long-term debt at the Corporation's regulated utilities, largely to finance energy infrastructure investment, and the impact of foreign exchange on the translation of US dollar-denominated long-term debt. The increase was partially offset by regularly scheduled debt repayments and net repayments under committed credit facilities, mainly at the Corporation, using net proceeds from the sale of commercial real estate and hotel assets.

2014/2013: Revenue increased $1,354 million, or 33.5%, from 2013. The increase in revenue was driven by the acquisition of UNS Energy in August 2014 and Central Hudson in June 2013. A higher commodity cost of natural gas charged to customers at FortisBC Energy, an increase in the base component of rates at most of the regulated utilities and higher electricity sales also contributed to the increase in revenue.

Net earnings attributable to common equity shareholders were $317 million in 2014 compared to $353 million in 2013. Results for both years were impacted by non-recurring items, largely associated with the acquisition of UNS Energy in 2014 and Central Hudson in 2013. Earnings for 2014 were reduced by $39 million due to acquisition-related expenses and customer benefits offered to obtain regulatory approval of the acquisition of UNS Energy, compared to $34 million associated with the acquisition of Central Hudson in 2013. Interest expense of $51 million after tax, including the make-whole payment, associated with convertible debentures issued to finance a portion of the acquisition of UNS Energy was recognized in 2014. In addition, earnings for 2013 were favourably impacted by an income tax recovery of $23 million due to the enactment of higher deductions associated with Part VI.1 tax on the Corporation's preference share dividends, an extraordinary gain of $20 million related to the settlement of expropriation matters associated with the Exploits River Hydro Partnership, and the release of income tax provisions of approximately $7 million. An $8 million foreign exchange gain was recognized in 2014 compared to $6 million in 2013. Earnings for 2014 included $5 million associated with Griffith to the date of sale, and earnings for 2013 were reduced by $5 million associated with Griffith.

Excluding the above-noted impacts, net earnings attributable to common equity shareholders for 2014 were $394 million, an increase of $58 million from $336 million for 2013. The increase was driven by $60 million of earnings contribution at UNS Energy from the date of acquisition and the first full year of earnings contribution from Central Hudson, which was acquired in June 2013. Rate base growth and an increase in the number of customers at FortisAlberta and electricity sales growth at Caribbean Regulated Electric Utilities also contributed to the increase. The increase was partially offset by lower earnings at FortisBC Electric, primarily due to the impact of lower-than-expected finance charges in 2013 and higher Corporate and Other expenses. The increase in Corporate and Other expenses was primarily due to higher finance charges, largely due to the acquisitions of UNS Energy and Central Hudson, and higher operating expenses, partially offset by a higher income tax recovery and interest income.

The growth in total assets reflects the Corporation's acquisition of UNS Energy in August 2014 and continued investment in energy infrastructure, driven by capital spending at the regulated utilities in western Canada and the continued construction of the Waneta Expansion. The increase in long-term debt was primarily due to the financing of the acquisition of UNS Energy, including debt assumed on acquisition, and the financing of energy infrastructure investments.

Basic earnings per common share were $1.41 in 2014 compared to $1.74 in 2013. Excluding the above-noted non-recurring items in 2014 and 2013, basic earnings per common share were $1.75 for 2014, an increase of $0.09 from $1.66 for 2013. The increase was driven by accretion associated with the acquisition of UNS Energy.

FOURTH QUARTER RESULTS

The following tables set forth unaudited financial information for the fourth quarters ended December 31, 2015 and 2014.

Summary of Gas Volumes and Electricity and Energy Sales

Fourth Quarters Ended December 31 *(Unaudited)*	**2015**	2014	Variance
Regulated Electric & Gas Utilities – United States			
UNS Energy – Electricity Sales *(GWh)*	**3,562**	3,583	(21)
UNS Energy – Gas Volumes *(PJ)*	**4**	4	–
Central Hudson – Electricity Sales *(GWh)*	**1,160**	1,176	(16)
Central Hudson – Gas Volumes *(PJ)*	**5**	5	–
Regulated Gas Utility – Canadian			
FortisBC Energy *(PJ)*	**62**	59	3
Regulated Electric Utilities – Canadian			
FortisAlberta *(GWh)*	**4,188**	4,446	(258)
FortisBC Electric *(GWh)*	**836**	846	(10)
Eastern Canadian *(GWh)*)	**2,189**	2,203	(14)
Regulated Electric Utilities – Caribbean *(GWh)*	**201**	187	14
Non-Regulated – Fortis Generation *(GWh)*	**122**	109	13

Gas Volumes

The increase in gas volumes at FortisBC Energy was mainly due to higher gas volumes for transportation customers due to certain customers switching to natural gas compared to alternative fuel sources.

Electricity and Energy Sales

The decrease in energy deliveries at FortisAlberta was primarily due to lower average consumption by oil and gas customers as a result of low commodity prices for oil and gas. At most of the other regulated electric utilities, the decrease was mainly due to lower average consumption due to warmer temperatures, which reduced heating requirements. At the Regulated Electric Utilities – Caribbean, the impact of warmer temperatures increased electricity sales, due to higher air conditioning load. The overall decrease was partially offset by higher non-regulated energy sales, driven by the Waneta Expansion.

Segmented Revenue and Net Earnings Attributable to Common Equity Shareholders

Fourth Quarters Ended December 31 *(Unaudited)*	**Revenue**			**Net Earnings**		
($ millions, except per share amounts)	**2015**	2014	Variance	**2015**	2014	Variance
Regulated Electric & Gas Utilities – United States						
UNS Energy	**482**	435	47	**26**	23	3
Central Hudson	**202**	186	16	**15**	4	11
	684	621	63	**41**	27	14
Regulated Gas Utility – Canadian						
FortisBC Energy	**411**	432	(21)	**65**	49	16
Regulated Electric Utilities – Canadian						
FortisAlberta	**140**	132	8	**29**	25	4
FortisBC Electric	**99**	90	9	**8**	12	(4)
Eastern Canadian Electric Utilities	**273**	266	7	**15**	14	1
	512	488	24	**52**	51	1
Regulated Electric Utilities – Caribbean	**82**	84	(2)	**9**	6	3
Non-Regulated – Fortis Generation	**30**	8	22	**11**	4	7
Non-Regulated – Non-Utility	**6**	62	(56)	**1**	7	(6)
Corporate and Other	**2**	7	(5)	**(44)**	(31)	(13)
Inter-Segment Eliminations	**(19)**	(9)	(10)	**–**	–	–
Total	**1,708**	1,693	15	**135**	113	22
Basic Earnings per Common Share *($)*				**0.48**	0.44	0.04

Revenue

The increase in revenue was mainly due to favourable foreign exchange associated with the translation of US dollar-denominated revenue, contribution from the Waneta Expansion, and an increase in base electricity rates at the Canadian Regulated Electric Utilities. The increase was partially offset by the flow through in customer rates of lower energy supply costs at FortisBC Energy, Central Hudson and Caribbean Regulated Electric Utilities, and a decrease in non-utility revenue due to the sale of commercial real estate and hotel assets.

Earnings

The increase in earnings was primarily due to: (i) favourable foreign exchange impacts; (ii) an increase in base electricity rates at Central Hudson effective July 1, 2015, combined with the impact of storm restoration and other non-recurring expenses recognized in the fourth quarter of 2014; (iii) earnings contribution of approximately $6 million from the Waneta Expansion; (iv) rate base growth associated with capital expenditures and growth in the number of customers at FortisAlberta; and (v) a higher AFUDC at FortisBC Energy, partially offset by higher operating expenses. The timing of regulatory deferral mechanisms had a favourable impact on FortisBC Energy's earnings for the quarter and an unfavourable impact on FortisBC Electric. The increase in earnings was partially offset by lower earnings contribution due to the sale of commercial real estate and hotel assets and higher Corporate and Other expenses. Corporate and Other expenses included $7 million in acquisition-related expenses in the fourth quarter of 2015 and in the fourth quarter of 2014 included $4 million in interest expense associated with the convertible debentures and a $3 million foreign exchange gain. Excluding these items, the increase in Corporate and Other expenses was mainly due to a lower income tax recovery and lower related-party interest income.

Summary of Consolidated Cash Flows

Fourth Quarters Ended December 31 *(Unaudited)*

($ millions)	**2015**	2014	Variance
Cash, Beginning of Period	**347**	458	(111)
Cash Provided by (Used in):			
Operating Activities	**397**	334	63
Investing Activities	**(234)**	(829)	595
Financing Activities	**(280)**	257	(537)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**12**	10	2
Cash, End of Period	**242**	230	12

Cash flow from operating activities was $63 million higher quarter over quarter. The increase was primarily due to higher cash earnings at the Corporation's regulated utilities.

Cash used in investing activities was $595 million lower quarter over quarter. The decrease was mainly due to lower capital expenditures at the regulated utilities, largely due to UNS Energy's purchase of Gila River Unit 3 generation station in December 2014 for approximately $252 million (US$219 million), and proceeds received from the sale of hotel assets in October 2015 for $365 million.

Cash provided by financing activities was $537 million lower quarter over quarter. The decrease was primarily due to the repayment of credit facility borrowings in the fourth quarter of 2015 using proceeds from the sale of hotel assets. In addition, lower proceeds from long-term debt and lower credit facility borrowings were partially offset by lower repayments of long-term debt. In the fourth quarter of 2014, proceeds from the second installment of the convertible debentures were received, which were used to repay acquisition credit facilities used initially to finance a portion of the acquisition of UNS Energy.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2014 through December 31, 2015. The quarterly information has been obtained from the Corporation's interim unaudited consolidated financial statements. These financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Summary of Quarterly Results
(Unaudited)

Quarter Ended	Revenue *($ millions)*	Net Earnings Attributable to Common Equity Shareholders *($ millions)*	Earnings per Common Share Basic *($)*	Earnings per Common Share Diluted *($)*
December 31, 2015	1,708	135	0.48	0.48
September 30, 2015	1,566	151	0.54	0.54
June 30, 2015	1,538	244	0.88	0.87
March 31, 2015	1,915	198	0.72	0.71
December 31, 2014	1,693	113	0.44	0.43
September 30, 2014	1,197	14	0.06	0.06
June 30, 2014	1,056	47	0.22	0.22
March 31, 2014	1,455	143	0.67	0.66

The summary of the past eight quarters reflects the Corporation's continued organic growth, growth from acquisitions and associated acquisition-related expenses, and the impact of sale transactions, as well as the seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of electricity and gas demand in different regions, as well as the timing and recognition of regulatory decisions. Revenue is also affected by the cost of fuel and purchased power and the cost of natural gas, which are flowed through to customers without markup. Given the diversified nature of the Corporation's subsidiaries, seasonality may vary. Most of the annual earnings of FortisBC Energy are realized in the first and fourth quarters. Earnings for UNS Energy's electric utilities are generally highest in the second and third quarters due to the use of air conditioning and other cooling equipment.

December 2015/December 2014: Net earnings attributable to common equity shareholders were $135 million, or $0.48 per common share, for the fourth quarter of 2015 compared to earnings of $113 million, or $0.44 per common share, for the fourth quarter of 2014. A discussion of the variances in financial results for the fourth quarter of 2015 and the fourth quarter of 2014 is provided in the "Fourth Quarter Results" section of this MD&A.

September 2015/September 2014: Net earnings attributable to common equity shareholders were $151 million, or $0.54 per common share, for the third quarter of 2015 compared to earnings of $14 million, or $0.06 per common share, for the third quarter of 2014. Earnings for the third quarter of 2015 were favourably impacted by a $5 million gain on the sale of non-regulated generation assets in Ontario and a $5 million positive adjustment associated with the sale of hotel assets, and were reduced by a $9 million loss on the settlement of expropriation matters related to the Corporation's investment in Belize Electricity. Earnings for the third quarter of 2014 were reduced by a total of $58 million due to acquisition-related expenses associated with UNS Energy. Excluding these items, the increase in earnings was driven by contribution of $97 million at UNS Energy compared to $37 million for the third quarter of 2014. Earnings contribution of $5 million from the Waneta Expansion also contributed to the increase. Performance was also driven by the Corporation's other regulated utilities, including rate base growth associated with capital expenditures and customer growth at FortisAlberta; improved performance at Central Hudson; and favourable foreign exchange associated with US dollar-denominated earnings. Earnings at FortisBC Energy and FortisBC Electric were impacted by the timing of regulatory deferral mechanisms; however, FortisBC Energy's earnings were favourably impacted by lower operating expenses and higher AFUDC. The increase was partially offset by higher preference share dividends and finance charges in the Corporate and Other segment, largely associated with the acquisition of UNS Energy.

June 2015/June 2014: Net earnings attributable to common equity shareholders were $244 million, or $0.88 per common share, for the second quarter of 2015 compared to earnings of $47 million, or $0.22 per common share, for the second quarter of 2014. The increase was driven by a net gain of $123 million on the sale of commercial real estate, hotel and non-regulated generation assets. The increase was also due to earnings contribution of $52 million at UNS Energy and $12 million from the Waneta Expansion, representing the Corporation's 51% controlling ownership. Performance was also driven by the Corporation's regulated utilities, including rate base growth associated with capital expenditures, customer growth and a decrease in depreciation and amortization at FortisAlberta; increases at FortisBC Electric, largely due to timing of quarterly earnings compared to the same period last year, resulting from the impact of regulatory deferral mechanisms; and improved performance at Central Hudson. The increase was partially offset by a $5 million decrease in earnings at FortisBC Energy due to the timing of regulatory flow-through deferral amounts, and higher preference share dividends and finance charges in the Corporate and Other segment associated with the acquisition of UNS Energy.

March 2015/March 2014: Net earnings attributable to common equity shareholders were $198 million, or $0.72 per common share, for the first quarter of 2015 compared to earnings of $143 million, or $0.67 per common share, for the first quarter of 2014. The increase in earnings was driven by the Corporation's regulated utilities. UNS Energy contributed earnings of $20 million in the first quarter of 2015. FortisAlberta's earnings were favourably impacted by higher capital tracker revenue, including approximately $10 million associated with 2013 and 2014, and customer growth. Earnings at FortisBC Energy and FortisBC Electric were $9 million and $5 million, respectively, higher quarter over quarter, largely due to timing of quarterly earnings compared to the same period last year resulting from the impact of regulatory deferral mechanisms. Central Hudson and Eastern Canadian Regulated Electric Utilities also reported improved performance. The increase in earnings at the regulated utilities was partially offset by lower earnings at the Corporation's non-regulated subsidiaries, largely due to decreased production in Belize as a result of lower rainfall, costs at Fortis Properties associated with the strategic review, and approximately $5 million earnings contribution in the first quarter of 2014 from Griffith to the date of sale. Corporate and Other expenses were lower quarter over quarter, due to approximately $11 million in after-tax interest expense associated with the convertible debentures in the first quarter of 2014 and a higher foreign exchange gain, partially offset by higher preference share dividends and finance charges associated with the acquisition of UNS Energy.

MANAGEMENT'S EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Disclosure Controls and Procedures: The President and Chief Executive Officer ("CEO") and the Executive Vice President, Chief Financial Officer ("CFO") of Fortis, together with management, have established and maintain disclosure controls and procedures for the Corporation in order to provide reasonable assurance that material information relating to the Corporation is made known to them in a timely manner, particularly during the period in which the annual filings are being prepared. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's disclosure controls and procedures as of December 31, 2015 and, based on that evaluation, have concluded that these controls and procedures are effective in providing such reasonable assurance.

Internal Controls over Financial Reporting: The CEO and CFO of Fortis, together with management, are also responsible for establishing and maintaining internal controls over financial reporting ("ICFR") within the Corporation in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements for external purposes in accordance with US GAAP. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's ICFR as of December 31, 2015 and, based on that evaluation, have concluded that the controls are effective in providing such reasonable assurance. During the fourth quarter of 2015, there was no change in the Corporation's ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

SUBSEQUENT EVENT

On February 9, 2016, Fortis and ITC entered into an agreement and plan of merger pursuant to which Fortis will acquire ITC in a transaction valued at approximately US$11.3 billion, based on the closing price for Fortis common shares and the foreign exchange rate on February 8, 2016. Under the terms of the transaction, ITC shareholders will receive US$22.57 in cash and 0.7520 Fortis common shares per ITC common share, representing total consideration of approximately US$6.9 billion, and Fortis will assume approximately US$4.4 billion of ITC consolidated indebtedness.

ITC is the largest independent pure-play electric transmission company in the United States. ITC owns and operates high-voltage transmission facilities in Michigan, Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma, serving a combined peak load exceeding 26,000 MW along approximately 15,600 miles of transmission line. In addition, ITC is a public utility and independent transmission owner in Wisconsin. ITC's tariff rates are regulated by FERC, which has been one of the most consistently supportive utility regulators in North America providing reasonable returns and equity ratios. Rates are set using a forward-looking rate-setting mechanism with an annual true-up, which provides timely cost recovery and reduces regulatory lag.

The closing of the Acquisition is subject to ITC and Fortis shareholder approvals, the satisfaction of other customary closing conditions, and certain regulatory, state and federal approvals including, among others, those of FERC, the Committee on Foreign Investment in the United States, and the United States Federal Trade Commission/Department of Justice under the *Hart-Scott-Rodino Antitrust Improvements Act*. The closing of the Acquisition is expected to occur in late 2016.

The pending Acquisition is in alignment with the Corporation's business model and acquisition strategy, and is expected to provide approximately 5% accretion to earnings per common share in the first full year following closing, excluding one-time acquisition-related expenses and assuming a stable currency exchange environment. The Acquisition represents a singular opportunity for Fortis to significantly diversify its business in terms of regulatory jurisdictions, business risk profile and regional economic mix. On a pro forma basis, 2016 forecast midyear rate base of Fortis is expected to increase by approximately $8 billion to approximately $26 billion, as a result of the Acquisition.

The financing of the Acquisition has been structured to allow Fortis to maintain investment-grade credit ratings and is consistent with the Corporation's existing capital structure. Financing of the cash portion of the Acquisition will be achieved primarily through the issuance of approximately US$2 billion of Fortis debt and the sale of up to 19.9% of ITC to one or more infrastructure-focused minority investors. In addition, Fortis has obtained commitments of US$2.0 billion from Goldman Sachs Bank USA to bridge the long-term debt financing and US$1.7 billion from The Bank of Nova Scotia to primarily bridge the sale of the minority investment in ITC. These non-revolving term credit facilities are repayable in full on the first anniversary of their advance, and although syndication is not required, Fortis expects that these bridge facilities will be syndicated.

Upon completion of the Acquisition, ITC will become a subsidiary of Fortis and approximately 27% of the common shares of Fortis will be held by ITC shareholders. In connection with the Acquisition, Fortis will become a registrant with the SEC and will apply to list its common shares on the New York Stock Exchange and will continue to have its shares listed on the TSX.

OUTLOOK

Fortis is focused on closing the acquisition of ITC by the end of 2016. The Acquisition is in alignment with the Corporation's business model and acquisition strategy, and is expected to provide approximately 5% accretion to earnings per common share in the first full year following closing, excluding one-time acquisition-related expenses and assuming a stable currency exchange environment. The Acquisition represents a singular opportunity for Fortis to significantly diversify its business in terms of regulatory jurisdictions, business risk profile and regional economic mix.

Substantially all of Fortis' assets are low-risk, regulated utilities and long-term contracted energy infrastructure. No single regulatory jurisdiction comprises more than one-third of total assets. Over the five-year period through 2020, excluding the acquisition of ITC, the Corporation's highly executable capital program is expected to be approximately $9 billion. This investment in energy infrastructure is expected to increase rate base to almost $21 billion in 2020 and produce a five-year compound annual growth rate in rate base of approximately 5%.

On a pro forma basis, 2016 forecast midyear rate base of Fortis is expected to increase by approximately $8 billion to approximately $26 billion, as a result of the acquisition of ITC. Following the Acquisition, Fortis will be one of the top 15 North American public utilities ranked by enterprise value, with an estimated enterprise value of $42 billion. Additionally, ITC's midyear rate base, including construction work in progress, is expected to increase at a compound annual growth rate of approximately 7.5% through 2018, based on ITC's planned capital expenditure program.

Fortis continues to target 6% average annual dividend growth through 2020. This dividend guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at the Corporation's utilities, the successful execution of the five-year capital expenditure plan, and management's continued confidence in the strength of the Corporation's diversified portfolio of assets and record of operational excellence. The pending acquisition of ITC further supports this dividend guidance.

Fortis expects long-term sustainable growth in rate base, assets and earnings resulting from strategic acquisitions and investment in its existing utility operations. The Corporation is also committed to identifying and executing on opportunities for incremental rate base and earnings growth through additional investments in existing service territories, and in new franchise areas.

OUTSTANDING SHARE DATA

As at February 16, 2016, the Corporation had issued and outstanding 281.9 million common shares; 8.0 million First Preference Shares, Series E; 5.0 million First Preference Shares, Series F; 9.2 million First Preference Shares, Series G; 7.0 million First Preference Shares, Series H; 3.0 million First Preference Shares, Series I; 8.0 million First Preference Shares, Series J; 10.0 million First Preference Shares, Series K; and 24.0 million First Preference Shares, Series M. Only the common shares of the Corporation have voting rights. The Corporation's First Preference Shares do not have voting rights unless and until Fortis fails to pay eight quarterly dividends, whether or not consecutive and whether such dividends have been declared.

The number of common shares of Fortis that would be issued if all outstanding stock options and First Preference Shares, Series E were converted as at February 16, 2016 is as follows.

Conversion of Securities into Common Shares

As at February 16, 2016 *(Unaudited)*	**Number of Common Shares**
Security	*(millions)*
Stock Options	**4.9**
First Preference Shares, Series E	**5.8**
Total	**10.7**

Additional information, including the Fortis 2015 Annual Information Form, Management Information Circular and Audited Consolidated Financial Statements, is available on SEDAR at www.sedar.com and on the Corporation's website at www.fortisinc.com.

Financials

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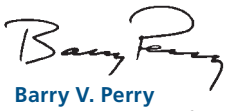
MANAGEMENT'S REPORT

The accompanying Annual Consolidated Financial Statements of Fortis Inc. have been prepared by management, who is responsible for the integrity of the information presented including the amounts that must, of necessity, be based on estimates and informed judgments. These Annual Consolidated Financial Statements were prepared in accordance with accounting principles generally accepted in the United States.

In meeting its responsibility for the reliability and integrity of the Annual Consolidated Financial Statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to ensure transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Corporation and its subsidiaries focus on the need for training of qualified and professional staff and the effective communication of management guidelines and policies. The effectiveness of the internal controls of Fortis Inc. is evaluated on an ongoing basis.

The Board of Directors oversees management's responsibilities for financial reporting through an Audit Committee which is composed entirely of outside independent directors. The Audit Committee oversees the external audit of the Corporation's Annual Consolidated Financial Statements and the accounting and financial reporting and disclosure processes and policies of the Corporation. The Audit Committee meets with management, the shareholders' auditors and the internal auditor to discuss the results of the external audit, the adequacy of the internal accounting controls and the quality and integrity of financial reporting. The Corporation's Annual Consolidated Financial Statements are reviewed by the Audit Committee with each of management and the shareholders' auditors before the statements are recommended to the Board of Directors for approval. The shareholders' auditors have full and free access to the Audit Committee. The Audit Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Corporation's Annual Consolidated Financial Statements and to review and report to the Board of Directors on policies relating to the accounting and financial reporting and disclosure processes.

The Audit Committee has the duty to review financial reports requiring Board of Directors' approval prior to the submission to securities commissions or other regulatory authorities, to assess and review management judgments material to reported financial information and to review shareholders' auditors' independence and auditors' fees. The 2015 Annual Consolidated Financial Statements were reviewed by the Audit Committee and, on their recommendation, were approved by the Board of Directors of Fortis Inc. Ernst & Young LLP, independent auditors appointed by the shareholders of Fortis Inc. upon recommendation of the Audit Committee, have performed an audit of the 2015 Annual Consolidated Financial Statements and their report follows.



Barry V. Perry
President and Chief Executive Officer, Fortis Inc.



Karl W. Smith
Executive Vice President, Chief Financial Officer, Fortis Inc.

St. John's, Canada

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Fortis Inc.

We have audited the accompanying consolidated financial statements of Fortis Inc., which comprise the consolidated balance sheets as at December 31, 2015 and 2014, and the consolidated statements of earnings, comprehensive income, cash flows and changes in equity for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Fortis Inc. as at December 31, 2015 and 2014, and its financial performance and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States.



St. John's, Canada
February 17, 2016

Chartered Professional Accountants

CONSOLIDATED BALANCE SHEETS

FORTIS INC.

As at December 31 (in millions of Canadian dollars)

ASSETS	2015	2014
Current assets		*(Note 36)*
Cash and cash equivalents	**$ 242**	$ 230
Accounts receivable and other current assets *(Note 6)*	**964**	900
Prepaid expenses	**68**	59
Inventories *(Note 7)*	**337**	321
Regulatory assets *(Note 8)*	**246**	277
	1,857	1,787
Other assets *(Note 9)*	**352**	272
Regulatory assets *(Note 8)*	**2,286**	2,138
Utility capital assets *(Note 10)*	**19,595**	17,179
Non-utility capital assets *(Note 11)*	**–**	664
Intangible assets *(Note 12)*	**541**	461
Goodwill *(Note 13)*	**4,173**	3,732
	$ 28,804	$ 26,233
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings *(Note 32)*	**$ 511**	$ 330
Accounts payable and other current liabilities *(Note 14)*	**1,419**	1,440
Regulatory liabilities *(Note 8)*	**298**	173
Current installments of long-term debt *(Note 15)*	**384**	525
Current installments of capital lease and finance obligations *(Note 16)*	**26**	208
	2,638	2,676
Other liabilities *(Note 17)*	**1,152**	1,141
Regulatory liabilities *(Note 8)*	**1,340**	1,272
Deferred income taxes *(Note 26)*	**2,050**	1,626
Long-term debt *(Note 15)*	**10,784**	9,911
Capital lease and finance obligations *(Note 16)*	**487**	495
	18,451	17,121
Shareholders' equity		
Common shares [(1)] *(Note 18)*	**5,867**	5,667
Preference shares *(Note 20)*	**1,820**	1,820
Additional paid-in capital	**14**	15
Accumulated other comprehensive income *(Note 21)*	**791**	129
Retained earnings	**1,388**	1,060
	9,880	8,691
Non-controlling interests *(Note 22)*	**473**	421
	10,353	9,112
	$ 28,804	$ 26,233

(1) No par value. Unlimited authorized shares; 281.6 million and 276.0 million issued and outstanding as at December 31, 2015 and 2014, respectively

Commitments *(Note 33)*
Contingencies *(Note 34)*

See accompanying Notes to Consolidated Financial Statements

Approved on Behalf of the Board



David G. Norris,
Director



Peter E. Case,
Director

CONSOLIDATED STATEMENTS OF EARNINGS

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except per share amounts)	2015	2014
Revenue	**$ 6,727**	$ 5,401
Expenses		
Energy supply costs	**2,561**	2,197
Operating	**1,864**	1,493
Depreciation and amortization	**873**	688
	5,298	4,378
Operating income	**1,429**	1,023
Other income (expenses), net *(Note 24)*	**187**	(25)
Finance charges *(Note 25)*	**553**	547
Earnings before income taxes and discontinued operations	**1,063**	451
Income tax expense *(Note 26)*	**223**	66
Earnings from continuing operations	**840**	385
Earnings from discontinued operations, net of tax *(Note 28)*	**–**	5
Net earnings	**$ 840**	$ 390
Net earnings attributable to:		
Non-controlling interests	**$ 35**	$ 11
Preference equity shareholders	**77**	62
Common equity shareholders	**728**	317
	$ 840	$ 390
Earnings per common share from continuing operations *(Note 19)*		
Basic	**$ 2.61**	$ 1.39
Diluted	**$ 2.59**	$ 1.38
Earnings per common share *(Note 19)*		
Basic	**$ 2.61**	$ 1.41
Diluted	**$ 2.59**	$ 1.40

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	2015	2014
Net earnings	**$ 840**	$ 390
Other comprehensive income (loss)		
Unrealized foreign currency translation gains, net of hedging activities and tax *(Note 21)*	**660**	204
Reclassification to earnings of foreign currency translation loss on disposal of investment in foreign operations, net of tax *(Note 21)*	**2**	–
Net change in fair value of cash flow hedges, net of tax *(Notes 21 and 31)*	**1**	1
Reclassification to earnings of net losses on derivative instruments discontinued as cash flow hedges, net of tax *(Note 21)*	**–**	1
Unrealized loss on available-for-sale investment, net of tax *(Notes 9, 21 and 31)*	**(2)**	–
Unrealized employee future benefits gains (losses), net of tax *(Notes 21 and 27)*	**1**	(5)
	662	201
Comprehensive income	**$ 1,502**	$ 591
Comprehensive income attributable to:		
Non-controlling interests	**$ 35**	$ 11
Preference equity shareholders	**77**	62
Common equity shareholders	**1,390**	518
	$ 1,502	$ 591

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2015**	2014
Operating activities		
Net earnings	**$ 840**	$ 390
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation – capital assets	**785**	597
Amortization – intangible assets	**64**	60
Amortization – other	**24**	31
Deferred income tax expense *(Note 26)*	**164**	23
Accrued employee future benefits	**(19)**	25
Equity component of allowance for funds used during construction *(Note 24)*	**(23)**	(11)
Gain on sale of non-utility capital assets *(Note 24)*	**(131)**	–
Gain on sale of non-regulated generation assets *(Note 24)*	**(62)**	–
Other	**79**	71
Change in long-term regulatory assets and liabilities	**(89)**	(80)
Change in non-cash operating working capital *(Note 30)*	**41**	(124)
	1,673	982
Investing activities		
Change in other assets and other liabilities	**(36)**	(4)
Capital expenditures – utility capital assets	**(2,122)**	(1,617)
Capital expenditures – non-utility capital assets	**(9)**	(39)
Capital expenditures – intangible assets	**(112)**	(69)
Contributions in aid of construction	**59**	69
Purchase of assets held for sale *(Notes 6 and 16)*	**(32)**	–
Proceeds on sale of assets *(Notes 16 and 28)*	**922**	109
Business acquisitions, net of cash acquired *(Notes 9 and 29)*	**(38)**	(2,648)
	(1,368)	(4,199)
Financing activities		
Change in short-term borrowings	**148**	167
Proceeds from convertible debentures, net of issue costs *(Note 18)*	**–**	1,725
Proceeds from long-term debt, net of issue costs *(Note 15)*	**1,002**	1,193
Repayments of long-term debt and capital lease and finance obligations	**(602)**	(743)
Net (repayments) borrowings under committed credit facilities	**(622)**	610
Advances from non-controlling interests	**20**	38
Issue of common shares, net of costs and dividends reinvested *(Note 18)*	**40**	51
Issue of preference shares, net of costs *(Note 20)*	**–**	586
Dividends		
Common shares, net of dividends reinvested	**(232)**	(194)
Preference shares	**(77)**	(62)
Subsidiary dividends paid to non-controlling interests	**(23)**	(10)
	(346)	3,361
Effect of exchange rate changes on cash and cash equivalents	**53**	14
Change in cash and cash equivalents	**12**	158
Cash and cash equivalents, beginning of year	**230**	72
Cash and cash equivalents, end of year	**$ 242**	$ 230

Supplementary Information to Consolidated Statements of Cash Flows *(Note 30)*

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

FORTIS INC.

For the years ended December 31, 2015 and 2014 (in millions of Canadian dollars)	Common Shares	Preference Shares	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-Controlling Interests	Total Equity
	(Note 18)	*(Note 20)*		*(Note 21)*		*(Note 22)*	
As at January 1, 2015	**$ 5,667**	**$ 1,820**	**$ 15**	**$ 129**	**$ 1,060**	**$ 421**	**$ 9,112**
Net earnings	**–**	**–**	**–**	**–**	**805**	**35**	**840**
Other comprehensive income	**–**	**–**	**–**	**662**	**–**	**–**	**662**
Common share issues	**200**	**–**	**(4)**	**–**	**–**	**–**	**196**
Stock-based compensation	**–**	**–**	**3**	**–**	**–**	**–**	**3**
Advances from non-controlling interests	**–**	**–**	**–**	**–**	**–**	**20**	**20**
Foreign currency translation impacts	**–**	**–**	**–**	**–**	**–**	**20**	**20**
Subsidiary dividends paid to non-controlling interests	**–**	**–**	**–**	**–**	**–**	**(23)**	**(23)**
Dividends declared on common shares ($1.43 per share)	**–**	**–**	**–**	**–**	**(400)**	**–**	**(400)**
Dividends declared on preference shares	**–**	**–**	**–**	**–**	**(77)**	**–**	**(77)**
As at December 31, 2015	**$ 5,867**	**$ 1,820**	**$ 14**	**$ 791**	**$ 1,388**	**$ 473**	**$ 10,353**
As at January 1, 2014	$ 3,783	$ 1,229	$ 17	$ (72)	$ 1,044	$ 375	$ 6,376
Net earnings	–	–	–	–	379	11	390
Other comprehensive income	–	–	–	201	–	–	201
Preference share issue	–	591	–	–	–	–	591
Common share issues	1,884	–	(5)	–	–	–	1,879
Stock-based compensation	–	–	3	–	–	–	3
Advances from non-controlling interests	–	–	–	–	–	38	38
Foreign currency translation impacts	–	–	–	–	–	7	7
Subsidiary dividends paid to non-controlling interests	–	–	–	–	–	(10)	(10)
Dividends declared on common shares ($1.30 per share)	–	–	–	–	(301)	–	(301)
Dividends declared on preference shares	–	–	–	–	(62)	–	(62)
As at December 31, 2014	$ 5,667	$ 1,820	$ 15	$ 129	$ 1,060	$ 421	$ 9,112

See accompanying Notes to Consolidated Financial Statements

For the years ended December 31, 2015 and 2014

1. DESCRIPTION OF THE BUSINESS

Nature of Operations

Fortis Inc. ("Fortis" or the "Corporation") is principally an international electric and gas utility holding company. Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation assets, which are treated as a separate segment. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each entity within the reporting segments operates with substantial autonomy, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following summary describes the operations included in each of the Corporation's reportable segments.

Regulated Utilities

The Corporation's interests in regulated electric and gas utilities are as follows.

Regulated Electric & Gas Utilities – United States

a. *UNS Energy:* Primarily comprised of Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas"), (collectively, the "UNS Utilities"), acquired by Fortis in August 2014 (Note 29).

   TEP, UNS Energy's largest operating subsidiary, is a vertically integrated regulated electric utility. TEP generates, transmits and distributes electricity to retail customers in southeastern Arizona, including the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP also sells wholesale electricity to other entities in the western United States.

   UNS Electric is a vertically integrated regulated electric utility, which generates, transmits and distributes electricity to retail customers in Arizona's Mohave and Santa Cruz counties.

   TEP and UNS Electric currently own generation resources with an aggregate capacity of 2,799 megawatts ("MW"), including 54 MW of solar capacity. Several of the generating assets in which TEP and UNS Electric have an interest are jointly owned. As at December 31, 2015, approximately 43% of the generating capacity was fuelled by coal.

   UNS Gas is a regulated gas distribution utility, serving retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties.

b. *Central Hudson:* Central Hudson Gas & Electric Corporation ("Central Hudson") is a regulated transmission and distribution ("T&D") utility, serving eight counties of New York State's Mid-Hudson River Valley. The Company owns gas-fired and hydroelectric generating capacity totalling 64 MW.

Regulated Gas Utility – Canadian

FortisBC Energy: Primarily includes FortisBC Energy Inc. ("FortisBC Energy" or "FEI") and, prior to December 31, 2014, FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy (Whistler) Inc. ("FEWI"). On December 31, 2014, FEI, FEVI and FEWI were amalgamated and FEI is the resulting Company (Note 2). FEI is the largest distributor of natural gas in British Columbia, serving more than 135 communities. Major areas served by the Company are the Lower Mainland, Vancouver Island and Whistler regions of British Columbia. FEI provides T&D services to customers, and obtains natural gas supplies on behalf of most residential, commercial and industrial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through FEI's Southern Crossing pipeline, from Alberta.

Regulated Electric Utilities – Canadian

a. *FortisAlberta:* FortisAlberta Inc. ("FortisAlberta") owns and operates the electricity distribution system in a substantial portion of southern and central Alberta. The Company does not own or operate generation or transmission assets and is not involved in the direct sale of electricity.

b. *FortisBC Electric:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia. FortisBC Inc. owns four hydroelectric generating facilities with a combined capacity of 225 MW. Also included in the FortisBC Electric segment are the operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generating facility owned by Teck Metals Ltd. and BC Hydro; the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion"), owned by Fortis and Columbia Power Corporation and Columbia Basin Trust ("CPC/CBT"); the 149-MW Brilliant hydroelectric plant and the 120-MW Brilliant hydroelectric expansion plant, both owned by CPC/CBT; and the 185-MW Arrow Lakes hydroelectric plant owned by CPC/CBT.

For the years ended December 31, 2015 and 2014

1. DESCRIPTION OF THE BUSINESS (cont'd)

Regulated Electric Utilities – Canadian (cont'd)

c. *Eastern Canadian:* Comprised of Newfoundland Power Inc. ("Newfoundland Power"), Maritime Electric Company, Limited ("Maritime Electric") and FortisOntario Inc. ("FortisOntario"). Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador. Newfoundland Power has an installed generating capacity of 139 MW, of which 97 MW is hydroelectric generation. Maritime Electric is an integrated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI"). Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario's operations are primarily comprised of Canadian Niagara Power Inc. ("Canadian Niagara Power"), Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric") and Algoma Power Inc. ("Algoma Power").

Regulated Electric Utilities – Caribbean

The Regulated Electric Utilities – Caribbean segment includes the Corporation's approximate 60% controlling ownership interest in Caribbean Utilities Company, Ltd. ("Caribbean Utilities") (December 31, 2014 – 60%), Fortis Turks and Caicos, and the Corporation's 33% equity investment in Belize Electricity Limited ("Belize Electricity") (Note 9). Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands. The Company has an installed diesel-powered generating capacity of 132 MW. Caribbean Utilities is a public company traded on the Toronto Stock Exchange ("TSX") (TSX:CUP.U). Fortis Turks and Caicos is comprised of two integrated electric utilities that provide electricity to certain islands in Turks and Caicos. The utilities have a combined diesel-powered generating capacity of 82 MW. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize.

Non-Regulated – Fortis Generation

Fortis Generation is primarily comprised of long-term contracted generation assets in British Columbia and Belize. Generating assets in British Columbia include the Corporation's 51% controlling ownership interest in the 335-MW Waneta Expansion. Construction of the Waneta Expansion was completed in April 2015 and the output is sold to BC Hydro and FortisBC Electric under 40-year contracts. The Corporation's 51% controlling ownership interest in the Waneta Expansion is conducted through the Waneta Expansion Limited Partnership ("Waneta Partnership"), with CPC/CBT holding the remaining 49% interest.

Generating assets in Belize are comprised of three hydroelectric generating facilities with a combined capacity of 51 MW. All of the output of these facilities is sold to Belize Electricity under 50-year power purchase agreements ("PPAs") expiring in 2055 and 2060. The hydroelectric generation operations in Belize are conducted through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the Government of Belize ("GOB").

As at December 31, 2015, the 16-MW run-of-river Walden hydroelectric generating facility ("Walden") has been classified as held for sale (Note 6).

In June 2015 and July 2015 the Corporation sold its non-regulated generation assets in Upstate New York and Ontario, respectively (Notes 24 and 28).

Non-Regulated – Non-Utility

The Non-Utility segment previously included Fortis Properties Corporation ("Fortis Properties") and Griffith Energy Services, Inc. ("Griffith"). Fortis Properties completed the sale of its commercial real estate assets in June 2015 and its hotel assets in October 2015, and Griffith was sold in March 2014 (Note 28).

Corporate and Other

The Corporate and Other segment captures expense and revenue items not specifically related to any reportable segment and those business operations that are below the required threshold for reporting as separate segments.

The Corporate and Other segment includes net corporate expenses of Fortis and non-regulated holding company expenses of FortisBC Holdings Inc. ("FHI"), CH Energy Group, Inc. ("CH Energy Group") and UNS Energy Corporation. Also included in the Corporate and Other segment are the financial results of FortisBC Alternative Energy Services Inc. ("FAES"). FAES is a wholly owned subsidiary of FHI that provides alternative energy solutions, including thermal-energy and geo-exchange systems.

2. NATURE OF REGULATION

The Corporation's regulated utilities are primarily determined under cost of service ("COS") regulation and, in certain jurisdictions, performance-based rate-setting ("PBR") mechanisms. Generally, under COS regulation the respective regulatory authority sets customer electricity and/or gas rates to permit a reasonable opportunity for the utility to recover, on a timely basis, estimated costs of providing service to customers, including a fair rate of return on a regulatory deemed or targeted capital structure applied to an approved regulatory asset value ("rate base"). The ability of a regulated utility to recover prudently incurred costs of providing service and earn the regulator-approved rate of return on common shareholders' equity ("ROE") and/or rate of return on rate base assets ("ROA") depends on the utility achieving the forecasts established in the rate-setting processes. If a historical test year is used to set customer rates, there may be regulatory lag between when costs are incurred and when they are reflected in customer rates. When PBR mechanisms are utilized in determining annual revenue requirements and resulting customer rates, a formula is generally applied that incorporates inflation and assumed productivity improvements. The use of PBR mechanisms should allow a utility a reasonable opportunity to recover prudently incurred costs and earn its allowed ROE or ROA.

When future test years are used to establish revenue requirements and set base customer rates, these rates are not adjusted as a result of the actual COS being different from that which is estimated, other than for certain prescribed costs that are eligible to be deferred on the balance sheet. In addition, the Corporation's regulated utilities, where applicable, are permitted by their respective regulatory authority to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms (Note 8).

The nature of regulation at the Corporation's utilities is as follows.

UNS Energy
The UNS Utilities are regulated by the Arizona Corporation Commission ("ACC") and certain activities are subject to regulation by the U.S. Federal Energy Regulatory Commission ("FERC") under the *Federal Power Act* (United States). The UNS Utilities operate under COS regulation as administered by the ACC, which provides for the use of a historical test year in the establishment of retail electric and gas rates. Retail electric and gas rates are set to provide the utilities with an opportunity to recover their COS and earn a reasonable rate of return on rate base, including an adjustment for the fair value of rate base as required under the laws of the State of Arizona.

TEP's allowed ROE is set at 10.0% on a capital structure of 43.5% common equity, effective from July 1, 2013. UNS Electric's allowed ROE is set at 9.50% on a capital structure of 52.6% common equity, effective from January 1, 2014. UNS Gas' allowed ROE is set at 9.75% on a capital structure of 50.8% common equity, effective from May 1, 2012.

Central Hudson
Central Hudson is regulated by the New York State Public Service Commission ("PSC") and certain activities are subject to regulation by FERC under the *Federal Power Act* (United States). The Company is also subject to regulation by the North American Electric Reliability Corporation. Central Hudson operates under COS regulation as administered by the PSC with the use of a future test year in the establishment of rates.

Central Hudson began operating under a three-year rate order issued by the PSC effective July 1, 2010 with an allowed ROE set at 10.0% on a deemed capital structure of 48% common equity. As approved by the PSC in June 2013, the original three-year rate order was extended for two years, through June 30, 2015, as part of the regulatory approval of the acquisition of Central Hudson by Fortis. In June 2015 the PSC issued a rate order for the Company covering a three-year period, with new electricity and natural gas delivery rates effective July 1, 2015. The new rate order reflects an allowed ROE of 9.0% and a 48% common equity component of capital structure.

Effective July 1, 2013, Central Hudson was also subject to an earnings sharing mechanism, whereby the Company and customers share equally earnings in excess of the allowed ROE up to an achieved ROE that is 50 basis points above the allowed ROE, and share 10%/90% (Company/customers) earnings in excess of 50 basis points above the allowed ROE. In the new rate order effective July 1, 2015, the earnings sharing mechanism was continued, whereby the Company and customers share equally earnings in excess of 50 basis points above the allowed ROE up to an achieved ROE that is 100 basis points above the allowed ROE. Earnings in excess of 100 basis points above the allowed ROE are shared primarily with the customer.

FortisBC Energy and FortisBC Electric
FortisBC Energy and FortisBC Electric are regulated by the British Columbia Utilities Commission ("BCUC") pursuant to the *Utilities Commission Act* (British Columbia). The Companies primarily operate under COS regulation and, from time to time, PBR mechanisms for establishing customer rates.

For the years ended December 31, 2015 and 2014

2. NATURE OF REGULATION (cont'd)

FortisBC Energy and FortisBC Electric (cont'd)

In the first stage of the Generic Cost of Capital ("GCOC") Proceeding in British Columbia, FEI was designated as the benchmark utility and a BCUC decision established that the allowed ROE for the benchmark utility would be set at 8.75% on a 38.5% common equity component of capital structure, both effective January 1, 2013 through December 31, 2015. In March 2014 the BCUC issued its decision on the second stage of the GCOC Proceeding, setting the common equity component of capital structure for FEVI and FEWI at 41.5%, and reaffirming the common equity component of capital structure for FortisBC Electric at 40%, all effective January 1, 2013. The resulting allowed ROEs for FEVI, FEWI and FortisBC Electric were 9.25%, 9.50% and 9.15%, respectively, also effective January 1, 2013. Effective January 1, 2015, following the amalgamation of FEI, FEVI and FEWI, the ROE and common equity component of capital structure for the amalgamated FEI, was set to equal the benchmark utility, at 8.75% and 38.5%, respectively.

FEI and FortisBC Electric are subject to Multi-Year PBR Plans for 2014 through 2019. The PBR Plans, as approved by the BCUC, incorporate incentive mechanisms for improving operating and capital expenditure efficiencies. Operation and maintenance expenses and base capital expenditures during the PBR period are subject to an incentive formula reflecting incremental costs for inflation and half of customer growth, less a fixed productivity adjustment factor of 1.1% for FEI and 1.03% for FortisBC Electric each year. The approved PBR Plans also include a 50%/50% sharing of variances from the formula-driven operation and maintenance expenses and capital expenditures over the PBR period, and a number of service quality measures designed to ensure FEI and FortisBC Electric maintain service levels. It also sets out the requirements for an annual review process which will provide a forum for discussion between the utilities and interested parties regarding current performance and future activities.

FortisAlberta

FortisAlberta is regulated by the Alberta Utilities Commission ("AUC") pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Act* (Alberta), the *Hydro and Electric Energy Act* (Alberta) and the *Alberta Utilities Commission Act* (Alberta). Effective January 1, 2013, the AUC prescribed that distribution utilities in Alberta, including FortisAlberta, move to PBR for a five-year term. Under PBR, each year the prescribed formula is applied to the preceding year's distribution rates, with 2012 used as the going-in distribution rates.

The PBR plan includes mechanisms for the recovery or settlement of items determined to flow through directly to customers ("Y factor") and the recovery of costs related to capital expenditures that are not being recovered through the formula ("K factor" or "capital tracker"). The AUC also approved a Z factor, a PBR re-opener and an ROE efficiency carry-over mechanism. The Z factor permits an application for recovery of costs related to significant unforeseen events. The PBR re-opener permits an application to re-open and review the PBR plan to address specific problems with the design or operation of the PBR plan. The use of the Z factor and PBR re-opener mechanisms is associated with certain thresholds. The ROE efficiency carry-over mechanism provides an efficiency incentive by permitting a utility to continue to benefit from any efficiency gains achieved during the PBR term for two years following the end of that term.

The funding of capital expenditures during the PBR term is a material aspect of the PBR plan for FortisAlberta. The PBR plan provides a capital tracker mechanism to fund the recovery of costs associated with certain qualifying capital expenditures. In March 2015 the AUC issued its decision related to FortisAlberta's 2013, 2014 and 2015 Capital Tracker Applications. The decision: (i) indicated that the majority of the Company's applied for capital trackers met the established criteria and were, therefore, approved for collection from customers; (ii) approved FortisAlberta's accounting test to determine qualifying K factor amounts; and (iii) confirmed certain inputs to be used in the accounting test, including the conclusion that the weighted average cost of capital be based on actual debt rates and the allowed ROE and capital structure approved in the GCOC Proceeding.

In September 2015 the AUC approved FortisAlberta's compliance filing related to the 2015 Capital Tracker Decision, substantially as filed. Capital tracker revenue of $17 million was approved for 2013 on an actual basis and capital tracker revenue of $42 million and $62 million was approved on a forecast basis for 2014 and 2015, respectively. FortisAlberta collected $15 million, $29 million and $62 million in 2013, 2014 and 2015, respectively, related to capital tracker expenditures.

FortisAlberta recognized capital tracker revenue of approximately $59 million in 2015, of which $9 million was related to updates to the 2013 and 2014 capital tracker approved amounts. The capital tracker revenue for 2015 of approximately $50 million incorporates an update for related 2015 capital tracker expenditures as compared to the approved forecast reflected in current rates. This resulted in a deferral of $12 million of 2015 capital tracker revenue as a regulatory liability.

In March 2015 the AUC issued its decision on the GCOC Proceeding in Alberta. The GCOC Proceeding set FortisAlberta's allowed ROE for 2013 through 2015 at 8.30%, down from the interim allowed ROE of 8.75%, and set the common equity component of capital structure at 40%, down from 41%. The AUC also determined that it would not re-establish a formula-based approach to setting the allowed ROE at this time. Instead, the allowed ROE of 8.30% and common equity component of capital structure of 40% will remain in effect on an interim basis for 2016 and beyond. For regulated utilities in Alberta under PBR mechanisms, including FortisAlberta, the impact of the changes to the allowed ROE and common equity component of capital structure resulting from the GCOC Proceeding applies to the portion of rate base that is funded by capital tracker revenue only. For assets not being funded by capital tracker revenue, no revenue adjustment is required for the change in the allowed ROE and common equity component of capital structure, from that set in an earlier GCOC decision.

Eastern Canadian Electric Utilities

Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") under the *Public Utilities Act* (Newfoundland and Labrador). Newfoundland Power operates under COS regulation with the use of a future test year in the establishment of rates. The PUB has set the allowed ROE at 8.80% and the common equity component of capital structure at 45% for 2013 through 2015.

Maritime Electric is regulated by the Island Regulatory and Appeals Commission ("IRAC") under the provisions of the *Electric Power Act* (PEI), the *Renewable Energy Act* (PEI), the *Electric Power (Electricity Rate-Reduction) Amendment Act* (PEI), and the *Electric Power (Energy Accord Continuation) Amendment Act* (PEI) ("Accord Continuation Act"), which covers the period March 1, 2013 to February 29, 2016. Maritime Electric operates under COS regulation with the use of a future test year for the establishment of rates. IRAC set the allowed ROE at 9.75% on a targeted minimum capital structure of 40% common equity for 2014 and 2015.

In Ontario, Canadian Niagara Power, Algoma Power and Cornwall Electric operate under the *Electricity Act* (Ontario) and the *Ontario Energy Board Act* (Ontario), as administered by the Ontario Energy Board ("OEB"). Canadian Niagara Power and Algoma Power operate under COS regulation and earnings are regulated on the basis of rate of return on rate base, plus a recovery of allowable distribution costs. In non-rebasing years, customer electricity distribution rates are set using inflationary factors less an efficiency target under the Fourth-Generation Incentive Regulation Mechanism as prescribed by the OEB. Algoma Power is also subject to the use and implementation of the Rural and Remote Rate Protection ("RRRP") Program. The RRRP Program is calculated as the deficiency between the approved revenue requirement from the OEB and current customer electricity distribution rates, adjusted for the average rate increase across the province of Ontario. Canadian Niagara Power and Algoma Power use a future test year in the establishment of rates. Canadian Niagara Power's allowed ROE for distribution assets was set at 8.93% for 2014 and 2015 and the allowed ROE for transmission assets was set at 8.93% for 2014 and 9.30% for 2015, both on a deemed capital structure of 40% common equity. Algoma Power's allowed ROE was set at 9.85% for 2014 and 9.30% for 2015 on a deemed capital structure of 40% common equity. Cornwall Electric is subject to a rate-setting mechanism under a 35-year Franchise Agreement with the City of Cornwall expiring in 2033 and, therefore, is exempt from many aspects of the above Acts. The rate-setting mechanism is based on a price cap with commodity cost flow through. The base revenue requirement is adjusted annually for inflation, load growth and customer growth.

Regulated Electric Utilities – Caribbean

Caribbean Utilities operates under T&D and generation licences from the Government of the Cayman Islands. The exclusive T&D licence is for an initial period of 20 years, expiring April 2028, with a provision for automatic renewal. In November 2014 a new non-exclusive generation licence was issued for a term of 25 years, expiring in November 2039. The licences detail the role of the Electricity Regulatory Authority, which oversees all licences, establishes and enforces licence standards, reviews the rate-cap adjustment mechanism ("RCAM"), and annually approves capital expenditures. The licences contain the provision for an RCAM based on published consumer price indices. Caribbean Utilities' targeted allowed ROA for 2015 was in the range of 7.25% to 9.25%, compared to a range of 7.00% to 9.00% for 2014.

Fortis Turks and Caicos operates under two 50-year licences expiring in 2036 and 2037. Among other matters, the licences describe how electricity rates are set by the Government of the Turks and Caicos Islands, using a historical test year, in order to provide the utilities with an allowed ROA of between 15.0% and 17.5% (the "Allowable Operating Profit"). The Allowable Operating Profit is based on a calculated rate base including interest on the amounts by which actual operating profits fall short of the Allowable Operating Profits on a cumulative basis (the "Cumulative Shortfall"). Annual submissions are made to the Government of the Turks and Caicos Islands calculating the amount of the Allowable Operating Profit and the Cumulative Shortfall. The submissions for 2015 calculated the Allowable Operating Profit to be $51 million (US$40 million) and the Cumulative Shortfall as at December 31, 2015 to be $274 million (US$198 million). The recovery of the Cumulative Shortfall is, however, dependent on future sales volumes and expenses. The achieved ROAs at the utilities have been significantly lower than those allowed under the licences as a result of the inability, due to economic and political factors, to increase base electricity rates associated with significant capital investment in recent years.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States ("US GAAP"), which for regulated utilities include specific accounting guidance for regulated operations, as outlined in Note 2, and the following summary of significant accounting policies.

All amounts presented are in Canadian dollars unless otherwise stated.

Basis of Presentation

The consolidated financial statements reflect the Corporation's investments in its subsidiaries on a consolidated basis, with the equity method used for entities in which Fortis has significant influence, but not control, and proportionate consolidation for generation and transmission assets that are jointly owned with non-affiliated entities. All material intercompany transactions have been eliminated in the consolidated financial statements.

An evaluation of subsequent events through to February 17, 2016, the date these consolidated financial statements were approved by the Board of Directors of Fortis ("Board of Directors"), was completed to determine whether the circumstances warranted recognition and disclosure of events or transactions in the consolidated financial statements as at December 31, 2015 (Note 35).

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term deposits with initial maturities of three months or less from the date of deposit.

Allowance for Doubtful Accounts

The allowance for doubtful accounts reflects management's best estimate of uncollectible accounts receivable balances. Fortis and each of its subsidiaries maintain an allowance for doubtful accounts that is estimated based on a variety of factors including accounts receivable aging, historical experience and other currently available information, including events such as customer bankruptcy and economic conditions. Interest is charged on accounts receivable balances that have been outstanding for more than 21 to 30 days. Accounts receivable are written-off in the period in which the receivable is deemed uncollectible.

Inventories

Inventories, consisting of materials and supplies, gas, fuel and coal in storage, are measured at the lower of weighted average cost and market value, unless evidence indicates that the weighted average cost, even in excess of market, will be recovered in future customer rates.

Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate-setting process at the Corporation's regulated utilities. Regulatory assets represent future revenues and/or receivables associated with certain costs incurred that will be, or are expected to be, recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that will be, or are expected to be, refunded to customers through the rate-setting process.

All amounts deferred as regulatory assets and liabilities are subject to regulatory approval. As such, the regulatory authorities could alter the amounts subject to deferral, at which time the change would be reflected in the consolidated financial statements. Certain remaining recovery and settlement periods are those expected by management and the actual recovery or settlement periods could differ based on regulatory approval.

Investments

Portfolio investments are accounted for on the cost basis. Declines in value considered to be other than temporary are recorded in the period in which such determinations are made. Investments in which the Corporation exercises significant influence are accounted for on the equity basis. The Corporation reviews its investments on an annual basis for potential impairment in investment value. Should an impairment be identified, it will be recognized in the period in which such impairment is identified.

Available-for-Sale Assets

The Corporation's assets designated as available-for-sale are measured at fair value based on quoted market prices. Unrealized gains or losses resulting from changes in fair value are recognized in accumulated other comprehensive income and are reclassified to earnings when the assets are sold.

Utility Capital Assets

Utility capital assets are recorded at cost less accumulated depreciation. Contributions in aid of construction represent amounts contributed by customers and governments for the cost of utility capital assets. These contributions are recorded as a reduction in the cost of utility capital assets and are being amortized annually by an amount equal to the charge for depreciation provided on the related assets.

Each of UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, Newfoundland Power and Maritime Electric accrue estimated non-asset retirement obligations ("AROs") removal costs in depreciation, as required by their respective regulator, with the amount provided for in depreciation recorded as a long-term regulatory liability (Note 8 *(xiv)*). Actual non-ARO removal costs are recorded against the regulatory liability when incurred. As permitted by the regulator, FortisBC Electric records actual non-ARO removal costs, net of salvage proceeds, against accumulated depreciation as incurred. FortisOntario, Fortis Turks and Caicos and Waneta Expansion recognize non-ARO removal costs, net of salvage proceeds, in earnings in the period incurred. Caribbean Utilities recognizes non-ARO removal costs in utility capital assets.

Utility capital assets are derecognized on disposal or when no future economic benefits are expected from their use. Upon retirement or disposal of utility capital assets, any difference between the cost and accumulated depreciation of the asset, net of salvage proceeds, is charged to accumulated depreciation by UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Fortis Turks and Caicos, as required by their respective regulator, with no gain or loss, if any, recognized in earnings. It is expected that any gains or losses charged to accumulated depreciation will be reflected in future depreciation expense when they are refunded or collected in customer electricity and gas rates. At FortisOntario, as required by its regulator, and the Waneta Partnership, any remaining net book value, net of salvage proceeds, upon retirement or disposal of utility capital assets is recognized immediately in earnings.

As required by their respective regulator, UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Fortis Turks and Caicos, capitalize overhead costs that are not directly attributable to specific utility capital assets but relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized general overhead costs to utility capital assets is established by the respective regulator.

As required by their respective regulator, UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and Caribbean Utilities include in the cost of utility capital assets both a debt and an equity component of the allowance for funds used during construction ("AFUDC"). The debt component of AFUDC is reported as a reduction of finance charges (Note 25) and the equity component of AFUDC is reported as other income (Note 24). Both components of AFUDC are charged to earnings through depreciation expense over the estimated service lives of the applicable utility capital assets. AFUDC is calculated in a manner as prescribed by the respective regulator.

At FortisAlberta, the cost of utility capital assets also includes Alberta Electric System Operator ("AESO") contributions, which are investments required by FortisAlberta to partially fund the construction of transmission facilities.

As approved by the regulator, FortisBC Energy has reduced the amounts reported for utility capital assets by the amount of government loans received in connection with the construction and operation of the Vancouver Island natural gas pipeline. As the loans are repaid and replaced with non-government loans, FortisBC Energy increases both utility capital assets and long-term debt (Note 15).

Utility capital assets include inventories held for the development, construction and betterment of other utility capital assets, with the exception of UNS Energy. As required by its regulator, UNS Energy recognizes inventories held for the development and construction of other utility capital assets in inventories until consumed. When put into service, the inventories are reclassified to utility capital assets (Note 7).

Maintenance and repairs of utility capital assets are charged to earnings in the period incurred, while replacements and betterments which extend the useful lives are capitalized.

Utility capital assets are depreciated using the straight-line method based on the estimated service lives of the utility capital assets. Depreciation rates for regulated utility capital assets are approved by the respective regulator. Depreciation rates for 2015 ranged from 1.3% to 43.2% (2014 – 1.3% to 43.2%). The weighted average composite rate of depreciation, before reduction for amortization of contributions in aid of construction, for 2015 was 3.1% (2014 – 3.2%).

For the years ended December 31, 2015 and 2014

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Utility Capital Assets (cont'd)

The service life ranges and weighted average remaining service life of the Corporation's distribution, transmission, generation and other assets as at December 31 were as follows:

	2015		2014	
(Years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Distribution				
Electric	**5–80**	**30**	5–80	28
Gas	**4–95**	**33**	4–85	31
Transmission				
Electric	**20–80**	**29**	20–70	27
Gas	**7–80**	**36**	4–71	38
Generation	**5–85**	**27**	4–75	24
Other	**3–70**	**8**	3–70	8

Non-Utility Capital Assets

In 2015 the Corporation sold its commercial real estate and hotel assets, which included office buildings, shopping malls, hotels, land, construction in progress, and related equipment and tenant inducements (Note 28). Non-utility capital assets were recorded at cost less accumulated depreciation, where applicable, using the straight-line method of depreciation.

Maintenance and repairs were charged to earnings in the period incurred, while replacements and betterments which extended the useful lives were capitalized.

Leases

Leases that transfer to the Corporation substantially all of the risks and benefits incidental to ownership of the leased item are capitalized at the present value of the minimum lease payments. Included as capital leases are any arrangements that qualify as leases by conveying the right to use a specific asset.

Capital leases are depreciated over the lease term, except where ownership of the asset is transferred at the end of the lease term, in which case capital leases are depreciated over the estimated service life of the underlying asset. Where the regulator has approved recovery of the arrangements as operating leases for rate-setting purposes that would otherwise qualify as capital leases for financial reporting purposes, the timing of the expense recognition related to the lease is modified to conform with the rate-setting process.

Operating lease payments are recognized as an expense in earnings on a straight-line basis over the lease term.

Intangible Assets

Intangible assets are recorded at cost less accumulated amortization. Intangible assets are comprised of computer software costs; land, transmission and water rights; and franchise fees. The cost of intangible assets at the Corporation's regulated subsidiaries includes amounts for AFUDC and allocated overhead, where permitted by the respective regulators. Costs incurred to renew or extend the term of an intangible asset are capitalized and amortized over the new term of the intangible asset.

The useful lives of intangible assets are assessed to be either indefinite or finite. Intangible assets with indefinite useful lives are tested for impairment annually, either individually or at the reporting unit level, if they are held in a regulated utility. Such intangible assets are not amortized. Indefinite-lived intangible assets, not subject to amortization, consist of certain land, transmission and water rights at UNS Energy, FortisBC Energy, FortisBC Electric and the Waneta Partnership. An intangible asset with an indefinite useful life is reviewed annually to determine whether the indefinite life assessment continues to be supportable. If not, the change in the useful life assessment from indefinite to finite is made on a prospective basis.

In testing indefinite-lived intangible assets for impairment, the Corporation has the option, on an annual basis, of performing a qualitative assessment before calculating fair value. If the qualitative factors indicate that fair value is 50% or more likely to be greater than the carrying value, calculation of fair value would not be required.

Impairment testing for indefinite-lived intangible assets is carried out at the reporting unit level at the regulated utilities. A fair rate of return on the indefinite-lived intangible assets is provided through customer electricity and gas rates, as approved by the respective regulatory authority. The net cash flows for regulated enterprises are not asset-specific but are pooled for the entire regulated utility.

Fortis performs the annual impairment test as at October 1. In addition, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of the indefinite-lived intangible assets is below its carrying value. No such event or change in circumstances occurred during 2015 or 2014 and there were no impairment provisions required in either year. For its annual testing of impairment for indefinite-lived intangible assets, Fortis uses the approach for the annual testing for goodwill impairment as disclosed in this Note under "Goodwill".

Intangible assets with finite lives are amortized using the straight-line method based on the estimated service lives of the assets and are assessed for impairment whenever there is an indication that the intangible asset may be impaired. Amortization rates for regulated intangible assets are approved by the respective regulator.

Amortization rates for 2015 ranged from 1.0% to 50.0% (2014 – 1.0% to 50.0%). The service life ranges and weighted average remaining service life of finite-life intangible assets as at December 31 were as follows:

	2015		2014	
(Years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	**3–10**	**4**	3–10	4
Land, transmission and water rights	**30–80**	**37**	30–75	32
Franchise fees and other	**10–104**	**15**	10–100	19

Intangible assets are derecognized on disposal or when no future economic benefits are expected from their use. Upon retirement or disposal of intangible assets, any difference between the cost and accumulated amortization of the asset, net of salvage proceeds, is charged to accumulated amortization by UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Fortis Turks and Caicos, as required by their respective regulator, with no gain or loss, if any, recognized in earnings. It is expected that any gains or losses charged to accumulated amortization will be reflected in future amortization costs when they are refunded or collected in customer electricity and gas rates. At FortisOntario, as required by its regulator, and the Waneta Partnership, any remaining net book value, net of salvage proceeds, upon retirement or disposal of intangible assets is recognized immediately in earnings.

Impairment of Long-Lived Assets

The Corporation reviews the valuation of utility capital assets, intangible assets with finite lives and other long-term assets when events or changes in circumstances indicate that the assets' carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. An impairment loss, calculated as the difference between the assets' carrying value and their fair value, which is determined using present value techniques, is recognized in earnings in the period in which it is identified. There was no material impact on the consolidated financial statements as a result of regulated long-lived asset or non-regulated generation asset impairments for the years ended December 31, 2015 and 2014. Certain of the Corporation's non-utility hotel assets, all of which were sold in 2015, were subject to an impairment charge as a result of the carrying amount of the assets exceeding their fair value (Note 28).

Asset-impairment testing at the regulated utilities is carried out at the enterprise level to determine if assets are impaired. The recovery of regulated assets' carrying value, including a fair rate of return, is provided through customer electricity and gas rates approved by the respective regulatory authority. The net cash flows for regulated enterprises are not asset-specific but are pooled for the entire regulated utility.

The process for asset-impairment testing differs for non-regulated generation assets compared to regulated utility assets. Since each non-regulated generating facility provides an individual cash flow stream, such an asset is tested individually and impairment is recorded if the future net cash flows are no longer sufficient to recover the carrying value of the generating facility.

For the years ended December 31, 2015 and 2014

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Goodwill

Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net tangible and identifiable intangible assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost less any write-down for impairment.

Fortis performs an annual internal quantitative assessment for each reporting unit. For those reporting units where: (i) management's assessment of quantitative and qualitative factors indicates that fair value is not 50% or more likely to be greater than carrying value; or (ii) where the excess of estimated fair value over carrying value, as determined by an external consultant as of the date of the immediately preceding impairment test, was not significant, then fair value of the reporting unit will be estimated by an external consultant in the current year. Irrespective of the above-noted approach, a reporting unit to which goodwill has been allocated may have its fair value estimated by an external consultant as at the annual impairment date, as Fortis will, at a minimum, have fair value for each material reporting unit estimated by an external consultant once every five years.

Fortis performs the annual impairment test as at October 1. In addition, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit is below its carrying value. No such event or change in circumstances occurred during 2015 or 2014 and no impairment provisions were required in either year.

In calculating goodwill impairment, Fortis determines those reporting units that will have fair value estimated by an external consultant, as described above, and such estimated fair value is then compared to the book value of the applicable reporting units. If the fair value of the reporting unit is less than the book value, a second measurement step is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill, and then comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of the goodwill over the implied fair value is the impairment amount recognized.

The primary method for estimating fair value of the reporting units is the income approach, whereby net cash flow projections for the reporting units are discounted using an enterprise value approach. Under the enterprise value approach, sustainable cash flow is determined on an after-tax basis, prior to the deduction of interest expense, and is then discounted at the weighted average cost of capital to yield the value of the enterprise. An enterprise value approach does not assess the appropriateness of the reporting unit's existing debt level. The estimated fair value of the reporting unit is then determined by subtracting the fair value of the reporting unit's interest-bearing debt from the enterprise value of the reporting unit. A secondary valuation method, the market approach, may also be performed by an external consultant as a check on the conclusions reached under the income approach. The market approach includes comparing various valuation multiples underlying the discounted cash flow analysis of the applicable reporting units to trading multiples of guideline entities and recent transactions involving guideline entities, recognizing differences in growth expectations, product mix and risks of those guideline entities with the applicable reporting units.

Employee Future Benefits

Defined Benefit and Defined Contribution Pension Plans

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, including retirement allowances and supplemental retirement plans for certain executive employees, and defined contribution pension plans, including group Registered Retirement Savings Plans and group 401(k) plans for employees. The projected benefit obligation and the value of pension cost associated with the defined benefit pension plans are actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan investment performance, salary escalation and expected retirement ages of employees. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments.

With the exception of FortisBC Energy and Newfoundland Power, pension plan assets are valued at fair value for the purpose of determining pension cost. At FortisBC Energy and Newfoundland Power, pension plan assets are valued using the market-related value for the purpose of determining pension cost, where investment returns in excess of, or below, expected returns are recognized in the asset value over a period of three years.

The excess of any cumulative net actuarial gain or loss over 10% of the greater of the projected benefit obligation and the fair value of plan assets (the market-related value of plan assets at FortisBC Energy and Newfoundland Power) at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

The net funded or unfunded status of defined benefit pension plans, measured as the difference between the fair value of the plan assets and the projected benefit obligation, is recognized on the Corporation's consolidated balance sheet.

With the exception of UNS Energy, FortisAlberta and Maritime Electric, any difference between pension cost recognized under US GAAP and that recovered from customers in current rates for defined benefit pension plans, which is expected to be recovered from, or refunded to, customers in future rates, is subject to deferral account treatment (Note 8 *(ii)*). As approved by the regulator, the cost of defined benefit pension plans at FortisAlberta is recovered in customer rates based on the cash payments made.

At UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and FortisOntario, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with defined benefit pension plans, which would otherwise be recognized in accumulated other comprehensive income, are subject to deferral account treatment (Note 8 *(ii)*). At Fortis, FHI and Caribbean Utilities, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with defined benefit pension plans are recognized in accumulated other comprehensive income.

The costs of the defined contribution pension plans are expensed as incurred.

Other Post-Employment Benefits Plans
UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, FortisOntario and the Corporation also offer other post-employment benefits ("OPEB") plans, including certain health and dental coverage and life insurance benefits, for qualifying members. The accumulated benefit obligation and the cost associated with OPEB plans are actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan performance, salary escalation, expected retirement ages of employees and health care costs. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected OPEB payments.

The excess of any cumulative net actuarial gain or loss over 10% of the accumulated benefit obligation and the fair value of plan assets at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

The net funded or unfunded status of OPEB plans, measured as the difference between the fair value of the plan assets and the accumulated benefit obligation, is recognized on the Corporation's consolidated balance sheet.

As approved by the regulator, the cost of OPEB plans at FortisAlberta is recovered in customer rates based on the cash payments made.

With the exception of UNS Energy and FortisAlberta, any difference between the cost of OPEB plans recognized under US GAAP and that recovered from customers in current rates, which is expected to be recovered from, or refunded to, customers in future rates, is subject to deferral account treatment (Note 8 *(ii)*).

At FortisAlberta, the difference between the cost of OPEB plans recognized under US GAAP and that recovered from customers in current rates does not meet the criteria for deferral account treatment and, therefore, FortisAlberta recognizes in earnings the cost associated with its OPEB plan as actuarially determined, rather than as approved by the regulator. Unamortized OPEB plan balances at FortisAlberta related to net actuarial gains and losses and past service costs are recognized as a component of other comprehensive income.

Stock-Based Compensation

The Corporation records compensation expense related to stock options granted under its 2002 Stock Option Plan ("2002 Plan"), 2006 Stock Option Plan ("2006 Plan") and 2012 Stock Option Plan ("2012 Plan") (Note 23). Compensation expense is measured at the date of grant using the Black-Scholes fair value option-pricing model and each grant is amortized as a single award evenly over the four-year vesting period of the options granted. The offsetting entry is an increase to additional paid-in capital for an amount equal to the annual compensation expense related to the issuance of stock options. The stock options become exercisable once time vesting requirements have been met. Upon exercise, the proceeds of the options are credited to capital stock at the option prices and the fair value of the options, as previously recognized, is reclassified from additional paid-in capital to capital stock. An exercise of options below the current market price of the Corporation's common shares has a dilutive effect on the Corporation's consolidated capital stock and shareholders' equity. Fortis satisfies stock option exercises by issuing common shares from treasury.

The Corporation also records liabilities associated with its Directors' Deferred Share Unit ("DSU"), Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") Plans, all representing cash settled awards, at fair value at each reporting date until settlement. Compensation expense is recognized on a straight-line basis over the vesting period, which, for the PSU and RSU Plans, is over the shorter of three years or the period to retirement eligibility. The fair value of the DSU, PSU and RSU liabilities is based on the five-day volume weighted average price ("VWAP") of the Corporation's common shares at the end of each reporting period. The VWAP of the Corporation's common shares as at December 31, 2015 was $37.72 (December 31, 2014 – $38.96). The fair value of the PSU liability is also based on the expected payout probability, based on historical performance in accordance with the defined metrics of each grant and management's best estimate.

For the years ended December 31, 2015 and 2014

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Foreign Currency Translation

The assets and liabilities of the Corporation's foreign operations, UNS Energy, Central Hudson, Caribbean Utilities, Fortis Turks and Caicos and BECOL, all of which have a US dollar functional currency, are translated at the exchange rate in effect as at the balance sheet date. The exchange rate in effect as at December 31, 2015 was US$1.00=CAD$1.38 (December 31, 2014 – US$1.00=CAD$1.16). The resulting unrealized translation gains and losses are excluded from the determination of earnings and are recognized in accumulated other comprehensive income until the foreign subsidiary is sold, substantially liquidated or evaluated for impairment in anticipation of disposal. Revenue and expenses of the Corporation's foreign operations are translated at the average exchange rate in effect during the reporting period, which was US$1.00=CAD$1.28 for 2015 (2014 – US$1.00=CAD$1.10).

The Corporation's approximate 33% equity investment in Belize Electricity is translated at the exchange rate in effect as at the balance sheet date. The resulting unrealized translation gains and losses are excluded from the determination of earnings and are recognized in accumulated other comprehensive income until the investment is sold, substantially liquidated or evaluated for impairment in anticipation of disposal (Notes 9 and 24).

Foreign exchange translation gains and losses on foreign currency-denominated long-term debt that is designated as an effective hedge of foreign net investments are accumulated as a separate component of shareholders' equity within accumulated other comprehensive income and the current period change is recorded in other comprehensive income.

Monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate prevailing at the balance sheet date. Revenue and expenses denominated in foreign currencies are translated at the exchange rate prevailing at the transaction date. Gains and losses on translation are recognized in earnings.

Derivative Instruments and Hedging Activities

The Corporation and its subsidiaries use various physical and financial derivative instruments to meet forecast load and reserve requirements, to reduce exposure to fluctuations in commodity prices and foreign exchange rates, and to hedge interest rate risk exposure. The Corporation does not hold or issue derivative instruments for trading purposes and generally limits the use of derivative instruments to those that qualify as accounting, economic or cash flow hedges. As at December 31, 2015, the Corporation's derivative instruments primarily consisted of electricity swap contracts, gas swap and option contracts, electricity power purchase contracts, gas purchase contract premiums, long-term wholesale trading contracts, and interest rate swaps (Note 31).

All derivative instruments that do not meet the normal purchase or normal sale scope exception are recognized as assets or liabilities on the consolidated balance sheet and are measured at fair value. Changes in fair value are recognized in earnings unless the instruments qualify, and are designated, as an accounting or economic hedge.

Derivative instruments that meet the normal purchase or normal sale scope exception are not measured at fair value and settled amounts are recognized as energy supply costs on the consolidated statements of earnings. Derivative contracts under master netting agreements and collateral positions are presented on a gross basis. The Corporation is required to bifurcate embedded derivatives from their host instruments and account for them as free-standing derivative instruments if they meet specified criteria.

For derivatives designated as hedging contracts, the Corporation's utilities formally assess, at inception and thereafter, whether the hedging contract is highly effective in offsetting changes in the hedged item. The hedging strategy by transaction type and risk management strategy is formally documented. As at December 31, 2015, the Corporation's hedging relationships primarily consisted of interest rate swaps and US dollar-denominated borrowings.

The Corporation's earnings from, and net investments in, foreign subsidiaries and significant influence investments are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has decreased a portion of the above-noted exposure through the use of US dollar-denominated borrowings at the corporate level. The Corporation has designated its corporately issued US dollar long-term debt as a hedge of a portion of the foreign exchange risk related to its foreign net investments. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar-denominated borrowings designated as hedges are recognized in other comprehensive income and help offset unrealized foreign currency exchange gains and losses on the foreign net investments, which gains and losses are also recognized in other comprehensive income.

For derivatives not designated as hedging contracts, the settled amount is generally included in regulated rates, as permitted by the respective regulators. Accordingly, the net unrealized gains and losses associated with changes in fair value of the derivative contracts are recorded as regulatory assets or liabilities for recovery from, or refund to, customers in future rates (Note 8 *(vii)*).

Income Taxes

The Corporation and its subsidiaries follow the asset and liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are more likely than not to be realized. Valuation allowances are recognized against deferred tax assets when it is more likely than not that a portion of, or the entire amount of, the deferred income tax asset will not be realized. Deferred income tax assets and liabilities are measured using enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. The effect of a change in income tax rates on deferred income tax assets and liabilities is recognized in earnings in the period that the change occurs. Current income tax expense or recovery is recognized for the estimated income taxes payable or receivable in the current year.

As approved by the respective regulator, UNS Energy, Central Hudson and Maritime Electric recover current and deferred income tax expense in customer rates. As approved by the regulator, FortisAlberta recovers income tax expense in customer rates based only on income taxes that are currently payable. FortisBC Energy, FortisBC Electric, Newfoundland Power and FortisOntario recover income tax expense in customer rates based only on income taxes that are currently payable, except for certain regulatory balances for which deferred income tax expense is recovered from, or refunded to, customers in current rates, as prescribed by the respective regulator. Therefore, with the exception of certain deferred tax balances of FortisBC Energy, FortisBC Electric, Newfoundland Power and FortisOntario, current customer rates do not include the recovery of deferred income taxes related to temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes, as these taxes are expected to be collected in customer rates when they become payable. These utilities recognize an offsetting regulatory asset or liability for the amount of deferred income taxes that are expected to be collected from or refunded to customers in rates once income taxes become payable or receivable (Note 8 *(i)*).

For regulatory reporting purposes, the capital cost allowance pool for certain utility capital assets at FortisAlberta is different from that for legal entity corporate income tax filing purposes. In a future reporting period, yet to be determined, the difference may result in higher income tax expense than that recognized for regulatory rate-setting purposes and collected in customer rates.

Caribbean Utilities and Fortis Turks and Caicos are not subject to income tax as they operate in tax-free jurisdictions. BECOL is not subject to income tax as it was granted tax-exempt status by the GOB for the terms of its 50-year PPAs.

Any difference between the income tax expense recognized under US GAAP and that recovered from customers in current rates that is expected to be recovered from customers in future rates, is subject to deferral account treatment (Note 8 *(i)*).

The Corporation intends to indefinitely reinvest earnings from certain foreign operations. Accordingly, the Corporation does not provide for deferred income taxes on temporary differences related to investments in foreign subsidiaries. The difference between the carrying values of these foreign investments and their tax bases, resulting from unrepatriated earnings and currency translation adjustments, is approximately $565 million as at December 31, 2015 (December 31, 2014 – $384 million). If such earnings are repatriated, in the form of dividends or otherwise, the Corporation may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is impractical. Canada has entered into Tax Information Exchange Agreements ("TIEAs") with Bermuda, the Cayman Islands and the Turks and Caicos Islands. Consequently, earnings from the Corporation's foreign subsidiaries operating in these regions, subsequent to 2010, can be repatriated to Canada on a tax-free basis and, therefore, are not included in the amount of temporary differences noted above, as no taxes are payable on these earnings. If a TIEA is entered into with Belize, earnings from the Corporation's operations in Belize would also be able to be repatriated to Canada on a tax-free basis. Negotiations between the Government of Canada and the GOB commenced in June 2010.

Tax benefits associated with income tax positions taken, or expected to be taken, in an income tax return are recognized only when the more likely than not recognition threshold is met. The tax benefits are measured at the largest amount of benefit that is greater than 50% likely to be realized upon settlement. The difference between a tax position taken, or expected to be taken, and the benefit recognized and measured pursuant to this guidance represents an unrecognized tax benefit.

Income tax interest and penalties are expensed as incurred and included in income tax expense. At FortisAlberta, investment tax credits are deducted from the related assets and are recognized as a reduction of income tax expense as the Company becomes taxable for rate-setting purposes.

For the years ended December 31, 2015 and 2014

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Sales Taxes

In the course of its operations, the Corporation's subsidiaries collect sales taxes from their customers. When customers are billed, a current liability is recognized for the sales taxes included on customers' bills. The liability is settled when the taxes are remitted to the appropriate government authority. The Corporation's revenue excludes sales taxes.

For regulatory reporting purposes, Central Hudson recognizes tax revenue collected on behalf of applicable government authorities on a gross basis. In 2015 approximately $19 million was included in both revenue and expenses (2014 – $22 million).

Revenue Recognition

Revenue from the sale of electricity and gas by the Corporation's regulated utilities is generally recognized on an accrual basis. Electricity and gas consumption is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Revenue at the regulated utilities is billed at rates approved by the applicable regulatory authority, and is generally bundled to include service associated with generation and T&D, except at FortisAlberta and FortisOntario. Meters are read periodically and bills are issued to customers based on these readings. At the end of each reporting period, a certain amount of consumed electricity and gas will not have been billed. Electricity and gas that is consumed but not yet billed to customers is estimated and accrued as revenue at each period end, as approved by the regulator. Effective July 1, 2015, Central Hudson is permitted by the regulator to accrue unbilled revenue for electricity consumed at each period end for all its electricity customers. As at December 31, 2014, approximately $15 million (US$13 million) in unbilled revenue at Central Hudson, associated with certain electricity customers, was not accrued, as permitted by the regulator.

In certain circumstances, UNS Energy enters into purchased power and wholesale sales contracts that are not settled with energy. The net sales contracts and power purchase contracts are reflected at the net amount in revenue.

As stipulated by the regulator, FortisAlberta is required to arrange and pay for transmission services with AESO and collect transmission revenue from its customers, which is achieved through invoicing the customers' retailers through FortisAlberta's transmission component of its regulator-approved rates. FortisAlberta is solely a distribution company and, as such, does not operate or provide any transmission or generation services. The Company is a conduit for the flow through of transmission costs to end-use customers, as the transmission provider does not have a direct relationship with these customers. As a result, FortisAlberta reports revenue and expenses related to transmission services on a net basis. The rates collected are based on forecast transmission expenses. FortisAlberta is not subject to any forecast risk with respect to transmission costs, as all differences between actual expenses related to transmission services and actual revenue collected from customers are deferred to be recovered from, or refunded to, customers in future rates (Note 8 *(xviii)*).

FortisBC Electric has entered into contracts to sell surplus capacity that may be available after it meets its load requirements. This revenue is recognized on an accrual basis at rates established in the sales contract.

All of the Corporation's non-regulated generation operations record revenue on an accrual basis and revenue is recognized on delivery of output at rates fixed under contract or based on observed market prices as stipulated in contractual arrangements.

Non-utility revenue, associated with commercial real estate and hotel assets that were sold in 2015, was recognized when services were provided or products were delivered to customers. Specifically, real estate revenue, derived from leasing retail and office space, was recognized in the month earned at rates in accordance with lease agreements. The leases were primarily of a net nature, with tenants paying basic rent plus a pro rata share of certain defined overhead expenses. Certain retail tenants paid additional rent based on a percentage of the tenants' sales. Expenses recovered from tenants were recorded as revenue on an accrual basis. Base rent and the escalation of lease rates included in long-term leases were recognized in earnings using the straight-line method over the term of the lease.

Asset Retirement Obligations

AROs, including conditional AROs, are recorded as a liability at fair value and are classified as long-term other liabilities, with a corresponding increase to utility capital assets (Note 17). The Corporation recognizes AROs in the periods in which they are incurred if a reasonable estimate of fair value can be determined. The fair value of AROs is based on an estimate of the present value of expected future cash outlays reflecting a range of possible outcomes, discounted at a credit-adjusted risk-free interest rate. AROs are adjusted at the end of each reporting period to reflect the passage of time and any changes in the estimated future cash flows underlying the obligation. Actual costs incurred upon the settlement of AROs are recorded as a reduction in the liabilities. As permitted by the respective regulator, at UNS Energy, Central Hudson and FortisBC Electric, changes in the obligations due to the passage of time are recognized as a regulatory asset using the effective interest method.

The Corporation has AROs associated with hydroelectric generation facilities, interconnection facilities and wholesale energy supply agreements. While each of the foregoing will have legal AROs, including land and environmental remediation and/or removal of assets, the final date and cost of remediation and/or removal of the related assets cannot be reasonably determined at this time. These assets are reasonably expected to operate in perpetuity due to the nature of their operation. The licences, permits, interconnection facilities agreements and wholesale energy supply agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the assets and ensure the continued provision of service to customers. In the event that environmental issues are identified, assets are decommissioned or the applicable licences, permits or agreements are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

The Corporation also has AROs associated with the removal of certain electricity distribution system assets from rights-of-way at the end of the life of the system. As it is expected that the system will be in service indefinitely, an estimate of the fair value of asset removal costs cannot be reasonably determined at this time.

The Corporation has determined that AROs may exist regarding the remediation of certain land. Certain leased land contains assets integral to operations and it is reasonably expected that the land-lease agreement will be renewed indefinitely; therefore, an estimate of the fair value of remediation costs cannot be reasonably determined at this time. Certain other land may require environmental remediation but the amount and nature of the remediation is indeterminable at this time. AROs associated with land remediation will be recorded when the timing, nature and amount of costs can be reasonably estimated.

New Accounting Policies

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity
Effective January 1, 2015, the Corporation prospectively adopted Accounting Standards Update ("ASU") No. 2014-08 that changes the criteria and disclosures for reporting discontinued operations. As a result, the sale of commercial real estate and hotel assets and the sale of non-regulated generation assets in 2015 did not meet the criteria for discontinued operations (Note 28). The sales are consistent with the Corporation's focus on its core utility business and, therefore, do not represent a strategic shift in operations.

Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved After the Requisite Service Period
Effective January 1, 2015, the Corporation early adopted ASU No. 2014-12 that resolves diversity in practice for employee share-based payments with performance targets that can entitle an employee to benefit from an award regardless of if they are rendering services at the date the performance target is achieved. The adoption of this update was applied prospectively and did not have a material impact on the Corporation's consolidated financial statements.

Simplifying the Presentation of Debt Issuance Costs
Effective October 1, 2015, the Corporation early adopted ASU No. 2015-03 that requires debt issuance costs to be presented on the consolidated balance sheet as a direct deduction from the carrying amount of debt liability, consistent with debt discounts or premiums. The adoption of this update was applied retrospectively and resulted in the reclassification of debt issuance costs of approximately $65 million from long-term other assets to long-term debt on the Corporation's consolidated balance sheet as at December 31, 2014 (Note 36). Additionally, the Corporation early adopted ASU No. 2015-15 that clarifies the presentation and subsequent measurement of debt issuance costs associated with line-of-credit arrangements. The update permits an entity to defer and present debt issuance costs as an asset and subsequently amortize the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. The adoption of this update was applied retrospectively and did not have a material impact on the Corporation's consolidated financial statements.

Balance Sheet Classification of Deferred Taxes
Effective October 1, 2015, the Corporation early adopted ASU No. 2015-17 that requires deferred tax assets and liabilities to be classified and presented as long term on the consolidated balance sheet. The adoption of this update was applied retrospectively and resulted in the reclassification of current deferred income taxes assets of $158 million, long-term deferred income tax assets of $62 million, and current deferred income tax liabilities of $9 million to long-term deferred income tax liabilities on the consolidated balance sheet as at December 31, 2014. As a result, the Corporation also reclassified current regulatory assets of $18 million, current regulatory liabilities of $19 million, and long-term regulatory liabilities of $91 million to long-term regulatory assets on the consolidated balance sheet as at December 31, 2014, all associated with regulatory deferred income taxes (Note 36).

For the years ended December 31, 2015 and 2014

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Use of Accounting Estimates

The preparation of the consolidated financial statements in accordance with US GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances.

Additionally, certain estimates and judgments are necessary since the regulatory environments in which the Corporation's utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances, and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are recognized in earnings in the period in which they become known. In the event that a regulatory decision is received after the balance sheet date but before the consolidated financial statements are issued, the facts and circumstances are reviewed to determine whether or not it is a recognized subsequent event.

The Corporation's critical accounting estimates are described above in Note 3 under the headings Regulatory Assets and Liabilities, Utility Capital Assets, Intangible Assets, Goodwill, Employee Future Benefits, Stock-Based Compensation, Income Taxes, Revenue Recognition and Asset Retirement Obligations, and in Notes 8, 23 and 34.

4. FUTURE ACCOUNTING PRONOUNCEMENTS

The Corporation considers the applicability and impact of all ASUs issued by the Financial Accounting Standards Board ("FASB"). The following updates have been issued by FASB, but have not yet been adopted by Fortis. Any ASUs not included below were assessed and determined to be either not applicable to the Corporation or are not expected to have a material impact on the consolidated financial statements.

Revenue from Contracts with Customers

ASU No. 2014-09 was issued in May 2014 and the amendments in this update create ASC Topic 606, *Revenue from Contracts with Customers*, and supersede the revenue recognition requirements in ASC Topic 605, *Revenue Recognition*, including most industry-specific revenue recognition guidance throughout the codification. This standard completes a joint effort by FASB and the International Accounting Standards Board to improve financial reporting by creating common revenue recognition guidance for US GAAP and International Financial Reporting Standards that clarifies the principles for recognizing revenue and that can be applied consistently across various transactions, industries and capital markets. This standard was originally effective for annual and interim periods beginning after December 15, 2016 and is to be applied on a full retrospective or modified retrospective basis. ASU No. 2015-14 was issued in August 2015 and the amendments in this update defer the effective date of ASU No. 2014-09 by one year to annual and interim periods beginning after December 15, 2017. Early adoption is permitted as of the original effective date. The majority of the Corporation's revenue is generated from energy sales to customers based on published tariff rates, as approved by the respective regulators, and is expected to be in the scope of ASU No. 2014-09. Fortis has not yet selected a transition method and is assessing the impact that the adoption of this standard will have on its consolidated financial statements and related disclosures. The Corporation plans to have this assessment substantially complete by the end of 2016.

Amendments to the Consolidation Analysis

ASU No. 2015-02 was issued in February 2015 and the amendments in this update change the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. Specifically, the amendments note the following with regard to limited partnerships: (i) modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities; and (ii) eliminate the presumption that a general partner should consolidate a limited partnership. This update is effective for annual and interim periods beginning after December 15, 2015 and may be applied using a modified retrospective approach or retrospectively. The adoption of this update is not expected to materially impact the Corporation's consolidated financial statements, however, it is expected to change the Corporation's 51% controlling ownership interest in Waneta Partnership from a voting interest entity to a variable interest entity, resulting in additional note disclosure.

5. SEGMENTED INFORMATION

Information by reportable segment is as follows:

	REGULATED									NON-REGULATED				
	United States			Canada										
	Electric & Gas			Gas	Electric									
Year Ended December 31, 2015 *($ in millions)*	UNS Energy	Central Hudson	**Total**	FortisBC Energy	Fortis Alberta	FortisBC Electric	Eastern Canadian	**Total**	**Caribbean Electric**	**Fortis Generation**	**Non-Utility**	**Corporate and Other**	**Inter-segment eliminations**	**Total**
Revenue	2,034	880	**2,914**	1,295	563	360	1,033	**3,251**	**321**	**107**	**171**	**24**	**(61)**	**6,727**
Energy supply costs	820	315	**1,135**	498	–	116	673	**1,287**	**169**	**1**	**–**	**–**	**(31)**	**2,561**
Operating expenses	573	381	**954**	292	183	89	143	**707**	**46**	**19**	**124**	**26**	**(12)**	**1,864**
Depreciation and amortization	242	56	**298**	190	168	57	82	**497**	**47**	**18**	**11**	**2**	**–**	**873**
Operating income (loss)	399	128	**527**	315	212	98	135	**760**	**59**	**69**	**36**	**(4)**	**(18)**	**1,429**
Other income (expenses), net	5	8	**13**	11	3	–	2	**16**	**2**	**56**	**109**	**(8)**	**(1)**	**187**
Finance charges	98	38	**136**	134	78	39	56	**307**	**14**	**3**	**18**	**94**	**(19)**	**553**
Income tax expense (recovery)	111	40	**151**	51	(1)	9	19	**78**	**–**	**24**	**13**	**(43)**	**–**	**223**
Net earnings (loss)	195	58	**253**	141	138	50	62	**391**	**47**	**98**	**114**	**(63)**	**–**	**840**
Non-controlling interests	–	–	**–**	1	–	–	–	**1**	**13**	**21**	**–**	**–**	**–**	**35**
Preference share dividends	–	–	**–**	–	–	–	–	**–**	**–**	**–**	**–**	**77**	**–**	**77**
Net earnings (loss) attributable to common equity shareholders	195	58	**253**	140	138	50	62	**390**	**34**	**77**	**114**	**(140)**	**–**	**728**
Goodwill	1,912	624	**2,536**	913	227	235	67	**1,442**	**195**	**–**	**–**	**–**	**–**	**4,173**
Identifiable assets	6,977	2,601	**9,578**	5,116	3,592	1,872	2,219	**12,799**	**1,084**	**1,025**	**–**	**352**	**(207)**	**24,631**
Total assets	8,889	3,225	**12,114**	6,029	3,819	2,107	2,286	**14,241**	**1,279**	**1,025**	**–**	**352**	**(207)**	**28,804**
Gross capital expenditures	669	181	**850**	460	452	103	175	**1,190**	**137**	**38**	**9**	**19**	**–**	**2,243**
Year Ended December 31, 2014 *($ in millions)*														
Revenue	684	821	1,505	1,435	518	334	1,008	3,295	321	38	249	31	(38)	5,401
Energy supply costs	272	345	617	646	–	87	653	1,386	195	1	–	–	(2)	2,197
Operating expenses	209	337	546	287	176	90	143	696	39	10	172	38	(8)	1,493
Depreciation and amortization	80	49	129	190	164	59	79	492	38	5	22	2	–	688
Operating income (loss)	123	90	213	312	178	98	133	721	49	22	55	(9)	(28)	1,023
Other income (expenses), net	4	6	10	4	3	1	2	10	2	(1)	–	(45)	(1)	(25)
Finance charges	34	35	69	139	79	41	56	315	14	–	24	154	(29)	547
Income tax expense (recovery)	33	24	57	49	(1)	12	19	79	–	1	8	(79)	–	66
Net earnings (loss) from continuing operations	60	37	97	128	103	46	60	337	37	20	23	(129)	–	385
Earnings from discontinued operations, net of tax	–	–	–	–	–	–	–	–	–	–	5	–	–	5
Net earnings (loss)	60	37	97	128	103	46	60	337	37	20	28	(129)	–	390
Non-controlling interests	–	–	–	1	–	–	–	1	10	–	–	–	–	11
Preference share dividends	–	–	–	–	–	–	–	–	–	–	–	62	–	62
Net earnings (loss) attributable to common equity shareholders	60	37	97	127	103	46	60	336	27	20	28	(191)	–	317
Goodwill	1,603	523	2,126	913	227	235	67	1,442	164	–	–	–	–	3,732
Identifiable assets	5,648	2,123	7,771	4,846	3,234	1,803	2,163	12,046	924	961	696	543	(440)	22,501
Total assets	7,251	2,646	9,897	5,759	3,461	2,038	2,230	13,488	1,088	961	696	543	(440)	26,233
Gross capital expenditures	444	126	570	332	348	92	166	938	71	102	38	6	–	1,725

For the years ended December 31, 2015 and 2014

5. SEGMENTED INFORMATION (cont'd)

Related-party transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The significant related party inter-segment transactions during the years ended December 31 were as follows.

Significant Related Party Inter-Segment Transactions

(in millions)	**2015**	2014
Sales from Fortis Generation to		
Regulated Electric Utilities – Canadian	**$ 31**	$ 2
Revenue from Regulated Electric Utilities – Canadian		
to Fortis Generation	**7**	–
Sales from Regulated Electric Utilities – Canadian to Non-Utility	**4**	6
Inter-segment finance charges on lending from:		
Fortis Generation to Eastern Canadian Electric Utilities	**1**	1
Corporate to Regulated Electric Utilities – Caribbean	**–**	5
Corporate to Non-Utility	**17**	22

The significant related party inter-segment asset balances as at December 31 were as follows.

Significant Related Party Inter-Segment Assets

(in millions)	**2015**	2014
Inter-segment borrowings from:		
Fortis Generation to Eastern Canadian Electric Utilities	**$ 20**	$ 20
Corporate to Regulated Electric Utilities – Canadian	**48**	–
Corporate to Non-Utility	**–**	402
Other inter-segment assets – Corporate to Regulated		
Electric & Gas Utilities – United States	**108**	–
Other inter-segment assets	**31**	18
Total inter-segment eliminations	**$ 207**	$ 440

6. ACCOUNTS RECEIVABLE AND OTHER CURRENT ASSETS

(in millions)	**2015**	2014
Trade accounts receivable	**$ 517**	$ 479
Unbilled accounts receivable	**404**	365
Allowance for doubtful accounts	**(66)**	(31)
Income tax receivable	**–**	25
Assets held for sale	**38**	–
Other	**71**	62
	$ 964	$ 900

The increase in the allowance for doubtful accounts was primarily due to an increase in the reserve for uncollectible accounts at UNS Energy in relation to billings to third-party owners of Springerville Unit 1 for their pro-rata share of costs to operate the facility. Due to ongoing litigation and uncertainty with Springerville Unit 1 third-party owners, the accounts receivable balance of $32 million (US$23 million) as at December 31, 2015 associated with operating expenses has been fully reserved (Note 34).

Assets held for sale include utility capital assets of approximately $29 million (US$21 million) purchased by UNS Energy upon expiration of the Springerville Coal Handling Facilities lease in April 2015 (Note 16). UNS Energy has an agreement with a third party whereby they can purchase a 17.05% interest or continue to make payments to UNS Energy for the use of the facility. The third party has until April 2016 to exercise its purchase option and, as a result, the assets have been classified as held for sale on the consolidated balance sheet as at December 31, 2015.

Additionally, in December 2015 FortisBC Electric entered into an agreement to sell the non-regulated Walden hydroelectric power plant assets for a sale price of approximately $9 million (Note 31). The sale is expected to close in the first quarter of 2016. For the year ended December 31, 2015, earnings before taxes of less than $1 million were recognized (December 31, 2014 – less than $1 million) associated with Walden.

Other accounts receivable consisted of customer billings for non-core services, collateral deposits for gas purchases at FortisBC Energy and advances on coal purchases at UNS Energy. Other accounts receivable also included the fair value of derivative instruments (Note 31).

7. INVENTORIES

(in millions)	**2015**	2014
Materials and supplies	**$ 194**	$ 149
Gas and fuel in storage	**101**	134
Coal inventory	**42**	38
	$ 337	$ 321

Materials and supplies included approximately $152 million (December 31, 2014 – $118 million) at UNS Energy, and consisted of construction and repair materials for distribution, transmission and generation assets, as required by the regulator (Note 3).

8. REGULATORY ASSETS AND LIABILITIES

Based on previous, existing or expected regulatory orders or decisions, the Corporation's regulated utilities have recorded the following amounts that are expected to be recovered from, or refunded to, customers in future periods.

(in millions)	**2015**	2014	**Remaining recovery period** *(Years)*
Regulatory assets			
Deferred income taxes *(i)*	**$ 936**	$ 832	To be determined
Employee future benefits *(ii)*	**627**	680	Various
Deferred energy management costs *(iii)*	**145**	111	1–10
Manufactured gas plant ("MGP") site remediation deferral *(iv)*	**121**	123	To be determined
Rate stabilization accounts *(v)*	**119**	119	Various
Deferred lease costs *(vi)*	**90**	101	Various
Derivative instruments *(vii)*	**74**	69	Various
Deferred operating overhead costs *(viii)*	**66**	54	Various
Final mine reclamation and retiree health care costs *(ix)*	**39**	34	1–22
Deferred net losses on disposal of utility capital assets and intangible assets *(x)*	**33**	37	8
Springerville Unit 1 unamortized leasehold improvements *(xi)*	**30**	–	8
Property tax deferrals *(xii)*	**30**	29	1
Other regulatory assets *(xiii)*	**222**	226	Various
Total regulatory assets	**2,532**	2,415	
Less: current portion	**(246)**	(277)	1
Long-term regulatory assets	**$ 2,286**	$ 2,138	

For the years ended December 31, 2015 and 2014

8. REGULATORY ASSETS AND LIABILITIES (cont'd)

(in millions)	**2015**	2014	**Remaining recovery period** *(Years)*
Regulatory liabilities			
Non-ARO removal cost provision *(xiv)*	**$ 1,060**	$ 951	To be determined
Rate stabilization accounts *(v)*	**212**	142	Various
Electric and gas moderator account *(xv)*	**88**	–	To be determined
Renewable energy surcharge *(xvi)*	**47**	44	To be determined
Employee future benefits *(ii)*	**44**	58	Various
Customer and community benefits obligation *(xvii)*	**32**	55	To be determined
AESO charges deferral *(xviii)*	**25**	49	1–4
Other regulatory liabilities *(xix)*	**130**	146	Various
Total regulatory liabilities	**1,638**	1,445	
Less: current portion	**(298)**	(173)	1
Long-term regulatory liabilities	**$ 1,340**	$ 1,272	

Description of the Nature of Regulatory Assets and Liabilities

(i) Deferred Income Taxes

The Corporation's regulated utilities recognize deferred income tax assets and liabilities and related regulatory liabilities and assets for the amount of deferred income taxes expected to be refunded to, or recovered from, customers in future electricity and gas rates. Included in deferred income tax assets and liabilities are the future income tax effects of the subsequent settlement of the related regulatory liabilities and assets through customer rates. The deferred income taxes on regulatory assets and liabilities are the result of the application of ASC Topic 740, *Income Taxes*. The regulatory asset balances are expected to be recovered from customers in future rates when the income taxes become payable or receivable. As at December 31, 2015, $351 million (December 31, 2014 – $265 million) in regulatory assets for deferred income taxes was not subject to a regulatory return.

(ii) Employee Future Benefits

The regulatory asset and liability associated with employee future benefits includes the actuarially determined unamortized net actuarial losses, past service costs and credits, and transitional obligations associated with defined benefit pension and OPEB plans maintained by the Corporation's regulated utilities, which are expected to be recovered from, or refunded to, customers in future rates (Note 27). At the Corporation's regulated utilities, as approved by the respective regulators, differences between defined benefit pension and OPEB plan costs recognized under US GAAP and those which are expected to be recovered from, or refunded to, customers in future rates are subject to deferral account treatment and have been recognized as a regulatory asset or liability. These amounts would otherwise be recognized in accumulated other comprehensive income on the consolidated balance sheet.

As at December 31, 2015, regulatory assets of approximately $367 million associated with employee future benefits were not subject to a regulatory return (December 31, 2014 – $339 million). As at December 31, 2015, regulatory liabilities of approximately $36 million associated with employee future benefits were not subject to a regulatory return (December 31, 2014 – $55 million).

(iii) Deferred Energy Management Costs

FortisBC Energy, FortisBC Electric, Central Hudson and Newfoundland Power provide energy management services to promote energy efficiency programs to their customers. As required by their respective regulator, these regulated utilities have capitalized related expenditures and are amortizing these expenditures on a straight-line basis over periods ranging from 1 to 10 years. This regulatory asset represents the unamortized balance of the energy management costs.

UNS Energy is required to implement cost-effective Demand-Side Management ("DSM") programs to comply with the ACC's energy efficiency standards. The energy efficiency standards provide for a DSM surcharge to recover the costs of implementing DSM programs, as well as an annual performance incentive. The existing rate orders provide for a lost fixed cost recovery mechanism to recover certain non-fuel costs that were previously unrecoverable, due to reduced electricity sales as a result of energy efficiency programs and distributed generation. As at December 31, 2015, $25 million of UNS Energy's regulatory asset balance was not subject to a regulatory return (December 31, 2014 – $16 million).

(iv) MGP Site Remediation Deferral

As approved by the regulator, Central Hudson is permitted to defer for future recovery from its customers the difference between actual costs for MGP site investigation and remediation and the associated rate allowances (Notes 14, 17 and 34). Central Hudson's MGP site remediation costs are not subject to a regulatory return.

(v) Rate Stabilization Accounts

Rate stabilization accounts associated with the Corporation's regulated electric and gas utilities are recovered from, or refunded to, customers in future rates, as approved by the respective regulatory authority. Electric rate stabilization accounts primarily mitigate the effect on earnings of variability in the cost of fuel and/or purchased power above or below a forecast or predetermined level and, at certain utilities, revenue decoupling mechanisms that minimize the earnings impact resulting from reduced energy consumption as energy efficiency programs are implemented. Gas rate stabilization accounts primarily mitigate the effect on earnings of unpredictable and uncontrollable factors, namely volume volatility caused principally by weather, and natural gas cost volatility.

As at December 31, 2015, approximately $49 million and $142 million of the rate stabilization accounts are expected to be recovered from, or refunded to, customers within one year and, as a result, are classified as current regulatory assets and liabilities, respectively (December 31, 2014 – approximately $105 million and $43 million, respectively).

As at December 31, 2015, regulatory assets of approximately $44 million associated with rate stabilization accounts were not subject to a regulatory return (December 31, 2014 – $104 million). As at December 31, 2015, regulatory liabilities of approximately $76 million associated with rate stabilization accounts were not subject to a regulatory return (December 31, 2014 – $42 million).

(vi) Deferred Lease Costs

Deferred lease costs at FortisBC Electric primarily relate to the Brilliant Power Purchase Agreement ("BPPA"), which ends in 2056. The depreciation of the asset under capital lease and interest expense associated with the capital lease obligation are not being fully recovered by FortisBC Electric in current customer rates, since those rates include only the cash payments set out under the BPPA. The regulatory asset balance as at December 31, 2015 included $90 million (December 31, 2014 – $83 million) of deferred lease costs that are expected to be recovered from customers in future rates over the term of the lease. In 2015, of the $30 million (2014 – $30 million) of interest expense related to the capital lease obligations and the $6 million (2014 – $6 million) of depreciation expense related to the assets under capital lease, a total of $26 million (2014 – $26 million) was recognized in energy supply costs and $3 million (2014 – $3 million) was recognized in operating expenses, respectively, as approved by the regulator, with the balance of $7 million (2014 – $7 million) deferred as a regulatory asset (Note 16).

The regulatory asset balance as at December 31, 2014 included $18 million of deferred lease costs at UNS Energy related to the remaining purchase commitments of Springerville Unit 1 and the Springerville Coal Handling Facility, of which both purchases occurred in 2015 (Note 16).

Deferred lease costs are not subject to a regulatory return.

(vii) Derivative Instruments

As approved by the respective regulatory authority, unrealized gains or losses associated with changes in the fair value of certain derivative instruments at UNS Energy, Central Hudson and FortisBC Energy are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates. These unrealized losses and gains would otherwise be recognized in earnings (Note 31). UNS Energy and Central Hudson's deferred regulatory asset balance totalling $57 million as at December 31, 2015 was not subject to a regulatory return (December 31, 2014 – $57 million).

(viii) Deferred Operating Overhead Costs

As approved by the regulator, FortisAlberta has deferred certain operating overhead costs. The deferred costs are expected to be collected in future customer rates over the lives of the related utility capital assets and intangible assets.

(ix) Final Mine Reclamation and Retiree Health Care Costs

Final mine reclamation and retiree health care costs are associated with TEP's jointly owned coal generating facilities at the San Juan, Four Corners and Navajo generating stations. TEP has the option to recognize its liability associated with final mine reclamation and retiree health care obligations at present or future value (Notes 17 and 34). TEP has elected to recognize these costs at future value and is permitted to fully recover these costs from customers through its rate stabilization accounts when the costs are paid. TEP expects to make continuous payments through 2037. These deferred costs are not subject to a regulatory return.

For the years ended December 31, 2015 and 2014

8. REGULATORY ASSETS AND LIABILITIES (cont'd)

Description of the Nature of Regulatory Assets and Liabilities (cont'd)

(x) Deferred Net Losses on Disposal of Utility Capital Assets and Intangible Assets

As approved by the regulator, from 2010 through 2013 net losses on the retirement or disposal of utility capital assets and intangible assets at FortisBC Energy were recorded in a regulatory deferral account to be recovered from customers in future rates. The regulator approved the recovery in customer rates of the resulting regulatory asset over a period of 10 years.

(xi) Springerville Unit 1 Unamortized Leasehold Improvements

Upon expiration of TEP's Springerville Unit 1 capital lease in January 2015, unamortized leasehold improvements were reclassified from utility capital assets to regulatory assets. The leasehold improvements represent investments made by TEP through the end of the lease term to ensure Springerville facilities continued providing safe, reliable service to TEP's customers. In its 2013 rate order, TEP received regulatory approval to amortize the leasehold improvements over a 10-year period. TEP continues to own an undivided 49.5% joint interest in Springerville Unit 1.

(xii) Property Tax Deferrals

Property taxes at UNS Energy and Central Hudson are deferred and are primarily collected from customers over a six-month to one-year period, as approved by the respective regulator. Property tax deferrals are not subject to a regulatory return.

(xiii) Other Regulatory Assets

Other regulatory assets relate to all of the Corporation's regulated utilities and are comprised of various items, each individually less than $30 million. As at December 31, 2015, $189 million (December 31, 2014 – $177 million) of the balance was approved to be recovered from customers in future rates, with the remaining balance expected to be approved. As at December 31, 2015, $69 million (December 31, 2014 – $74 million) of the balance was not subject to a regulatory return.

(xiv) Non-ARO Removal Cost Provision

As required by the respective regulator, depreciation rates at UNS Energy, Central Hudson, FortisBC Energy, FortisAlberta, Newfoundland Power and Maritime Electric include an amount allowed for regulatory purposes to accrue for non-ARO removal costs. Actual non-ARO removal costs are recorded against the regulatory liability when incurred. This regulatory liability represents amounts collected in customer electricity rates at the respective utilities in excess of incurred non-ARO removal costs.

(xv) Electric and Gas Moderator Account

Under the terms of Central Hudson's three-year Rate Order issued in June 2015, certain of the Company's regulatory assets and liabilities were identified and approved by the PSC for offset and a net regulatory liability electric and gas moderator account was established, which will be used for future customer rate moderation. These electric and gas moderator accounts are not subject to a regulatory return.

(xvi) Renewable Energy Surcharge

As ordered by the regulator under its Renewable Energy Standard ("RES"), UNS Energy is required to increase its use of renewable energy each year until it represents at least 15% of its total annual retail energy requirements in 2025, with distributed generation accounting for 30% of the annual renewable energy requirement. The Company must file an annual RES implementation plan for review and approval by the ACC. The approved cost of carrying out the plan is recovered from retail customers through the RES surcharge. The ACC has also approved recovery of operating costs, depreciation, property taxes and return on investments on certain company-owned solar projects through the RES tariff until such costs are reflected in retail customer rates. Any RES surcharge collections above or below the costs incurred to implement the plans are deferred as a regulatory asset or liability.

The ACC measures compliance with its RES requirements through Renewable Energy Credits ("REC"), which represent one kilowatt hour generated from renewable resources. When UNS Energy purchases renewable energy, the premium paid above the market cost of conventional power equals the REC recoverable through the RES surcharge. When RECs are purchased, UNS Energy records the cost of the RECs as long-term other assets and a corresponding regulatory liability, to reflect the obligation to use the RECs for future RES compliance. When RECs are reported to the ACC for compliance with RES requirements, energy supply costs and revenue are recognized in an equal amount (Note 9).

(xvii) Customer and Community Benefits Obligation

As approved by the respective regulator for UNS Energy and Central Hudson, Fortis committed to provide their customers and community with financial benefits that would have not been realized in the absence of the acquisitions. These commitments resulted in the recognition of regulatory liabilities to be used to mitigate future customer rate increase at the utilities. In 2014 these commitments for UNS Energy's customers included US$10 million in year one and US$5 million in years two through five to cover credits in retail customer rates. As a result, expenses of approximately $33 million (US$30 million) were recognized in 2014 related to the acquisition of UNS Energy for customer benefit obligations (Notes 24 and 29).

(xviii) AESO Charges Deferral

FortisAlberta maintains an AESO charges deferral account that represents expenses incurred in excess of revenue collected for various items, such as transmission costs incurred and flowed through to customers, that are subject to deferral to be collected in future customer rates. To the extent that the amount of revenue collected in rates for these items exceeds actual costs incurred, the excess is deferred as a regulatory liability to be refunded in future customer rates. As at December 31, 2015, the regulatory liability primarily represented the over collection of the AESO charges deferral accounts for 2014 and 2015.

(xix) Other Regulatory Liabilities

Other regulatory liabilities relate to all of the Corporation's regulated utilities and are comprised of various items, each individually less than $30 million. As at December 31, 2015, $120 million (December 31, 2014 – $140 million) of the balance was approved for refund to customers or reduction in future rates, with the remaining balance expected to be approved. As at December 31, 2015, $68 million (December 31, 2014 – $76 million) of the balance was not subject to a regulatory return.

9. OTHER ASSETS

(in millions)	2015	2014
Equity investment – Belize Electricity	**$ 79**	$ –
Supplemental Executive Retirement Plan assets	**58**	41
Deposit on pending business acquisition *(Note 29)*	**38**	–
Available-for-sale investment *(Notes 28 and 31)*	**33**	–
Deferred compensation plan assets *(Note 17)*	**25**	21
Renewable Energy Credits *(Note 8 (xvi))*	**17**	13
Long-term income tax receivable	**13**	13
Other investments	**13**	12
Other asset – Belize Electricity	**–**	116
Other	**76**	56
	$ 352	$ 272

In August 2015 the Corporation agreed to terms of a settlement with the GOB regarding the GOB's expropriation of the Corporation's approximate 70% interest in Belize Electricity in June 2011. The terms of the settlement included a one-time US$35 million cash payment to Fortis from the GOB and an approximate 33% equity investment in Belize Electricity. As a result of the settlement, the Corporation recognized an approximate $9 million loss in 2015 (Note 24).

UNS Energy and Central Hudson provide additional post-employment benefits through both a deferred compensation plan for Directors and Officers of the Companies, as well as Supplemental Executive Retirement Plans ("SERP"). Since both plans are considered non-qualified plans under the *Employee Retirement Income Security Act of 1974*, the assets are reported separately from the related liabilities (Note 17). The assets of the plans are held in trust and funded mostly through the use of trust-owned life insurance policies and mutual funds. A portion of the SERP assets is invested in corporate-owned life insurance policies. Amounts held in mutual and money market funds are recorded at fair value (Note 31).

In June 2015 the Corporation completed the sale of commercial real estate assets for gross proceeds of $430 million (Note 28). As part of the transaction, Fortis subscribed to $35 million in trust units of Slate Office REIT in conjunction with the REIT's public offering. The investment in trust units is recorded as an available-for-sale asset. The assets are measured at fair value based on quoted market prices and unrealized gains or losses resulting from changes in fair value are recognized in accumulated other comprehensive income and are reclassified to earnings when the assets are sold (Notes 21 and 31).

Other assets are recorded at cost and are recovered or amortized over the estimated period of future benefit, where applicable. Other assets include the fair value of derivative instruments at UNS Energy and Central Hudson (Note 31).

For the years ended December 31, 2015 and 2014

10. UTILITY CAPITAL ASSETS

2015

(in millions)	Cost	Accumulated Depreciation	Net Book Value
Distribution			
Electric	**$ 9,245**	**$ (2,634)**	**$ 6,611**
Gas	**3,829**	**(1,021)**	**2,808**
Transmission			
Electric	**3,093**	**(997)**	**2,096**
Gas	**1,735**	**(531)**	**1,204**
Generation	**6,465**	**(2,241)**	**4,224**
Other	**2,429**	**(849)**	**1,580**
Assets under construction	**886**	**–**	**886**
Land	**186**	**–**	**186**
	$ 27,868	**$ (8,273)**	**$ 19,595**

2014

(in millions)	Cost	Accumulated Depreciation	Net Book Value
Distribution			
Electric	$ 8,102	$ (2,317)	$ 5,785
Gas	3,475	(920)	2,555
Transmission			
Electric	2,562	(859)	1,703
Gas	1,649	(491)	1,158
Generation	5,296	(2,189)	3,107
Other	2,158	(731)	1,427
Assets under construction	1,277	–	1,277
Land	167	–	167
	$ 24,686	$ (7,507)	$ 17,179

Electric distribution assets are those used to distribute electricity at lower voltages (generally below 69 kV). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment. Gas distribution assets are those used to transport natural gas at low pressures (generally below 2,070 kPa) or a hoop stress of less than 20% of standard minimum yield strength. These assets include distribution stations, telemetry, distribution pipe for mains and services, meter sets and other related equipment.

Electric transmission assets are those used to transmit electricity at higher voltages (generally at 69 kV and higher). These assets include poles, wires, switching equipment, transformers, support structures and other related equipment. Gas transmission assets are those used to transport natural gas at higher pressures (generally at 2,070 kPa and higher) or a hoop stress of 20% or more of standard minimum yield strength. These assets include transmission stations, telemetry, transmission pipe and other related equipment.

Generation assets are those used to generate electricity. These assets include hydroelectric and thermal generation stations, gas and combustion turbines, coal-fired generating stations, dams, reservoirs, photovoltaic systems and other related equipment.

Other assets include buildings, equipment, vehicles, inventory and information technology assets.

Construction of the Waneta Expansion was completed in April 2015. As at December 31, 2015, assets under construction are primarily associated with FortisBC Energy's Tilbury liquefied natural gas facility expansion and other capital projects at the Corporation's regulated utilities.

The cost of utility capital assets under capital lease as at December 31, 2015 was $496 million (December 31, 2014 – $1,088 million) and related accumulated depreciation was $221 million (December 31, 2014 – $627 million). The decrease was primarily due to the purchase of certain utility capital assets at TEP in 2015 following the expiry of lease arrangements (Note 16).

Jointly Owned Facilities

As at December 31, 2015, UNS Energy's interests in jointly owned generating stations and transmission systems primarily consisted of the following:

2015

(in millions)	Ownership *(%)*	Cost	Accumulated Depreciation	Net Book Value
San Juan Units 1 and 2	50.0	**$ 690**	**$ (347)**	**$ 343**
Navajo Units 1, 2 and 3	7.5	**207**	**(155)**	**52**
Four Corners Units 4 and 5	7.0	**154**	**(107)**	**47**
Luna Energy Facility	33.3	**75**	**(1)**	**74**
Gila River Common Facilities	25.0	**47**	**(14)**	**33**
Springerville Unit 1 [1]	49.5	**452**	**(240)**	**212**
Springerville Coal Handling Facilities [2]	65.9	**228**	**(90)**	**138**
Transmission Facilities	Various	**531**	**(238)**	**293**
		$ 2,384	**$ (1,192)**	**$ 1,192**

[1] TEP is obligated to operate the unit for third-party owners under existing agreements. The third-party owners are obligated to compensate TEP for their pro rata share of expenses (Notes 16 and 34).
[2] TEP owns an additional 17.05% undivided interest in the Springerville Coal Handling Facilities, which is classified as assets held for sale (Notes 6 and 16).

UNS Energy holds an undivided interest in the above facilities and is entitled to its pro rata share of the utility capital assets. UNS Energy is proportionately liable for its share of operating costs and liabilities in respect of the jointly owned facilities.

11. NON-UTILITY CAPITAL ASSETS

In 2015 the Corporation sold its commercial real estate and hotel assets (Note 28). As a result, the Corporation did not hold any non-utility capital assets as at December 31, 2015.

2014

(in millions)	Cost	Accumulated Depreciation	Net Book Value
Buildings	$ 599	$ (105)	$ 494
Equipment	145	(73)	72
Tenant inducements	35	(27)	8
Land	72	–	72
Assets under construction	18	–	18
	$ 869	$ (205)	$ 664

12. INTANGIBLE ASSETS

2015

(in millions)	Cost	Accumulated Amortization	Net Book Value
Computer software	**$ 685**	**$ (436)**	**$ 249**
Land, transmission and water rights	**328**	**(76)**	**252**
Franchise fees and other	**17**	**(13)**	**4**
Assets under construction	**36**	**–**	**36**
	$ 1,066	**$ (525)**	**$ 541**

For the years ended December 31, 2015 and 2014

12. INTANGIBLE ASSETS (cont'd)

2014

(in millions)	Cost	Accumulated Amortization	Net Book Value
Computer software	$ 573	$ (368)	$ 205
Land, transmission and water rights	258	(66)	192
Franchise fees and other	16	(12)	4
Assets under construction	60	–	60
	$ 907	$ (446)	$ 461

Included in the cost of land, transmission and water rights as at December 31, 2015 was $106 million (December 31, 2014 – $77 million) not subject to amortization.

Amortization expense related to intangible assets was $64 million for 2015 (2014 – $60 million). Amortization is estimated to average approximately $78 million annually for each of the next five years.

13. GOODWILL

(in millions)	**2015**	2014
Balance, beginning of year	**$ 3,732**	$ 2,075
Acquisition of UNS Energy *(Note 29)*	**–**	1,510
Sale of Griffith *(Note 28)*	**–**	(3)
Foreign currency translation impacts	**441**	150
Balance, end of year	**$ 4,173**	$ 3,732

Goodwill associated with the acquisitions of UNS Energy, Central Hudson, Caribbean Utilities and Fortis Turks and Caicos is denominated in US dollars, as the functional currency of these companies is the US dollar. Foreign currency translation impacts are the result of the translation of US dollar-denominated goodwill and the impact of the movement of the Canadian dollar relative to the US dollar.

14. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

(in millions)	**2015**	2014
Trade accounts payable	**$ 574**	$ 612
Gas and fuel cost payable	**153**	195
Employee compensation and benefits payable	**137**	134
Interest payable	**127**	128
Dividends payable	**113**	101
Accrued taxes other than income taxes	**108**	96
Fair value of derivative instruments *(Note 31)*	**69**	66
MGP site remediation *(Notes 8 (iv), 17 and 34)*	**32**	13
Defined benefit pension and OPEB plan liabilities *(Note 27)*	**13**	11
Other	**93**	84
	$ 1,419	$ 1,440

Accrued taxes other than income taxes primarily consisted of property taxes at UNS Energy and carbon tax at FortisBC Energy.

15. LONG-TERM DEBT

(in millions)	Maturity Date	**2015**	2014
Regulated Utilities			
UNS Energy			
Unsecured US Tax-Exempt Bonds –			
3.83% weighted average fixed and variable rate (2014 – 3.92%)	2020 – 2040	**$ 848**	$ 956
Unsecured US Fixed Rate Notes –			
4.26% weighted average fixed rate (2014 – 4.98%)	2021 – 2045	**1,557**	754
Secured US Fixed Rate Notes –			
5.38% weighted average fixed and variable rate (2014 – 5.38%)	2023 – 2026	**–**	151
Central Hudson			
Unsecured US Promissory Notes –			
4.30% weighted average fixed and variable rate (2014 – 4.31%)	2016 – 2042	**728**	587
FortisBC Energy			
Secured Purchase Money Mortgages –			
10.30% weighted average fixed rate (2014 – 10.71%)	2016	**200**	275
Unsecured Debentures –			
5.73% weighted average fixed rate (2014 – 5.95%)	2029 – 2045	**1,770**	1,620
Government loan	2016	**5**	10
FortisAlberta			
Unsecured Debentures –			
4.95% weighted average fixed rate (2014 – 5.01%)	2024 – 2052	**1,684**	1,534
FortisBC Electric			
Secured Debentures –			
8.80% weighted average fixed rate (2014 – 8.80%)	2023	**25**	25
Unsecured Debentures –			
5.36% weighted average fixed rate (2014 – 5.36%)	2016 – 2050	**660**	660
Eastern Canadian			
Secured First Mortgage Sinking Fund Bonds –			
6.72% weighted average fixed rate (2014 – 7.08%)	2016 – 2045	**553**	484
Secured First Mortgage Bonds –			
7.18% weighted average fixed rate (2014 – 7.18%)	2016 – 2061	**167**	167
Unsecured Senior Notes –			
6.11% weighted average fixed rate (2014 – 6.11%)	2018 – 2041	**104**	104
Caribbean Electric			
Unsecured US Senior Loan Notes –			
4.89% weighted average fixed rate (2014 – 4.91%)	2016 – 2046	**467**	400
Non-Regulated – Non-Utility			
Secured First Mortgages and Senior Notes –			
7.46% weighted average fixed rate (2014 – 7.46%)	n/a	**–**	34
Corporate			
Unsecured US Senior Notes and Promissory Notes –			
4.43% weighted average fixed rate (2014 – 4.43%)	2019 – 2044	**1,720**	1,443
Unsecured Debentures –			
6.49% weighted average fixed rate (2014 – 6.49%)	2039	**201**	201
Long-term classification of credit facility borrowings *(Note 31)*		**551**	1,096
Total long-term debt *(Note 31)*		**11,240**	10,501
Less: Deferred financing costs *(Notes 3 and 36)*		**(72)**	(65)
Less: Current installments of long-term debt		**(384)**	(525)
		$ 10,784	$ 9,911

For the years ended December 31, 2015 and 2014

15. LONG-TERM DEBT (cont'd)

As noted in the previous table, certain long-term debt instruments issued by UNS Energy, FortisBC Energy, FortisBC Electric, Newfoundland Power, and Maritime Electric are secured. When security is provided, it is typically a fixed or floating first charge on the specific assets of the Company to which the long-term debt is associated. The purchase money mortgages of FortisBC Energy are secured equally and ratably by a first fixed and specific mortgage and charge on the Company's coastal division assets. The aggregate principal amount of the purchase money mortgages that may be issued is limited to $350 million.

UNS Energy entered into a four-year US$30 million variable rate term loan credit agreement and, at the same time, entered into a fixed-for-floating interest rate swap. Both the term loan and interest rate swap expired in 2015. The interest rate swap was designated as a cash flow hedge (Note 31).

Covenants

Certain of the Corporation's long-term debt obligations have covenants restricting the issuance of additional debt such that consolidated debt cannot exceed 70% of the Corporation's consolidated capital structure, as defined by the long-term debt agreements. In addition, one of the Corporation's long-term debt obligations contains a covenant which provides that Fortis shall not declare or pay any dividends, other than stock dividends or cumulative preferred dividends on preference shares not issued as stock dividends, or make any other distribution on its shares or redeem any of its shares or prepay subordinated debt if, immediately thereafter, its consolidated funded obligations would be in excess of 75% of its total consolidated capitalization.

As at December 31, 2015, the Corporation and its subsidiaries were in compliance with their debt covenants.

Regulated Utilities

The majority of the long-term debt instruments at the Corporation's regulated utilities are redeemable at the option of the respective utilities, at any time, at the greater of par or a specified price as defined in the respective long-term debt agreements, together with accrued and unpaid interest.

In January 2015 TEP redeemed at par US$130 million of fixed rate tax-exempt bonds that had an original maturity date of 2029. As at December 31, 2015, TEP had not remarketed the repurchase bonds.

In January 2015 Fortis Turks and Caicos issued 15-year US$10 million 4.75% unsecured notes. The net proceeds were used to finance capital expenditures and for general corporate purposes.

In February 2015 TEP issued 10-year US$300 million 3.05% senior unsecured notes. Net proceeds were used to repay long-term debt and credit facility borrowings and to finance capital expenditures.

In March 2015 Central Hudson issued 10-year US$20 million 2.98% unsecured notes. The net proceeds were used to finance capital expenditures and for general corporate purposes.

In April 2015 UNS Electric issued 30-year US$50 million 3.95% unsecured notes. The net proceeds were primarily used for general corporate purposes.

In April 2015 FortisBC Energy issued 30-year $150 million 3.38% unsecured debentures. The net proceeds were used to repay short-term borrowings and for general corporate purposes.

In August 2015 UNS Electric issued 12-year US$80 million 3.22% unsecured debentures and UNS Gas issued 30-year US$45 million 4.00% unsecured notes. The net proceeds were used to repay maturing long-term debt. Additionally, in August 2015 TEP redeemed at par US$79 million of variable rate tax-exempt bonds that had an original maturity date of 2022.

In September 2015 FortisAlberta issued 30-year $150 million 4.27% unsecured debentures. The net proceeds were used to repay credit facility borrowings and for general corporate purposes.

In September 2015 Newfoundland Power issued 30-year $75 million 4.446% secured first mortgage sinking fund bonds. The net proceeds were used to repay credit facility borrowings and for general corporate purposes.

Corporate

The unsecured debentures and US senior notes are redeemable at the option of Fortis at a price calculated as the greater of par or a specified price as defined in the respective long-term debt agreements, together with accrued and unpaid interest.

Repayment of Long-Term Debt

The consolidated annual requirements to meet principal repayments and maturities in each of the next five years and thereafter are as follows:

Year	Subsidiaries *(in millions)*	Corporate *(in millions)*	Total *(in millions)*
2016	$ 382	$ 2	$ 384
2017	69	2	71
2018	281	2	283
2019	112	127	239
2020	202	655	857
Thereafter	7,793	1,613	9,406
	$ 8,839	$ 2,401	$ 11,240

16. CAPITAL LEASE AND FINANCE OBLIGATIONS

Capital Lease Obligations

UNS Energy

In 2014 and 2015, TEP purchased certain Springerville assets upon expiry of the lease arrangements, as detailed below. As at December 31, 2015, capital lease obligations at TEP consist of an undivided one-half interest in certain Springerville Common Facilities.

Springerville Unit 1 Capital Lease Purchases

In December 2014 and January 2015, upon expiration of the Springerville Unit 1 lease, TEP purchased an additional 35.4% ownership interest in the previously leased assets for US$20 million and US$46 million, respectively. As a result of the purchases, TEP owns 49.5% of Springerville Unit 1, or 192 MW of capacity. Furthermore, TEP is obligated to operate the unit for the third-party owners under an existing agreement. The third-party owners are obligated to compensate TEP for their pro rata share of expenditures (Note 34).

Springerville Coal Handling Facilities Lease Purchase

In April 2015, upon expiration of the Springerville Coal Handling Facilities lease, TEP purchased an 86.7% ownership interest in the previously leased coal handling assets for a total of US$120 million. In May 2015 TEP sold a 17.05% interest in the facilities to a third party for US$24 million and has an agreement with another third party to either purchase a 17.05% interest for US$24 million or to continue to make payments to TEP for the use of the facility. The third party has until April 2016 to exercise its purchase option and, as a result, the associated assets have been classified as held for sale on the consolidated balance sheet as at December 31, 2015 (Note 6).

Springerville Common Facilities Leases

TEP is party to three Springerville Common Facilities leases, which have an initial term to December 2017 for one lease and January 2021 for the other two leases, subject to optional renewal periods of two or more years through 2025 (Note 33). Instead of extending the leases, TEP may exercise a fixed-price purchase provision of US$38 million in 2017 and US$68 million in 2021. TEP has agreements with third parties that if the Springerville Common Facilities leases are not renewed, TEP will exercise the purchase options under these contracts. The third parties would be obligated to buy a portion of these facilities or continue to make payments to TEP for the use of these facilities.

UNS Energy entered into an interest rate swap that hedges a portion of the floating interest rate risk associated with the Springerville Common Facilities lease debt. As at December 31, 2015, interest on the lease debt is payable at a six-month LIBOR plus a spread of 1.88% (December 31, 2014 – 1.75%). The swap has the effect of fixing the interest rates on a portion of the amortizing principal balances of US$29 million (December 31, 2014 – US$33 million). The interest rate swap expires in 2020 and is recorded as a cash flow hedge (Note 31).

The Springerville Common Facilities capital lease obligation bears interest at a rate of 5.08%. For the year ended December 31, 2015, in total $5 million (December 31, 2014 – $2 million) of interest expense on the Springerville capital lease obligations was recognized in finance charges and $3 million (December 31, 2014 – $3 million) and $8 million (December 31, 2014 – $7 million) of depreciation expense on the Springerville leased assets was recognized in energy supply costs and depreciation, respectively.

For the years ended December 31, 2015 and 2014

16. CAPITAL LEASE AND FINANCE OBLIGATIONS (cont'd)

FortisBC Electric

FortisBC Electric has a capital lease obligation with respect to the operation of the Brilliant Plant located near Castlegar, British Columbia. FortisBC Electric operates and maintains the Brilliant Plant, under the BPPA which expires in 2056, in return for a management fee. In exchange for the specified take-or-pay amounts of power, the BPPA requires semi-annual payments based on a return on capital, comprised of the original plant capital charge and periodic upgrade capital charges, which are both subject to fixed annual escalators, as well as sustaining capital charges and operating expenses. The BPPA includes a market-related price adjustment in 2026. Due to the fixed annual escalators, the interest expense on the capital lease obligation presently exceeds the required payments. The capital lease obligation will continue to increase through to 2024, and subsequently decrease for the remainder of the term when the required payments exceed the interest expense on the capital lease obligation. Approximately 94% of the output from the Brilliant Plant is being purchased by FortisBC Electric through the BPPA.

The BPPA capital lease obligation bears interest at a composite rate of 5.00%. Included in energy supply costs for 2015 was $26 million (2014 – $26 million) recognized in accordance with the BPPA, as approved by the BCUC (Note 8 *(vi)*).

FortisBC Electric also has a capital lease obligation with respect to the operation of the Brilliant Terminal Station ("BTS"), under an agreement which expires in 2056. The agreement provides that FortisBC Electric will pay a charge related to the recovery of the capital cost of the BTS and related operating costs. The obligation bears interest at a composite rate of 9.00%. Included in operating expenses for 2015 was $3 million (2014 – $3 million) recognized in accordance with the BTS agreement, as approved by the BCUC (Note 8 *(vi)*).

Finance Obligations

Between 2000 and 2005 FEI entered into arrangements whereby certain natural gas distribution assets were leased to certain municipalities and then leased back by FEI from the municipalities. The natural gas distribution assets are considered to be integral equipment to real estate assets and, as such, the transactions have been accounted for as finance transactions. The proceeds from these transactions have been recognized as finance obligations on the consolidated balance sheet. Lease payments, net of the portion considered to be interest expense, reduce the finance obligations.

Obligations under the above-noted lease-in lease-out transactions at FEI have implicit interest at rates ranging from 6.82% to 8.66% and are being repaid over a 35-year period. Each of the lease-in lease-out arrangements allows FEI, at its option, to terminate the lease arrangements early, after 17 years. If the Company exercises this option, FEI would pay the municipality an early termination payment which is equal to the carrying value of the obligation at that point in time.

Repayment of Capital Lease and Finance Obligations

The present value of the minimum lease payments required for the capital lease and finance obligations over the next five years and thereafter are as follows:

Year	Capital Leases *(in millions)*	Finance Obligations *(in millions)*	Total *(in millions)*
2016	$ 68	$ 4	$ 72
2017	70	4	74
2018	61	32	93
2019	62	15	77
2020	73	2	75
Thereafter	2,049	38	2,087
	$ 2,383	$ 95	$ 2,478
Less: Amounts representing imputed interest and executory costs on capital lease and finance obligations			(1,965)
Total capital lease and finance obligations			513
Less: Current portion			(26)
			$ 487

17. OTHER LIABILITIES

(in millions)	**2015**	2014
OPEB plan liabilities *(Note 27)*	**$ 385**	$ 403
Defined benefit pension plan liabilities *(Note 27)*	**368**	390
MGP site remediation *(Notes 8 (iv), 14 and 34)*	**96**	109
Waneta Partnership promissory note *(Notes 31 and 33)*	**56**	53
Asset retirement obligations	**49**	37
Final mine reclamation and retiree health care liabilities *(Notes 8 (ix) and 34)*	**39**	34
Customer security deposits	**38**	26
Deferred compensation plan liabilities *(Note 9)*	**25**	21
DSU, PSU and RSU liabilities *(Note 23)*	**20**	17
Fair value of derivative instruments *(Note 31)*	**13**	13
Other	**63**	38
	$ 1,152	$ 1,141

The Waneta Partnership promissory note is non-interest bearing with a face value of $72 million. As at December 31, 2015, its discounted net present value was $56 million (December 31, 2014 – $53 million). The promissory note was incurred by the Waneta Partnership on the acquisition of certain intangible assets and project design costs, from a company affiliated with CPC/CBT, associated with the construction of the Waneta Expansion. The promissory note is payable on April 1, 2020, the fifth anniversary of the commercial operation date of the Waneta Expansion.

As at December 31, 2015, UNS Energy, Central Hudson and FortisBC Electric recognized asset retirement obligations.

Other liabilities primarily include long-term accrued liabilities, deferred lease revenue, funds received in advance of expenditures and unrecognized tax benefits.

18. COMMON SHARES

Common shares issued during the year were as follows:

	2015		2014	
	Number of Shares *(in thousands)*	**Amount *(in millions)***	Number of Shares *(in thousands)*	Amount *(in millions)*
Balance, beginning of year	**275,997**	**$ 5,667**	213,165	$ 3,783
Conversion of Convertible Debentures	**24**	**1**	58,545	1,747
Dividend Reinvestment Plan	**4,272**	**157**	2,495	82
Consumer Share Purchase Plan	**28**	**1**	33	1
Employee Share Purchase Plan	**356**	**13**	384	12
Stock Option Plans	**885**	**28**	1,375	42
Balance, end of year	**281,562**	**$ 5,867**	275,997	$ 5,667

Convertible Debentures

To finance a portion of the acquisition of UNS Energy, in January 2014, Fortis completed the sale of $1.8 billion aggregate principal amount of 4% convertible unsecured subordinated debentures, represented by Installment Receipts ("Convertible Debentures"). The Convertible Debentures were sold on an installment basis at a price of $1,000 per Convertible Debenture, of which $333 was paid on closing in January 2014 and the remaining $667 was paid on October 27, 2014 (the "Final Installment Date"). Prior to the Final Installment Date, the Convertible Debentures were represented by Installment Receipts, which were traded on the TSX under the symbol "FTS.IR". Since the Final Installment Date occurred prior to the first anniversary of the closing of the offering, holders of Convertible Debentures received, in addition to the payment of accrued and unpaid interest, a make-whole payment, representing interest that would have accrued from the day following the Final Installment Date to and including January 9, 2015. Approximately $72 million ($51 million after tax) in interest expense associated with the Convertible Debentures, including the make-whole payment, was recognized in 2014 (Note 25).

For the years ended December 31, 2015 and 2014

18. COMMON SHARES (cont'd)

Convertible Debentures (cont'd)

At the option of the holders, each Convertible Debenture was convertible into common shares of Fortis at any time after the Final Installment Date but prior to maturity or redemption by the Corporation at a conversion price of $30.72 per common share, being a conversion rate of 32.5521 common shares per $1,000 principal amount of Convertible Debentures. On October 28, 2014, approximately 58.2 million common shares of Fortis were issued, representing conversion into common shares of more than 99% of the Convertible Debentures. As at December 31, 2015, a total of approximately 58.6 million common shares of Fortis were issued on the conversion of Convertible Debentures, for proceeds of $1.748 billion, net of after-tax expenses. The net proceeds were used to finance a portion of the acquisition of UNS Energy (Note 29).

19. EARNINGS PER COMMON SHARE

The Corporation calculates earnings per common share ("EPS") on the weighted average number of common shares outstanding. The weighted average number of common shares outstanding was 278.6 million for 2015 and 225.6 million for 2014.

Diluted EPS was calculated using the treasury stock method for options and the "if-converted" method for convertible securities.

EPS were as follows:

	2015						
	Net Earnings to Common Shareholders *(in millions)*			**Weighted Average Number of Shares *(millions)***	**EPS**		
	Continuing Operations	**Discontinued Operations**	**Total**		**Continuing Operations**	**Discontinued Operations**	**Total**
Basic EPS	**$ 728**	**$ –**	**$ 728**	**278.6**	**$ 2.61**	**$ –**	**$ 2.61**
Effect of potential dilutive securities:							
Stock Options	**–**	**–**	**–**	**0.7**			
Preference Shares	**10**	**–**	**10**	**5.4**			
Diluted EPS	**$ 738**	**$ –**	**$ 738**	**284.7**	**$ 2.59**	**$ –**	**$ 2.59**

	2014						
	Net Earnings to Common Shareholders *(in millions)*			Weighted Average Number of Shares *(millions)*	EPS		
	Continuing Operations	Discontinued Operations	Total		Continuing Operations	Discontinued Operations	Total
Basic EPS	$ 312	$ 5	$ 317	225.6	$ 1.39	$ 0.02	$ 1.41
Effect of potential dilutive securities:							
Stock Options	–	–	–	0.5			
Preference Shares	10	–	10	6.9			
	322	5	327	233.0			
Deduct anti-dilutive impacts:							
Preference Shares	(10)	–	(10)	(6.9)			
Diluted EPS	$ 312	$ 5	$ 317	226.1	$ 1.38	$ 0.02	$ 1.40

20. PREFERENCE SHARES

Authorized

(a) an unlimited number of First Preference Shares, without nominal or par value
(b) an unlimited number of Second Preference Shares, without nominal or par value

Issued and Outstanding		**2015**		2014	
First Preference Shares	Annual Dividend Per Share	**Number of Shares**	**Amount *(in millions)***	Number of Shares	Amount *(in millions)*
Series E [1]	$ 1.2250	**7,993,500**	**$ 197**	7,993,500	$ 197
Series F [1]	$ 1.2250	**5,000,000**	**122**	5,000,000	122
Series G [2]	$ 0.9708	**9,200,000**	**225**	9,200,000	225
Series H [2] [3]	$ 0.6250	**7,024,846**	**172**	10,000,000	245
Series I [4]		**2,975,154**	**73**	–	–
Series J [1]	$ 1.1875	**8,000,000**	**196**	8,000,000	196
Series K [2]	$ 1.0000	**10,000,000**	**244**	10,000,000	244
Series M [2]	$ 1.0250	**24,000,000**	**591**	24,000,000	591
		74,193,500	**$ 1,820**	74,193,500	$ 1,820

[1] Cumulative Redeemable First Preference Shares
[2] Cumulative Redeemable Five-Year Fixed Rate Reset First Preference Shares
[3] The annual fixed dividend per share for the First Preference Shares, Series H was reset from $1.0625 to $0.6250 for the five-year period from and including June 1, 2015 to but excluding June 1, 2020.
[4] Cumulative Redeemable Five-Year Floating Rate Preference Shares. The floating quarterly dividend rate will be reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus 1.45%.

In September 2014 the Corporation issued 24 million Cumulative Redeemable Fixed Rate Reset First Preference Shares, Series M ("First Preference Shares, Series M") at a price of $25.00 per share for net after-tax proceeds of $591 million.

Holders of the First Preference Shares, Series E, Series F and Series J are each entitled to receive a fixed cumulative quarterly cash dividend as and when declared by the Board of Directors of the Corporation, payable in equal quarterly installments on the first day of each quarter.

On or after September 1, 2016, each First Preference Share, Series E will be convertible at the option of the holder on the first day of September, December, March and June of each year into fully paid and freely tradeable common shares of the Corporation, determined by dividing $25.00, together with all accrued and unpaid dividends, by the greater of $1.00 or 95% of the then-current market price of the common shares at such time. If a holder of First Preference Shares, Series E elects to convert any such shares into common shares, the Corporation can redeem such First Preference Shares, Series E for cash or arrange for the sale of those shares to other purchasers.

The Corporation has the option to convert all, or from time to time any part, of the outstanding First Preference Shares, Series E into fully paid and freely tradeable common shares of the Corporation. The number of common shares into which each First Preference Share, Series E may be converted will be determined by dividing the then-applicable redemption price per First Preference Share, Series E, together with all accrued and unpaid dividends, by the greater of $1.00 or 95% of the then-current market price of the common shares at such time.

The First Preference Shares, Series G, Series H, Series K and Series M are entitled to receive fixed cumulative cash dividends as and when declared by the Board of Directors of the Corporation in the amounts of $0.9708, $0.6250, $1.0000 and $1.0250 per share per annum, respectively, for each year up to but excluding September 1, 2018, June 1, 2020, March 1, 2019, and December 1, 2019, respectively. The dividends are payable in equal quarterly installments on the first day of each quarter. As at September 1, 2018, June 1, 2020, March 1, 2019, and December 1, 2019, and each five-year period thereafter, the holders of First Preference Shares, Series G, Series H, Series K and Series M, respectively, are entitled to receive reset fixed cumulative cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate of the First Preference Shares, Series G, Series H, Series K and Series M, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 2.13%, 1.45%, 2.05% and 2.48%, respectively.

For the years ended December 31, 2015 and 2014

20. PREFERENCE SHARES (cont'd)

On each First Preference Shares, Series H, Series K and Series M Conversion Date, the holders of First Preference Shares, Series H, Series K and Series M have the option to convert any or all of their First Preference Shares, Series H, Series K and Series M into an equal number of cumulative redeemable floating rate First Preference Shares, Series I, Series L and Series N, respectively. On June 1, 2015, 2,975,154 of the 10,000,000 First Preference Shares, Series H were converted on a one-for-one basis into First Preference Shares, Series I. As a result of the conversion, Fortis has issued and outstanding 7,024,846 First Preference Shares, Series H and 2,975,154 First Preference Shares, Series I.

The holders of First Preference Shares, Series I are entitled to receive floating rate cumulative cash dividends, as and when declared by the Board of Directors of the Corporation, for the five-year period beginning after June 1, 2015. The floating quarterly dividend rate will be reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus 1.45%. The holders of First Preference Shares, Series L and Series N will be entitled to receive floating rate cumulative cash dividends in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate of the First Preference Shares, Series L and Series N will be equal to the sum of the average yield expressed as a percentage per annum on three-month Government of Canada Treasury Bills plus 2.05% and 2.48%, respectively.

On or after specified dates, the Corporation has the option to redeem for cash the outstanding First Preference Shares, in whole at any time or in part from time to time, at specified fixed prices per share plus all accrued and unpaid dividends up to but excluding the dates fixed for redemption.

21. ACCUMULATED OTHER COMPREHENSIVE INCOME

Other comprehensive income or loss results from items deferred from recognition in the consolidated statement of earnings. The change in accumulated other comprehensive income by category is provided as follows.

	2015		
(in millions)	Opening balance January 1	Net change	Ending balance December 31
Net unrealized foreign currency translation gains (losses):			
Unrealized foreign currency translation gains on net investments in foreign operations	$ 273	$ 1,008	$ 1,281
Losses on hedges of net investments in foreign operations	(131)	(345)	(476)
Income tax recovery	2	(1)	1
	144	662	806
Available-for-sale investment: *(Notes 9, 28 and 31)*			
Unrealized losses on available-for-sale investment	–	(2)	(2)
Cash flow hedges: *(Note 31)*			
Net change in fair value of cash flow hedges	1	2	3
Income tax expense	–	(1)	(1)
	1	1	2
Unrealized employee future benefits (losses) gains: *(Note 27)*			
Unamortized past service costs	(2)	1	(1)
Unamortized net actuarial losses	(20)	–	(20)
Income tax recovery	6	–	6
	(16)	1	(15)
Accumulated other comprehensive income	$ 129	$ 662	$ 791

	2014		
(in millions)	Opening balance January 1	Net change	Ending balance December 31
Net unrealized foreign currency translation (losses) gains:			
Unrealized foreign currency translation (losses) gains on net investments in foreign operations	$ (60)	$ 333	$ 273
Losses on hedges of net investments in foreign operations	–	(131)	(131)
Income tax recovery	–	2	2
	(60)	204	144
Cash flow hedges: *(Note 31)*			
Net change in fair value of cash flow hedges	–	1	1
Discontinued cash flow hedges:			
Net losses on derivative instruments discontinued as cash flow hedges	(1)	1	–
Unrealized employee future benefits (losses) gains: *(Note 27)*			
Unamortized past service costs	(3)	1	(2)
Unamortized net actuarial losses	(9)	(11)	(20)
Income tax recovery	1	5	6
	(11)	(5)	(16)
Accumulated other comprehensive (loss) income	$ (72)	$ 201	$ 129

22. NON-CONTROLLING INTERESTS

(in millions)	**2015**	2014
Waneta Partnership	**$ 335**	$ 316
Caribbean Utilities	**122**	88
Mount Hayes Limited Partnership	**10**	11
Preference shares of Newfoundland Power	**6**	6
	$ 473	$ 421

23. STOCK-BASED COMPENSATION PLANS

Stock Options

The Corporation is authorized to grant officers and certain key employees of Fortis and its subsidiaries options to purchase common shares of the Corporation. As at December 31, 2015, the Corporation had the following stock option plans: the 2012 Plan, the 2006 Plan and the 2002 Plan. The 2012 Plan was approved at the May 4, 2012 Annual General Meeting and will ultimately replace the 2002 and 2006 Plans. The 2002 and 2006 Plans will cease to exist when all outstanding options are exercised or expire in or before 2016 and 2018, respectively. The Corporation has ceased the granting of options under the 2002 and 2006 Plans and all new options granted after 2011 are being made under the 2012 Plan. Directors are not eligible to receive grants of options under the 2012 Plan.

Options granted under the 2006 Plan are exercisable for a period not to exceed seven years from the date of grant, expire no later than three years after the termination, death or retirement of the optionee and vest evenly over a four-year period on each anniversary of the date of grant.

Options granted under the 2012 Plan are exercisable for a period not to exceed ten years from the date of grant, expire no later than three years after the termination, death or retirement of the optionee and vest evenly over a four-year period on each anniversary of the date of grant.

For the years ended December 31, 2015 and 2014

23. STOCK-BASED COMPENSATION PLANS (cont'd)

Stock Options (cont'd)

The following options were granted in 2015 and 2014. The fair values of the options were estimated at the date of grant using the Black-Scholes fair value option-pricing model and the following assumptions:

	2015	2014		
	March	August	June	February
Options granted (#)	**667,244**	12,216	23,584	925,172
Exercise price *($)* [1]	**39.25**	33.44	32.23	30.73
Grant date fair value *($)*	**2.46**	2.47	2.69	3.53
Assumptions:				
Dividend yield *(%)* [2]	**3.6**	3.8	3.8	3.8
Expected volatility *(%)* [3]	**14.6**	15.7	15.9	20.3
Risk-free interest rate *(%)* [4]	**0.90**	1.45	1.52	1.69
Weighted average expected life *(years)* [5]	**5.5**	5.5	5.5	5.5

[1] Five-day VWAP immediately preceding the date of grant
[2] Based on average annual dividend yield up to the date of grant and the weighted average expected life of the options
[3] Based on historical experience over a period equal to the weighted average expected life of the options
[4] Government of Canada benchmark bond yield in effect at the date of grant that covers the weighted average expected life of the options
[5] Based on historical experience

The Corporation records compensation expense upon the issuance of stock options granted under its 2002, 2006 and 2012 Plans. Using the fair value method, each grant is treated as a single award, the fair value of which is amortized to compensation expense evenly over the four-year vesting period of the options.

The following table summarizes information related to stock options for 2015.

	Total Options		**Non-vested Options** [1]	
	Number of Options	**Weighted Average Exercise Price**	**Number of Options**	**Weighted Average Grant Date Fair Value**
Options outstanding, January 1, 2015	**4,705,935**	**$ 30.27**	**2,148,380**	**$ 3.84**
Granted	**667,244**	**$ 39.25**	**667,244**	**$ 2.46**
Exercised	**(885,242)**	**$ 27.55**	**n/a**	**n/a**
Vested	**n/a**	**n/a**	**(828,547)**	**$ 4.01**
Cancelled/Forfeited	**(71,483)**	**$ 33.16**	**(50,545)**	**$ 3.49**
Options outstanding, December 31, 2015	**4,416,454**	**$ 32.12**	**1,936,532**	**$ 3.30**
Options vested, December 31, 2015 [2]	**2,479,922**	**$ 30.22**		

[1] As at December 31, 2015, there was $6 million of unrecognized compensation expense related to stock options not yet vested, which is expected to be recognized over a weighted average period of approximately three years.
[2] As at December 31, 2015, the weighted average remaining term of vested options was four years with an aggregate intrinsic value of $18 million.

The following table summarizes additional 2015 and 2014 stock option information.

(in millions)	**2015**	2014
Stock option expense recognized	**$ 3**	$ 3
Stock options exercised:		
Cash received for exercise price	**24**	36
Intrinsic value realized by employees	**10**	12
Fair value of options that vested	**3**	3

Directors' DSU Plan

Under the Corporation's Directors' DSU Plan, directors who are not officers of the Corporation are eligible for grants of DSUs representing the equity portion of directors' annual compensation. In addition, directors can elect to receive credit for their quarterly cash retainer in a notional account of DSUs in lieu of cash. The Corporation may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled.

Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

Number of DSUs	2015	2014
DSUs outstanding, beginning of year	**176,124**	203,172
Granted	**28,737**	29,279
Granted – notional dividends reinvested	**7,037**	8,526
DSUs paid out	**(44,136)**	(64,853)
DSUs outstanding, end of year	**167,762**	176,124

For the year ended December 31, 2015, expense of $1 million (2014 – $3 million) was recognized in earnings with respect to the DSU Plan.

In 2015, 44,136 DSUs were paid out to retired and deceased directors at a weighted average price of $37.58 per DSU for a total of approximately $2 million.

As at December 31, 2015, the liability related to outstanding DSUs has been recorded at the VWAP of the Corporation's common shares for the last five trading days of 2015 of $37.72, for a total of $6 million (December 31, 2014 – $7 million), and is included in long-term other liabilities (Note 17).

PSU Plans

The Corporation's PSU Plans represent a component of long-term compensation awarded to senior management of the Corporation and its subsidiaries. As at December 31, 2015, the Corporation had the following PSU plans: the 2013 PSU Plan, the 2015 PSU Plan, and certain subsidiaries of the Corporation have also adopted similar share unit plans that are modelled after the Corporation's plans. Each PSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

The PSUs are subject to a three-year vesting and performance period, at which time a cash payment may be made, as determined by the Human Resources Committee of the Board of Directors. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by the VWAP of the Corporation's common shares for five trading days prior to the maturity of the grant and by a payout percentage that may range from 0% to 150%.

The payout percentage for the PSU Plans is based on the Corporation's performance over the three-year period, mainly determined by: (i) the Corporation's total shareholder return as compared to a pre-defined peer group of companies; and (ii) the Corporation's cumulative compound annual growth rate in earnings per common share or, for certain subsidiaries, the Company's cumulative net income, as compared to the target established at the time of the grant. As at December 31, 2015, the estimated payout percentages for the grants under the 2013 and 2015 PSU Plans range from 96% to 118%.

The following table summarizes information related to the PSUs for 2015 and 2014.

Number of PSUs	2015	2014
PSUs outstanding, beginning of year	**481,700**	257,419
Granted	**276,381**	261,737
Granted – notional dividends reinvested	**25,687**	17,691
PSUs paid out	**(83,637)**	(33,559)
PSUs cancelled/forfeited	**(5,745)**	(21,588)
PSUs outstanding, end of year	**694,386**	481,700

In January 2015, 68,759 PSUs were paid out to the former Chief Executive Officer ("CEO") of the Corporation at $38.90 per PSU, for a total of approximately $3 million. The payout was made in respect of the PSU grant made in March 2012 and the former CEO satisfying the payment requirements, as determined by the Human Resources Committee of the Board of Directors. As a result of the sale of commercial real estate and hotel assets, in October 2015, 14,878 PSUs were paid out to certain employees at a 100% payout percentage under the 2013 PSU Plan and the 2015 PSU Plan at $38.48 per PSU, for a total of approximately $1 million.

For the years ended December 31, 2015 and 2014

23. STOCK-BASED COMPENSATION PLANS (cont'd)

PSU Plans (cont'd)

For the year ended December 31, 2015, expense of approximately $12 million (2014 – $7 million) was recognized in earnings with respect to the PSU Plans and there was $9 million of unrecognized compensation expense related to PSUs not yet vested, which is expected to be recognized over a weighted average period of approximately two years.

As at December 31, 2015, the aggregate intrinsic value of the outstanding PSUs was $28 million, with a weighted average contractual life of approximately one year. The liability related to outstanding PSUs has been recorded at the VWAP of the Corporation's common shares for the last five trading days of 2015 of $37.72, for a total of $19 million (December 31, 2014 – $10 million), and is included in accounts payable and other current liabilities and long-term other liabilities (Notes 14 and 17).

RSU Plans

In February 2015 the Corporation's Board of Directors approved the 2015 RSU Plan, effective January 1, 2015. The Corporation's 2015 RSU Plan represents a component of long-term compensation awarded to senior management of the Corporation and its subsidiaries. Each RSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is subject to a three-year vesting period, at which time a cash payment may be made. Each RSU is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

Number of RSUs	**2015**
Granted	**59,462**
Granted – notional dividends reinvested	**2,150**
RSUs cancelled/forfeited	**(2,872)**
RSUs outstanding, end of year	**58,740**

For the year ended December 31, 2015, expense of approximately $1 million was recognized in earnings with respect to the RSU Plan and there was approximately $1 million of unrecognized compensation expense related to RSUs not yet vested, which is expected to be recognized over a weighted average period of approximately two years.

As at December 31, 2015, the liability related to outstanding RSUs was recorded at the VWAP of the Corporation's common shares for the last five trading days of 2015 of $37.72, for a total of $1 million, and is included in long-term other liabilities (Note 17).

24. OTHER INCOME (EXPENSES), NET

(in millions)	**2015**	2014
Net gain on sale of commercial real estate and hotel assets *(Note 28)* [1]	**$ 109**	$ –
Gain on sale of non-regulated generation assets *(Note 28)* [2]	**56**	–
Equity component of AFUDC	**23**	11
Net foreign exchange gain	**13**	8
Interest income	**8**	13
Loss on settlement of expropriation matters *(Note 9)*	**(9)**	–
Acquisition-related expenses *(Notes 29 and 35)*	**(10)**	(25)
Acquisition-related customer and community benefits *(Notes 8 (xvii) and 29)*	**–**	(33)
Other	**(3)**	1
	$ 187	$ (25)

[1] Net of $23 million of expenses associated with the sale
[2] Net of $6 million of expenses and foreign exchange impacts associated with the sale

The net foreign exchange gain relates to the translation into Canadian dollars of the Corporation's previous US dollar-denominated long-term other asset, representing the book value of the Corporation's expropriated investment in Belize Electricity, up to the date of settlement of expropriation matters in August 2015 (Note 9). As a result of the settlement, the Corporation recognized an approximate $9 million loss in 2015. Unrealized foreign exchange gains and losses associated with the Corporation's 33% equity investment in Belize Electricity are recognized on the balance sheet in accumulated other comprehensive income.

The acquisition-related expenses and customer and community benefits in 2014 were associated with the acquisition of UNS Energy (Note 29).

25. FINANCE CHARGES

(in millions)	2015	2014
Interest – Long-term debt and capital lease and finance obligations	**$ 572**	$ 482
– Short-term borrowings	**8**	20
– Convertible Debentures *(Note 18)*	**–**	72
Debt component of AFUDC	**(27)**	(27)
	$ 553	$ 547

26. INCOME TAXES

Deferred Income Taxes

Deferred income taxes are provided for temporary differences. The significant components of deferred income tax assets and liabilities consist of the following.

(in millions)	2015	2014
Gross deferred income tax assets		
Tax loss and credit carryforwards	**$ 387**	$ 376
Regulatory liabilities	**210**	186
Employee future benefits	**116**	108
Share issue and debt financing costs	**13**	20
Unrealized foreign exchange losses on long-term debt	**65**	17
Other	**45**	70
	836	777
Deferred income tax assets valuation allowance	**(73)**	(24)
Net deferred income tax assets	**$ 763**	$ 753
Gross deferred income tax liabilities		
Utility capital assets	**$ (2,575)**	$ (2,096)
Regulatory assets	**(201)**	(204)
Non-utility capital assets	**–**	(40)
Intangible assets	**(37)**	(39)
	(2,813)	(2,379)
Net deferred income tax liability	**$ (2,050)**	$ (1,626)

The deferred income tax asset associated with unrealized foreign exchange losses on long-term debt reflects $65 million of capital losses as at December 31, 2015 (December 31, 2014 – $17 million). The deferred income tax asset can only be used if the Corporation has capital gains to offset the losses. Management believes that it is more likely than not that Fortis will not be able to generate future capital gains and, as a result, the Corporation recorded a $65 million valuation allowance against the deferred income tax asset as at December 31, 2015 (December 31, 2014 – $17 million). Management believes that based on its historical pattern of taxable income, Fortis will produce sufficient income in the future to realize all other deferred income tax assets.

For the years ended December 31, 2015 and 2014

26. INCOME TAXES (cont'd)

Unrecognized Tax Benefits

The following table summarizes the change in unrecognized tax benefits during 2015 and 2014.

(in millions)	2015	2014
Total unrecognized tax benefits, beginning of year	**$ 11**	$ 3
Additions related to the current year	**1**	7
Adjustments related to prior years	**1**	1
Total unrecognized tax benefits, end of year	**$ 13**	$ 11

Unrecognized tax benefits, if recognized, would reduce income tax expense by $1 million in 2015. Fortis has not recognized interest expense in 2015 and 2014 related to unrecognized tax benefits.

The components of the income tax expense were as follows.

(in millions)	2015	2014
Canadian		
Current income taxes	**$ 59**	$ 43
Deferred income taxes	**113**	64
Less: regulatory adjustments	**(100)**	(67)
	13	(3)
Total Canadian	**$ 72**	$ 40
Foreign		
Deferred income taxes	**151**	26
Total Foreign	**$ 151**	$ 26
Income tax expense	**$ 223**	$ 66

Income taxes differ from the amount that would be expected to be generated by applying the enacted combined Canadian federal and provincial statutory income tax rate to earnings before income taxes. The following is a reconciliation of consolidated statutory taxes to consolidated effective taxes.

(in millions, except as noted)	2015	2014
Combined Canadian federal and provincial statutory income tax rate	**27.5%**	29.0%
Statutory income tax rate applied to earnings before income taxes	**$ 292**	$ 131
Difference between Canadian statutory income tax rate and rates applicable to foreign subsidiaries	**(7)**	(23)
Difference in Canadian provincial statutory income tax rates applicable to subsidiaries in different Canadian jurisdictions	**(4)**	(10)
Items capitalized for accounting purposes but expensed for income tax purposes	**(39)**	(26)
Difference between gain on sale of assets for accounting and amounts calculated for tax purposes	**(18)**	–
Change in tax rates and legislation	**13**	–
Other	**(14)**	(6)
Income tax expense	**$ 223**	$ 66
Effective tax rate	**21.0%**	14.6%

In 2015 the Corporation's combined Canadian federal and provincial statutory income tax rate decreased from 29.0% to 27.5%. This change resulted from the inclusion of the Waneta Partnership's taxable income, which is taxable in the province of British Columbia at a lower provincial income tax rate, and increased income tax expense by approximately $3 million in 2015, through the re-measurement of deferred income tax assets. In addition, a change in New York State tax legislation in 2015 resulted in the need to include UNS Energy as part of the combined New York State tax return. As a result, existing deferred income tax balances were adjusted to reflect the effect of the change in the tax law, resulting in an increase in income tax expense of approximately $10 million in 2015.

As at December 31, 2015, the Corporation had the following tax carryforward amounts.

(in millions)	Expiring Year	Amount
Canadian		
Capital loss	n/a	**$ 15**
Non-capital loss	2025 – 2035	**129**
Other tax credits	2026 – 2035	**2**
		146
Unrecognized in the consolidated financial statements		**(15)**
		$ 131
Foreign		
Capital loss	2017	**$ 12**
Federal and state net operating loss	2031 – 2034	**653**
Other tax credits	2016 – 2035	**69**
Alternative minimum tax credits	n/a	**64**
		798
Unrecognized in the consolidated financial statements		**(17)**
		781
Total tax carryforwards		**$ 912**

As at December 31, 2015, the Corporation had approximately $912 million in tax carryforward amounts recognized in the consolidated financial statements (December 31, 2014 – $1,093 million).

The Corporation and one or more of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Corporation is subject to potential examinations include the United States (Federal, Arizona and New York) and Canada (Federal and British Columbia). The Corporation's 2010 to 2015 taxation years are still open for audit in the Canadian jurisdictions and 2011 to 2015 taxation years are still open for audit in the United States jurisdictions. The Corporation is not currently under examination for income tax matters in any of these jurisdictions.

27. EMPLOYEE FUTURE BENEFITS

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, defined contribution pension plans, and OPEB plans. For the defined benefit pension and OPEB plan arrangements, the benefit obligation and the fair value of plan assets are measured for accounting purposes as at December 31 of each year.

Actuarial valuations are required to determine funding contributions for pension plans, at least, every three years for Fortis' Canadian and Caribbean subsidiaries. The most recent valuations were as of December 31, 2012 for FortisBC Energy (plan covering non-unionized employees), FortisAlberta and Caribbean Utilities; December 31, 2013 for FortisBC Electric and FortisBC Energy (plans covering unionized employees); as of December 31, 2014 for Newfoundland Power, FortisOntario, and the Corporation.

UNS Energy and Central Hudson perform annual actuarial valuations, as their funding contribution requirements are based on maintaining annual target fund percentages. Both UNS Energy and Central Hudson have met the minimum funding requirements.

For the years ended December 31, 2015 and 2014

27. EMPLOYEE FUTURE BENEFITS (cont'd)

The Corporation's investment policy is to ensure that the defined benefit pension and OPEB plan assets, together with expected contributions, are invested in a prudent and cost-effective manner to optimally meet the liabilities of the plans for its members. The investment objective of the defined benefit pension and OPEB plans is to maximize return in order to manage the funded status of the plans and minimize the Corporation's cost over the long term, as measured by both cash contributions and defined benefit pension and OPEB expense for consolidated financial statement purposes.

The Corporation's consolidated defined benefit pension and OPEB plan weighted average asset allocations were as follows.

Plan assets as at December 31 *(%)*	**2015 Target Allocation**	**2015**	2014
Equities	**50**	**51**	49
Fixed income	**46**	**44**	46
Real estate	**4**	**4**	4
Cash and other	**–**	**1**	1
	100	**100**	100

The fair value measurements of defined benefit pension and OPEB plan assets by fair value hierarchy, as defined in Note 31, were as follows.

Fair value of plan assets as at December 31, 2015

(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Equities	**$ 417**	**$ 922**	**$ –**	**$ 1,339**
Fixed income	**–**	**1,166**	**–**	**1,166**
Real estate	**–**	**14**	**97**	**111**
Private equities	**–**	**–**	**10**	**10**
Cash and other	**3**	**18**	**–**	**21**
	$ 420	**$ 2,120**	**$ 107**	**$ 2,647**

Fair value of plan assets as at December 31, 2014

(in millions)	Level 1	Level 2	Level 3	Total
Equities	$ 352	$ 806	$ –	$ 1,158
Fixed income	23	1,069	–	1,092
Real estate	–	11	85	96
Private equities	–	–	8	8
Cash and other	6	10	–	16
	$ 381	$ 1,896	$ 93	$ 2,370

The following table is a reconciliation of changes in the fair value of pension plan assets that have been measured using Level 3 inputs for the years ended December 31, 2015 and 2014.

(in millions)	**2015**	2014
Balance, beginning of year	**$ 93**	$ 62
Assets assumed on acquisition	**–**	24
Actual return on plan assets held at end of year	**9**	6
Foreign currency translation impacts	**5**	–
Purchases, sales and settlements	**–**	1
Balance, end of year	**$ 107**	$ 93

The following is a breakdown of the Corporation's and subsidiaries' defined benefit pension and OPEB plans and their respective funded status.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2015**	2014	**2015**	2014
Change in benefit obligation [1]				
Balance, beginning of year	**$ 2,604**	$ 1,724	**$ 564**	$ 417
Liabilities assumed on acquisition	**–**	403	**–**	83
Service costs	**68**	43	**17**	11
Employee contributions	**17**	17	**1**	1
Interest costs	**109**	90	**23**	21
Benefits paid	**(118)**	(101)	**(21)**	(15)
Actuarial (gains) losses	**(102)**	335	**(50)**	27
Past service credits/plan amendments	**–**	–	**(10)**	–
Foreign currency translation impacts	**250**	93	**50**	19
Balance, end of year [2]	**$ 2,828**	$ 2,604	**$ 574**	$ 564
Change in value of plan assets				
Balance, beginning of year	**$ 2,216**	$ 1,541	**$ 154**	$ 121
Assets assumed on acquisition	**–**	373	**–**	13
Actual return on plan assets	**30**	236	**–**	11
Benefits paid	**(118)**	(101)	**(21)**	(15)
Employee contributions	**17**	17	**1**	1
Employer contributions	**99**	70	**17**	11
Foreign currency translation impacts	**222**	80	**30**	12
Balance, end of year	**$ 2,466**	$ 2,216	**$ 181**	$ 154
Funded status	**$ (362)**	$ (388)	**$ (393)**	$ (410)

[1] Amounts reflect projected benefit obligation for defined benefit pension plans and accumulated benefit obligation for OPEB plans

[2] The accumulated benefit obligation for defined benefit pension plans, excluding assumptions about future salary levels, was $2,595 million as at December 31, 2015 (December 31, 2014 – $2,378 million).

The following table summarizes the employee future benefit assets and liabilities and their classifications on the consolidated balance sheet.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2015**	2014	**2015**	2014
Assets				
Defined benefit pension assets:				
Long-term other assets	**$ 11**	$ 6	**$ –**	$ –
Liabilities				
Defined benefit pension liabilities:				
Current *(Note 14)*	**5**	4	**–**	–
Long-term other liabilities *(Note 17)*	**368**	390	**–**	–
OPEB plan liabilities:				
Current *(Note 14)*	**–**	–	**8**	7
Long-term other liabilities *(Note 17)*	**–**	–	**385**	403
Net liabilities	**$ 362**	$ 388	**$ 393**	$ 410

For the years ended December 31, 2015 and 2014

27. EMPLOYEE FUTURE BENEFITS (cont'd)

The net benefit cost for the Corporation's defined benefit pension plans and OPEB plans were as follows:

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2015**	2014	**2015**	2014
Components of net benefit cost				
Service costs	**$ 68**	$ 43	**$ 17**	$ 11
Interest costs	**109**	90	**23**	21
Expected return on plan assets	**(140)**	(106)	**(12)**	(9)
Amortization of actuarial losses	**57**	32	**5**	3
Amortization of past service credits/plan amendments	**–**	(1)	**(5)**	(3)
Amortization of transitional obligation (asset)	**2**	2	**(7)**	(6)
Regulatory adjustments	**1**	11	**6**	4
Net benefit cost	**$ 97**	$ 71	**$ 27**	$ 21

The following tables provide the components of accumulated other comprehensive loss and regulatory assets and liabilities, which would otherwise have been recognized as accumulated other comprehensive loss, for the years ended December 31, 2015 and 2014 that have not been recognized as components of net benefit cost.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2015**	2014	**2015**	2014
Unamortized net actuarial losses	**$ 16**	$ 16	**$ 4**	$ 4
Unamortized past service costs	**1**	–	**–**	2
Income tax recovery	**(5)**	(5)	**(1)**	(1)
Accumulated other comprehensive loss *(Note 21)*	**$ 12**	$ 11	**$ 3**	$ 5
Net actuarial losses	**$ 513**	$ 513	**$ 41**	$ 95
Past service credits	**–**	–	**(33)**	(43)
Amount deferred due to actions of regulators	**23**	18	**39**	39
	$ 536	$ 531	**$ 47**	$ 91
Regulatory assets *(Note 8 (ii))*	**$ 536**	$ 531	**$ 91**	$ 149
Regulatory liabilities *(Note 8 (ii))*	**–**	–	**(44)**	(58)
Net regulatory assets	**$ 536**	$ 531	**$ 47**	$ 91

The following tables provide the components recognized in comprehensive income or as regulatory assets, which would otherwise have been recognized in comprehensive income.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2015**	2014	**2015**	2014
Current year net actuarial losses (gains)	**$ –**	$ 9	**$ (1)**	$ 3
Past service credits/plan amendments	**–**	–	**(1)**	(1)
Amortization of actuarial gains (losses)	**1**	(1)	**–**	–
Income tax recovery	**–**	(4)	**–**	(1)
Total recognized in comprehensive income	**$ 1**	$ 4	**$ (2)**	$ 1
Assets assumed on acquisition	**$ –**	$ 79	**$ –**	$ 6
Current year net actuarial losses (gains)	**8**	197	**(28)**	23
Past service credits/plan amendments	**–**	–	**(10)**	–
Amortization of actuarial losses	**(56)**	(31)	**(5)**	(5)
Amortization of past service costs	**(1)**	(1)	**(2)**	(3)
Foreign currency translation impacts	**49**	14	**(6)**	(4)
Regulatory adjustments	**5**	(37)	**7**	(1)
Total recognized in regulatory assets	**$ 5**	$ 221	**$ (44)**	$ 16

Net actuarial losses of $1 million are expected to be amortized from accumulated other comprehensive income into net benefit cost in 2016 related to defined benefit pension plans.

Net actuarial losses of $47 million, past service credits of $1 million and regulatory adjustments of $2 million are expected to be amortized from regulatory assets into net benefit cost in 2016 related to defined benefit pension plans. Net actuarial losses of $3 million, past service credits of $1 million and regulatory adjustments of $5 million are expected to be amortized from regulatory assets into net benefit cost in 2016 related to OPEB plans.

Significant weighted average assumptions	**Defined Benefit Pension Plans**		**OPEB Plans**	
(%)	**2015**	2014	**2015**	2014
Discount rate during the year	**4.00**	4.81	**3.95**	4.72
Discount rate as at December 31	**4.21**	4.00	**4.12**	3.95
Expected long-term rate of return on plan assets [1]	**6.25**	6.46	**6.95**	7.08
Rate of compensation increase	**3.48**	3.48	**–**	–
Health care cost trend increase as at December 31 [2]	**–**	–	**4.67**	4.67

[1] Developed by management with assistance from independent actuaries using best estimates of expected returns, volatilities and correlations for each class of asset. The best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes.

[2] The projected 2016 weighted average health care cost trend rate is 6.98% for OPEB plans and is assumed to decrease over the next 13 years by 2028 to the weighted average ultimate health care cost trend rate of 4.67% and remain at that level thereafter.

For 2015 the effects of changing the health care cost trend rate by 1% were as follows.

(in millions)	**1% increase in rate**	**1% decrease in rate**
Increase (decrease) in accumulated benefit obligation	**$ 51**	**$ (43)**
Increase (decrease) in service and interest costs	**5**	**(3)**

The following table provides the amount of benefit payments expected to be made over the next 10 years.

Year	**Defined Benefit Pension Payments** *(in millions)*	**OPEB Payments** *(in millions)*
2016	$ 122	$ 24
2017	127	26
2018	131	27
2019	136	29
2020	141	30
2021 – 2025	796	173

Refer to Note 33 for expected defined benefit pension and OPEB plan funding contributions.

During 2015 the Corporation expensed $28 million (2014 – $21 million) related to defined contribution pension plans.

28. DISPOSITIONS AND DISCONTINUED OPERATIONS

Sale of Commercial Real Estate and Hotel Assets

In June 2015 the Corporation completed the sale of the commercial real estate assets of Fortis Properties for gross proceeds of $430 million. As a result of the sale, the Corporation recognized a gain on sale of $129 million ($109 million after tax), net of expenses (Note 24). As part of the transaction, Fortis subscribed to $35 million in trust units of Slate Office REIT in conjunction with the REIT's public offering (Notes 9 and 31).

In October 2015 the Corporation completed the sale of the hotel assets of Fortis Properties for gross proceeds of $365 million. As a result of the sale, the Corporation recognized a loss of approximately $20 million ($8 million after tax), which reflects an impairment loss and expenses associated with the sale transaction (Note 24).

For the years ended December 31, 2015 and 2014

28. DISPOSITIONS AND DISCONTINUED OPERATIONS (cont'd)

Sale of Commercial Real Estate and Hotel Assets (cont'd)

Net proceeds from the sales were used by the Corporation to repay credit facility borrowings, the majority of which were used to finance a portion of the acquisition of UNS Energy (Note 29), and for other general corporate purposes.

Earnings before taxes related to Fortis Properties of approximately $18 million were recognized in 2015, excluding the net gain on sale, compared to $31 million in 2014.

Sale of Non-Regulated Generation Assets in New York and Ontario

In June 2015 the Corporation sold its non-regulated generation assets in Upstate New York for gross proceeds of approximately $77 million (US$63 million). As a result of the sale, the Corporation recognized a gain on sale of $51 million (US$41 million) ($27 million (US$22 million) after tax), net of expenses and foreign exchange impacts (Note 24).

In July 2015 the Corporation sold its non-regulated generation assets in Ontario for gross proceeds of approximately $16 million. As a result of the sale, the Corporation recognized a gain on sale of $5 million ($5 million after tax) (Note 24).

Earnings before taxes of less than $1 million were recognized in 2015, excluding the gain on sale, compared to $3 million in 2014.

Sale of Griffith

In March 2014 Griffith was sold for proceeds of approximately $105 million (US$95 million). The results of operations to the date of sale are presented as discontinued operations on the consolidated statements of earnings. As a result of the disposal, earnings from discontinued operations of $8 million ($5 million after tax) were recognized in the first quarter of 2014.

29. BUSINESS ACQUISITIONS

2015

Pending Acquisition of Aitken Creek Gas Storage Facility

In December 2015 Fortis, through an indirect wholly owned subsidiary, entered into a definitive share purchase and sale agreement with Chevron Canada Properties Ltd. to acquire its shares of the Aitken Creek Gas Storage Facility ("Aitken Creek") for approximately US$266 million, subject to customary closing conditions and adjustments. Aitken Creek is the largest gas storage facility in British Columbia with a total working gas capacity of 77 billion cubic feet and is an integral part of Western Canada's natural gas transmission network. The acquisition is subject to regulatory approval and is expected to close in the first half of 2016. The net cash purchase price is expected to be initially financed with borrowings under the Corporation's credit facility. In December 2015 the Corporation paid a deposit of US$29 million related to the transaction, which is included in long-term other assets on the consolidated balance sheet (Note 9).

2014

UNS Energy

On August 15, 2014, Fortis acquired all of the outstanding common shares of UNS Energy for US$60.25 per common share in cash, for an aggregate purchase price of approximately US$4.5 billion, including the assumption of US$2.0 billion of debt on closing.

Financing of the net cash purchase price of approximately $2.7 billion (US$2.5 billion) is complete. Fortis completed the sale of $1.8 billion 4% Convertible Debentures. Proceeds from the first installment of approximately $599 million were received in January 2014. A significant portion of these cash proceeds were used to finance a portion of the UNS Energy acquisition. Proceeds from the final installment of approximately $1.2 billion were received on October 28, 2014 and were used to repay borrowings under acquisition credit facilities initially used to finance a portion of the UNS Energy acquisition. Substantially all of the Convertible Debentures have been converted into approximately 58.6 million common shares of Fortis (Note 18). In September 2014 Fortis issued 24 million 4.1% Cumulative Redeemable Fixed Rate Reset First Preference Shares, Series M for gross proceeds of $600 million (Note 20). The net proceeds were also used to repay a portion of borrowings under the acquisition credit facilities. The remainder of the purchase price was financed through credit facility borrowings under a medium-term bridge facility and the Corporation's revolving credit facility (Note 32), which were subsequently repaid using net proceeds from the sale of commercial real estate and hotel assets (Note 28).

UNS Energy's operations are regulated by the ACC and FERC (Note 2). The determination of revenue and earnings is based on a regulated rate of return that is applied to historic values, which do not change with a change of ownership. No fair value adjustments, other than goodwill, were recorded for the net assets acquired because all of the economic benefits and obligations associated with them beyond regulated rates of return accrue to the customers.

The following table summarizes the final allocation of the purchase consideration to the assets and liabilities acquired as at August 15, 2014, based on their fair values, using an exchange rate of US$1.00=CAD$1.0925.

(in millions)	Total
Purchase consideration	**$ 2,745**
Fair value assigned to net assets:	
Current assets	**539**
Long-term regulatory assets	**185**
Utility capital assets	**3,972**
Intangible assets	**116**
Other long-term assets	**108**
Current liabilities	**(458)**
Assumed long-term debt and capital lease and finance obligations (including current portion)	**(2,186)**
Long-term regulatory liabilities	**(341)**
Other long-term liabilities	**(797)**
	1,138
Cash and cash equivalents	**97**
Fair value of net assets acquired	**1,235**
Goodwill *(Note 13)*	**$ 1,510**

The acquisition has been accounted for using the acquisition method, whereby financial results of the business acquired have been consolidated in the financial statements of Fortis commencing on August 15, 2014.

In 2014 acquisition-related expenses of approximately $25 million ($19 million after tax) were recognized in other income (expenses), net on the consolidated statement of earnings (Note 24). In addition, approximately $33 million (US$30 million), or $20 million (US$18 million) after tax, in customer benefits offered to obtain regulatory approval of the acquisition were expensed in 2014 and were also recognized in other income (expenses), net on the consolidated statement of earnings (Notes 8 *(xvii)* and 24).

30. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	2015	2014
Cash paid for:		
Interest	**$ 561**	$ 538
Income taxes	**109**	83
Change in non-cash operating working capital:		
Accounts receivable and other current assets	**$ 14**	$ 53
Prepaid expenses	**(1)**	2
Inventories	**15**	(11)
Regulatory assets – current portion	**57**	(16)
Accounts payable and other current liabilities	**(82)**	(123)
Regulatory liabilities – current portion	**38**	(29)
	$ 41	$ (124)
Non-cash investing and financing activities:		
Common share dividends reinvested	**$ 156**	$ 81
Conversion of Convertible Debentures into common shares *(Note 18)*	**1**	1,747
Additions to utility capital assets, non-utility capital assets, and intangible assets included in current and long-term liabilities	**187**	200
Contributions in aid of construction included in current assets	**4**	7
Exercise of stock options into common shares	**4**	5

31. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS

Fair value is the price at which a market participant could sell an asset or transfer a liability to an unrelated party. A fair value measurement is required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. A fair value hierarchy exists that prioritizes the inputs used to measure fair value.

The three levels of the fair value hierarchy are defined as follows:

Level 1: Fair value determined using unadjusted quoted prices in active markets;
Level 2: Fair value determined using pricing inputs that are observable; and
Level 3: Fair value determined using unobservable inputs only when relevant observable inputs are not available.

The fair values of the Corporation's financial instruments, including derivatives, reflect point-in-time estimates based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flows.

The following table presents, by level within the fair value hierarchy, the Corporation's assets and liabilities accounted for at fair value on a recurring basis. These assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement and there were no transfers between the levels in the periods presented. For derivative instruments, the Corporation has elected gross presentation for its derivative contracts under master netting agreements and collateral positions.

(in millions)	Fair value hierarchy	As at December 31 2015	2014
Assets			
Energy contracts subject to regulatory deferral [1] [2] [3]	Levels 2/3	**$ 7**	$ 3
Energy contracts not subject to regulatory deferral [1] [2]	Level 3	**2**	1
Available-for-sale investment *(Note 9)* [4] [5]	Level 1	**33**	–
Assets held for sale *(Note 6)*	Level 2	**9**	–
Other investments [4]	Level 1	**12**	5
Total gross assets		**63**	9
Less: Counterparty netting not offset on the balance sheet [6]		**(6)**	(3)
Total net assets		**$ 57**	$ 6
Liabilities			
Energy contracts subject to regulatory deferral [1] [2] [7]	Levels 1/2/3	**$ 78**	$ 72
Energy contracts not subject to regulatory deferral [1] [2]	Level 3	**–**	1
Energy contracts – cash flow hedges [2] [8]	Level 3	**–**	1
Interest rate swaps – cash flow hedges [8]	Level 2	**5**	5
Total gross liabilities		**83**	79
Less: Counterparty netting not offset on the balance sheet [6]		**(6)**	(3)
Total net liabilities		**$ 77**	$ 76

[1] The fair value of the Corporation's energy contracts is recorded in accounts receivable and other current assets, long-term other assets, accounts payable and other current liabilities and long-term other liabilities. Unrealized gains and losses arising from changes in fair value of these contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in rates as permitted by the regulators, with the exception of long-term wholesale trading contracts.

[2] Changes in one or more of the unobservable inputs could have a significant impact on the fair value measurement depending on the magnitude and direction of the change for each input. The impacts of changes in fair value are subject to regulatory recovery, with the exception of long-term wholesale trading contracts and those that qualify as cash flow hedges.

[3] Includes $2 million – level 2 and $5 million – level 3 (2014 – $3 million – level 3)

[4] Included in long-term other assets on the consolidated balance sheet

[5] The cost of the available-for-sale investment was $35 million and unrealized gains and losses arising from changes in fair value are recorded in other comprehensive income until they become realized and are reclassified to earnings (Notes 9 and 28).

[6] Certain energy contracts are subject to legally enforceable master netting arrangements to mitigate credit risk and netted by counterparty where the intent and legal right to offset exists.

[7] Includes $1 million – level 1, $52 million – level 2 and $25 million – level 3 (2014 – $2 million – level 1, $35 million – level 2 and $35 million – level 3)

[8] The fair value of certain of the Corporation's energy contracts are recorded in accounts payable and other current liabilities and the fair value of the Corporation's interest rate swaps are recorded in accounts payable and other current liabilities and long-term other liabilities. Unrealized gains and losses arising from changes in fair value are recorded in other comprehensive income until they become realized and are reclassified to earnings.

Derivative Instruments

The Corporation generally limits the use of derivative instruments to those that qualify as accounting, economic or cash flow hedges, or those that are approved for regulatory recovery. The Corporation records all derivative instruments at fair value, with certain exceptions including those derivatives that qualify for the normal purchase and normal sale exception. The fair value of derivative instruments are estimates of the amounts that the utilities would receive or have to pay to terminate the outstanding contracts as at the balance sheet dates.

Energy Contracts Subject to Regulatory Deferral

UNS Energy holds electricity power purchase contracts and gas swap and option contracts to reduce its exposure to energy price risk associated with purchased power and gas requirements. UNS Energy primarily applies the market approach for fair value measurements using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships and transmission and line losses. The fair value of gas option contracts is estimated using a Black-Scholes option-pricing model, which includes inputs such as implied volatility, interest rates, and forward price curves. UNS Energy also considers the impact of counterparty credit risk using current and historical default and recovery rates, as well as its own credit risk using credit default swap data.

Central Hudson holds electricity swap contracts and gas swap and option contracts to minimize commodity price volatility for electricity and natural gas purchases by fixing the effective purchase price for the defined commodities. The fair value of the electricity swap contracts and gas swap and option contracts was calculated using forward pricing provided by independent third parties.

FortisBC Energy holds gas purchase contract premiums to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. The fair value of the natural gas derivatives was calculated using the present value of cash flows based on market prices and forward curves for the cost of natural gas.

As at December 31, 2015, these energy contract derivatives were not designated as hedges; however, any unrealized gains or losses associated with changes in the fair value of the derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. These unrealized losses and gains would otherwise be recorded in earnings. As at December 31, 2015, unrealized losses of $74 million (December 31, 2014 – $69 million) were recognized in regulatory assets and unrealized gains of $3 million were recognized in regulatory liabilities (Note 8 *(vii)*).

Energy Contracts Not Subject to Regulatory Deferral

In June 2015 UNS Energy entered into long-term wholesale trading contracts that qualify as derivative instruments. The unrealized gains and losses on these derivative instruments are recorded in earnings, as they do not qualify for regulatory deferral. Ten percent of any realized gains on these contracts are shared with the ratepayer through UNS Energy's rate stabilization accounts.

Cash Flow Hedges

UNS Energy holds an interest rate swap, expiring in 2020, to mitigate its exposure to volatility in variable interest rates on lease debt, and held a power purchase swap, that expired in September 2015, to hedge the cash flow risk associated with a long-term power supply agreement. The after-tax unrealized gains and losses on cash flow hedges are recorded in other comprehensive income and reclassified to earnings as they become realized. The loss expected to be reclassified to earnings within the next 12 months is estimated to be approximately $1 million.

Central Hudson holds interest rate cap contracts expiring in 2016 and 2017 on bonds with a total principal amount of US$64 million. Variations in the interest costs of the bonds, including any gains or losses associated with the interest rate cap contracts, are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator and do not impact earnings.

Cash flows associated with the settlement of all derivative instruments are included in operating activities on the Corporation's consolidated statement of cash flows.

For the years ended December 31, 2015 and 2014

31. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS (cont'd)

Volume of Derivative Activity

As at December 31, 2015, the following notional volumes related to electricity and natural gas derivatives that are expected to be settled are outlined below.

Volume	Maturity *(year)*	Contracts *(#)*	2016	2017	2018	2019	2020	There-after
Energy contracts subject to regulatory deferral:								
Electricity swap contracts (gigawatt hours *("GWh")*)	2019	8	1,043	730	438	219	–	–
Electricity power purchase contracts *(GWh)*	2017	28	1,027	145	–	–	–	–
Gas swap and option contracts (petajoules *("PJ")*)	2018	154	40	10	4	–	–	–
Gas purchase contract premiums *(PJ)*	2024	89	91	42	38	22	22	64
Energy contracts not subject to regulatory deferral:								
Long-term wholesale trading contracts *(GWh)*	2016	6	1,310	–	–	–	–	–

Financial Instruments Not Carried At Fair Value

The following table discloses the estimated fair value measurements of the Corporation's financial instruments not carried at fair value. The fair values were measured using Level 2 pricing inputs, except as noted. The carrying values of the Corporation's consolidated financial instruments approximate their fair values, reflecting the short-term maturity, normal trade credit terms and/or nature of these instruments, except as follows:

Asset (Liability)	As at December 31, 2015		As at December 31, 2014	
(in millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term other asset – Belize Electricity [1]	**$ –**	**$ –**	$ 116	$ n/a
Long-term debt, including current portion *(Note 15)* [2]	**(11,240)**	**(12,614)**	(10,501)	(12,237)
Waneta Partnership promissory note *(Note 17)*	**(56)**	**(59)**	(53)	(56)

[1] In August 2015 the Corporation settled expropriation matters with the GOB regarding the GOB's expropriation of Belize Electricity (Note 9).

[2] The Corporation's $200 million unsecured debentures due 2039 and consolidated borrowings under credit facilities classified as long-term debt of $551 million (December 31, 2014 – $1,096 million) are valued using Level 1 inputs. All other long-term debt is valued using Level 2 inputs.

The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, as is the case with the Waneta Partnership promissory note and certain long-term debt, the fair value is determined by either: (i) discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality; or (ii) obtaining from third parties indicative prices for the same or similarly rated issues of debt of the same remaining maturities. Since the Corporation does not intend to settle the long-term debt or promissory note prior to maturity, the excess of the estimated fair value above the carrying value does not represent an actual liability.

32. FINANCIAL RISK MANAGEMENT

The Corporation is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit risk Risk that a counterparty to a financial instrument might fail to meet its obligations under the terms of the financial instrument.

Liquidity risk Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.

Market risk Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices. The Corporation is exposed to foreign exchange risk, interest rate risk and commodity price risk.

Credit Risk

For cash equivalents, trade and other accounts receivable, and long-term other receivables, the Corporation's credit risk is generally limited to the carrying value on the consolidated balance sheet. The Corporation generally has a large and diversified customer base, which minimizes the concentration of credit risk. The Corporation and its subsidiaries have various policies to minimize credit risk, which include requiring customer deposits, prepayments and/or credit checks for certain customers and performing disconnections and/or using third-party collection agencies for overdue accounts.

FortisAlberta has a concentration of credit risk as a result of its distribution service billings being to a relatively small group of retailers. As at December 31, 2015, FortisAlberta's gross credit risk exposure was approximately $116 million, representing the projected value of retailer billings over a 37-day period. The Company has reduced its exposure to $3 million by obtaining from the retailers either a cash deposit, bond, letter of credit, an investment-grade credit rating from a major rating agency, or a financial guarantee from an entity with an investment-grade credit rating.

UNS Energy, Central Hudson and FortisBC Energy may be exposed to credit risk in the event of non-performance by counterparties to derivative instruments. The Companies use netting arrangements to reduce credit risk and net settle payments with counterparties where net settlement provisions exist. They also limit credit risk by only dealing with counterparties that have investment-grade credit ratings. At UNS Energy, contractual arrangements also contain certain provisions requiring counterparties to derivative instruments to post collateral under certain circumstances.

Liquidity Risk

The Corporation's consolidated financial position could be adversely affected if it, or one of its subsidiaries, fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures, acquisitions and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the consolidated results of operations and financial position of the Corporation and its subsidiaries, conditions in capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To help mitigate liquidity risk, the Corporation and its regulated utilities have secured committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements.

The Corporation's committed corporate credit facility is used for interim financing of acquisitions and for general corporate purposes. Depending on the timing of cash payments from subsidiaries, borrowings under the Corporation's committed corporate credit facility may be required from time to time to support the servicing of debt and payment of dividends. As at December 31, 2015, over the next five years, average annual consolidated fixed-term debt maturities and repayments are expected to be approximately $260 million. The combination of available credit facilities and relatively low annual debt maturities and repayments provides the Corporation and its subsidiaries with flexibility in the timing of access to capital markets.

As at December 31, 2015, the Corporation and its subsidiaries had consolidated credit facilities of approximately $3.6 billion, of which approximately $2.4 billion was unused, including $570 million unused under the Corporation's committed revolving corporate credit facility. The credit facilities are syndicated mostly with the seven largest Canadian banks, as well as large banks in the United States, with no one bank holding more than 20% of these facilities. Approximately $3.3 billion of the total credit facilities are committed facilities with maturities ranging from 2016 through 2020.

The following summary outlines the credit facilities of the Corporation and its subsidiaries.

(in millions)	Regulated Utilities	Corporate and Other	**Total as at December 31, 2015**	Total as at December 31, 2014
Total credit facilities [1]	$ 2,211	$ 1,354	**$ 3,565**	$ 3,854
Credit facilities utilized:				
Short-term borrowings [2]	(511)	–	**(511)**	(330)
Long-term debt *(Note 15)* [3]	(71)	(480)	**(551)**	(1,096)
Letters of credit outstanding	(68)	(36)	**(104)**	(192)
Credit facilities unused	$ 1,561	$ 838	**$ 2,399**	$ 2,236

[1] Total credit facilities exclude a $300 million option to increase the Corporation's committed corporate credit facility, as discussed below.
[2] The weighted average interest rate on short-term borrowings was approximately 1.0% as at December 31, 2015 (December 31, 2014 – 1.3%).
[3] As at December 31, 2015, credit facility borrowings classified as long-term debt included $71 million in current installments of long-term debt on the consolidated balance sheet (December 31, 2014 – $257 million). The weighted average interest rate on credit facility borrowings classified as long-term debt was approximately 1.5% as at December 31, 2015 (December 31, 2014 – 1.8%).

For the years ended December 31, 2015 and 2014

32. FINANCIAL RISK MANAGEMENT (cont'd)

Liquidity Risk (cont'd)

As at December 31, 2015 and 2014, certain borrowings under the Corporation's and subsidiaries' long-term committed credit facilities were classified as long-term debt. It is management's intention to refinance these borrowings with long-term permanent financing during future periods.

Regulated Utilities
The UNS Utilities have a total of US$350 million ($484 million) in unsecured committed revolving credit facilities maturing in October 2020, with the option of two one-year extensions.

Central Hudson has a US$200 million ($277 million) unsecured committed revolving credit facility, maturing in October 2020, that is utilized to finance capital expenditures and for general corporate purposes. Central Hudson also has an uncommitted credit facility totalling US$25 million ($34 million).

FEI has a $700 million unsecured committed revolving credit facility, maturing in August 2018, that is utilized to finance working capital requirements, capital expenditures and for general corporate purposes.

FortisAlberta has a $250 million unsecured committed revolving credit facility, maturing in August 2020, that is utilized to finance capital expenditures and for general corporate purposes.

FortisBC Electric has a $150 million unsecured committed revolving credit facility, maturing in May 2018. This facility is utilized to finance capital expenditures and for general corporate purposes. FortisBC Electric also has a $10 million unsecured demand overdraft facility.

Newfoundland Power has a $100 million unsecured committed revolving credit facility, maturing in August 2019, and a $20 million demand credit facility. Maritime Electric has a $50 million unsecured committed revolving credit facility, maturing in February 2019, and a $5 million unsecured demand credit facility. FortisOntario has a $30 million unsecured committed revolving credit facility, maturing in June 2016.

Caribbean Utilities has unsecured credit facilities totalling approximately US$47 million ($65 million). Fortis Turks and Caicos has short-term unsecured demand credit facilities of US$26 million ($36 million), maturing in September 2016.

Corporate and Other
Fortis has a $1 billion unsecured committed revolving credit facility, maturing in July 2020, that is available for general corporate purposes. The Corporation has the ability to increase this facility to $1.3 billion. As at December 31, 2015, the Corporation has not yet exercised its option for the additional $300 million. The Corporation also has a $35 million letter of credit facility, maturing in January 2017.

UNS Energy Corporation has a US$150 million ($208 million) unsecured committed revolving credit facility, maturing in October 2020, with the option of two one-year extensions.

CH Energy Group has a US$50 million ($69 million) unsecured committed revolving credit facility, maturing in July 2020, that can be utilized for general corporate purposes.

FHI has a $30 million unsecured committed revolving credit facility, maturing in April 2018, that is available for general corporate purposes.

The Corporation and its currently rated utilities target investment-grade credit ratings to maintain capital market access at reasonable interest rates. As at December 31, 2015, the Corporation's credit ratings were as follows:

Standard & Poor's ("S&P")	A– / Stable (long-term corporate and unsecured debt credit rating)
DBRS	A (low) / Stable (unsecured debt credit rating)

The above-noted credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, and management's commitment to maintaining reasonable levels of debt at the holding company level. In February 2016, after the announcement by Fortis that it had entered into an agreement to acquire ITC Holdings Corp. ("ITC") (Note 35), S&P affirmed the Corporation's long-term corporate credit rating at A–, revised its unsecured debt rating to BBB+ from A–, and revised its outlook on the Corporation to negative from stable. Similarly, in February 2016 DBRS placed the Corporation's credit rating under review with negative implications.

Market Risk

Foreign Exchange Risk
The Corporation's earnings from, and net investments in, foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has decreased the above-noted exposure through the use of US dollar-denominated borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange gain or loss on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars. The reporting currency of UNS Energy, Central Hudson, Caribbean Utilities, Fortis Turks and Caicos and BECOL is the US dollar.

As at December 31, 2015, the Corporation's corporately issued US$1,535 million (December 31, 2014 – US$1,496 million) long-term debt had been designated as an effective hedge of a portion of the Corporation's foreign net investments. As at December 31, 2015, the Corporation had approximately US$3,137 million (December 31, 2014 – US$2,762 million) in foreign net investments remaining to be hedged. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar-denominated borrowings designated as effective hedges are recorded on the consolidated balance sheet in accumulated other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the net investments in foreign subsidiaries, which gains and losses are also recorded on the consolidated balance sheet in accumulated other comprehensive income.

On an annual basis, it is estimated that a 5 cent, or 5%, increase or decrease in the US dollar relative to the Canadian dollar exchange rate of US$1.00=CAD$1.38 as at December 31, 2015 would increase or decrease earnings per common share of Fortis by approximately 4 cents. Management will continue to hedge future exchange rate fluctuations related to the Corporation's foreign net investments and US dollar-denominated earnings streams, where possible, through future US dollar-denominated borrowings, and will continue to monitor the Corporation's exposure to foreign currency fluctuations on a regular basis.

Interest Rate Risk

The Corporation and most of its subsidiaries are exposed to interest rate risk associated with borrowings under variable-rate credit facilities, variable-rate long-term debt and the refinancing of long-term debt. The Corporation and its subsidiaries may enter into interest rate swap agreements to help reduce this risk (Notes 15, 16 and 31).

Commodity Price Risk

UNS Energy is exposed to commodity price risk associated with changes in the market price of gas, purchased power and coal. Central Hudson is exposed to commodity price risk associated with changes in the market price of electricity and natural gas. FortisBC Energy is exposed to commodity price risk associated with changes in the market price of natural gas. The risks have been reduced by entering into derivative contracts that effectively fix the price of natural gas, power and electricity purchases. These derivative instruments are recorded on the consolidated balance sheet at fair value and any change in the fair value is deferred as a regulatory asset or liability, as permitted by the regulators, for recovery from, or refund to, customers in future rates (Note 31).

33. COMMITMENTS

As at December 31, 2015, the Corporation's consolidated commitments in each of the next five years and for periods thereafter, excluding repayments of long-term debt and capital lease and finance obligations separately disclosed in Notes 15 and 16, respectively, are as follows:

($ in millions)	**Total**	Due within 1 year	Due in year 2	Due in year 3	Due in year 4	Due in year 5	Due after 5 years
Interest obligations on long-term debt	**9,435**	536	512	507	495	488	6,897
Renewable power purchase obligations [1]	**1,589**	93	93	92	92	92	1,127
Gas purchase obligations [2]	**1,449**	366	253	222	153	131	324
Power purchase obligations [3]	**1,440**	281	209	180	102	36	632
Long-term contracts – UNS Energy [4]	**1,057**	146	141	105	102	82	481
Capital cost [5]	**488**	19	19	19	19	19	393
Operating lease obligations [6]	**181**	12	11	11	11	8	128
Renewable energy credit purchase agreements [7]	**162**	13	13	13	13	13	97
Purchase of Springerville Common Facilities [8]	**147**	–	53	–	–	–	94
Defined benefit pension and OPEB funding contributions *(Note 27)*	**139**	49	12	8	9	9	52
Waneta Partnership promissory note *(Note 17)*	**72**	–	–	–	–	72	–
Joint-use asset and shared service agreements	**53**	3	3	3	3	3	38
Other [9]	**71**	15	12	16	3	–	25
Total	**16,283**	1,533	1,331	1,176	1,002	953	10,288

For the years ended December 31, 2015 and 2014

33. COMMITMENTS (cont'd)

(1) TEP and UNS Electric are party to 20-year long-term renewable PPAs totalling approximately US$1,148 million as at December 31, 2015, which require TEP and UNS Electric to purchase 100% of the output of certain renewable energy generating facilities that have achieved commercial operation. While TEP and UNS Electric are not required to make payments under these contracts if power is not delivered, the table above includes estimated future payments based on expected power deliveries. These agreements have various expiry dates through 2035. TEP has entered into additional long-term renewable PPAs to comply with renewable energy standards of the State of Arizona; however, the Company's obligation to purchase power under these agreements does not begin until the facilities are operational. In February 2016 one of the generating facilities achieved commercial operation, increasing estimated future payments of renewable PPAs by US$58 million, which is not included in the table above.

(2) Certain of the Corporation's subsidiaries, mainly FortisBC Energy and Central Hudson, enter into contracts for the purchase of gas, gas transportation and storage services. FortisBC Energy's gas purchase obligations are based on gas commodity indices that vary with market prices and the obligations are based on index prices as at December 31, 2015. At Central Hudson, the obligations are based on tariff rates, negotiated rates and market prices as at December 31, 2015.

(3) Power purchase obligations include various power purchase contracts held by certain of the Corporation's subsidiaries, as described below.

FortisBC Energy
In March 2015 FortisBC Energy entered into an Electricity Supply Agreement with BC Hydro for the purchase of electricity supply to the Tilbury Expansion Project, with purchase obligations totalling $513 million as at December 31, 2015.

FortisBC Electric
Power purchase obligations for FortisBC Electric, totalling $292 million as at December 31, 2015, mainly include a PPA with BC Hydro to purchase up to 200 MW of capacity and 1,752 GWh of associated energy annually for a 20-year term, as approved by the BCUC. The capacity and energy to be purchased under this agreement do not relate to a specific plant.

In addition, in November 2011 FortisBC Electric executed the Waneta Expansion Capacity Agreement ("WECA"), allowing FortisBC Electric to purchase 234 MW of capacity for 40 years, effective April 2015, as approved by the BCUC. Amounts associated with the WECA have not been included in the Commitments table as they are to be paid by FortisBC Electric to a related party and such a related-party transaction would be eliminated upon consolidation with Fortis.

FortisOntario
Power purchase obligations for FortisOntario, totalling $208 million as at December 31, 2015, primarily include two long-term take-or-pay contracts between Cornwall Electric and Hydro-Quebec Energy Marketing for the supply of electricity and capacity, both expiring in December 2019. The first contract provides approximately 237 GWh of energy per year and up to 45 MW of capacity at any one time. The second contract provides 100 MW of capacity and provides a minimum of 300 GWh of electricity per contract year.

Maritime Electric
Power purchase obligations for Maritime Electric, totalling $194 million as at December 31, 2015, primarily include two take-or-pay contracts for the purchase of either capacity or energy, expiring in February 2019 and November 2032, as well as an Energy Purchase Agreement with New Brunswick Power ("NB Power") expiring in February 2019.

Central Hudson
Central Hudson's power purchase obligations totalled US$124 million as at December 31, 2015. In June 2014 Central Hudson entered into a contract to purchase available installed capacity from the Danskammer Generating Facility from October 2014 through August 2018 with approximately US$76 million in purchase commitments remaining as at December 31, 2015. During 2015 Central Hudson entered into agreements to purchase electricity on a unit-contingent basis at defined prices during peak load periods from June 2015 through August 2016, replacing existing contracts which expired in March 2015.

(4) UNS Energy has entered into various long-term contracts for the purchase and delivery of coal to fuel its generating facilities, the purchase of gas transportation services to meet its load requirements, and the purchase of transmission services for purchased power, with obligations totalling US$440 million, US$261 million and US$63 million, respectively, as at December 31, 2015. Amounts paid under contracts for the purchase and delivery of coal depend on actual quantities purchased and delivered. Certain of these contracts also have price adjustment clauses that will affect future costs under the contracts. As a result of the restructuring of the ownership of the San Juan generating station in January 2016, a new coal supply agreement came into effect under which TEP's minimum purchase obligations are US$137 million, which is not included in the previous table.

(5) Maritime Electric has entitlement to approximately 4.55% of the output from NB Power's Point Lepreau nuclear generating station for the life of the unit. As part of its entitlement, Maritime Electric is required to pay its share of the capital and operating costs of the unit.

(6) Operating lease obligations include certain office, warehouse, natural gas T&D asset, rail car, land easement and rights-of-way, and vehicle and equipment leases.

(7) UNS Energy is party to renewable energy credit purchase agreements, totalling approximately US$117 million as at December 31, 2015, to purchase the environmental attributions from retail customers with solar installations. Payments for the renewable energy credit purchase agreements are paid in contractually agreed-upon intervals based on metered renewable energy production.

(8) UNS Energy has entered into a commitment to exercise its fixed-price purchase provision to purchase an undivided 50% leased interest in the Springerville Common Facilities if the lease is not renewed, for a purchase price of US$106 million, with one facility to be acquired in 2017 and the remaining two facilities to be acquired in 2021 (Note 16).

(9) Other contractual obligations include various other commitments entered into by the Corporation and its subsidiaries, including PSU, RSU and DSU Plan obligations and asset retirement obligations.

Other Commitments

Capital Expenditures: The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by the need to ensure continued and enhanced performance, reliability and safety of the electricity and gas systems and to meet customer growth. The Corporation's consolidated capital expenditure program, including capital spending at its non-regulated operations, is forecast to be approximately $1.9 billion for 2016. Over the five years 2016 through 2020, the Corporation's consolidated capital expenditure program is expected to be approximately $9 billion, which has not been included in the Commitments table.

Other: CH Energy Group is party to an investment to develop, own and operate electric transmission projects in New York State. In December 2014 an application was filed with FERC for the recovery of the cost of and return on five high-voltage transmission projects totalling US$1.7 billion, of which CH Energy Group's maximum commitment is US$182 million. CH Energy Group issued a parental guarantee to assure the payment of a maximum commitment of US$182 million. As at December 31, 2015, no payment obligation is expected under this guarantee.

FortisBC Energy issued commitment letters to customers, totalling $33 million as at December 31, 2015, to provide Energy Efficiency and Conservation ("EEC") funding under the EEC program approved by the BCUC.

Caribbean Utilities is party to primary and secondary fuel supply contracts and is committed to purchasing approximately 60% and 40%, respectively, of the Company's diesel fuel requirements under the contracts for the operation of its diesel-powered generating plant. The approximate combined quantity under the contracts for 2016 is 20 million imperial gallons. Fortis Turks and Caicos has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

The Corporation's long-term regulatory liabilities of $1,340 million as at December 31, 2015 have been excluded from the Commitments table, as the final timing of settlement of many of the liabilities is subject to further regulatory determination or the settlement periods are not currently known. The nature and amount of the long-term regulatory liabilities are detailed in Note 8.

34. CONTINGENCIES

The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with the ordinary course of business operations. Management believes that the amount of liability, if any, from these actions would not have a material adverse effect on the Corporation's consolidated financial position or results of operations.

The following describes the nature of the Corporation's contingencies.

UNS Energy

Springerville Unit 1

In November 2014 the Springerville Unit 1 third-party owners filed a complaint ("FERC Action") against TEP with FERC, alleging that TEP had not agreed to wheel power and energy for the third-party owners in the manner specified in the existing Springerville Unit 1 facility support agreement between TEP and the third-party owners and for the cost specified by the third-party owners. The third-party owners requested an order from FERC requiring such wheeling of the third-party owners' energy from their Springerville Unit 1 interests beginning in January 2015 for the price specified by the third-party owners. In February 2015 FERC issued an order denying the third-party owners' complaint. In March 2015 the third-party owners filed a request for rehearing in the FERC Action, which FERC denied in October 2015. In December 2015 the third-party owners appealed FERC's order denying the third-party owners' complaint to the U.S. Court of Appeals for the Ninth Circuit. In December 2015 TEP filed an unopposed motion to intervene in the Ninth Circuit appeal.

In December 2014 the third-party owners filed a complaint ("New York Action") against TEP in the Supreme Court of the State of New York, New York County. In response to motions filed by TEP to dismiss various counts and compel arbitration of certain of the matters alleged and the court's subsequent ruling on the motions, the third-party owners have amended the complaint three times, dropping certain of the allegations and raising others in the New York Action and in the arbitration proceeding described below. As amended, the New York Action alleges, among other things, that TEP failed to properly operate, maintain and make capital investments in Springerville Unit 1 during the term of the leases; and that TEP breached the lease transaction documents by refusing to pay certain of the third-party owners' claimed expenses. The third amended complaint seeks US$71 million in liquidated damages and direct and consequential damages in an amount to be determined at trial. The third-party owners have also agreed to stay their claim that TEP has not agreed to wheel power and energy as required pending the outcome of the FERC Action. In November 2015 the third-party owners filed a motion for summary judgment on their claim that TEP failed to pay certain of the third-party owners' claimed expenses.

In December 2014 and January 2015, Wilmington Trust Company, as owner trustees and lessors under the leases of the third-party owners, sent notices to TEP that alleged that TEP had defaulted under the third-party owners' leases. The notices demanded that TEP pay liquidated damages totalling approximately US$71 million. In letters to the owner trustees, TEP denied the allegations in the notices.

In April 2015 TEP filed a demand for arbitration with the American Arbitration Association ("AAA") seeking an award of the owner trustees and co-trustees' share of unreimbursed expenses and capital expenditures for Springerville Unit 1. In June 2015 the third-party owners filed a separate demand for arbitration with the AAA alleging, among other things, that TEP has failed to properly operate, maintain and make capital investments in Springerville Unit 1 since the leases have expired. The third-party owners' arbitration demand seeks declaratory judgments, damages in an amount to be determined by the arbitration panel and the third-party owners' fees and expenses. TEP and the third-party owners have since agreed to consolidate their arbitration demands into one proceeding. In August 2015 the third-party owners filed an amended arbitration demand adding claims that TEP has converted the third-party owners' water rights and certain emission reduction payments and that TEP is improperly dispatching the third-party owners' unscheduled Springerville Unit 1 power and capacity.

In October 2015 the arbitration panel granted TEP's motion for interim relief, ordering the owner trustees and co-trustees to pay TEP their pro-rata share of unreimbursed expenses and capital expenditures for Springerville Unit 1 during the pendency of the arbitration. The arbitration panel also denied the third-party owners' motion for interim relief, which had requested that TEP be enjoined from dispatching the third-party owners' unscheduled Springerville Unit 1 power and capacity. TEP has been scheduling the third-party owners' entitlement share of power from Springerville Unit 1, as permitted under the Springerville Unit 1 facility support agreement, since June 2015. The arbitration hearing is scheduled for July 2016.

In November 2015 TEP filed a petition to confirm the interim arbitration order in the Supreme Court of the State of New York naming owner trustee and co-trustee as respondents. The petition seeks an order from the court confirming the interim arbitration order under the *Federal Arbitration Act*. In December 2015 the owner trustees filed an answer to the petition and a cross-motion to vacate the interim arbitration order.

As at December 31, 2015, TEP billed the third-party owners approximately US$23 million for their pro-rata share of Springerville Unit 1 expenses and US$4 million for their pro-rata share of capital expenditures, none of which had been paid as of February 17, 2016.

TEP cannot predict the outcome of the claims relating to Springerville Unit 1 and, due to the general and non-specific scope and nature of the claims, the Company cannot determine estimates of the range of loss, if any, at this time and, accordingly, no amount has been accrued in the consolidated financial statements. TEP intends to vigorously defend itself against the claims asserted by the third-party owners and to vigorously pursue the claims it has asserted against the third-party owners.

TEP and the third-party owners have agreed to stay these litigation matters relating to Springerville Unit 1 in furtherance of settlement negotiations. However, there is no assurance that a settlement will be reached or that the litigation will not continue.

Mine Reclamation Costs

TEP pays ongoing reclamation costs related to coal mines that supply generating stations in which the Company has an ownership interest but does not operate. TEP is liable for a portion of final reclamation costs upon closure of the mines servicing the San Juan, Four Corners and Navajo generating stations. TEP's share of reclamation costs at all three mines is expected to be US$43 million upon expiration of the coal supply agreements, which expire between 2019 and 2031. The mine reclamation liability recorded as at December 31, 2015 was US$25 million (December 31, 2014 – US$22 million), and represents the present value of the estimated future liability (Note 17).

Amounts recorded for final reclamation are subject to various assumptions, such as estimations of reclamation costs, the dates when final reclamation will occur, and the expected inflation rate. As these assumptions change, TEP will prospectively adjust the expense amounts for final reclamation over the remaining coal supply agreements' terms.

TEP is permitted to fully recover these costs from retail customers and, accordingly, these costs are deferred as a regulatory asset (Note 8 *(ix)*).

Central Hudson

Site Investigation and Remediation Program

Central Hudson and its predecessors owned and operated MGPs to serve their customers' heating and lighting needs. These plants manufactured gas from coal and oil beginning in the mid to late 1800s, with all sites ceasing operations by the 1950s. This process produced certain by-products that may pose risks to human health and the environment.

The New York State Department of Environmental Conservation ("DEC"), which regulates the timing and extent of remediation of MGP sites in New York State, has notified Central Hudson that it believes the Company or its predecessors at one time owned and/or operated MGPs at seven sites in Central Hudson's franchise territory. The DEC has further requested that the Company investigate and, if necessary, remediate these sites under a Consent Order, Voluntary Clean-up Agreement or Brownfield Clean-up Agreement. Central Hudson accrues for remediation costs based on the amounts that can be reasonably estimated. As at December 31, 2015, an obligation of US$92 million (December 31, 2014 – US$105 million) was recognized in respect of site investigation and remediation and, based upon cost model analysis completed in 2014, it is estimated, with a 90% confidence level, that total costs to remediate these sites over the next 30 years will not exceed US$169 million.

Central Hudson has notified its insurers and intends to seek reimbursement from insurers for remediation, where coverage exists. Further, as authorized by the PSC, Central Hudson is currently permitted to defer, for future recovery from customers, differences between actual costs for MGP site investigation and remediation and the associated rate allowances, with carrying charges to be accrued on the deferred balances at the authorized pre-tax rate of return. In the three-year rate order issued by the PSC in June 2015, Central Hudson's authorization to defer all site investigation and remediation costs was reaffirmed and extended through June 2018 (Note 8 *(iv)*).

For the years ended December 31, 2015 and 2014

34. CONTINGENCIES (cont'd)

Central Hudson (cont'd)

Asbestos Litigation

Prior to and after its acquisition by Fortis, various asbestos lawsuits have been brought against Central Hudson. While a total of 3,350 asbestos cases have been raised, 1,167 remained pending as at December 31, 2015. Of the cases no longer pending against Central Hudson, 2,027 have been dismissed or discontinued without payment by the Company, and Central Hudson has settled the remaining 156 cases. The Company is presently unable to assess the validity of the outstanding asbestos lawsuits; however, based on information known to Central Hudson at this time, including the Company's experience in the settlement and/or dismissal of asbestos cases, Central Hudson believes that the costs which may be incurred in connection with the remaining lawsuits will not have a material effect on its financial position, results of operations or cash flows and, accordingly, no amount has been accrued in the consolidated financial statements.

FortisBC Electric

The Government of British Columbia filed a claim in the British Columbia Supreme Court in June 2012 claiming on its behalf, and on behalf of approximately 17 homeowners, damages suffered as a result of a landslide caused by a dam failure in Oliver, British Columbia in 2010. The Government of British Columbia alleges in its claim that the dam failure was caused by the defendants', which include FortisBC Electric, use of a road on top of the dam. The Government of British Columbia estimates its damages and the damages of the homeowners, on whose behalf it is claiming, to be approximately $15 million. While FortisBC Electric has notified its insurers, it has been advised by the Government of British Columbia that a response to the claim is not required at this time. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

FHI

In April 2013 FHI and Fortis were named as defendants in an action in the B.C. Supreme Court by the Coldwater Indian Band ("Band"). The claim is in regard to interests in a pipeline right of way on reserve lands. The pipeline on the right of way was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in April 2007. The Band seeks orders cancelling the right of way and claims damages for wrongful interference with the Band's use and enjoyment of reserve lands. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

35. SUBSEQUENT EVENT

On February 9, 2016, Fortis and ITC (NYSE:ITC) entered into an agreement and plan of merger pursuant to which Fortis will acquire ITC in a transaction (the "Acquisition") valued at approximately US$11.3 billion, based on the closing price for Fortis common shares and the foreign exchange rate on February 8, 2016. Under the terms of the transaction, ITC shareholders will receive US$22.57 in cash and 0.7520 Fortis common shares per ITC common share, representing total consideration of approximately US$6.9 billion, and Fortis will assume approximately US$4.4 billion of ITC consolidated indebtedness.

ITC is the largest independent pure-play electric transmission company in the United States. ITC owns and operates high-voltage transmission facilities in Michigan, Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma, serving a combined peak load exceeding 26,000 MW along approximately 15,600 miles of transmission line. In addition, ITC is a public utility and independent transmission owner in Wisconsin. ITC's tariff rates are regulated by FERC, which has been one of the most consistently supportive utility regulators in North America providing reasonable returns and equity ratios. Rates are set using a forward-looking rate-setting mechanism with an annual true-up, which provides timely cost recovery and reduces regulatory lag.

The closing of the Acquisition is subject to ITC and Fortis shareholder approvals, the satisfaction of other customary closing conditions, and certain regulatory, state and federal approvals including, among others, those of FERC, the Committee on Foreign Investment in the United States, and the United States Federal Trade Commission/Department of Justice under the *Hart-Scott-Rodino Antitrust Improvements Act*. The closing of the Acquisition is expected to occur in late 2016.

The pending Acquisition is in alignment with the Corporation's business model and acquisition strategy, and is expected to provide approximately 5% accretion to earnings per common share in the first full year following closing, excluding one-time acquisition-related expenses and assuming a stable currency exchange environment. The Acquisition represents a singular opportunity for Fortis to significantly diversify its business in terms of regulatory jurisdictions, business risk profile and regional economic mix. On a pro forma basis, 2016 forecast midyear rate base of Fortis is expected to increase by approximately $8 billion to approximately $26 billion, as a result of the Acquisition.

The financing of the Acquisition has been structured to allow Fortis to maintain investment-grade credit ratings and is consistent with the Corporation's existing capital structure. Financing of the cash portion of the Acquisition will be achieved primarily through the issuance of approximately US$2 billion of Fortis debt and the sale of up to 19.9% of ITC to one or more infrastructure-focused minority investors. In addition, Fortis has obtained commitments of US$2.0 billion from Goldman Sachs Bank USA to bridge the long-term debt financing and US$1.7 billion from The Bank of Nova Scotia to primarily bridge the sale of the minority investment in ITC. These non-revolving term credit facilities are repayable in full on the first anniversary of their advance and although syndication is not required, Fortis expects that these bridge facilities will be syndicated.

Upon completion of the Acquisition, ITC will become a subsidiary of Fortis and approximately 27% of the common shares of Fortis will be held by ITC shareholders. In connection with the Acquisition, Fortis will become a registrant with the U.S. Securities and Exchange Commission and will apply to list its common shares on the New York Stock Exchange and will continue to have its shares listed on the TSX.

36. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to comply with current period presentation. As a result of the adoption of new accounting policies in 2015 (Note 3), the following changes to the Corporation's comparative financial statements were made:

(i) the reclassification of deferred financing costs of approximately $65 million from long-term other assets to long-term debt on the Corporation's consolidated balance sheet as at December 31, 2014 (Note 15); and

(ii) the presentation of all deferred income tax assets and liabilities as long term. This change in presentation resulted in the following reclassifications: (i) a decrease in current deferred income taxes assets of $158 million; (ii) a decrease in long-term deferred income tax assets of $62 million; (iii) a decrease in current deferred income tax liabilities of $9 million; and (iv) a decrease in long-term deferred income tax liabilities of $211 million on the consolidated balance sheet as at December 31, 2014 (Note 26). In addition, the Corporation also reclassified the associated regulatory deferred income taxes as long-term, resulting in the following reclassifications: (i) a decrease in current regulatory assets of $18 million; (ii) a decrease in long-term regulatory assets of $92 million; (iii) a decrease in current regulatory liabilities of $19 million; and (iv) a decrease in long-term regulatory liabilities of $91 million on the consolidated balance sheet as at December 31, 2014 (Note 8).

Historical Financial Summary

Statements of Earnings *(in $ millions)*	**2015** [1]	2014 [1][2][3]	2013 [1][3]
Revenue	**6,727**	5,401	4,047
Energy supply costs and operating expenses	**4,425**	3,690	2,654
Depreciation and amortization	**873**	688	541
Other income (expenses), net	**187**	(25)	(31)
Finance charges	**553**	547	389
Income tax expense	**223**	66	32
Earnings from continuing operations	**840**	385	400
Earnings from discontinued operations, net of tax	**–**	5	–
Extraordinary gain, net of tax	**–**	–	20
Net earnings	**840**	390	420
Net earnings attributable to non-controlling interests	**35**	11	10
Net earnings attributable to preference equity shareholders	**77**	62	57
Net earnings attributable to common equity shareholders	**728**	317	353
Balance Sheets *(in $ millions)*			
Current assets	**1,857**	1,787	1,296
Goodwill	**4,173**	3,732	2,075
Other long-term assets	**2,638**	2,410	1,925
Utility capital assets, non-utility capital assets and intangible assets	**20,136**	18,304	12,612
Total assets	**28,804**	26,233	17,908
Current liabilities	**2,638**	2,676	2,084
Other long-term liabilities	**5,029**	4,534	3,024
Long-term debt (excluding current portion)	**10,784**	9,911	6,424
Preference shares (classified as debt)	**–**	–	–
Total liabilities	**18,451**	17,121	11,532
Shareholders' equity	**10,353**	9,112	6,376
Cash Flows *(in $ millions)*			
Operating activities	**1,673**	982	899
Investing activities	**(1,368)**	(4,199)	(2,164)
Financing activities, excluding dividends	**(14)**	3,627	1,434
Dividends, excluding dividends on preference shares classified as debt	**(332)**	(266)	(248)
Financial Statistics			
Return on average book common shareholders' equity *(%)*	**9.75**	5.45	8.06
Capitalization Ratios *(%)* (year end)			
Total debt and capital lease and finance obligations (net of cash)	**54.8**	56.4	56.2
Preference shares (classified as debt and equity)	**8.3**	9.1	9.0
Common shareholders' equity	**36.9**	34.5	34.8
Interest Coverage *(x)*			
Debt	**2.7**	1.6	1.9
All fixed charges	**2.7**	1.6	1.9
Total gross capital expenditures *(in $ millions)*	**2,243**	1,725	1,175
Common share data			
Book value per share (year end) *($)*	**28.62**	24.89	22.38
Average common shares outstanding *(in millions)*	**278.6**	225.6	202.5
Basic earnings per common share *($)*	**2.61**	1.41	1.74
Dividends declared per common share *($)*	**1.43**	1.30	1.25
Dividends paid per common share *($)*	**1.40**	1.28	1.24
Dividend payout ratio *(%)*	**53.6**	90.8	71.3
Price earnings ratio *(x)*	**14.3**	27.6	17.5
Share trading summary (TSX)			
High price *($)*	**42.23**	40.83	35.14
Low price *($)*	**34.16**	29.78	29.51
Closing price *($)*	**37.41**	38.96	30.45
Volume *(in thousands)*	**172,038**	174,566	120,470

[1] Financial information for the years 2010 through 2015 prepared under US generally accepted accounting principles ("GAAP"); prior to 2010 prepared under Canadian GAAP.

[2] Certain 2014 comparative figures have been reclassified to comply with current period classifications.

[3] Results were impacted by non-recurring items, largely associated with the acquisition of UNS Energy in 2014 and Central Hudson in 2013.

Historical Financial Summary

2012 [1]	2011 [1]	2010 [1]	2009	2008	2007	2006
3,654	3,738	3,647	3,641	3,907	2,718	1,472
2,390	2,547	2,448	2,577	2,859	1,904	939
470	416	406	364	348	273	178
4	38	13	10	–	8	2
366	363	359	369	363	299	168
61	84	72	49	65	36	32
371	366	375	292	272	214	157
–	–	–	–	–	–	–
–	–	–	–	–	–	–
371	366	375	292	272	214	157
9	9	10	12	13	15	8
47	46	45	18	14	6	2
315	311	320	262	245	193	147
1,093	1,132	1,205	1,124	1,150	1,038	405
1,568	1,565	1,561	1,560	1,575	1,544	661
1,715	1,580	1,309	917	487	424	331
10,574	9,937	9,336	8,538	7,954	7,276	4,049
14,950	14,214	13,411	12,139	11,166	10,282	5,446
1,350	1,305	1,491	1,592	1,697	1,804	558
2,449	2,281	1,977	1,325	763	732	508
5,741	5,685	5,616	5,239	4,848	4,588	2,532
–	–	–	320	320	320	320
9,540	9,271	9,084	8,476	7,628	7,444	3,918
5,410	4,943	4,327	3,663	3,538	2,838	1,528
992	915	742	681	661	373	263
(1,096)	(1,115)	(980)	(1,045)	(852)	(2,033)	(634)
396	386	451	563	387	1,826	456
(225)	(206)	(189)	(176)	(191)	(146)	(77)
8.06	8.79	10.06	8.41	8.70	10.00	11.87
55.3	57.1	60.4	60.2	59.5	64.3	61.1
9.7	8.3	8.7	6.9	7.3	5.2	10.0
35.0	34.6	30.9	32.9	33.2	30.5	28.9
2.0	2.0	2.0	1.9	1.9	1.9	2.2
2.0	2.0	2.0	1.8	1.8	1.7	2.0
1,146	1,171	1,071	1,024	935	803	500
20.84	20.25	18.65	18.61	17.97	16.69	12.19
190.0	181.6	172.9	170.2	157.4	137.6	103.6
1.66	1.71	1.85	1.54	1.56	1.40	1.42
1.21	1.17	1.41	0.78	1.01	0.88	0.70
1.20	1.16	1.12	1.04	1.00	0.82	0.67
72.3	67.8	60.5	67.5	64.1	58.6	47.2
20.6	19.5	18.4	18.6	15.8	20.7	21.0
34.98	35.45	34.54	29.24	29.94	30.00	30.00
31.70	28.24	21.60	21.52	20.70	24.50	20.36
34.22	33.37	33.98	28.68	24.59	28.99	29.77
115,962	126,341	120,855	121,162	132,108	100,920	60,094

Investor Information

Expected Dividend* and Earnings Release Dates

Dividend Record Dates

May 18, 2016	August 19, 2016
November 18, 2016	February 16, 2017

Dividend Payment Dates

June 1, 2016	September 1, 2016
December 1, 2016	March 1, 2017

Earnings Release Dates

May 3, 2016	July 29, 2016
November 4, 2016	February 16, 2017

** The setting of dividend record dates and the declaration and payment of dividends are subject to the Board of Directors' approval.*

Transfer Agent and Registrar

Computershare Trust Company of Canada ("Computershare" or "Transfer Agent") is responsible for the maintenance of shareholder records and the issuance, transfer and cancellation of stock certificates. Transfers can be effected at its Halifax, Montreal and Toronto offices. Computershare also distributes dividends and shareholder communications. Inquiries with respect to these matters and corrections to shareholder information should be addressed to the Transfer Agent.

Computershare Trust Company of Canada

8th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
T: 514.982.7555 or 1.866.586.7638
F: 416.263.9394 or 1.888.453.0330
W: www.investorcentre.com/fortisinc

Direct Deposit of Dividends

Shareholders may arrange for automatic electronic deposit of dividends to their designated Canadian financial institutions by contacting the Transfer Agent.

Duplicate Annual Reports

While every effort is made to avoid duplications, some shareholders may receive extra reports as a result of multiple share registrations. Shareholders wishing to consolidate these accounts should contact the Transfer Agent.

Eligible Dividend Designation

For purposes of the enhanced dividend tax credit rules contained in the *Income Tax Act* (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on common and preferred shares after December 31, 2005 by Fortis to Canadian residents are designated as "eligible dividends". Unless stated otherwise, all dividends paid by Fortis hereafter are designated as "eligible dividends" for the purposes of such rules.

Annual Meeting

Thursday, May 5, 2016
10:30 a.m.
Holiday Inn St. John's
180 Portugal Cove Road
St. John's, NL Canada

Dividend Reinvestment Plan and Consumer Share Purchase Plan

Fortis offers a Dividend Reinvestment Plan ("DRIP")[1] and a Consumer Share Purchase Plan ("CSPP")[2] as a convenient method for Common Shareholders to increase their investments in Fortis. Participants have dividends plus any optional contributions (DRIP: minimum of $100, maximum of $30,000 annually; CSPP: minimum of $25, maximum of $20,000 annually) automatically deposited in the Plans to purchase additional Common Shares. Shares can be purchased quarterly on March 1, June 1, September 1 and December 1 at the average market price then prevailing on the Toronto Stock Exchange. The DRIP currently offers a 2% discount on the purchase of Common Shares, issued from treasury, with the reinvested dividends. Inquiries should be directed to the Transfer Agent.

[1] *All registered holders of Common Shares who are residents of Canada are eligible to participate in the DRIP. Shareholders residing outside Canada may also participate unless participation is not allowed in that jurisdiction. Residents of the United States, its territories or possessions are not eligible to participate.*

[2] *The CSPP is offered to residents of the provinces of Newfoundland and Labrador and Prince Edward Island.*

Share Listings

The Common Shares; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series I; First Preference Shares, Series J; First Preference Shares, Series K; and First Preference Shares, Series M of Fortis Inc. are listed on the Toronto Stock Exchange and trade under the ticker symbols FTS, FTS.PR.E, FTS.PR.F, FTS.PR.G, FTS.PR.H, FTS.PR.I, FTS.PR.J, FTS.PR.K and FTS.PR.M, respectively.

Valuation Day

For capital gains purposes, the valuation day prices are as follows:

December 22, 1971	$1.531
February 22, 1994	$7.156

Analyst and Investor Inquiries

T: 709.737.2800
F: 709.737.5307
E: investorrelations@fortisinc.com

Fortis Inc. Executive

Barry V. Perry
President and Chief Executive Officer

Karl W. Smith
Executive Vice President, Chief Financial Officer

Nora M. Duke
Executive Vice President,
Corporate Services and Chief Human Resource Officer

Earl A. Ludlow
Executive Vice President,
Eastern Canadian and Caribbean Operations

David C. Bennett
Vice President, Chief Legal Officer and Corporate Secretary

Janet A. Craig
Vice President, Investor Relations

Karen J. Gosse
Vice President, Planning and Forecasting

Annette M. Iwasaki
Vice President, Talent Management

James D. Roberts
Vice President, Controller

James D. Spinney
Vice President, Treasurer

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Shawn Talbot, Kelowna, BC
Ned Pratt, St. John's, NL

Design and Production:
Colour, St. John's, NL
colour-nl.ca

Moveable Inc., Toronto, ON

Printer:
The Lowe-Martin Group, Ottawa, ON

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Chair, Fortis Inc.
St. John's, Newfoundland and Labrador

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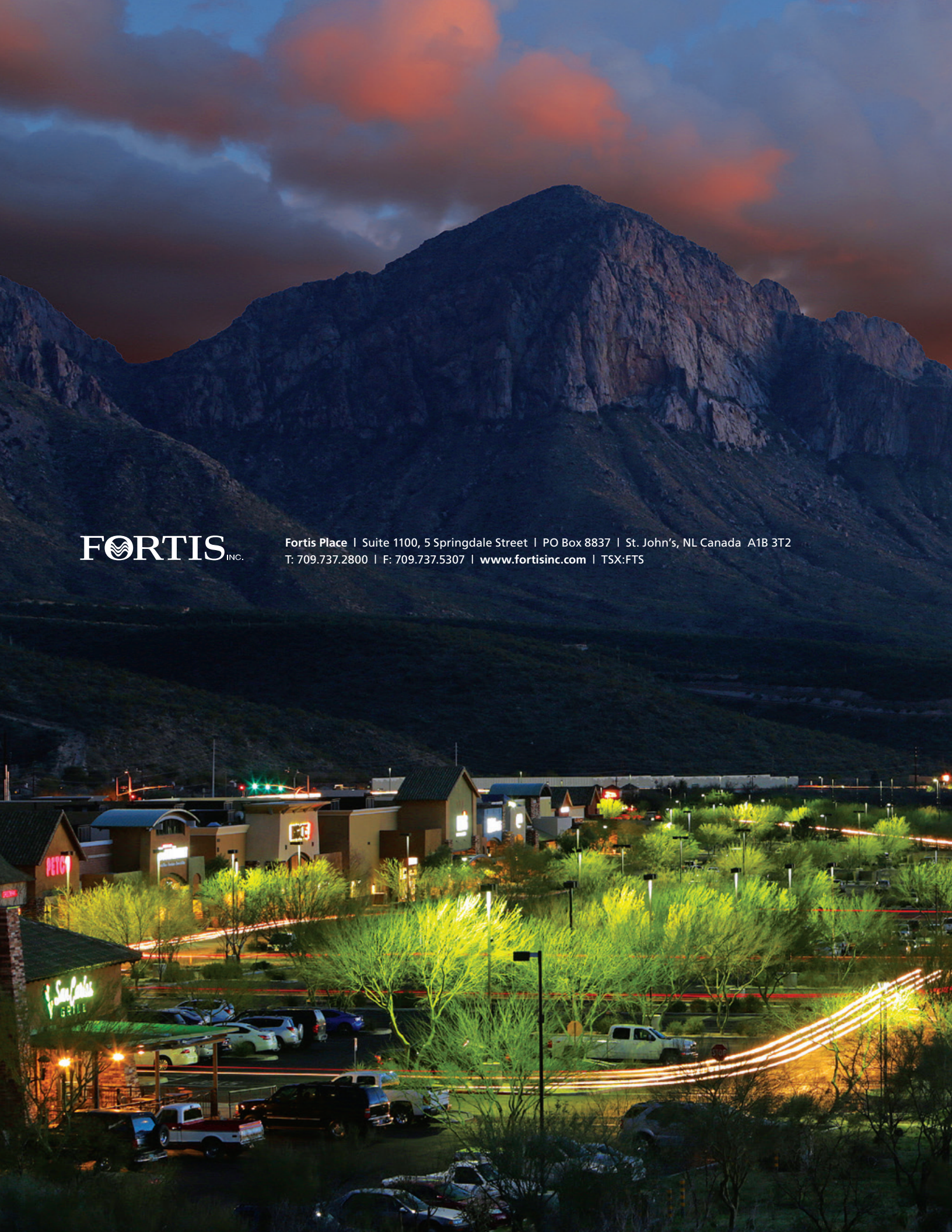
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President, Vintage Consulting Group Inc.
Summerland, British Columbia

Ronald D. Munkley ✷ ★
Corporate Director
Mississauga, Ontario

Barry V. Perry
President and CEO, Fortis Inc.
St. John's, Newfoundland and Labrador

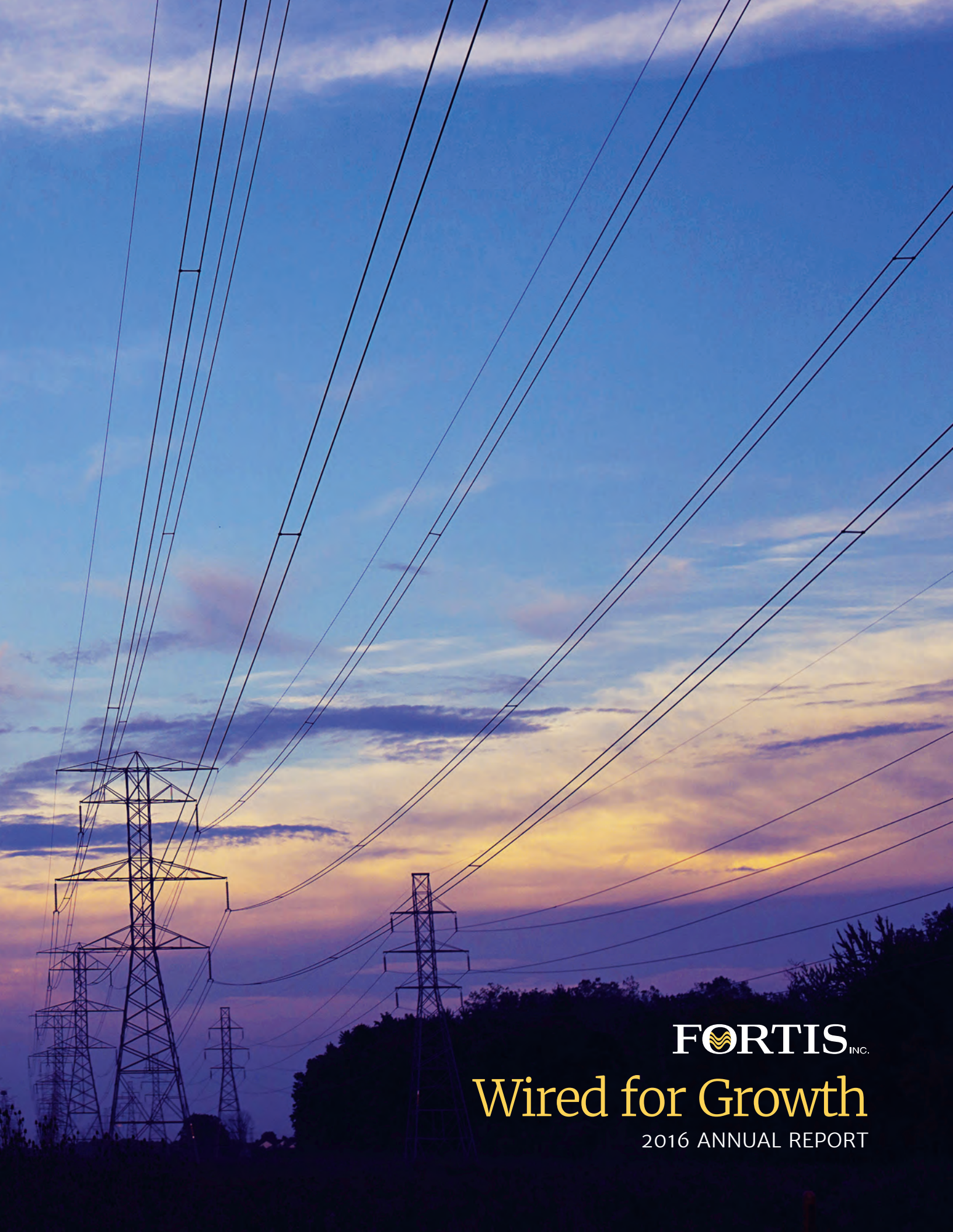
⁎ Audit Committee
✷ Human Resources Committee
★ Governance and Nominating Committee

For Board of Directors' biographies, please visit www.fortisinc.com.



FORTIS INC.

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T: 709.737.2800 | F: 709.737.5307 | **www.fortisinc.com** | TSX:FTS



FORTIS INC.

Wired for Growth

2016 ANNUAL REPORT



FORTIS INC. Quick Facts

Based in
ST. JOHN'S,
Newfoundland and Labrador

10 UTILITY OPERATIONS
in Canada, the U.S. and the Caribbean

8,000+
EMPLOYEES

$48 BILLION
IN **ASSETS**

2 MILLION
ELECTRIC
Utility Customers

1.2 MILLION
GAS
Utility Customers

$16.6 BILLION
MARKET CAP
(as of December 31, 2016)

TSX/NYSE:FTS

Newfoundland and Labrador

Prince Edward Island

Ontario

Minnesota

Michigan

New York

Iowa

Illinois

Kansas

Missouri

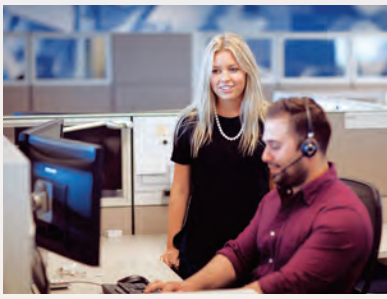
Oklahoma

Turks and Caicos Islands

Cayman Islands

Belize

- Regulated Electric
- Regulated Gas
- FERC-Regulated Electric Transmission
- Long-Term Contracted Hydro Generation











Regulated, Low Risk and Diversified Utility Business

Regulated

Utility	Customers Electric (#)	Customers Gas (#)	Employees (#)	Peak Demand Electric (MW)	Peak Demand Gas (TJ)	Sales Electric (GWh)	Volumes Gas (PJ)	Earnings ($M)	Total Assets ($B)	2017F[1] Midyear Rate Base ($B)	2017F[1] Capital Program ($M)
ITC[2]	–	–	660	23,231	–	–	–	59	18.0	7.3	958
UNS Energy	515,000	154,000	2,023	3,386	103	14,387	13	199	8.9	4.7	520
Central Hudson	300,000	79,000	992	1,088	149	5,112	24	70	3.2	1.6	222
FortisBC[3]	170,000	994,000	2,134	712	1,334	3,119	197	205	8.4	5.4	578
FortisAlberta	549,000	–	1,132	2,581	–	16,788	–	121	4.1	3.2	419
Eastern Canadian[4]	408,000	–	1,011	1,880	–	8,374	–	64	2.4	1.7	153
Caribbean Electric[5]	44,000	–	372	143	–	837	–	46	1.3	1.0	99
Total	**1,986,000**	**1,227,000**	**8,324**	**33,021**	**1,586**	**48,617**	**234**	**764**	**46.3**	**24.9**	**2,949**

(1) Forecast

(2) ITC Holdings Corp. (ITC) was acquired by Fortis on October 14, 2016. Data includes 100% of ITC's operations except for earnings, which represent ITC's contribution to consolidated earnings of Fortis based on the Corporation's 80.1% ownership interest since October 14, 2016, the date of acquisition.

(3) Includes FortisBC Energy and FortisBC Electric.

(4) Includes Newfoundland Power, Maritime Electric and FortisOntario.

(5) Includes Caribbean Utilities and Fortis Turks and Caicos. Data includes 100% of Caribbean Utilities' operations except for earnings, which represent Caribbean Utilities' contribution to consolidated earnings of Fortis based on the Corporation's approximate 60% ownership interest. Also includes the Corporation's 33% equity investment in Belize Electricity.

Non-Regulated

	Generating Capacity (MW)	Employees (#)	Sales Energy (GWh)	Earnings ($M)	Total Assets ($B)	2017F[1] Capital Program ($M)
Non-Regulated Energy Infrastructure[2]	391	51	901	60	1.5	18

(1) Forecast

(2) Comprised of investments in British Columbia, Belize and Ontario.

All financial information is presented in Canadian dollars.
Information is for the fiscal year ended December 31, 2016 unless otherwise indicated.



Fortis is a leader in the North American electric and gas utility industry.

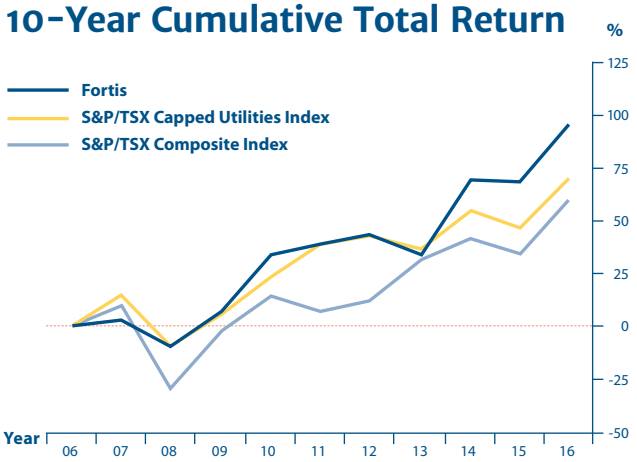


Fortis is committed to meeting the existing and future energy needs of our customers while improving sustainability and reducing our environmental footprint.

Strong Track Record of Total Shareholder Returns

The 10-year cumulative total return of 98% for the period ended December 31, 2016 is approximately 24% and 39% higher than the performance of the S&P/TSX Capped Utilities and S&P/TSX Composite Indices, respectively.

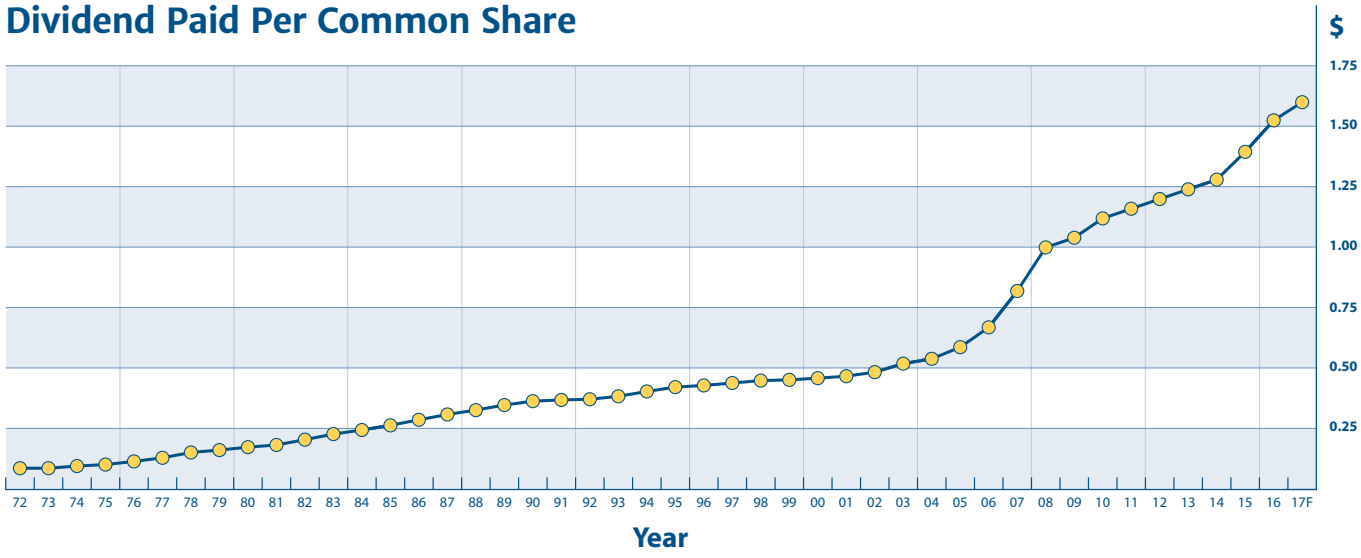
10-Year Cumulative Total Return



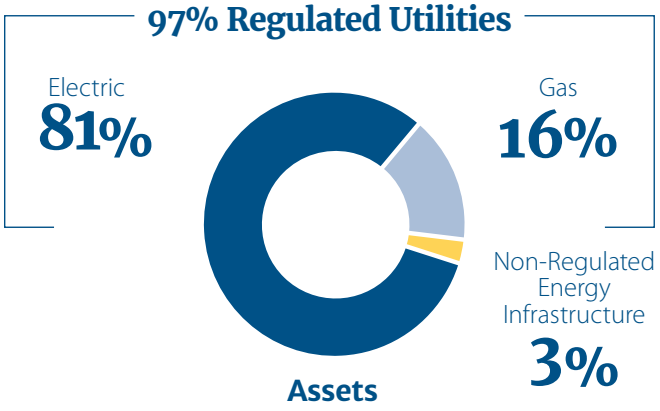
Achieved Average Annualized Total Shareholder Return of 7.3% Over the Last 10 Years

Fortis has introduced guidance to increase its common share dividend by 6%, on average, annually through 2021. 2016 was the 43rd consecutive year of annual dividend payment increases, the longest period of any public company in Canada.

Dividend Paid Per Common Share



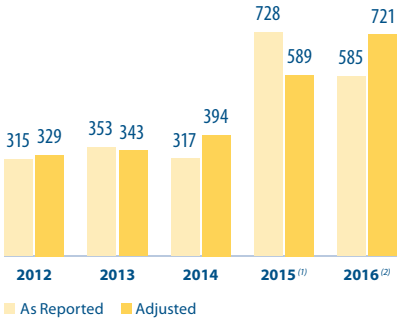
Total Assets of $48 Billion as of December 31, 2016, an increase of 66% from 2015



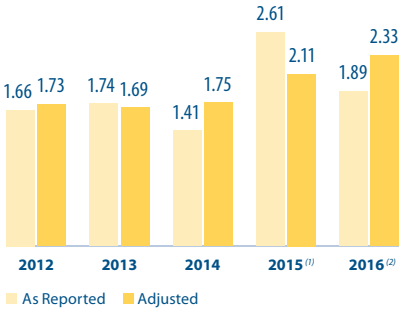
Financial Highlights

Financial performance in 2016 was driven by the acquisition of ITC, strong performance at most of the regulated utilities, and contribution from the Aitken Creek gas storage facility and the Waneta hydroelectric generating facility (Waneta Expansion).

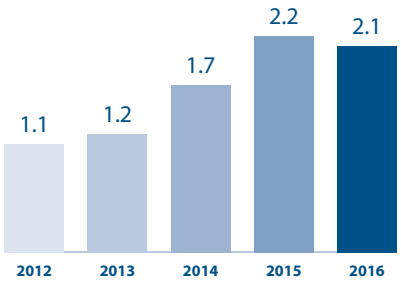
Earnings Attributable to Common Equity Shareholders ($M)



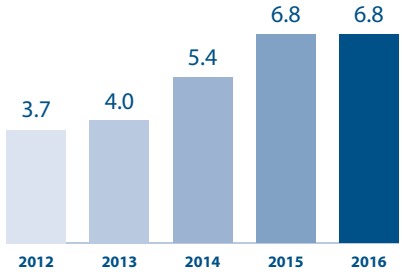
Basic Earnings per Common Share ($)



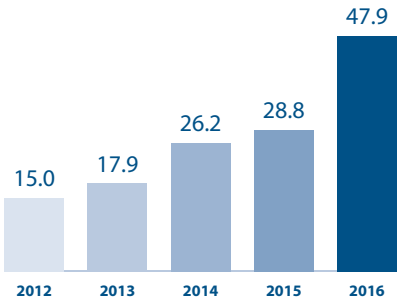
Capital Expenditures ($B)



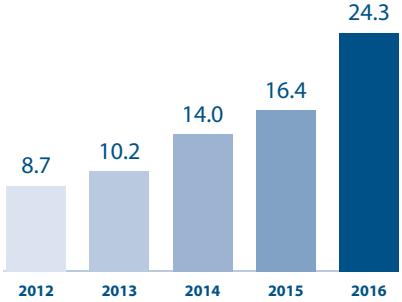
Revenue ($B)



Assets ($B)



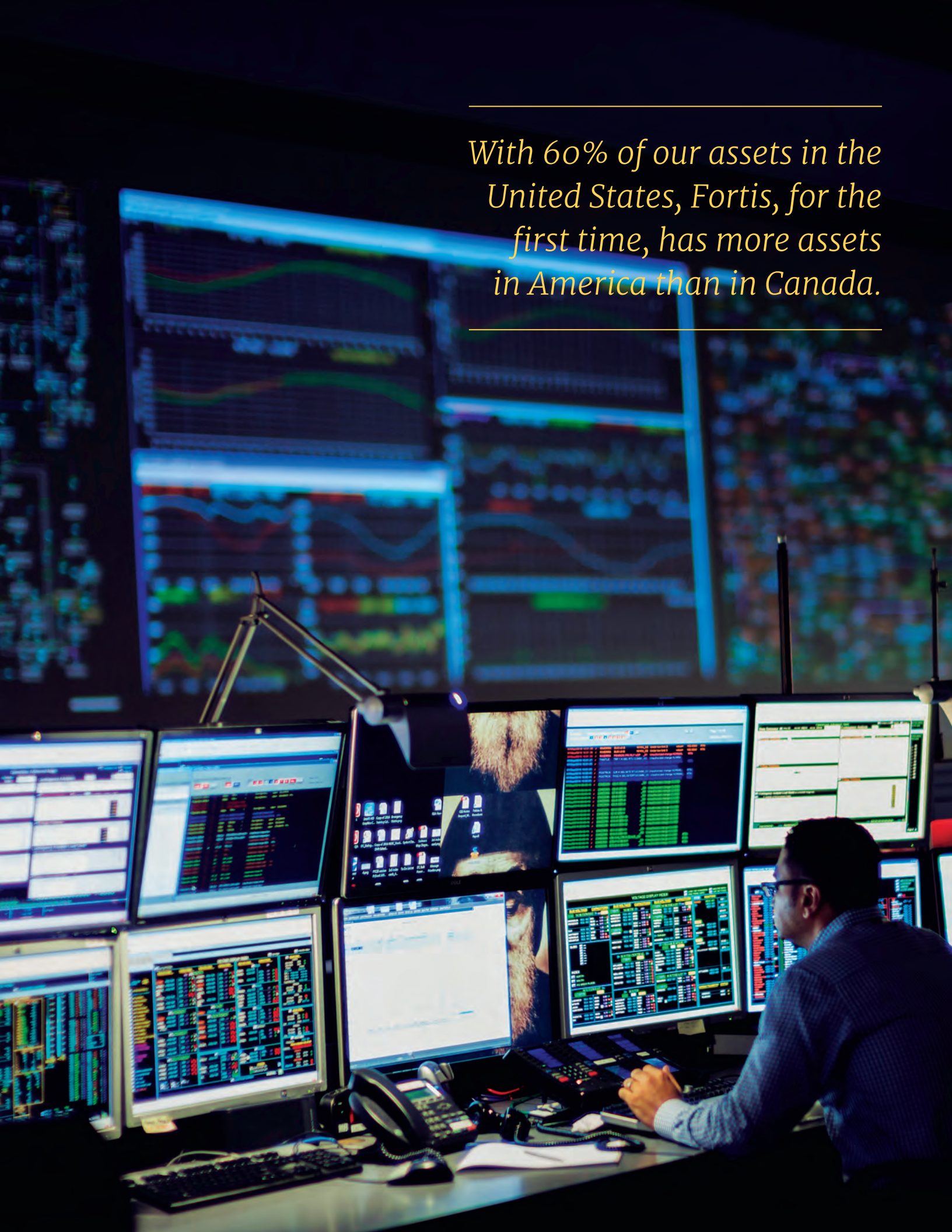
Midyear Rate Base ($B)



(1) Results were impacted by a full year's contribution from UNS Energy, completion of the Waneta Expansion and gains on the sale of non-core assets. Adjusted earnings excludes the gains on sale of non-core assets and other non-operating items.

(2) Results were impacted by accretion associated with the acquisition of ITC in October 2016 as well as associated acquisition-related costs. Adjusted earnings excludes acquisition-related costs and other non-operating items.

All financial information is presented in Canadian dollars.
Information is for the fiscal years ended December 31.



With 60% of our assets in the United States, Fortis, for the first time, has more assets in America than in Canada.

2016 was a Transformational Year for Fortis

2016 has been an exciting year for Fortis – monumental in many ways. We grew our utility business significantly with the acquisition of ITC Holdings Corp. (ITC), the largest independent electric transmission company in the United States. The acquisition was the largest transaction in the history of Fortis at US$11.8 billion, and significantly changed the face of our business. Today we are operating in 17 jurisdictions throughout North America (five Canadian provinces, nine U.S. states and three Caribbean countries). With 60% of our assets in the United States, Fortis, for the first time, has more assets in America than in Canada, increasing the diversity of our business as well as our presence in the larger U.S. regulated utility sector.

Our Financial Performance is Strong

Even though 2016 was a complex year with the acquisition of ITC, we remained diligent in steering our Company to strong financial results again. Normalized for certain items, our adjusted earnings came in at $721 million, or $2.33 per share, an increase of $0.22 per common share, or 10.4%, compared to 2015. Our focus is always on creating shareholder value. Our shareholders benefitted from a total shareholder return of over 15% in 2016.

Dividend Record Continues

We have raised our dividend payment to shareholders for the 43rd consecutive year, the longest period for any public company in Canada. Also, we extended our dividend guidance and aim to increase our common share dividend by 6%, on average, annually through 2021.

A North American Utility Leader

The purchase of ITC also put Fortis among the top 15 investor-owned utilities in North America based on enterprise value. We have grown from just $390 million in assets when we were formed in 1987 to $48 billion today. Fortis continues to maximize shareholder value as we seek additional opportunities to grow our Company both within our existing franchise territories and beyond.



Douglas Haughey,
Chair of the Board, Fortis Inc.

Rate Base to Grow to $30 Billion in 2021

The Corporation's capital program continues to address the infrastructure needs of our customers. Over the next five years, Fortis is expecting to spend approximately $13 billion, increasing rate base to almost $30 billion in 2021. Fortis expects this long-term sustainable growth in rate base to support continuing growth in earnings and shareholder dividends.

We Rang the Bell at the New York Stock Exchange

Given our size and a significant portion of our business now being in the United States, we listed our common shares on the New York Stock Exchange. This was another big step for Fortis allowing us to access the largest pool of capital in the world. We held exceptional events with key people from the capital markets and utility sector at the time of our listing in October, helping to raise our profile in the United States. We remain listed on the Toronto Stock Exchange and our common shares now trade on both the Toronto Stock Exchange (TSX:FTS) and the New York Stock Exchange (NYSE:FTS).

Strength in Diversity and People

Our business is highly diversified on an economic, geographic and regulatory basis. That said, it is our people who are our greatest strength. Fortis is proud of its more than 8,000 talented and committed employees and thanks them for striving to provide safe, reliable and affordable energy to our 3.2 million customers each and every day.



Barry Perry,
President and CEO, Fortis Inc.

Report to Shareholders

Strong Financial Performance

Our total shareholder return surpassed 15% in 2016. We achieved net earnings of $585 million, or $1.89 per common share, compared to $728 million, or $2.61 per common share, for 2015. Year over year, results were impacted by the acquisition of ITC in 2016, and gains on the sale of non-core assets in 2015. On an adjusted basis, net earnings for 2016 were $721 million, or $2.33 per common share, an increase of $0.22 per common share, or 10.4%, over 2015. Cash flow from operations for 2016 totalled $1.9 billion, approximately 13% higher than 2015. Our financial performance was driven by strong performance from our low-risk and highly diversified portfolio of utilities, as well as contributions from the acquisition of ITC. The Corporation also benefitted from favourable foreign exchange rates, contribution from the Aitken Creek gas storage facility and higher earnings from the Waneta Expansion hydroelectric facility in British Columbia.

Over the 10-year period ended December 31, 2016, Fortis delivered an average annualized total return to shareholders of 7.3%, exceeding the S&P/TSX Capped Utilities and S&P/TSX Composite Indices, which delivered average annualized performance of 5.7% and 4.7%, respectively.

Execution of ITC Transaction

On February 9, 2016 we announced the US$11.8 billion acquisition of ITC, the largest transaction ever undertaken in the history of Fortis; a short 248 days later on October 14, 2016, after successfully obtaining regulatory approvals from the United States Federal Energy Regulatory Commission (FERC) and five states, we closed the transaction. We welcome the employees of ITC, and look forward to working with them as we integrate the utility into our group of companies.

ITC owns and operates high-voltage electric transmission lines serving a system peak load exceeding 26,000 megawatts in 2016 along approximately 25,000 kilometres in the American Midwest. ITC can take advantage of new opportunities throughout North America, including potential transmission projects between Canada and the United States.

New York Stock Exchange Listing Provides Access to Additional Capital

Fortis listed its common shares on the New York Stock Exchange on October 14, 2016, providing the Corporation access to the largest pool of capital in the world. Our common shares now trade on both the Toronto Stock Exchange (TSX:FTS) and the New York Stock Exchange (NYSE:FTS). The U.S. listing was successful in raising the profile of Fortis among the financial, investor and key stakeholder communities. It also allows for increased share trading and liquidity and supports our vision for continued growth. For 2016, Fortis was the largest Canadian listing on the NYSE.

43 Consecutive Years of Annual Dividend Increases

Our base capital program supports the ability to grow our dividend and target 6% average annual dividend growth through 2021. We raised our fourth quarter 2016 dividend by almost 7%, translating into an annualized dividend of $1.60 per common share. Fortis has seen tremendous growth in its stock price since its inception in 1987, when the closing price at year-end was $4.75 versus $41.46 at the end of 2016.



Significant Capital Investment

Significant capital investments were made in 2016 at our subsidiaries. Consolidated expenditures were $2.1 billion, including approximately $200 million at ITC from the date of acquisition. We expect to invest approximately $3 billion in capital expenditures in 2017, with almost $1 billion expected to be invested by ITC.

FortisBC Energy – Tilbury LNG Facility Expansion

Construction continues on the Tilbury liquefied natural gas (LNG) facility expansion in British Columbia, the Corporation's largest ongoing capital project at an estimated capital cost of $400 million, before allowance for funds used during construction and development costs. The commissioning and start-up phase of this regulated project commenced in the fourth quarter of 2016, with an expected in-service date of mid-2017.

ITC Regional Electric Transmission Projects

ITC is involved in the construction of four significant regional electric transmission projects identified by Midcontinent Independent System Operator (MISO) to address system capacity and reliability needs. Approximately US$43 million was invested in the projects from the date of acquisition of ITC and an additional US$272 million is expected to be spent in 2017. Three of the projects are expected to be completed by the end of 2018, with the fourth scheduled for completion in 2023.

Regulatory Advances

Key regulatory developments in 2016 provide stability for our utilities in the near term. Generic Cost of Capital Proceedings concluded in British Columbia and Alberta. Tucson Electric Power received a rate order, regarding new rates effective February 27, 2017. Work also advanced on key files at FERC, including proceedings concerning the authorized regional base return on equity for MISO-member transmission organizations, including three ITC utilities. Central Hudson also continued to be an active participant in a multitude of regulatory activities in New York State, including participation in Reforming the Energy Vision – ongoing generic proceedings seeking to transform the energy industry.

All of our utilities continue to be actively engaged with their regulators and are focused on maintaining constructive regulatory relationships and outcomes.

Commitment to Sustainable Operations

We have undertaken a number of initiatives and programs that benefit the environment and our customers. We have made progress in connecting renewable energy, including solar, into the electric grid, and current projects, once implemented, will boost our solar generation significantly. Our mix of wind, natural gas, solar, renewable natural gas and hydro helps ensure we are delivering clean energy.

Given that Fortis is primarily a transmission and distribution company, we have a lower environmental impact relative to utilities with substantial fossil fuel-based generation assets. That said, we are improving sustainability, and focusing on reducing our environmental footprint. In Arizona, where we have coal-based generation, we are diversifying our generation and reducing reliance on coal as part of a well-executed resource management plan.





Our mix of wind, natural gas, solar, renewable natural gas and hydro helps ensure we are delivering clean energy.

Our transmission and distribution systems are becoming more efficient and our water management programs ensure recovery and reuse. We are putting in place energy storage systems to help meet long-term renewable energy needs and we are providing options to our customers to purchase green energy. We are providing incentives to use natural gas for transportation in commercial vehicles, displacing diesel fuel and reducing greenhouse gas emissions. Assisting our customers in becoming more energy efficient and taking advantage of programs that will reduce their cost of energy is a high priority for our utilities.

We remain focused on meeting the existing and future energy needs of our customers in the most reasonable, sustainable and affordable manner.

Fortis Joins Energy Impact Partners

In September 2016 we became a strategic partner in the Energy Impact Partners (EIP) Utility Coalition. EIP is a private firm that invests in emerging technologies, products, services and business models across the full electricity supply chain from generation to consumption. Over five years, Fortis will invest $25 million in this partnership. Working with the EIP team, we will remain at the forefront of emerging technologies in the ever-changing industry.

Investing in Our Community

The hallmark of our community stewardship in 2016 was our leadership in the 100th anniversary of the Battle of Beaumont-Hamel commemorative events at The Rooms. The Rooms is a cultural institution in Newfoundland and Labrador that houses the provincial archives, art gallery and museum. Our contribution of $3.25 million to the *Where Once They Stood We Stand* campaign allowed The Rooms to build the Fortis Courtyard and Amphitheatre. A touching ceremony on July 1, 2016 allowed Fortis to join with officials and thousands across Canada and the globe to remember the dedication of our forefathers and acknowledge the contributions of families in Newfoundland and Labrador whose loved ones faced the ultimate sacrifice. Further war recognition events are anticipated to take place in 2017, including our participation in the 100th anniversary of the Battle of Monchy-le-Preux.

Fortis subsidiaries continue to play a large role in investing in local communities in their service territories, providing support to many sectors including healthcare and the environment.

Looking Forward

Today our footprint in North America extends to nine U.S. states, five Canadian provinces and three Caribbean countries with more than 8,000 employees, positioning us as a leader in the North American regulated electric and gas utility business, with a concentration of assets in transmission and distribution. The addition of ITC to our portfolio of utilities provides a strong platform in the electric transmission sector in North America, and we are extremely well positioned to capitalize on and contribute to the infrastructure investment required to maintain, improve and secure the transmission grid in the United States. We acknowledge and welcome again our colleagues at ITC.

Our acquisition track record speaks for itself. Our business has grown from under $4 billion in assets in 2004 to $48 billion today with the acquisitions of our FortisBC, FortisAlberta, Central Hudson, UNS Energy and ITC utilities. We have created a company with tremendous economic, geographic and regulatory diversity, while at the same time delivering superior shareholder returns.

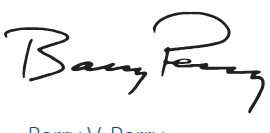
In 2016 we appointed a new Chair of the Board of Directors, Douglas Haughey, and welcomed new directors Margarita Dilley and Jo Mark Zurel. All three have extensive experience and will serve Fortis shareholders well in their deliberations and oversight. We are grateful for the direction and support of past Chair, David Norris, under whose leadership Fortis grew and diversified with confidence.

We are very pleased with our progress this year and appreciate the support of our existing and new shareholders. Rest assured, we remain focused on continuing to achieve strong operational and financial performance in 2017 while we continue to execute on our strategy and integrate ITC into our business.

On behalf of the Board of Directors,



Douglas J. Haughey
Chair of the Board
Fortis Inc.



Barry V. Perry
President and CEO
Fortis Inc.

Fortis Lights Up Wall Street

On October 14, 2016, we celebrated a milestone event in our history – our Company's listing on the New York Stock Exchange. It was, in fact, the largest Canadian listing on the NYSE in 2016. Fortis now trades on both the Toronto Stock Exchange (TSX:FTS) and the New York Stock Exchange (NYSE:FTS). It's a confirmation of our organization's financial strength and stability, and of the great work being done for millions of customers by 8,000 Fortis employees throughout Canada, the United States and the Caribbean.

Not only did our U.S. listing raise the profile of Fortis among key stakeholders, it now allows for increased share trading and liquidity, and supports our vision for continued growth. We're confident in our future and excited by the road ahead.





First World War Commemoration

An important event in the lives of Newfoundlanders and Labradorians was marked on July 1, 2016 with the 100th anniversary of the Battle of Beaumont-Hamel. Fortis was proud to stand with The Rooms, the Government of Canada, the Government of Newfoundland and Labrador and all other donors as we together unveiled the Fortis Courtyard and Amphitheatre and The Royal Newfoundland Regiment Gallery to dedicate both to the memory of all those who served overseas and on the home front during the First World War.

Management Discussion and Analysis

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Dated February 15, 2017

FORWARD-LOOKING INFORMATION

The following Fortis Inc. ("Fortis" or the "Corporation") Management Discussion and Analysis ("MD&A") has been prepared in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations*. The MD&A should be read in conjunction with the Audited Consolidated Financial Statements and notes thereto for the year ended December 31, 2016. Financial information for 2016 and comparative periods contained in the MD&A has been prepared in accordance with accounting principles generally accepted in the United States ("US GAAP") and is presented in Canadian dollars unless otherwise specified.

Fortis includes forward-looking information in the MD&A within the meaning of applicable securities laws including the Private Securities Litigation Reform Act of 1995. Forward-looking statements included in the MD&A reflect expectations of Fortis management regarding future growth, results of operations, performance and business prospects and opportunities. Wherever possible, words such as "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "target", "will", "would" and the negative of these terms and other similar terminology or expressions have been used to identify the forward-looking statements, which include, without limitation: the expectation that the acquisition of ITC Holdings Corp. ("ITC") will be accretive to earnings per common share in 2017; the Corporation's business model provides superior transparency and best serves the interest of customers; target average annual dividend growth through 2021; the Corporation's forecast midyear rate base through 2021; expected compound annual growth rate in rate base through 2019; the expected timing of filing of regulatory applications and receipt and outcome of regulatory decisions; the Corporation's forecast gross consolidated and segmented capital expenditures for 2017 and from 2017 to 2021; the nature, timing and expected costs of certain capital projects including, without limitation, expansions of the Tilbury liquefied natural gas ("LNG") facility, ITC Multi-Value Projects, the 34.5 to 69 kilovolt Conversion Project, the Gas Main Replacement Program, the Lower Mainland System Upgrade, the Pole Management Program, and additional opportunities including the pipeline expansion to the Woodfibre LNG site, the Wataynikaneyap Project and the Lake Erie Connector Project; the expectation that the Corporation's significant capital expenditure program will support continuing growth in earnings and dividends; expected consolidated fixed term debt maturities and repayments in 2017 and over the next five years; the expectation that the Corporation and its utilities will have reasonable access to long-term capital in 2017; the expectation that the Corporation will repay borrowings under the equity bridge facility using proceeds from a common equity offering in 2017; the expectation that subsidiary operating expenses and interest costs will be paid out of subsidiary operating cash flows; the expectation that cash required to complete subsidiary capital expenditure programs will be sourced from a combination of cash from operations, borrowings under credit facilities, equity injections from Fortis and long term debt offerings; the expectation that cash required of Fortis to support subsidiary capital expenditure programs and finance acquisitions will be derived from a combination of borrowings under the Corporation's committed corporate credit facility and proceeds from the issuance of common shares, preference shares and long-term debt and advances from minority investors; the expectation that borrowings under the

Corporation's committed credit facility may be required from time to time to support the servicing of debt and payment of dividends; the expectation that maintaining the targeted capital structure of the Corporation's regulated operating subsidiaries will not have an impact on its ability to pay dividends in the foreseeable future; the intent of management to refinance certain borrowings under the Corporation's and its subsidiaries' long-term committed credit facilities with long-term permanent financing; the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants throughout 2017; the expectation that the Corporation may enter into forward foreign exchange contracts and utilize certain derivatives as cash flow hedges of its exposure to foreign currency risk to a greater extent than in the past; the expectation that long-term debt will not be settled prior to maturity; the expectation that any liability from current legal proceedings will not have a material adverse effect on the Corporation's consolidated financial position and results of operations; Tucson Electric Power Company's expected share of mine reclamation costs; the expectation that any increases or decreases in defined benefit net pension cost at the regulated utilities for 2017 will be recovered from or refunded to customers in rates; and the expectation that the adoption of future accounting pronouncements will not have a material impact on the Corporation's consolidated financial statements.

Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking statements, including, without limitation: the receipt of applicable regulatory approvals and requested rate orders, no material adverse regulatory decisions being received, and the expectation of regulatory stability; no material capital project and financing cost overrun related to any of the Corporation's capital projects; the realization of additional opportunities including natural gas related infrastructure and generation; the Board of Directors exercising its discretion to declare dividends, taking into account the business performance and financial conditions of the Corporation; no significant variability in interest rates; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the continued ability to maintain the electricity and gas systems to ensure their continued performance; no severe and prolonged downturn in economic conditions; no significant decline in capital spending; sufficient liquidity and capital resources; the continuation of regulator approved mechanisms to flow through the cost of natural gas and energy supply costs in customer rates; the ability to hedge exposures to fluctuations in foreign exchange rates, natural gas prices and electricity prices; no significant changes in tax laws; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas, fuel, coal and electricity supply; continuation and regulatory approval of power supply and capacity purchase contracts; the ability to fund defined benefit pension plans, earn the assumed long-term rates of return on the related assets and recover net pension costs in customer rates; no significant changes in government energy plans, environmental laws and regulations that may materially negatively affect the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; the continued tax deferred treatment of earnings from the Corporation's Caribbean operations; continued maintenance of information technology infrastructure and no material breach of cyber-security; continued favourable relations with First Nations; favourable labour relations; that the Corporation can reasonably assess the merit of and potential liability attributable to ongoing legal proceedings; and sufficient human resources to deliver service and execute the capital program.

Forward-looking statements involve significant risks, uncertainties and assumptions. Fortis cautions readers that a number of factors could cause actual results, performance or achievements to differ materially from the results discussed or implied in the forward-looking statements. These factors should be considered carefully and undue reliance should not be placed on the forward-looking statements. Risk factors which could cause results or events to differ from current expectations are detailed under the heading "Business Risk Management" in this MD&A and in continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and the Securities and Exchange Commission. Key risk factors for 2017 include, but are not limited to: uncertainty regarding the outcome of regulatory proceedings at the Corporation's utilities; uncertainty of the impact a continuation of a low interest rate environment may have on the allowed rate of return on common shareholders' equity at the Corporation's regulated utilities; the impact of fluctuations in foreign exchange rates; uncertainty related to proposed tax reform in the United States; risk associated with the impacts of less favourable economic conditions on the Corporation's results of operations; risk that the expected benefits of the acquisition of ITC may fail to materialize, or may not occur within the time periods anticipated; risk associated with the Corporation's ability to comply with Section 404(a) of the Sarbanes-Oxley Act of 2002 and the related rules of the U.S. Securities and Exchange Commission and the Public Company Accounting Oversight Board; risk associated with the completion of the Corporation's 2017 capital expenditures plan, including completion of major capital projects in the timelines anticipated and at the expected amounts; and uncertainty in the timing and access to capital markets to arrange sufficient and cost-effective financing to finance, among other things, capital expenditures and the repayment of maturing debt.

All forward-looking information in the MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, Fortis disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

CORPORATE OVERVIEW



Karl Smith, EVP, CFO, Fortis Inc.

Fortis is a leader in the North American regulated electric and gas utility business, with total assets of approximately $48 billion and fiscal 2016 revenue of $6.8 billion. More than 8,000 employees of the Corporation serve utility customers in five Canadian provinces, nine U.S. states and three Caribbean countries. In 2016 the Corporation's electricity systems met a combined peak demand of 33,021 megawatts ("MW") and its gas distribution systems met a peak day demand of 1,586 terajoules.

The Corporation's main business, utility operations, is highly regulated and the earnings of the Corporation's utilities are primarily determined under cost of service ("COS") regulation and, in certain jurisdictions, performance-based rate-setting ("PBR") mechanisms. Generally, under COS regulation the respective regulatory authority sets customer electricity and/or gas rates to permit a reasonable opportunity for the utility to recover, on a timely basis, estimated costs of providing service to customers, including a fair rate of return on a regulatory deemed or targeted capital structure applied to an approved regulatory asset value ("rate base"). The ability of a regulated utility to recover prudently incurred costs of providing service and earn the regulator-approved rate of return on common shareholders' equity ("ROE") and/or rate of return on rate base assets ("ROA") may depend on the utility achieving the forecasts established in the rate-setting processes. If a historical test year is used to set customer rates, there may be regulatory lag between when costs are incurred and when they are reflected in customer rates. When PBR mechanisms are utilized in determining annual revenue requirements and resulting customer rates, a formula is generally applied that incorporates inflation and assumed productivity improvements. The use of PBR mechanisms should allow a utility a reasonable opportunity to recover prudently incurred costs and earn its allowed ROE or ROA.

Earnings of regulated utilities may be impacted by: (i) changes in the regulator-approved allowed ROE and/or ROA and common equity component of capital structure; (ii) changes in rate base; (iii) changes in energy sales or gas delivery volumes; (iv) changes in the number and composition of customers; (v) variances between actual expenses incurred and forecast expenses used to determine revenue requirements and set customer rates, as applicable; (vi) regulatory lag in the case of a historical test year and (vii) foreign exchange rates. The Corporation's regulated utilities, where applicable, are permitted by their respective regulatory authority to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms.

Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated energy infrastructure, which is treated as a separate segment. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each entity within the reporting segments operates with substantial autonomy, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following summary describes the operations included in each of the Corporation's reportable segments.

Regulated Utilities

Electric & Gas Utilities – United States

a. *ITC:* Primarily comprised of ITC Holdings Corp. ("ITC Holdings") and the electric transmission operations of its regulated operating subsidiaries, which include International Transmission Company ("ITCTransmission"), Michigan Electric Transmission Company, LLC ("METC"), ITC Midwest LLC ("ITC Midwest"), and ITC Great Plains, LLC ("ITC Great Plains"), (collectively "ITC"). ITC was acquired by Fortis in October 2016, with Fortis owning 80.1% of ITC and an affiliate of GIC Private Limited ("GIC") owning a 19.9% minority interest.

   ITC owns and operates high-voltage transmission lines serving a system peak load exceeding 26,000 MW along approximately 25,000 kilometres in Michigan's lower peninsula and portions of Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma that transmit electricity from approximately 570 generating stations to local distribution facilities connected to ITC's systems.

b. *UNS Energy:* Primarily comprised of Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas"), (collectively "UNS Energy").

   TEP, UNS Energy's largest operating subsidiary, is a vertically integrated regulated electric utility. TEP generates, transmits and distributes electricity to approximately 420,000 retail customers in southeastern Arizona, including the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP also sells wholesale electricity to other entities in the western United States. UNS Electric is a vertically integrated regulated electric utility, which generates, transmits and distributes electricity to approximately 95,000 retail customers in Arizona's Mohave and Santa Cruz counties. TEP and UNS Electric currently own generation resources with an aggregate capacity of 2,994 MW, including 54 MW of solar capacity. Several of the generating assets in which TEP and UNS Electric have an interest are jointly owned. As at December 31, 2016, approximately 47% of the generating capacity was fuelled by coal.

   UNS Gas is a regulated gas distribution utility, serving approximately 154,000 retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties.

c. *Central Hudson:* Central Hudson Gas & Electric Corporation ("Central Hudson") is a regulated transmission and distribution ("T&D") utility, serving approximately 300,000 electricity customers and 79,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. The Company owns gas-fired and hydroelectric generating capacity totalling 64 MW.

Gas & Electric Utilities – Canadian

a. *FortisBC Energy:* FortisBC Energy Inc. ("FortisBC Energy" or "FEI") is the largest distributor of natural gas in British Columbia, serving approximately 994,000 customers in more than 135 communities. Major areas served by the Company are the Mainland, Vancouver Island and Whistler regions of British Columbia. FEI provides T&D services to customers, and obtains natural gas supplies on behalf of most residential, commercial and industrial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through FEI's Southern Crossing pipeline, from Alberta.

b. *FortisAlberta:* FortisAlberta Inc. ("FortisAlberta") owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, serving approximately 549,000 customers. The Company does not own or operate generation or transmission assets and is not involved in the direct sale of electricity.

c. *FortisBC Electric:* Includes FortisBC Inc. ("FortisBC Electric"), an integrated electric utility operating in the southern interior of British Columbia, serving approximately 170,000 customers directly and indirectly. FortisBC Electric owns four hydroelectric generating facilities with a combined capacity of 225 MW. Also included in the FortisBC Electric segment are the operating, maintenance and management services relating to five hydroelectric generating facilities in British Columbia primarily owned by third parties, one of which is the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion"), owned by Fortis and Columbia Power Corporation and Columbia Basin Trust ("CPC/CBT").

d. *Eastern Canadian:* Comprised of Newfoundland Power Inc. ("Newfoundland Power"), Maritime Electric Company, Limited ("Maritime Electric") and FortisOntario Inc. ("FortisOntario"). Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador, serving approximately 264,000 customers. Newfoundland Power has an installed generating capacity of 139 MW, of which 97 MW is hydroelectric generation. Maritime Electric is an integrated electric utility and the principal distributor of electricity on Prince Edward Island, serving approximately 79,000 customers. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 145 MW. FortisOntario is comprised of three electric utilities that provide service to approximately 65,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario.

Electric Utilities – Caribbean

The Electric Utilities – Caribbean segment includes the Corporation's approximate 60% controlling ownership interest in Caribbean Utilities Company, Ltd. ("Caribbean Utilities") (December 31, 2015 – 60%), Fortis Turks and Caicos, and the Corporation's 33% equity investment in Belize Electricity Limited ("Belize Electricity"). Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands, serving approximately 29,000 customers. The Company has an installed diesel-powered generating capacity of 161 MW. Caribbean Utilities is a public company traded on the Toronto Stock Exchange ("TSX") (TSX:CUP.U). Fortis Turks and Caicos is comprised of two integrated electric utilities serving approximately 15,000 customers on certain islands in Turks and Caicos. The utilities have a combined diesel-powered generating capacity of 82 MW. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize.

Non-Regulated – Energy Infrastructure

Non-Regulated – Energy Infrastructure is primarily comprised of long-term contracted generation assets in British Columbia and Belize, and the Aitken Creek natural gas storage facility ("Aitken Creek"). Generating assets in British Columbia include the Corporation's 51% controlling ownership interest in the 335-MW Waneta Expansion, conducted through the Waneta Expansion Limited Partnership ("Waneta Partnership"), with CPC/CBT holding the remaining 49% interest. The output is sold to BC Hydro and FortisBC Electric under 40-year contracts. Generating assets in Belize are comprised of three hydroelectric generating facilities with a combined capacity of 51 MW, conducted through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL"). The output is sold to Belize Electricity under 50-year power purchase agreements ("PPAs"). Aitken Creek Gas Storage ULC ("ACGS"), acquired by Fortis in April 2016, owns 93.8% of Aitken Creek, with the remaining share owned by BP Canada Energy Company. Aitken Creek is the only underground natural gas storage facility in British Columbia and has a total working gas capacity of 77 billion cubic feet.

In 2016 the Corporation sold its 16-MW run-of-river Walden hydroelectric generating facility ("Walden") and in 2015 the Corporation sold its non-regulated generation assets in Upstate New York and Ontario.

Non-Regulated – Non-Utility

The Non-Utility segment previously included Fortis Properties Corporation ("Fortis Properties"). Fortis Properties completed the sale of its commercial real estate and hotel assets in 2015.

Corporate and Other

The Corporate and Other segment captures expense and revenue items not specifically related to any reportable segment and those business operations that are below the required threshold for reporting as separate segments. The Corporate and Other segment includes net corporate expenses of Fortis and non-regulated holding company expenses of FortisBC Holdings Inc. ("FHI"), CH Energy Group, Inc. ("CH Energy Group"), and UNS Energy Corporation. Also included in the Corporate and Other segment are the financial results of FortisBC Alternative Energy Services Inc. ("FAES"). FAES is a wholly owned subsidiary of FHI that provides alternative energy solutions, including thermal-energy and geo-exchange systems.

CORPORATE STRATEGY

Fortis is a leader in the North American utility industry and its strategic vision is to provide safe, reliable and cost-effective energy service to customers, while delivering long-term profitable growth. The Corporation is a well-diversified, regulated, primarily wires and gas distribution business characterized by low-risk, stable and predictable earnings and cash flows.

Earnings per common share and total shareholder return are the primary measures of financial performance. Over the 10-year period ended December 31, 2016, earnings per common share of Fortis grew at a compound annual growth rate of 5.2%, on an adjusted basis. Over the same period, Fortis delivered an average annualized total return to shareholders of 7.3%, exceeding the S&P/TSX Capped Utilities and S&P/TSX Composite Indices, which delivered average annualized performance of 5.7% and 4.7%, respectively, over the same period.

The Corporation is committed to achieving long-term sustainable growth in rate base, assets and earnings resulting from investment in existing utility operations. Management remains focused on executing the consolidated capital program and pursuing additional investment opportunities within existing service territories. Fortis has also demonstrated its ability to acquire regulated utilities in North America. The Corporation's standalone operating model positions it well for future investment opportunities in existing and new franchise areas. The Corporation maintains a small head office and its utilities are operated on a substantially autonomous basis. Each of the utilities has its own management team and most have oversight by a Board of Directors comprised of a majority of independent directors. Given that regulatory oversight is usually state or provincially based, the Corporation believes this model provides superior transparency and best serves the interests of customers.

KEY TRENDS, RISKS AND OPPORTUNITIES

Energy Industry Developments: The North American energy industry continues to transform. There is continued focus on clean energy and energy conservation initiatives, while balancing technology advancements and changes in customer needs. Notwithstanding the changes occurring in the utility industry, safety, reliability and serving customers at the lowest reasonable cost remain at the forefront of the utility industry's focus.

The desire for cleaner energy continues to gain momentum throughout North America. Government and regulatory policy in Canada and the United States is being directed at environmental protection, requiring utilities to develop and execute plans to cost-effectively reduce carbon emissions. Such environmental regulations create additional opportunities to expand investment in new generation sources, including natural gas and solar and wind generation, as well as infrastructure to interconnect renewable energy sources to the grid. The Corporation's regulated utilities are well positioned and actively involved in pursuing these opportunities.

Technological development, particularly in the area of distributed generation, continues to play a significant role in the transformation of the utility industry. The move towards cleaner energy has created an increase in the use of distributed generation, particularly solar generation, by customers. This creates a shift in the role of the utility to be a distribution grid network integrator and facilitator, and will require utilities of the future to be able to dispatch and control customer distributed energy resources and integrate those sources into the grid. Distributed generation creates an opportunity for investment in distribution automation, management systems and other grid-modernizing technology. It also presents challenges in the rate designs for distributed generation and other customers to ensure fairness in pricing across all customers. The Corporation's utilities are working with their regulators to address such rate design issues.

Customer expectations on grid resiliency continue to increase. This expectation, in combination with the aging infrastructure of electric and gas utilities in North America, creates an opportunity for increased capital investment. The construction of new infrastructure, such as pipelines and transmission lines, is becoming increasingly challenged by the public, particularly environmental activists. Constructive and collaborative relationships with regulators, policy makers and customers will be critical to the continued long-term success of utilities.

Industry consolidation, particularly in the United States, is continuing with the number of investor-owned utilities decreasing. Consolidation is being driven by a low cost of capital environment, and the need for utilities to sustain earnings growth in an economy that is characterized by low sales growth. The Corporation's proven track record of successfully acquiring and integrating utilities, as well as its standalone business operating model, positions it well in this environment.

Despite the challenges facing the utility industry, Fortis is well positioned to capitalize on any resulting opportunities. Its decentralized structure and customer-focused business culture will support the efforts required to meet evolving customer expectations and to work with policy makers and regulators on solutions that are financially sustainable for the utilities. Leveraging those relationships to remain in front of these evolving challenges will be essential to meeting the industry challenges.

Regulation: The Corporation's key business risk is regulation. Each of the Corporation's utilities is subject to regulation by the regulatory body in its respective operating jurisdiction. Relationships with the regulatory authorities are managed at the local utility level. Commitment by the Corporation's utilities to provide safe and reliable service, operational excellence and promote positive customer and regulatory relations is important to ensure supportive regulatory relationships and obtain full cost recovery and competitive returns for the Corporation's shareholders.

In 2016, the Corporation's utilities made significant progress on a number of key regulatory proceedings, providing stability for the utilities in the near term. In addition to the proceedings noted below, Generic Cost of Capital ("GCOC") Proceedings concluded in British Columbia and Alberta in the second half of 2016.

In February 2017, the Arizona Corporation Commission ("ACC") issued a Rate Order in TEP's general rate application ("GRA") filed in November 2015, based on a historical test year ended June 30, 2015. The Rate Order approved rates effective on or before March 1, 2017. The provisions of the Rate Order include, but are not limited to an increase in non-fuel base revenue of US$81.5 million, an allowed ROE of 9.75%, and a common equity component of capital structure of approximately 50%.

In September 2016, ITC received an order from the United States Federal Energy Regulatory Commission ("FERC") regarding one of two third-party complaints requesting that FERC find the Midcontinent Independent System Operator ("MISO") regional base ROE for all MISO transmission owners, including ITC's MISO-member regulated utilities, to no longer be just and reasonable. The two complaints cover the period from November 2013 through May 2016. The FERC order on the first complaint set the base ROE at 10.32%, with a maximum ROE of 11.35%, and established that those rates are to be used prospectively until a new approved rate is established for the second complaint. In June 2016 the presiding Administrative Law Judge ("ALJ") issued an initial decision on the second complaint, which recommended a base ROE of 9.70%, with a maximum ROE of 10.68%, which is a recommendation to FERC. A decision from FERC on the second complaint is expected in 2017.

The utilities continue to be actively engaged with all of their regulators and are focused on maintaining constructive regulatory relationships and outcomes.

For a further discussion of material regulatory decisions and applications and regulatory risk, refer to the "Regulatory Highlights" and "Business Risk Management" sections of this MD&A.

Capital Expenditure Program and Rate Base Growth: The Corporation's regulated midyear rate base for 2016 was $24.3 billion, including ITC. Over the five-year period through 2021, the Corporation's capital program is expected to be approximately $13 billion. This investment in energy infrastructure is expected to increase rate base to almost $30 billion in 2021 and produce a five-year compound annual growth rate in rate base of approximately 4%. The three-year compound annual growth rate in rate base through 2019 is expected to be over 5%, reflecting greater visibility in capital expenditures in the next three years. Fortis expects this capital investment to support growth in earnings and dividends.

For further information on the Corporation's consolidated capital expenditure program and rate base of its regulated utilities, refer to the "Liquidity and Capital Resources – Capital Expenditure Program" section of this MD&A.

Access to Capital and Liquidity: The Corporation's regulated utilities require ongoing access to long-term capital to fund investments in infrastructure necessary to provide service to customers. Long-term capital required to carry out the utility capital expenditure programs is mostly obtained at the regulated utility level. The regulated utilities usually issue debt at terms ranging between 5 and 40 years. As at December 31, 2016, almost 80% of the Corporation's consolidated long-term debt, excluding borrowings under long-term committed credit facilities, had maturities beyond five years. Management expects consolidated fixed-term debt maturities and repayments to average approximately $680 million annually over the next five years.

To help ensure uninterrupted access to capital and sufficient liquidity to fund capital programs and working capital requirements, the Corporation and its subsidiaries have approximately $6.0 billion in credit facilities, of which approximately $3.7 billion was unused as at December 31, 2016. Based on current credit ratings and capital structures, the Corporation and its subsidiaries expect to continue to have reasonable access to long-term capital in 2017.

Dividend Increases: Dividends paid per common share increased to $1.53 in 2016. In 2016 Fortis increased its quarterly dividend per common share by almost 7% to $0.40 per quarter, or $1.60 on an annualized basis. This continues the Corporation's record of raising its annualized dividend to common shareholders for 43 consecutive years, the record for a public corporation in Canada.

Fortis also extended its dividend guidance, targeting average annual dividend per common share growth of 6% through 2021. This guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at its utilities, the successful execution of its $13 billion five-year capital expenditure plan, and management's continued confidence in the strength of the Corporation's diversified portfolio of assets and record of operational excellence.

SIGNIFICANT ITEMS

Acquisition of ITC: On October 14, 2016, Fortis and GIC acquired all of the outstanding common shares of ITC for an aggregate purchase price of approximately US$11.8 billion ($15.7 billion) on closing, including approximately US$4.8 billion ($6.3 billion) of ITC consolidated indebtedness. ITC is now a subsidiary of Fortis, with an affiliate of GIC owning a 19.9% minority interest in ITC. For additional information on ITC, refer to the "Segmented Results of Operations – Regulated Electric & Gas Utilities – United States" section of this MD&A.

Under the terms of the transaction, ITC shareholders received US$22.57 in cash and 0.7520 of a Fortis common share per ITC share, representing total consideration of approximately US$7.0 billion ($9.4 billion). The net cash consideration totalled approximately US$3.5 billion ($4.7 billion) and was financed using: (i) net proceeds from the issuance of US$2.0 billion unsecured notes in October 2016; (ii) net proceeds from GIC's US$1.228 billion minority investment, which includes a shareholder note of US$199 million; and (iii) drawings of approximately US$404 million ($535 million) under the Corporation's non-revolving term senior unsecured equity bridge credit facility. On October 14, 2016, approximately 114.4 million common shares of Fortis were issued to shareholders of ITC, representing share consideration of approximately US$3.5 billion ($4.7 billion), based on the closing price for Fortis common shares of $40.96 and the closing foreign exchange rate of US$1.00=CAD$1.32 on October 13, 2016. The financing of the acquisition was structured to allow Fortis to maintain investment-grade credit ratings.

Fortis and ITC shareholders approved the acquisition at shareholder meetings held in May and June 2016, respectively. All required regulatory, state and federal approvals associated with the acquisition were received prior to closing. In connection with the acquisition, on May 17, 2016, Fortis became a United States Securities and Exchange Commission ("SEC") registrant and, on October 14, 2016, commenced trading its common shares on the New York Stock Exchange. Fortis continues to list its shares on the TSX.

Acquisition-related expenses totalling $118 million ($90 million after tax) were recognized in earnings in 2016 (2015 – $10 million ($7 million after tax)). For additional details on the acquisition-related expenses refer to the "Segmented Results of Operations – Corporate and Other" section of this MD&A. Earnings of ITC from the date of acquisition were reduced by US$21 million ($27 million) in after-tax expenses associated with the accelerated vesting of the Company's stock-based compensation awards as a result of the acquisition, of which the Corporation's share was US$17 million ($22 million).

Acquisition of Aitken Creek Gas Storage Facility: On April 1, 2016, Fortis acquired Aitken Creek from Chevron Canada Properties Ltd. for approximately $349 million (US$266 million), plus the cost of working gas inventory. The net cash purchase price was initially financed through US dollar-denominated borrowings under the Corporation's committed revolving credit facility.

ACGS owns 93.8% of Aitken Creek, with the remaining share owned by BP Canada Energy Company. Aitken Creek is the only underground natural gas storage facility in British Columbia and has a total working gas capacity of 77 billion cubic feet. The facility is an integral part of western Canada's natural gas transmission network. ACGS also owns 100% of the North Aitken Creek gas storage site which offers future expansion potential. The financial results of ACGS have been included in the Corporation's consolidated results from the date of acquisition.

SUMMARY FINANCIAL HIGHLIGHTS

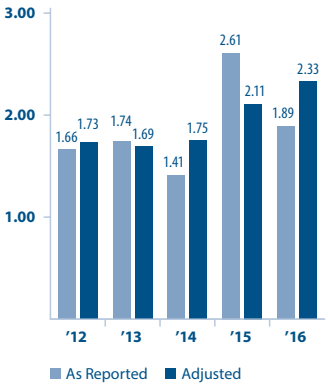
For the Years Ended December 31	**2016**	2015	Variance
Net Earnings Attributable to Common Equity Shareholders *($ millions)*	**585**	728	(143)
Basic Earnings per Common Share *($)*	**1.89**	2.61	(0.72)
Adjusted Basic Earnings per Common Share *($)* [1]	**2.33**	2.11	0.22
Weighted Average Number of Common Shares Outstanding *(millions)*	**308.9**	278.6	30.3
Cash Flow from Operating Activities *($ billions)*	**1.9**	1.7	0.2
Dividends Paid per Common Share *($)*	**1.53**	1.40	0.13
Dividend Payout Ratio *(%)*	**81.0**	53.6	27.4
Total Assets *($ billions)*	**47.9**	28.8	19.1
Gross Capital Expenditures *($ billions)*	**2.1**	2.2	(0.1)
Common Shares Issued on Business Acquisition *($ billions)*	**4.7**	–	4.7
Long-Term Debt Offerings *($ billions)*	**4.1**	1.0	3.1

[1] Adjusted basic earnings per common share is a non-US GAAP measure. For a definition and reconciliation of this non-US GAAP measure, refer to the "Consolidated Results of Operations" section of this MD&A.

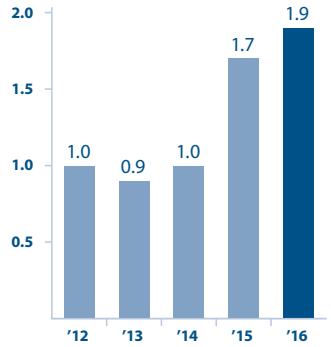
Net Earnings Attributable to Common Equity Shareholders: Fortis achieved net earnings attributable to common equity shareholders of $585 million in 2016 compared to $728 million in 2015. Results reflect the acquisition of ITC in 2016, including acquisition-related expenses, and gains on the sale of non-core assets in 2015. On an adjusted basis, net earnings attributable to common equity shareholders for 2016 were $721 million, an increase of $132 million, or approximately 22%, compared to 2015. The increase was driven by the acquisition of ITC, strong performance at most of the Corporation's regulated utilities, contribution from Aitken Creek and favourable foreign exchange associated with US dollar-denominated earnings. A reconciliation of adjusted net earnings attributable to common equity shareholders and adjusted earnings per common share is provided in the "Consolidated Results of Operations" section of this MD&A.

Basic Earnings per Common Share: Basic earnings per common share were $1.89 in 2016 compared to $2.61 in 2015. On an adjusted basis, basic earnings per common share were $2.33 for 2016, an increase of $0.22, or 10%, compared to 2015. The increase was driven by accretion associated with the acquisition of ITC in October 2016, including the impact of finance charges associated with the acquisition and the increase in the weighted average number of common shares outstanding. The impact of the other above-noted items on adjusted earnings attributable to common equity shareholders were partially offset by an increase in the weighted average number of common shares outstanding associated with the Corporation's dividend reinvestment and share plans.

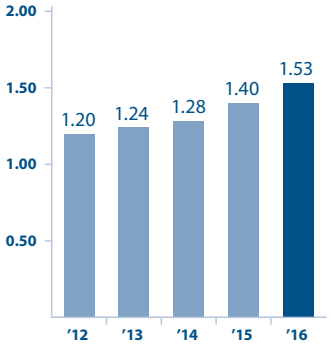
Earnings per Common Share
($)



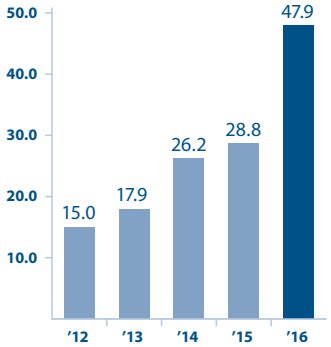
Cash Flow from Operating Activities
($ billions)



Dividends Paid per Common Share
($)



Total Assets
($ billions)
(as at December 31)



Cash Flow from Operating Activities: Cash flow from operating activities was $1.9 billion for 2016, an increase of $0.2 billion, or 13%, compared to 2015. The increase was primarily due to higher cash earnings at the regulated utilities, driven by the acquisition of ITC, partially offset by the Corporation's acquisition-related expenses. Favourable changes in long-term regulatory deferrals were partially offset by unfavourable changes in working capital.

Dividends: Dividends paid per common share increased to $1.53 in 2016, 9% higher than $1.40 in 2015. During 2016 Fortis increased its quarterly dividend per common share by almost 7% to $0.40 per quarter. The Corporation's dividend payout ratio was 81.0% in 2016 compared to 53.6% in 2015. On an adjusted basis, the dividend payout ratio was 65.7% in 2016 compared to 66.4% in 2015.

Total Assets: Total assets increased 66% to approximately $47.9 billion at the end of 2016 compared to approximately $28.8 billion at the end of 2015. The growth in total assets was driven by the acquisition of ITC in October 2016 and continued investment in energy infrastructure, driven by capital spending at the regulated utilities and the acquisition of Aitken Creek, partially offset by unfavourable foreign exchange on the translation of US dollar-denominated assets.

Gross Capital Expenditures: Consolidated capital expenditures, before customer contributions, were $2.1 billion in 2016 compared to $2.2 billion in 2015. Consolidated capital expenditures for 2016 were higher than the Corporation's forecast of $1.9 billion. The higher-than-forecast capital investments were driven by capital spending at ITC from the date of acquisition. For a detailed discussion of the Corporation's consolidated capital expenditure program, refer to the "Liquidity and Capital Resources – Capital Expenditure Program" section of this MD&A.

Long-Term Capital: In October 2016, to finance a portion of the acquisition of ITC, the Corporation issued approximately 114.4 million common shares to shareholders of ITC, representing share consideration of approximately $4.7 billion (US$3.5 billion). The net cash consideration totalled approximately $4.7 billion (US$3.5 billion) and was financed using: (i) net proceeds from the issuance of US$2.0 billion unsecured notes in October 2016; (ii) net proceeds from GIC's US$1.228 billion minority investment, which includes a shareholder note of US$199 million; and (iii) drawings of approximately US$404 million ($535 million) under the Corporation's non-revolving term senior unsecured equity bridge credit facility.

In addition to financing associated with the acquisition of ITC, the Corporation and its regulated utilities raised over $1.5 billion in long-term debt in 2016, largely in support of energy infrastructure investment, including the acquisition of Aitken Creek in April 2016, and for regularly scheduled debt repayments. In September 2016, the Corporation redeemed all of the First Preference Shares, Series E for $200 million.

For further information, refer to the "Liquidity and Capital Resources – Summary of Consolidated Cash Flows" section of this MD&A.

CONSOLIDATED RESULTS OF OPERATIONS

Years Ended December 31

($ millions)	**2016**	2015	Variance
Revenue	**6,838**	6,757	81
Energy Supply Costs	**2,341**	2,591	(250)
Operating Expenses	**2,031**	1,874	157
Depreciation and Amortization	**983**	873	110
Other Income (Expenses), Net	**53**	197	(144)
Finance Charges	**678**	553	125
Income Tax Expense	**145**	223	(78)
Net Earnings	**713**	840	(127)
Net Earnings Attributable to:			
Non-Controlling Interests	**53**	35	18
Preference Equity Shareholders	**75**	77	(2)
Common Equity Shareholders	**585**	728	(143)
Net Earnings	**713**	840	(127)

Revenue

The increase in revenue was driven by the acquisition of ITC in October 2016, contribution from Aitken Creek, and favourable foreign exchange associated with the translation of US dollar-denominated revenue. The increase was partially offset by lower non-utility revenue due to the sale of commercial real estate and hotel assets in 2015 and the flow through in customer rates of lower overall energy supply costs.

Energy Supply Costs

The decrease in energy supply costs was mainly due to lower overall commodity costs. The decrease was partially offset by energy supply costs at Aitken Creek and unfavourable foreign exchange associated with the translation of US dollar-denominated energy supply costs.

Operating Expenses

The increase in operating expenses was primarily due to the acquisition of ITC, including acquisition-related expenses, operating expenses at Aitken Creek, unfavourable foreign exchange associated with the translation of US dollar-denominated operating expenses and general inflationary and employee-related cost increases. The increase was partially offset by a decrease in non-utility operating expenses due to the sale of commercial real estate and hotel assets in 2015.

Depreciation and Amortization

The increase in depreciation and amortization was primarily due to the acquisition of ITC, continued investment in energy infrastructure at the Corporation's regulated utilities, depreciation at Aitken Creek, and unfavourable foreign exchange associated with the translation of US dollar-denominated depreciation. The increase was partially offset by lower non-utility depreciation due to the sale of commercial real estate and hotel assets in 2015.

Other Income (Expenses), Net

The decrease in other income, net of expenses, was primarily due to a net gain of approximately $109 million ($101 million after tax), net of expenses, related to the sale of commercial real estate and hotel assets in 2015 and a gain of approximately $56 million ($32 million after tax), net of expenses and foreign exchange impacts, on the sale of non-regulated generation assets in 2015.

Finance Charges

The increase in finance charges was primarily due to the acquisition of ITC, including acquisition-related fees associated with the Corporation's acquisition credit facilities and deal-contingent interest rate swap contracts, and interest expense on debt issued to complete the financing of the acquisition. The impact of unfavourable foreign exchange associated with the translation of US-dollar denominated interest expense also contributed to the increase.

Income Tax Expense

The decrease in income tax expense was primarily due to lower earnings before income taxes, mainly due to acquisition-related expenses in 2016 and the net gains on the sale of commercial real estate, hotel and non-regulated generation assets in 2015.

Net Earnings Attributable to Common Equity Shareholders and Basic Earnings per Common Share

Fortis supplements the use of US GAAP financial measures with non-US GAAP financial measures, including adjusted net earnings attributable to common equity shareholders and adjusted basic earnings per common share. The Corporation refers to these measures as non-US GAAP financial measures since they are not required by, or presented in accordance with, US GAAP.

The Corporation defines: (i) adjusted net earnings attributable to common equity shareholders as net earnings attributable to common equity shareholders plus or minus items that management believes help investors better evaluate results of operations; and (ii) adjusted basic earnings per common share as adjusted net earnings attributable to common equity shareholders divided by the weighted average number of common shares outstanding. The most directly comparable US GAAP measures to adjusted net earnings attributable to common equity shareholders and adjusted basic earnings per common share are net earnings attributable to common equity shareholders and basic earnings per common share.

The following table provides a reconciliation of the non-US GAAP financial measures and each of the adjusting items are discussed in the segmented results of operations for the respective reporting segments. The adjusting items do not have a standardized meaning as prescribed under US GAAP and are not considered US GAAP measures. Therefore, these adjusting items may not be comparable with similar measures presented by other companies.

Non-US GAAP Reconciliation

Years Ended December 31 *($ millions, except for common share data)*	**2016**	2015	Variance
Net Earnings Attributable to Common Equity Shareholders	**585**	728	(143)
Adjusting Items:			
ITC –			
Accelerated vesting of stock-based compensation awards	**22**	–	22
UNS Energy –			
FERC ordered transmission refunds	**18**	–	18
FortisAlberta –			
Capital tracker revenue adjustment for 2013 and 2014	**–**	(9)	9
Non-Regulated – Energy Infrastructure –			
Gain on sale of non-regulated generation assets	**–**	(32)	32
Unrealized loss on mark-to-market of derivatives	**6**	–	6
Non-Utility –			
Net gain on sale of commercial real estate and hotel assets	**–**	(101)	101
Corporate and Other –			
Acquisition-related expenses and fees	**90**	7	83
Foreign exchange gain	**–**	(13)	13
Loss on settlement of expropriation matters	**–**	9	(9)
Adjusted Net Earnings Attributable to Common Equity Shareholders	**721**	589	132
Adjusted Basic Earnings per Common Share *($)*	**2.33**	2.11	0.22
Weighted Average Number of Common Shares Outstanding *(# millions)*	**308.9**	278.6	30.3

Adjusted Net Earnings Attributable to Common Equity Shareholders

The increase in adjusted net earnings attributable to common equity shareholders was driven by earnings contribution of $81 million at ITC from the date of acquisition in October 2016. The increase was also due to: (i) strong performance at most of the Corporation's regulated utilities driven by UNS Energy, largely due to the settlement of Springerville Unit 1 matters, Central Hudson, due to an increase in delivery revenue, a higher allowance for funds used during construction ("AFUDC") at FortisBC Energy, and stronger performance from the Caribbean; (ii) favourable foreign exchange associated with US dollar-denominated earnings; and (iii) contribution from Aitken Creek and higher earnings at the Waneta Expansion, which commenced production in early April 2015. The increase was partially offset by: (i) higher Corporate and Other expenses, largely due to finance charges associated with the acquisition of ITC; (ii) the sale of commercial real estate and hotel assets in 2015; and (iii) lower earnings at FortisAlberta mainly due to lower average energy consumption and higher operating expenses.

Adjusted Basic Earnings per Common Share

The increase in adjusted earnings per common share was driven by accretion associated with the acquisition of ITC, including the impact of finance charges associated with the acquisition and the increase in the weighted average number of common shares outstanding. The impact of the other above-noted items on adjusted earnings attributable to common equity shareholders were partially offset by an increase in the weighted average number of common shares outstanding associated with the Corporation's dividend reinvestment and share plans.

SEGMENTED RESULTS OF OPERATIONS

Segmented Net Earnings Attributable to Common Equity Shareholders

Years Ended December 31 *($ millions)*	**2016**	2015	Variance
Regulated Electric & Gas Utilities – United States			
ITC	**59**	–	59
UNS Energy	**199**	195	4
Central Hudson	**70**	58	12
	328	253	75
Regulated Gas & Electric Utilities – Canadian			
FortisBC Energy	**151**	140	11
FortisAlberta	**121**	138	(17)
FortisBC Electric	**54**	50	4
Eastern Canadian	**64**	62	2
	390	390	–
Regulated Electric Utilities – Caribbean	**46**	34	12
Non-Regulated – Energy Infrastructure	**60**	77	(17)
Non-Regulated – Non-Utility	**–**	114	(114)
Corporate and Other	**(239)**	(140)	(99)
Net Earnings Attributable to Common Equity Shareholders	**585**	728	(143)

The following is a discussion of the financial results of the Corporation's reporting segments. A discussion of the material regulatory decisions and applications pertaining to the Corporation's regulated utilities is provided in the "Regulatory Highlights" section of this MD&A.

REGULATED UTILITIES

The Corporation's primary business is the ownership and operation of regulated utilities. In 2016 earnings from regulated utilities represented approximately 93% (2015 – 92%, excluding the gains on sale of non-core assets) of the Corporation's earnings from its operating segments (excluding Corporate and Other segment expenses). Total regulated assets represented 97% of the Corporation's total assets as at December 31, 2016 (December 31, 2015 – 96%).

Regulated Electric & Gas Utilities – United States

Regulated Electric & Gas Utilities – United States earnings for 2016 were $328 million (2015 – $253 million), which represented approximately 43% (2015 – 37%) of the Corporation's total regulated earnings. Total segment assets were approximately $30.1 billion as at December 31, 2016 (December 31, 2015 – $12.1 billion), which represented approximately 65% of the Corporation's total regulated assets as at December 31, 2016 (December 31, 2015 – 44%). The increases were driven by the acquisition of ITC.

ITC

Financial Highlights [1]

Year Ended December 31	**2016**
Average US:CAD Exchange Rate [2]	**1.34**
Revenue *($ millions)*	**334**
Earnings *($ millions)*	**59**

[1] Financial results of ITC are from October 14, 2016, the date of acquisition. For additional information on the acquisition of ITC, refer to the "Significant Items – Acquisition of ITC" section of this MD&A. Revenue represents 100% of ITC, while earnings represent the Corporation's 80.1% controlling ownership interest in ITC and reflects consolidated purchase price accounting adjustments.

[2] The reporting currency of ITC is the US dollar. The average US:CAD exchange rate is from the date of acquisition.

Revenue

ITC derives the majority of its revenue from providing transmission, scheduling, control and dispatch services over its transmission systems to its customers and other entities that provide electricity to end-use customers. Revenue was US$250 million ($334 million) from the date of acquisition. On an annual basis, revenue was US$1,125 million for 2016 compared to US$1,045 million for 2015. Revenue for both years was reduced due to the recognition of refund liabilities, largely related to base ROE complaints, which totalled US$80 million for 2016 and US$115 million for 2015. The refund liabilities for both years included amounts related to prior periods. Excluding the impact of the refund liabilities, ITC's revenue increased by US$45 million, driven by higher network revenue and regional cost-sharing revenue largely due to rate base growth.

Earnings

Earnings contribution from ITC was US$44 million ($59 million) from the date of acquisition. Earnings of ITC from the date of acquisition were reduced by US$21 million ($27 million) in after-tax expenses associated with the accelerated vesting of the Company's stock-based compensation awards as a result of the acquisition, of which the Corporation's share was US$17 million ($22 million).

On an annual basis, earnings of ITC were US$246 million for 2016 compared to US$242 million for 2015. Earnings for 2016 were reduced by after-tax acquisition-related expenses of US$69 million, including the accelerated vesting of the Company's stock-based compensation awards, as discussed above. Excluding the acquisition-related expenses, earnings of ITC increased by US$73 million. The increase was driven by rate base growth, higher AFUDC, and lower income tax expense.

UNS Energy

Financial Highlights

Years Ended December 31	**2016**	2015	Variance
Average US:CAD Exchange Rate [1]	**1.33**	1.28	0.05
Electricity Sales *(gigawatt hours ("GWh"))*	**14,387**	15,366	(979)
Gas Volumes *(petajoules ("PJ"))*	**13**	13	–
Revenue *($ millions)*	**2,002**	2,034	(32)
Earnings *($ millions)*	**199**	195	4

[1] The reporting currency of UNS Energy is the US dollar.

Electricity Sales & Gas Volumes

The decrease in electricity sales was primarily due to lower mining retail and short-term wholesale sales, both due to the impact of less favourable commodity prices compared to 2015. The majority of short-term wholesale sales is flowed through to customers and has no impact on earnings. Gas volumes were comparable with 2015.

Revenue

The decrease in revenue was mainly due to the flow through to customers of lower purchased power and fuel supply costs, lower mining retail and short-term wholesale electricity sales, and approximately $29 million (US$22 million), or $18 million (US$13 million) after tax, in FERC ordered transmission refunds. The decrease was partially offset by approximately $47 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue, $17 million (US$13 million), or $10 million (US$8 million) after tax, in revenue related to the settlement of Springerville Unit 1, and an increase in lost fixed-cost recovery revenue.

Earnings

The increase in earnings was primarily due to the settlement of Springerville Unit 1, lower deferred income tax expense, approximately $6 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings, and an increase in lost fixed-cost recovery revenue. The increase was partially offset by FERC ordered transmission refunds, higher operating expenses and depreciation and amortization.

Central Hudson

Financial Highlights

Years Ended December 31	**2016**	2015	Variance
Average US:CAD Exchange Rate [1]	**1.33**	1.28	0.05
Electricity Sales *(GWh)*	**5,112**	5,132	(20)
Gas Volumes *(PJ)*	**24**	24	–
Revenue *($ millions)*	**849**	880	(31)
Earnings *($ millions)*	**70**	58	12

[1] The reporting currency of Central Hudson is the US dollar.

Electricity Sales & Gas Volumes

The decrease in electricity sales was mainly due to lower average consumption as a result of changes in temperatures, partially offset by the timing of customer billings as a result of regulatory approval to increase billing frequency to monthly, effective July 1, 2016. Gas volumes were comparable with 2015.

Changes in electricity sales and gas volumes at Central Hudson are subject to regulatory revenue decoupling mechanisms and, as a result, do not have a material impact on revenue and earnings.

Revenue

The decrease in revenue was mainly due to the recovery from customers of lower commodity costs, which were mainly due to overall lower wholesale prices, and the impact of energy-efficiency incentives earned during the first half of 2015 upon achieving energy saving targets established by the regulator. The decrease was partially offset by higher delivery revenue from increases in base electricity rates effective July 1, 2015 and July 1, 2016 and approximately $20 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue.

Earnings

The increase in earnings was primarily due to increases in delivery revenue, approximately $5 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings, and lower-than-expected operating expenses. The increase was partially offset by the impact of energy-efficiency incentives earned during the first half of 2015, as discussed above.

Regulated Gas & Electric Utilities – Canadian

Regulated Gas & Electric Utilities – Canadian earnings for 2016 were $390 million (2015 – $390 million), which represented approximately 51% of the Corporation's total regulated earnings (2015 – 58%). Total segment assets were approximately $14.8 billion as at December 31, 2016 (December 31, 2015 – $14.2 billion), which represented approximately 32% of the Corporation's total regulated assets as at December 31, 2016 (December 31, 2015 – 52%). The decrease in percentage of regulated earnings and assets as compared to 2015 were due to the acquisition of ITC.

FortisBC Energy

Financial Highlights

Years Ended December 31	**2016**	2015	Variance
Gas Volumes *(PJ)*	**197**	186	11
Revenue *($ millions)*	**1,151**	1,295	(144)
Earnings *($ millions)*	**151**	140	11

Gas Volumes

The increase in gas volumes was primarily due to customer growth, higher average consumption by residential and commercial customers in 2016 due to colder temperatures, and higher volumes for transportation customers due to certain transportation customers switching to natural gas compared to alternative fuel sources.

Revenue

The decrease in revenue was primarily due to a lower commodity cost of natural gas charged to customers, partially offset by an increase in customer delivery rates effective January 1, 2016 and higher gas volumes.

Earnings

The increase in earnings was primarily due to higher AFUDC associated with the Tilbury liquefied natural gas ("LNG") facility expansion ("Tilbury LNG Facility Expansion"), and operating expense savings, net of the earnings sharing mechanism. Changes in consumption levels and the commodity cost of natural gas do not materially impact earnings as a result of regulatory deferral mechanisms.

FortisAlberta

Financial Highlights

Years Ended December 31	**2016**	2015	Variance
Energy Deliveries *(GWh)*	**16,788**	17,132	(344)
Revenue *($ millions)*	**572**	563	9
Earnings *($ millions)*	**121**	138	(17)

Energy Deliveries

The decrease in energy deliveries was primarily due to lower average consumption by oil and gas customers as a result of low commodity prices for oil and gas, and lower average consumption by residential, commercial and irrigation customers, mainly due to changes in weather. The decrease was partially offset by higher energy deliveries to residential customers due to growth in the number of customers.

Revenue

As a significant portion of FortisAlberta's distribution revenue is derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered are not entirely correlated with changes in revenue. Revenue is a function of numerous variables, many of which are independent of actual energy deliveries.

The increase in revenue was due to an increase in customer rates effective January 1, 2016 based on a combined inflation and productivity factor of 0.9%, growth in the number of customers and higher revenue related to flow-through costs to customers. The increase was partially offset by the impact of a $9 million positive capital tracker revenue adjustment recognized in 2015 that related to 2013 and 2014, lower average consumption, and a $3 million negative capital tracker revenue adjustment as a result of the outcome of the 2016 GCOC Proceeding in Alberta.

Earnings

The decrease in earnings was mainly due to the $9 million positive capital tracker revenue adjustment recognized in the first half of 2015, lower average energy consumption, and higher operating expenses. The decrease was partially offset by rate base growth, tempered by the impact of the 2016 GCOC Proceeding, and growth in the number of customers.

FortisBC Electric

Financial Highlights

Years Ended December 31	**2016**	2015	Variance
Electricity Sales *(GWh)*	**3,119**	3,116	3
Revenue *($ millions)*	**377**	360	17
Earnings *($ millions)*	**54**	50	4

Electricity Sales

Electricity sales were comparable with 2015.

Revenue

The increase in revenue was driven by increases in base electricity rates and surplus capacity sales. Higher contribution from non-regulated operating, maintenance and management services associated with the Waneta Expansion also favourably impacted revenue.

Earnings

The increase in earnings was primarily due to higher earnings from non-regulated operating, maintenance and management services, and rate base growth.

Eastern Canadian Electric Utilities

Financial Highlights

Years Ended December 31	**2016**	2015	Variance
Electricity Sales *(GWh)*	**8,374**	8,403	(29)
Revenue *($ millions)*	**1,063**	1,033	30
Earnings *($ millions)*	**64**	62	2

Electricity Sales

The decrease in electricity sales was primarily due to lower average consumption by residential customers in all regions, mainly due to warmer temperatures. The decrease was partially offset by customer growth in Newfoundland.

Revenue

The increase in revenue was mainly due to the flow through in customer electricity rates of higher energy supply costs at Newfoundland Power and FortisOntario, partially offset by lower electricity sales.

Earnings

The increase in earnings was primarily due to rate base growth and lower-than-forecast expenses at Newfoundland Power, and lower business development costs at FortisOntario. The increase was partially offset by a decrease in Newfoundland Power's allowed ROE effective January 1, 2016 and lower electricity sales.

Regulated Electric Utilities – Caribbean

Regulated Electric Utilities – Caribbean earnings for 2016 were $46 million (2015 – $34 million), which represented approximately 6% of the Corporation's total regulated earnings (2015 – 5%). Total segment assets were approximately $1.3 billion as at December 31, 2016 (December 31, 2015 – $1.3 billion), which represented approximately 3% of the Corporation's total regulated assets as at December 31, 2016 (December 31, 2015 – 4%).

Financial Highlights

Years Ended December 31	**2016**	2015	Variance
Average US:CAD Exchange Rate [1]	**1.33**	1.28	0.05
Electricity Sales *(GWh)*	**837**	802	35
Revenue *($ millions)*	**301**	321	(20)
Earnings *($ millions)*	**46**	34	12

[1] The reporting currency of Caribbean Utilities and Fortis Turks and Caicos is the US dollar. The reporting currency of Belize Electricity is the Belizean dollar, which is pegged to the US dollar at BZ$2.00=US$1.00.

Electricity Sales

The increase in electricity sales was primarily due to growth in the number of customers as a result of increased economic activity and overall warmer temperatures on Grand Cayman, which increased air conditioning load.

Revenue

The decrease in revenue was mainly due to the flow through in customer electricity rates of lower fuel costs. The decrease was partially offset by electricity sales growth and approximately $4 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue.

Earnings

The increase in earnings was primarily due to equity income from Belize Electricity, favourable foreign exchange of approximately $4 million associated with the translation of US dollar-denominated earnings, and electricity sales growth. The increase was partially offset by higher depreciation and amortization.

NON-REGULATED

Non-Regulated – Energy Infrastructure

Financial Highlights

Years Ended December 31	**2016**	2015	Variance
Energy Sales *(GWh)*	**901**	844	57
Revenue *($ millions)*	**193**	107	86
Earnings *($ millions)*	**60**	77	(17)

Energy Sales

The increase in energy sales was driven by the Waneta Expansion, which commenced production in April 2015, and increased production in Belize. The increase was partially offset by lower energy sales due to the sale of generation assets in 2015 and February 2016.

Revenue

The increase in revenue was driven by the acquisition of Aitken Creek and a full year of contribution from the Waneta Expansion. The impacts of increased production in Belize and approximately $1 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue were largely offset by lower revenue due to the sale of generation assets.

Earnings

The decrease in earnings was primarily due to the recognition of $32 million in after-tax gains in 2015 on the sale of generation assets, and lower earnings due to the sale of generation assets. The decrease was partially offset by contribution of $9 million from Aitken Creek, net of an after-tax $6 million unrealized loss on the mark-to-market of derivatives, a full year of contribution from the Waneta Expansion, increased production in Belize, and approximately $1 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings.

Non-Regulated – Non-Utility

Financial Highlights

Years Ended December 31

($ millions)	**2016**	2015	Variance
Revenue	**–**	171	(171)
Earnings	**–**	114	(114)

Revenue

The decrease in revenue was due to the sale of commercial real estate and hotel assets in 2015.

Earnings

The decrease in earnings was due to the sale of commercial real estate and hotel assets in 2015. In 2015, an after-tax net gain of approximately $101 million was recognized related to the sale of commercial real estate and hotel assets.

Corporate and Other

Financial Highlights

Years Ended December 31

($ millions)	**2016**	2015	Variance
Revenue	**9**	24	(15)
Operating Expenses	**108**	36	72
Depreciation and Amortization	**4**	2	2
Other Income (Expenses), Net	**–**	2	(2)
Finance Charges	**162**	94	68
Income Tax Recovery	**(101)**	(43)	(58)
	(164)	(63)	(101)
Preference Share Dividends	**75**	77	(2)
Net Corporate and Other Expenses	**(239)**	(140)	(99)

Net Corporate and Other expenses were impacted by the following items.

(i) Acquisition-related expenses totalling $118 million ($90 million after tax) in 2016 associated with ITC (2015 – $10 million ($7 million after tax)). Acquisition-related expenses included: (i) investment banking, legal, consulting and other fees totalling approximately $79 million ($62 million after tax) in 2016 (2015 – $10 million ($7 million after tax)), which were included in operating expenses; and (ii) fees associated with the Corporation's acquisition credit facilities and deal-contingent interest rate swap contracts totalling approximately $39 million ($28 million after tax) in 2016 (2015 – nil), which were included in finance charges;

(ii) A foreign exchange gain of $13 million in 2015 associated with the Corporation's previous US dollar-denominated long-term other asset that represented the book value of its expropriated investment in Belize Electricity, which was included in other income; and

(iii) A loss of $9 million in 2015 on settlement of expropriation matters related to the Corporation's investment in Belize Electricity, which was included in other income, net of expenses.

Excluding the above-noted items, net Corporate and Other expenses were $149 million for 2016 compared to $137 million for 2015. The increase was primarily due to higher finance charges, lower revenue, and higher operating expenses, partially offset by a higher income tax recovery.

The increase in finance charges was mainly due to the acquisition of ITC in October 2016. The impact of no longer capitalizing interest upon the completion of the Waneta Expansion in April 2015, finance charges associated with the acquisition of Aitken Creek in April 2016, and the impact of unfavourable foreign exchange associated with the translation of US dollar-denominated interest expense also contributed to the increase in finance charges. The decrease in revenue was due to lower related-party interest income, mainly due to the sale of commercial real estate and hotel assets in 2015. The increase in operating expenses was primarily due to higher compensation-related expenditures, including higher stock-based compensation as a result of share price appreciation, business development costs, general inflationary increases and ancillary expenses to support the acquisition of ITC and the Corporation's listing on the New York Stock Exchange. The increase was partially offset by a $3 million ($2 million after tax) corporate donation recognized in 2015. The higher income tax recovery was mainly related to the increase in net Corporate and Other expenses and the Corporation's financing structure associated with the acquisition of ITC.

REGULATORY HIGHLIGHTS

The following summarizes the significant regulatory decisions and applications for the Corporation's utilities for 2016.

ITC

ROE Complaints

Since 2013 two third-party complaints were filed with FERC requesting that FERC find the MISO regional base ROE for all MISO transmission owners, including ITCTransmission, METC and ITC Midwest, for the periods November 2013 through February 2015 (the "Initial Refund Period") and February 2015 through May 2016 (the "Second Refund Period") to no longer be just and reasonable. In September 2016 FERC issued an order affirming the presiding ALJ's initial decision for the Initial Refund Period and setting the base ROE for the Initial Refund Period at 10.32%, with a maximum ROE of 11.35%. Additionally, the rates established by the September 2016 order will be used prospectively from the date of the order until a new approved rate is established for the Second Refund Period. In June 2016 the presiding ALJ issued an initial decision for the Second Refund Period, which recommended a base ROE of 9.70%, with a maximum ROE of 10.68%, which is a recommendation to FERC. A decision from FERC for the Second Refund Period is expected in 2017. The base ROE for the three affected utilities for the period of May 2016 through September 2016 was 12.38% and any authorized adders that were approved prior to the filing of the complaints were collected during this time, up to a maximum of 13.88%. As at December 31, 2016, the estimated range of refunds for both periods was between US$221 million and US$258 million and ITC has recognized an aggregate estimated regulatory liability of US$258 million. In February 2017 ITC provided refunds totalling US$119 million, including interest, for the initial complaint. The estimated regulatory liability was accrued by ITC before its acquisition by Fortis. It is possible that the outcome of these matters could differ materially from the estimated range of refunds.

Challenges on Bonus Depreciation

In December 2015 a formal challenge was filed with FERC alleging that ITC Midwest unreasonably and imprudently opted out of using bonus depreciation in the calculation of its federal income tax expense, resulting in increased charges for transmission service to customers. In March 2016 FERC issued an order requiring ITC Midwest to recalculate its revenue requirements, effective January 1, 2015, to simulate the election of bonus depreciation for 2015. While FERC denied the challenge for ITC Midwest to elect bonus depreciation in any past or future years, stakeholders are able to challenge any decision by ITC Midwest, or any of ITC's regulated operating subsidiaries, not to take bonus depreciation in future years. ITC's financial statements reflect the election of bonus depreciation for tax years 2015 and 2016, the corresponding effects on 2015 and 2016 revenue requirements for its regulated operating subsidiaries, and the corresponding refund obligation. The total impact from reflecting the election of bonus depreciation, as described above, was lower revenue of US$20 million and lower net earnings of approximately US$12 million for the year ended December 31, 2016, and an increase in deferred income tax liabilities of US$109 million and a corresponding tax receivable of US$12 million as at December 31, 2016. In addition, the above-noted elections resulted in an income tax refund of US$128 million, which was received in August 2016. The election of bonus depreciation will result in higher cash flows in the year of election or future subsequent periods and a reduction in rate base, resulting in a decrease in revenue and net earnings over the tax lives of the eligible assets.

UNS Energy

General Rate Application

In February 2017 the ACC issued a Rate Order on TEP's GRA filed in November 2015, based on a historical test year ended June 30, 2015. The 2017 Rate Order approved new rates effective on or before March 1, 2017. The provisions of the 2017 Rate Order include, but are not limited to: (i) an increase in non-fuel base revenue of US$81.5 million, including US$15 million of operating costs related to the 50.5% undivided interest in Springerville Unit 1 purchased by TEP in September 2016; (ii) a 7.04% return on original cost rate base, including a cost of equity of 9.75% and an embedded cost of long-term debt of 4.32%; (iii) a common equity component of capital structure of approximately 50%; and (iv) the adoption of proposed depreciation rates which reflect a reduction in the depreciable life for San Juan Unit 1. Certain aspects of the GRA, including net metering and rate design for distributed generation customers, have been deferred to a second rate case proceeding, which is expected to begin in the first half of 2017.

FERC Order

In 2015 and 2016 TEP reported to FERC that it had not filed on a timely basis certain FERC jurisdictional agreements and, at that time, TEP made compliance filings, including the filing of several TEP transmission service agreements, the majority of which were entered into before the acquisition of UNS Energy by Fortis in 2014, that contained certain deviations from TEP's standard form of service agreement. In 2016 FERC issued two orders relating to the late-filed transmission service agreements, which directed TEP to issue time value refunds to the counterparties of the agreements. In 2016 TEP accrued time value refunds of $29 million (US$22 million), or $18 million (US$13 million) after tax, of which US$17 million has been paid.

In June 2016, to preserve its rights, TEP petitioned the District of Columbia Circuit Court of Appeals to review the refund order. In January 2017 TEP and one of the counterparties to the late-filed transmission service agreements entered into a settlement regarding the time value refunds. Under the settlement, in January 2017, the counterparty paid TEP US$8 million and TEP dismissed its appeal with prejudice. The impact of the settlement agreement will be recognized in the first quarter of 2017. FERC's Office of Enforcement is still reviewing the matter, and FERC could impose civil penalties on TEP as a result of this review. At this time, TEP cannot predict the outcome or the range of additional losses, if any.

FortisBC Energy and FortisBC Electric

Generic Cost of Capital Proceeding

In October 2015, as required by the regulator, FEI filed its application to review the 2016 benchmark allowed ROE and common equity component of capital structure. In August 2016 the British Columbia Utilities Commission ("BCUC") issued its decision on FEI's application, which reaffirmed FEI as the benchmark utility and established that the ROE and common equity component of capital structure for the benchmark utility would remain unchanged at 8.75% and 38.5%, respectively, both effective January 1, 2016. As FEI is the benchmark utility, FortisBC Electric's allowed ROE also remains unchanged at 9.15%.

FortisAlberta

Capital Tracker Applications

In February 2016 the Alberta Utilities Commission ("AUC") issued its decision related to FortisAlberta's 2014 True-Up and 2016–2017 Capital Tracker Applications, resulting in a capital tracker revenue adjustment of less than $1 million. In January 2017 the AUC issued its decision on FortisAlberta's 2015 True-Up Application approving capital tracker revenue as filed, pending the Company's submission of a Compliance Filing in February 2017.

In September 2016 the AUC approved FortisAlberta's Compliance Filing related to the February 2016 capital tracker decision, including approval of capital tracker revenue of $71 million and $90 million for 2016 and 2017, respectively. The adjustments to capital tracker revenue have been included in FortisAlberta's 2017 Annual Rates Application. Any further differences between 2015 and 2016 capital tracker revenue collected from customers and actual capital expenditures will be included in 2017 applications to be refunded to or collected from customers in 2018.

FortisAlberta recognized capital tracker revenue of $59 million for 2016, down $12 million from the $71 million approved in the Compliance Filing, which reflects actual capital expenditures and associated financing costs compared to forecast, and the impact of the 2016 GCOC Decision, as discussed below.

Generic Cost of Capital Proceeding

In October 2016 the AUC issued its decision related to FortisAlberta's 2016 and 2017 GCOC Proceeding, establishing that FortisAlberta's allowed ROE remain unchanged at 8.30% for 2016 and increase to 8.50% for 2017. The decision also set the common equity component of capital structure at 37%, effective January 1, 2016, down from 40% approved on an interim basis. Changes in FortisAlberta's allowed ROE and common equity component of capital structure impact only the portion of rate base that is funded by capital tracker revenue.

Next Generation PBR Proceeding

In December 2016 the AUC issued its decision outlining the manner in which distribution rates will be determined during the second PBR term, being the five-year period from 2018 through 2022. The parameters of the second PBR term are generally consistent with the first PBR term; except for: (i) the productivity factor, which is set at 0.3% for the second PBR term, as compared to 1.16% for the first PBR term; and (ii) the capital tracker mechanism, which will be replaced by two incremental capital funding mechanisms in the second PBR term. The capital funding mechanisms will include a capital tracker mechanism similar to the first PBR term for incremental capital not previously included in FortisAlberta's rate base, and a K-bar mechanism, submitted annually through the annual rates application, for all capital included in FortisAlberta's going-in rate base. The AUC has directed Alberta utilities to file a rebasing application in March 2017 to establish the going-in revenue requirement for the second PBR term, which will be used to determine the going-in rates upon which the PBR formula will be applied to establish distribution rates for 2018. A decision on this application is expected in the second half of 2017.

Eastern Canadian Electric Utilities

In June 2016 the Newfoundland and Labrador Board of Commissioners of Public Utilities issued an order on Newfoundland Power's 2016/2017 GRA, with new customer rates effective July 1, 2016. The order, which established the cost of capital for rate-making purposes for 2016 through 2018, resulted in a decrease in the allowed ROE to 8.50% from 8.80%, effective January 1, 2016, on a 45% common equity component of capital structure. Newfoundland Power is required to file its next GRA for 2019 on or before June 1, 2018.

Significant Regulatory Proceedings

The following table summarizes significant ongoing regulatory proceedings, including filing dates and expected timing of decisions for the Corporation's utilities.

Regulated Utility	Application/Proceeding	Filing Date	Expected Decision
ITC	Second MISO Base ROE Complaint	Not applicable	2017

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets between December 31, 2016 and December 31, 2015. The increase due to ITC reflects the net assets acquired as at December 31, 2016.

Significant Changes in the Consolidated Balance Sheets between December 31, 2016 and December 31, 2015

Balance Sheet Account	Increase Due to ITC *($ millions)*	Other Increase/ (Decrease) *($ millions)*	Explanation for Other Increase/(Decrease)
Accounts receivable and other current assets	179	(16)	The decrease was not significant.
Regulatory assets – current and long-term	390	11	The increase was not significant.
Utility capital assets	8,608	1,134	The increase was mainly due to utility capital expenditures and the acquisition of Aitken Creek, partially offset by depreciation and the impact of foreign exchange on the translation of US dollar-denominated utility capital assets.
Intangible assets	442	28	The increase was not significant.
Goodwill	8,246	(55)	The decrease was not significant.
Short-term borrowings	195	449	The increase was mainly due to drawings under the Corporation's equity bridge credit facility to finance a portion of the acquisition of ITC, partially offset by the repayment of short-term borrowings at FortisBC Energy using net proceeds from the issuance of long-term debt.
Accounts payable and other current liabilities	364	187	The increase was mainly due to higher customer deposits at FortisBC Energy and higher dividends payable at the Corporation, driven by an increase in the number of common shares outstanding. Higher amounts owing for energy supply costs and an increase in capital accruals at FortisBC Energy also contributed to the increase.
Other liabilities	165	(38)	The decrease was not significant.
Regulatory liabilities – current and long-term	496	49	The increase was not significant.
Long-term debt (including current portion)	6,461	3,439	The increase was mainly due to the issuance of long-term debt at the Corporation to finance a portion of the acquisition of ITC, the acquisition of Aitken Creek, and the redemption of First Preference Shares, Series E. Issuances of long-term debt at the regulated utilities, largely in support of energy infrastructure investment, were partially offset by regularly scheduled debt repayments and the impact of foreign exchange on the translation of US dollar-denominated debt.
Deferred income tax liabilities	991	222	The increase was mainly due to timing differences related to capital expenditures at the regulated utilities and the acquisition of Aitken Creek, partially offset by taxable losses at the Corporation and the impact of foreign exchange on the translation of US dollar-denominated deferred income tax liabilities.
Shareholders' equity (before non-controlling interests)	–	4,717	The increase was driven by the issuance of approximately 114.4 million common shares to finance a portion of the acquisition of ITC. Net earnings attributable to common equity shareholders for 2016, less dividends declared on common shares, and the issuance of common shares under the Corporation's dividend reinvestment, employee share purchase and stock option plans also contributed to the increase. The increase was partially offset by the redemption of First Preference Shares, Series E.
Non-controlling interests	–	1,380	The increase was primarily due to proceeds from GIC's minority investment in ITC.

LIQUIDITY AND CAPITAL RESOURCES

Summary of Consolidated Cash Flows

The table below outlines the Corporation's sources and uses of cash in 2016 compared to 2015, followed by a discussion of the nature of the variances in cash flows.

Summary of Consolidated Cash Flows

Years Ended December 31 *($ millions)*	**2016**	2015	Variance
Cash, Beginning of Year	**242**	230	12
Cash Provided by (Used in):			
Operating Activities	**1,884**	1,673	211
Investing Activities	**(6,891)**	(1,368)	(5,523)
Financing Activities	**5,050**	(346)	5,396
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**(16)**	53	(69)
Cash, End of Year	**269**	242	27

Operating Activities: Cash flow from operating activities in 2016 was $211 million higher than in 2015. The increase was primarily due to higher cash earnings at the regulated utilities, driven by the acquisition of ITC, partially offset by the Corporation's acquisition-related expenses. Favourable changes in long-term regulatory deferrals were partially offset by unfavourable changes in working capital.

Investing Activities: Cash used in investing activities in 2016 was $5,523 million higher than in 2015. The increase was driven by the acquisition of ITC in October 2016 for net cash consideration of approximately $4.5 billion (US$3.5 billion) and the acquisition of Aitken Creek in April 2016 for a net purchase price of $318 million. Proceeds received from the sale of commercial real estate, hotel and generation assets in 2015 of approximately $430 million, $365 million and $77 million (US$63 million), respectively, also contributed to the increase in cash used in investing activities.

Capital expenditures for 2016 were $182 million lower than 2015 mainly due to lower capital spending at UNS Energy, FortisBC Energy and FortisAlberta. The decrease in capital spending at UNS Energy was mainly due to the purchase of additional ownership interests in the Springerville Unit 1 generating facility and previously leased coal-handling assets in 2015, partially offset by the purchase of the third-party owners' 50.5% undivided interest in Springerville Unit 1 generating facility for US$85 million in 2016. Lower capital spending at FortisBC Energy was related to the Tilbury LNG Facility Expansion and the decrease at FortisAlberta was mainly due to lower Alberta Electric System Operator ("AESO") contributions and lower capital expenditures for new customers. The decrease in capital expenditures was partially offset by investments of approximately US$167 million at ITC from the date of acquisition.

Financing Activities: Cash provided by financing activities in 2016 was $5,396 million higher than in 2015. The increase was driven by financing activities associated with the acquisition of ITC. The net cash consideration associated with the acquisition of ITC was financed using: (i) net proceeds from the issuance of US$2.0 billion unsecured notes in October 2016; (ii) net proceeds from GIC's US$1.228 billion minority investment, which includes a shareholder note of US$199 million; and (iii) drawings of approximately US$404 million ($535 million) under the Corporation's non-revolving term senior unsecured equity bridge credit facility.

In addition to the impact of financing activities associated with ITC, higher net borrowings under committed credit facilities, lower repayments of long-term debt and higher proceeds from the issuance of long-term debt also contributed to the increase in cash provided by financing activities. The increase was partially offset by other changes in short-term borrowings and the redemption of preference shares.

Proceeds from long-term debt, net of issue costs, repayments of long-term debt and capital lease and finance obligations, and net borrowings (repayments) under committed credit facilities for 2016 and 2015 are summarized in the following tables.

Proceeds from Long-Term Debt, Net of Issue Costs

Years Ended December 31

($ millions)	**2016**	2015	Variance
ITC[1]	**264**	–	264
UNS Energy[2]	**–**	591	(591)
Central Hudson[3]	**68**	25	43
FortisBC Energy[4]	**446**	150	296
FortisAlberta[5]	**149**	149	–
Eastern Canadian[6]	**40**	75	(35)
Caribbean Electric[7]	**65**	12	53
Corporate[8]	**3,104**	–	3,104
Total	**4,136**	1,002	3,134

(1) In October 2016 a 12-year shareholder note of US$199 million at 6.00% was issued to an affiliate of GIC as part of its minority investment in ITC. The proceeds were used to finance a portion of the cash purchase price of the acquisition of ITC.

(2) In February 2015 TEP issued 10-year US$300 million 3.05% senior unsecured notes. Net proceeds were used to repay long-term debt and credit facility borrowings and to finance capital expenditures. In April 2015 UNS Electric issued 30-year US$50 million 3.95% unsecured notes. The net proceeds were primarily used for general corporate purposes. In August 2015 UNS Electric issued 12-year US$80 million 3.22% unsecured notes and UNS Gas issued 30-year US$45 million 4.00% unsecured notes. The net proceeds were used to repay maturing long-term debt.

(3) In June 2016 Central Hudson issued 4-year US$24 million unsecured notes at 2.16%. The net proceeds were used to finance capital expenditures and for general corporate purposes. In October 2016 Central Hudson issued US$30 million of unsecured notes in a dual tranche of 10-year US$10 million unsecured notes at 2.56% and 30-year US$20 million unsecured debentures at 3.63%. The net proceeds were used to finance capital expenditures and for general corporate purposes. In March 2015 Central Hudson issued 10-year US$20 million 2.98% unsecured notes. The net proceeds were used to finance capital expenditures and for general corporate purposes.

(4) In April 2016 FortisBC Energy issued $300 million of unsecured debentures in a dual tranche of 10-year $150 million unsecured debentures at 2.58% and 30-year $150 million unsecured debentures at 3.67%. In December 2016 FortisBC Energy issued 30-year $150 million unsecured debentures at 3.78%. The net proceeds from the issuances were used to repay short-term borrowings and to finance capital expenditures. In April 2015 FortisBC Energy issued 30-year $150 million 3.38% unsecured debentures. The net proceeds were used to repay short-term borrowings.

(5) In September 2016 FortisAlberta issued 30-year $150 million unsecured debentures at 3.34%. The net proceeds were used to repay credit facility borrowings, to finance capital expenditures and for general corporate purposes. In September 2015 FortisAlberta issued 30-year $150 million 4.27% senior unsecured debentures. The net proceeds were used to repay credit facility borrowings and for general corporate purposes.

(6) In August 2016 Maritime Electric issued 40-year $40 million secured first mortgage bonds at 3.657%. The net proceeds were primarily used to repay long-term debt and short-term borrowings. In September 2015 Newfoundland Power issued 30-year $75 million 4.446% secured first mortgage sinking fund bonds. The net proceeds were used to repay credit facility borrowings and for general corporate purposes.

(7) In May and September 2016, Fortis Turks and Caicos issued 15-year US$45 million unsecured notes in a dual tranche of US$22.5 million at 5.14% and 5.29%, respectively. In July 2016 Fortis Turks and Caicos issued 15-year US$5 million unsecured bonds at 5.14%. The net proceeds were used to finance capital expenditures and for general corporate purposes. In January 2015 Fortis Turks and Caicos issued 15-year US$10 million 4.75% unsecured notes. The net proceeds were used to finance capital expenditures and for general corporate purposes.

(8) In October 2016 the Corporation issued 5-year US$500 million unsecured notes at 2.100% and 10-year US$1.5 billion unsecured notes at 3.055%. The net proceeds were used to finance a portion of the cash purchase price of the acquisition of ITC. In December 2016 the Corporation issued 7-year $500 million unsecured notes at 2.85%. The net proceeds were used to repay credit facility borrowings, mainly related to the financing of the acquisition of Aitken Creek in April 2016 and the redemption of First Preference Shares, Series E in September 2016, and for general corporate purposes.

Repayments of Long-Term Debt and Capital Lease and Finance Obligations

Years Ended December 31

($ millions)	**2016**	2015	Variance
UNS Energy	**(19)**	(449)	430
Central Hudson	**(11)**	–	(11)
FortisBC Energy	**(212)**	(92)	(120)
FortisBC Electric	**(25)**	–	(25)
Eastern Canadian	**(48)**	(6)	(42)
Caribbean Electric	**(21)**	(21)	–
Other	**–**	(34)	34
Total	**(336)**	(602)	266

Net Borrowings (Repayments) Under Committed Credit Facilities

Years Ended December 31 *($ millions)*	**2016**	2015	Variance
ITC	**111**	–	111
UNS Energy	**33**	(199)	232
FortisAlberta	**(53)**	30	(83)
Eastern Canadian	**43**	(47)	90
Corporate[1]	**(41)**	(406)	365
Total	**93**	(622)	715

[1] Repayments under the Corporation's committed credit facility in 2015 were made using net proceeds from the sale of commercial real estate and hotel assets in 2015, partially offset by borrowings to finance equity injections into UNS Energy and FortisBC Energy, and for other general corporate purposes.

Borrowings under credit facilities by the utilities are primarily in support of their respective capital expenditure programs and/or for working capital requirements. Repayments are primarily financed through the issuance of long-term debt, cash from operations and/or equity injections from Fortis. From time to time, proceeds from preference share, common share and long-term debt offerings are used to repay borrowings under the Corporation's committed credit facility.

In September 2016 the Corporation redeemed all of the First Preference Shares, Series E for $200 million.

Common share dividends paid in 2016 totalled $316 million, net of $162 million of dividends reinvested, compared to $232 million, net of $156 million of dividends reinvested, paid in 2015. The increase in dividends paid was due to a higher annual dividend paid per common share and an increase in the number of common shares outstanding. The dividend paid per common share was $1.53 in 2016 compared to $1.40 in 2015. The weighted average number of common shares outstanding was 308.9 million for 2016 compared to 278.6 million for 2015.

Contractual Obligations

The Corporation's consolidated contractual obligations with external third parties in each of the next five years and for periods thereafter, as at December 31, 2016, are outlined in the following table.

Contractual Obligations

As at December 31, 2016 *($ millions)*	**Total**	Due within 1 year	Due in year 2	Due in year 3	Due in year 4	Due in year 5	Due after 5 years
Long-term debt	**21,219**	251	931	679	725	1,756	16,877
Interest obligations on long-term debt	**14,586**	892	854	837	817	793	10,393
Capital lease and finance obligations[1]	**2,422**	121	92	76	73	81	1,979
Power purchase obligations[2]	**2,295**	290	200	119	107	107	1,472
Renewable power purchase obligations[3]	**1,625**	100	99	99	98	97	1,132
Gas purchase obligations[4]	**1,329**	411	290	177	141	110	200
Long-term contracts – UNS Energy[5]	**1,146**	192	161	161	127	85	420
ITC easement agreement[6]	**453**	13	13	13	13	13	388
Operating lease obligations	**175**	13	13	11	8	7	123
Renewable energy credit purchase agreements[7]	**154**	20	15	12	12	12	83
Purchase of Springerville Common Facilities[8]	**91**	–	–	–	–	91	–
Waneta Partnership promissory note	**72**	–	–	–	72	–	–
Joint-use asset and shared service agreements	**53**	3	3	3	3	3	38
Other[9]	**156**	93	18	19	–	–	26
Total	**45,776**	2,399	2,689	2,206	2,196	3,155	33,131

[1] Includes principal payments, imputed interest and executory costs, mainly related to FortisBC Electric's capital lease obligations.

[2] Power purchase obligations include various power purchase contracts held by the Corporation's regulated utilities, of which the most significant contracts are described below.

FortisOntario: Power purchase obligations for FortisOntario, totalling $743 million as at December 31, 2016, include a contract with Hydro-Quebec for the supply of up to 145 MW of capacity and a minimum of 537 GWh of associated energy annually from January 2020 through to December 2030. This contract will replace FortisOntario's existing long-term take-or-pay contracts with Hydro-Quebec to supply 145 MW of capacity expiring in 2019.

FortisBC Energy: FortisBC Energy is party to an electricity supply agreement with BC Hydro for the purchase of electricity supply to the Tilbury LNG Facility Expansion, with purchase obligations totalling $486 million as at December 31, 2016.

FortisBC Electric: Power purchase obligations for FortisBC Electric, totalling $288 million as at December 31, 2016, include a PPA with BC Hydro to purchase up to 200 MW of capacity and 1,752 GWh of associated energy annually for a 20-year term. FortisBC Electric is also party to the Waneta Expansion Capacity Agreement ("WECA"), allowing it to purchase 234 MW of capacity for 40 years, effective April 2015, as approved by the BCUC. Amounts associated with the WECA have not been included in the Contractual Obligations table as they will be paid by FortisBC Electric to a related party.

Maritime Electric: Maritime Electric's power purchase obligations include two take-or-pay contracts for the purchase of either capacity or energy, expiring in February 2019, as well as an Energy Purchase Agreement with New Brunswick Power ("NB Power"). Maritime Electric has entitlement to approximately 4.55% of the output from NB Power's Point Lepreau nuclear generating station for the life of the unit. As part of its entitlement, Maritime Electric is required to pay its share of the capital and operating costs of the unit, and as at December 31, 2016, had commitments of $480 million under this arrangement.

(3) TEP and UNS Electric are party to long-term renewable PPAs totalling approximately US$1,210 million as at December 31, 2016, which require TEP and UNS Electric to purchase 100% of the output of certain renewable energy generating facilities once commercial operation is achieved. While TEP and UNS Electric are not required to make payments under these contracts if power is not delivered, the Contractual Obligations table includes estimated future payments. These agreements have various expiry dates from 2030 through 2036.

(4) Certain of the Corporation's subsidiaries, mainly FortisBC Energy, enter into contracts for the purchase of gas, gas transportation and storage services. FortisBC Energy's gas purchase obligations are based on gas commodity indices that vary with market prices and the obligations are based on index prices as at December 31, 2016.

(5) UNS Energy enters into various long-term contracts for the purchase and delivery of coal to fuel its generating facilities, the purchase of gas transportation services to meet its load requirements, and the purchase of transmission services for purchased power, with obligations totalling US$496 million, US$244 million and US$113 million, respectively, as at December 31, 2016. Amounts paid under contracts for the purchase and delivery of coal depend on actual quantities purchased and delivered. Certain of these contracts also have price adjustment clauses that will affect future costs under the contracts.

(6) ITC is party to an easement agreement with Consumers Energy, the primary customer of METC, which provides the Company with an easement for transmission purposes and rights-of-way, leasehold interests, fee interests and licenses associated with the land over which its transmission lines cross. The agreement expires in December 2050, subject to 10 additional 50-year renewals thereafter.

(7) UNS Energy and Central Hudson are party to renewable energy credit purchase agreements. UNS Energy's renewable energy credit purchase agreements totalled approximately US$107 million as at December 31, 2016 for the purchase of environmental attributions from retail customers with solar installations. Payments for the renewable energy credit purchase agreements are paid in contractually agreed-upon intervals based on metered renewable energy production.

(8) UNS Energy has an obligation to purchase an undivided 32.2% leased interest in the Springerville Common Facilities if the related two leases are not renewed, for a total purchase price of US$68 million.

(9) Other contractual obligations include various other commitments entered into by the Corporation and its subsidiaries, including Performance Share Unit, Restricted Share Unit and Directors' Deferred Share Unit plan obligations, asset retirement obligations, and defined benefit pension plan funding obligations.

Other Contractual Obligations

Capital Expenditures: The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by the need to ensure continued and enhanced performance, reliability and safety of the electricity and gas systems and to meet customer growth. The Corporation's consolidated capital expenditure program, including capital spending at its non-regulated operations, is forecast to be approximately $3.0 billion for 2017. Over the five years 2017 through 2021, the Corporation's consolidated capital expenditure program is expected to be approximately $13 billion, which has not been included in the Contractual Obligations table.

Other: CH Energy Group is party to an investment to develop, own and operate electric transmission projects in New York State. In December 2014 an application was filed with FERC for the recovery of the cost of and return on five high-voltage transmission projects totalling US$1.7 billion, of which CH Energy Group's maximum commitment is US$182 million. CH Energy Group issued a parental guarantee to assure the payment of the maximum commitment of US$182 million. As at December 31, 2016, there was no obligation under this guarantee.

In 2016 FHI issued a parental guarantee of $77 million to secure the storage optimization transactions of Aitken Creek.

The Corporation's long-term regulatory liabilities of $2,183 million as at December 31, 2016 have been excluded from the Contractual Obligations table, as the final timing of settlement of many of the liabilities is subject to further regulatory determination or the settlement periods are not currently known.

Capital Structure

The Corporation's principal businesses of regulated electric and gas utilities require ongoing access to capital to enable the utilities to fund maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. Fortis generally finances a significant portion of acquisitions at the corporate level with proceeds from common share, preference share and long-term debt offerings, and advances from minority investors. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure that will enable it to maintain investment-grade credit ratings. Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in their customer rates.

The consolidated capital structure of Fortis is presented in the following table.

Capital Structure

	2016		2015	
As at December 31	*($ millions)*	*(%)*	*($ millions)*	*(%)*
Total debt and capital lease and finance obligations (net of cash) [1]	**22,490**	**60.6**	11,950	54.8
Preference shares	**1,623**	**4.4**	1,820	8.3
Common shareholders' equity	**12,974**	**35.0**	8,060	36.9
Total	**37,087**	**100.0**	21,830	100.0

[1] Includes long-term debt and capital lease and finance obligations, including current portion, and short-term borrowings, net of cash

Including amounts related to non-controlling interests, the Corporation's capital structure as at December 31, 2016 was 57.8% total debt and capital lease and finance obligations (net of cash), 4.2% preference shares, 33.3% common shareholders' equity and 4.7% non-controlling interests (December 31, 2015 – 53.6% total debt and capital lease and finance obligations (net of cash), 8.2% preference shares, 36.1% common shareholders' equity and 2.1% non-controlling interests).

The acquisition of ITC significantly impacted the components of the Corporation's consolidated capital structure and included the following: (i) the issuance of US$2.0 billion unsecured notes and borrowings under the Corporation's non-revolving term senior unsecured equity bridge credit facility to finance a portion of the acquisition; (ii) debt assumed upon acquisition; (iii) the issuance of 114.4 million common shares, representing share consideration for the acquisition; and (iv) proceeds from GIC's US$1.228 billion minority investment, which includes a shareholder note of US$199 million. The Corporation expects to repay borrowings under the equity bridge facility using proceeds from a common equity offering in 2017.

The capital structure was also impacted by: (i) the issuance of long-term debt at the Corporation, primarily to finance the acquisition of Aitken Creek and the redemption of First Preference Shares, Series E, and at the regulated utilities, largely in support of energy infrastructure investment, partially offset by regularly scheduled debt repayments and the impact of foreign exchange on the translation of US-dollar denominated debt; (ii) net earnings attributable to common equity shareholders for 2016, less dividends declared on common shares; (iii) the issuance of common shares under the Corporation's dividend reinvestment, employee share purchase and stock option plans; and (iv) the redemption of First Preference Shares, Series E.

Credit Ratings

As at December 31, 2016, the Corporation's credit ratings were as follows:

Rating Agency	Credit Rating	Type of Rating	Outlook
Standard & Poor's ("S&P")	A–	Corporate	Stable
	BBB+	Unsecured debt	Stable
DBRS	BBB (high)	Unsecured debt	Stable
Moody's Investor Service ("Moody's")	Baa3	Issuer	Stable
	Baa3	Unsecured debt	Stable

The above-noted credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, and the level of debt at the holding company. In September 2016 Moody's commenced rating Fortis. In October 2016, following the completion of the acquisition of ITC, DBRS revised the Corporation's unsecured debt credit rating to BBB (high) from A (low) and revised its outlook to stable from under review with negative implications, and S&P affirmed the Corporation's long-term corporate and unsecured debt credit ratings as A– and BBB+, respectively, and revised its outlook to stable from negative.

Capital Expenditure Program

Capital investment in energy infrastructure is required to ensure continued and enhanced performance, reliability and safety of the electricity and gas systems, and to meet customer growth. All costs considered to be maintenance and repairs are expensed as incurred. Costs related to replacements, upgrades and betterments of capital assets are capitalized as incurred. Approximately $330 million in maintenance and repairs was expensed in 2016 compared to approximately $302 million in 2015. The increase was largely due to the acquisition of ITC in 2016.

Gross consolidated capital expenditures for 2016 were approximately $2.1 billion. A breakdown of these capital expenditures by segment and asset category for 2016 is provided in the following table.

Gross Consolidated Capital Expenditures[1]

Year Ended December 31, 2016

	Regulated Utilities										
($ millions)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Eastern Canadian	Caribbean Electric	**Total Regulated Utilities**	**Non-Regulated[2]**	**Total**
Generation	–	257	–	–	–	3	23	50	**333**	**19**	**352**
Transmission	195	33	38	72	–	11	16	2	**367**	**–**	**367**
Distribution	–	150	144	133	285	38	103	27	**880**	**–**	**880**
Facilities, equipment, vehicles and other[3]	14	38	26	113	68	16	8	22	**305**	**10**	**315**
Information technology	14	46	25	18	22	6	11	5	**147**	**–**	**147**
Total	223	524	233	336	375	74	161	106	**2,032**	**29**	**2,061**

[1] Represents cash payments to construct utility capital assets and intangible assets, as reflected on the consolidated statement of cash flows. Excludes the non-cash equity component of AFUDC

[2] Includes Energy Infrastructure and Corporate and Other segments

[3] Includes capital expenditures associated with the Tilbury LNG Facility Expansion at FortisBC Energy and Alberta Electric System Operator ("AESO") transmission-related capital expenditures at FortisAlberta

Planned capital expenditures are based on detailed forecasts of energy demand, cost of labour and materials, as well as other factors, including economic conditions and foreign exchange rates, which could change and cause actual expenditures to differ from those forecast. Gross consolidated capital expenditures of $2.1 billion for 2016 were $160 million higher than $1.9 billion forecast for 2016, as disclosed in the MD&A for the year ended December 31, 2015. The increase was primarily due to capital investments at ITC of US$167 million from the date of acquisition. Capital spending at UNS Energy was higher than forecast primarily due to the purchase of the remaining 50.5% undivided interest in Springerville Unit 1 for US$85 million in September 2016, which was partially offset by lower capital expenditures for system reinforcement and renewables. The higher-than-forecast capital expenditures for 2016 was partially offset by lower capital spending at FortisAlberta, primarily due to lower AESO contributions and as a result of the current economic downturn in Alberta, and the impact of foreign exchange associated with the translation of US dollar-denominated capital expenditures.

Gross consolidated capital expenditures for 2017 are expected to be approximately $3.0 billion. A breakdown of forecast gross consolidated capital expenditures by segment and asset category for 2017 is provided in the following table.

Forecast Gross Consolidated Capital Expenditures[1]

Year Ending December 31, 2017

	Regulated Utilities										
($ millions)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Eastern Canadian	Caribbean Electric	**Total Regulated Utilities**	**Non-Regulated[2]**	**Total**
Generation	–	161	3	–	–	19	6	45	**234**	**7**	**241**
Transmission	907	84	30	215	–	20	18	17	**1,291**	**–**	**1,291**
Distribution	–	185	142	131	303	41	113	23	**938**	**–**	**938**
Facilities, equipment, vehicles and other[3]	24	54	29	99	95	24	8	10	**343**	**11**	**354**
Information technology	27	36	18	22	21	7	8	4	**143**	**–**	**143**
Total	958	520	222	467	419	111	153	99	**2,949**	**18**	**2,967**

[1] Represents forecast cash payments to construct utility capital assets and intangible assets, as would be reflected on the consolidated statement of cash flows. Excludes the non-cash equity component of AFUDC. Forecast capital expenditures for 2017 are based on a forecast exchange rate of US$1.00=CAD$1.30. Based on the closing foreign exchange rate on December 31, 2016 of US$1.00=CAD$1.34 forecast capital expenditures for 2017 would be approximately $3.0 billion.

[2] Includes Energy Infrastructure and Corporate and Other segments

[3] Includes forecast capital expenditures associated with the Tilbury LNG Facility Expansion at FortisBC Energy and AESO transmission-related capital expenditures at FortisAlberta

The percentage breakdown of 2016 actual and 2017 forecast gross consolidated capital expenditures among growth, sustaining and other is as follows.

Gross Consolidated Capital Expenditures

Year Ending December 31	**Actual**	Forecast
(%)	**2016**	2017
Growth[1]	**29**	39
Sustaining[2]	**54**	48
Other[3]	**17**	13
Total	**100**	100

[1] Includes capital expenditures associated with the Tilbury LNG Facility Expansion at FortisBC Energy and AESO transmission-related capital expenditures at FortisAlberta

[2] Capital expenditures required to ensure continued and enhanced performance, reliability and safety of generation and T&D assets

[3] Relates to facilities, equipment, vehicles, information technology systems and other assets

Over the five-year period 2017 through 2021, gross consolidated capital expenditures are expected to be approximately $13 billion. The approximate breakdown of the capital spending expected to be incurred is as follows: 57% at U.S. Regulated Electric & Gas Utilities, including 28% at ITC; 39% at Canadian Regulated Gas & Electric Utilities; 3% at Caribbean Regulated Electric Utilities; and the remaining 1% at non-regulated operations. Capital expenditures at the regulated utilities are subject to regulatory approval. Over the five-year period, on average annually, the approximate breakdown of the total capital spending to be incurred is as follows: 58% for sustaining capital expenditures, 30% to meet customer growth, and 12% for facilities, equipment, vehicles, information technology and other assets.

Actual 2016 and forecast 2017 midyear rate base for the Corporation's regulated utilities and the Waneta Expansion is provided in the following table.

Midyear Rate Base

($ billions)	**Actual 2016**	Forecast 2017
ITC[1]	**6.9**	7.3
UNS Energy[1]	**4.6**	4.7
Central Hudson[1]	**1.5**	1.6
FortisBC Energy[2]	**3.7**	4.1
FortisAlberta	**2.9**	3.2
FortisBC Electric	**1.3**	1.3
Eastern Canadian	**1.7**	1.7
Caribbean Electric[1]	**0.9**	1.0
Waneta Expansion	**0.8**	0.8
Total	**24.3**	25.7

(1) Actual midyear rate base for 2016 is based on the actual average exchange rate of US$1.00=CAD$1.33 and forecast midyear rate base for 2017 is based on a forecast exchange rate of US$1.00=CAD$1.30. Based on the closing foreign exchange rate on December 31, 2016 of US$1.00=CAD$1.34 forecast midyear rate base for 2017 would be approximately $26.1 billion.

(2) Forecast midyear rate base for 2017 includes approximately $0.4 billion related to the Tilbury LNG Facility Expansion, prior to the inclusion of AFUDC and development costs, which is subject to a regulatory return.

The most significant capital projects that are included in the Corporation's base consolidated capital expenditures for 2016 and 2017 are summarized in the table below.

Significant Capital Projects[1]

($ millions)		Pre-	**Actual**	Forecast	Forecast	Expected Year of
Company	**Nature of Project**	2016	**2016**	2017	2018–2021	Completion
ITC[2][3]	Multi-Value Regional Transmission Projects ("MVPs")	–	**57**	354	96	Post-2021
	34.5 to 69 kilovolt ("kV") Conversion Project	–	**11**	89	369	Post-2021
UNS Energy[3]	Springerville Unit 1 Purchase	–	**112**	–	–	2016
Central Hudson[3]	Gas Main Replacement Program	26	**26**	33	169	Post-2021
FortisBC Energy	Tilbury LNG Facility Expansion[4]	326	**79**	65	–	2017
	Lower Mainland System Upgrade	15	**28**	162	220	2018
FortisAlberta	Pole-Management Program	200	**45**	43	53	Post-2021
Caribbean Utilities	Generation Expansion	73	**26**	–	–	2016

(1) Represents utility capital asset and intangible asset expenditures, including both the capitalized debt and equity components of AFUDC, where applicable

(2) Capital expenditures for 2016 are from the date of the acquisition.

(3) Forecast capital expenditures are based on a forecast exchange rate of US$1.00=CAD$1.30 for 2017 through 2021.

(4) Total project investment as at December 31, 2015 and 2016 includes approximately $11 million and $7 million, respectively, in non-cash capital accruals.

The MVPs at ITC consist of four regional electric transmission projects that have been identified by MISO to address system capacity needs and reliability in various states. The MVPs are in various stages of construction and include construction of new breaker stations, new transmission lines and the extension of existing substations. Approximately US$43 million was invested in the MVPs from the date of acquisition and an additional US$272 million is expected to be spent in 2017. Three of the MVPs are expected to be completed by the end of 2018, with the fourth scheduled for completion in 2023.

The 34.5 to 69 kV Conversion Project at ITC consists of multiple capital initiatives designed to construct and rebuild new 69-kV lines, with in-service dates ranging from 2017 to post 2021. Approximately US$352 million is expected to be invested in this project over the five-year period through 2021.

In September 2016 UNS Energy purchased the remaining 50.5% undivided interest in Springerville Unit 1 as part of a settlement agreement with the third-party owners for US$85 million.

The Gas Main Replacement Program at Central Hudson is a 15-year replacement program to eliminate and replace leakage-prone pipes throughout the gas distribution system. The proposed replacement program increases the rate of annual expenditures on pipe replacements to approximately US$30 million to expedite the replacement plan. Approximately US$20 million was spent on this program in 2016 and an additional US$25 million is expected to be spent in 2017. The majority of spending is expected post 2021.

FortisBC Energy's ongoing Tilbury LNG Facility Expansion is estimated at a total project cost of approximately $470 million, including approximately $70 million of AFUDC and development costs, which could be impacted by the date the project is put in use for rate-making purposes. The facility will include a second LNG tank and a new liquefier, both to be in service in mid-2017. FortisBC Energy received an Order in Council from the Government of British Columbia exempting the Tilbury LNG Facility Expansion from further regulatory review. Key construction activities in 2016 were focused on construction of the LNG storage tank and control building and the installation of the liquefaction process area major equipment. The commissioning and start-up phase of the project also commenced in the fourth quarter of 2016. Total project costs to the end of 2016 were approximately $405 million, including AFUDC and development costs, and $65 million is expected to be incurred on completion of the project in 2017.

The Lower Mainland System Upgrade project at FortisBC Energy is in place to address system capacity and pipeline condition issues for the gas supply system in the Lower Mainland area of British Columbia. The project will be completed in two phases: (i) the Lower Mainland Intermediate Pressure System Upgrade project phase, which is focused on addressing pipeline condition issues, estimated at $255 million; and (ii) the Coastal Transmission System phase, which is intended to increase security of supply, estimated at $170 million. The project has an estimated total capital cost of $425 million, with approximately $162 million forecast to be spent in 2017, and is expected to be completed in 2018. The BCUC approved the application to replace certain sections of intermediate pressure pipeline segments within the Greater Vancouver area in October 2015. The Coastal Transmission System phase was approved by a Special Direction by the Government of British Columbia in 2014 and will not be subject to further regulatory review.

During 2016 FortisAlberta continued with the replacement of vintage poles under its Pole-Management Program to extend the service life of existing poles and to replace poles when deterioration is beyond repair. The total capital cost of the program through 2021 is expected to be approximately $341 million. Approximately $45 million was spent on this program in 2016, for a total of $245 million spent to the end of 2016.

In the second quarter of 2016, Caribbean Utilities completed its 39.7-MW generation expansion project, which included two 18.5 MW diesel-generating units, one 2.7 MW waste heat recovery steam turbine and associated auxiliary equipment. The generating units replaced retiring generators and provide firm capacity to meet expected load growth. The generation expansion project was completed on schedule and below budget, for a total cost of US$79 million.

Additional Investment Opportunities

In addition to the Corporation's base consolidated capital expenditure forecast, management is pursuing additional investment opportunities within existing service territories. These additional investment opportunities, as discussed below, are not included in the Corporation's base capital expenditure forecast.

The Corporation continues to pursue additional LNG infrastructure investment opportunities in British Columbia, including a pipeline expansion to the proposed Woodfibre LNG site in Squamish, British Columbia and a further expansion of Tilbury. In December 2014 FortisBC Energy received an Order in Council from the Government of British Columbia effectively exempting these projects from further regulatory approval by the BCUC.

FortisBC Energy's potential pipeline expansion is conditional on Woodfibre LNG proceeding with its LNG export facility. Woodfibre LNG has obtained an export license from the National Energy Board and received environmental assessment approvals from the Squamish First Nation, the British Columbia Environmental Assessment Office, and the Canadian Environmental Assessment Agency. FortisBC Energy also received environmental assessment approval from the Squamish First Nation and provincial environmental assessment approval in 2016. The potential pipeline expansion had an estimated total project cost of up to $600 million, however, this estimate will be updated for final scoping, detailed construction estimates and scheduling. In November 2016 Woodfibre LNG announced the approval from its parent company, Pacific Oil & Gas Limited, which is part of the Singapore-based RGE group of companies, of the funds necessary to complete the project. This project could move forward in 2017 pending additional approvals and a final investment decision by Woodfibre LNG.

The Corporation's Tilbury LNG Facility is uniquely positioned to meet customer demand for clean-burning natural gas. The site is scalable and can accommodate additional storage and liquefaction equipment, and is relatively close to international shipping lanes. The further expansion of Tilbury is conditional upon having long-term supply contracts in place with investment-grade off-takers. In July 2016, following the dissolution of a proposed merger between Hawaiian Electric Company, Inc. ("Hawaiian Electric") and NextEra Energy Resources, the 20-year agreement between Fortis Hawaii Energy Inc., a wholly owned subsidiary of Fortis, and Hawaiian Electric to export LNG to Hawaii was terminated. Despite the termination of the agreement with Hawaiian Electric, Fortis continues to have discussions with a number of other potential export customers.

The Lake Erie Connector project at ITC is a proposed 1,000 MW, bi-directional, high-voltage direct current underwater transmission line that would provide the first direct link between the markets of the Ontario Independent Electricity System Operator and PJM Interconnection, LLC ("PJM"). The project would enable transmission customers to more efficiently access energy, capacity and renewable energy credit opportunities in both markets. In January 2017 ITC received approval of a Presidential Permit from the U.S. Department of Energy ("DOE") for the Lake Erie Connector transmission line, which is a required approval for international border-crossing projects. Also in January, ITC received a report from Canada's National Energy Board recommending the issuance of a Certificate of Public Convenience and Necessity with prescribed conditions for the transmission line. The project continues to advance through regulatory, operational, and economic milestones. Key milestones for 2017 include: receiving approval from the U.S. Army Corps of Engineers and Pennsylvania Department of Environmental Protection in a joint application; completing project cost refinements; and securing favourable transmission service agreements with prospective counterparties. Pending achievement of key milestones, the expected in-service date for the project is late 2020.

The Wataynikaneyap Power Project continues to advance in Ontario. Wataynikaneyap Power consists of a partnership between 22 First Nations and FortisOntario, with a mandate to develop new transmission lines to connect remote First Nations communities to clean electricity in Ontario. In the second quarter of 2016, the Government of Ontario designated Wataynikaneyap Power as the licensed transmission company to complete this project and an application for a deferral account was filed with the Ontario Energy Board ("OEB") in August 2016. In December 2016 FortisOntario reached an agreement with Renewable Energy Systems Canada to acquire its ownership interest in the Wataynikaneyap Partnership. The transaction is subject to approval by the OEB and is expected to close in the first quarter of 2017. As a result, FortisOntario's ownership interest in the Wataynikaneyap Partnership will increase to 49%, with the remaining 51% ownership interest held by the 22 First Nations communities. The total estimated capital cost for the project is approximately $1.35 billion and is expected to contribute to savings of over $1 billion for the First Nations communities and result in a significant reduction in greenhouse gas emissions. Regulatory approvals are currently being sought. In addition to environmental assessments which are underway, an order from the OEB establishing a deferral account to record costs is expected in 2017. The next regulatory milestone will be the preparation and filing of the leave to construct with the OEB.

The Corporation also has other significant opportunities that have not yet been included in the Corporation's capital expenditure forecast including, but not limited to: transmission investment opportunities at ITC; the New York Transco, LLC to address electric transmission constraints in New York State; renewable energy alternatives and transmission investments at UNS Energy; further gas infrastructure opportunities at FortisBC Energy; and potential further consolidation of Rural Electrification Associations at FortisAlberta.

Cash Flow Requirements

At the subsidiary level, it is expected that operating expenses and interest costs will generally be paid out of subsidiary operating cash flows, with varying levels of residual cash flows available for subsidiary capital expenditures and/or dividend payments to Fortis. Borrowings under credit facilities may be required from time to time to support seasonal working capital requirements. Cash required to complete subsidiary capital expenditure programs is also expected to be financed from a combination of borrowings under credit facilities, long-term debt offerings and equity injections from Fortis.

The Corporation's ability to service its debt obligations and pay dividends on its common and preference shares is dependent on the financial results of the operating subsidiaries and the related cash payments from these subsidiaries. Certain regulated subsidiaries may be subject to restrictions that may limit their ability to distribute cash to Fortis. These include restrictions by certain regulators limiting the amount of annual dividends and restrictions by certain lenders limiting the amount of debt to total capitalization at the subsidiaries. In addition, there are practical limitations on using the net assets of each of the Corporation's regulated operating subsidiaries to pay dividends based on management's intent to maintain the regulator-approved capital structures for each of its regulated operating subsidiaries. The Corporation does not expect that maintaining the targeted capital structures of its regulated operating subsidiaries will have an impact on its ability to pay dividends in the foreseeable future.

Cash required of Fortis to support subsidiary capital expenditure programs and finance acquisitions is expected to be derived from a combination of borrowings under the Corporation's committed corporate credit facility and proceeds from the issuance of common shares, preference shares and long-term debt, and advances from minority investors. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed corporate credit facility may be required from time to time to support the servicing of debt and payment of dividends.

In November 2016 Fortis filed a short-form base shelf prospectus, under which the Corporation may issue common or preference shares, subscription receipts or debt securities in an aggregate principal amount of up to $5 billion during the 25-month life of the base shelf prospectus. In December 2016 Fortis issued $500 million unsecured notes at 2.85% under the base shelf prospectus.

As at December 31, 2016, management expects consolidated fixed-term debt maturities and repayments to be $190 million in 2017 and to average approximately $680 million annually over the next five years. The combination of available credit facilities and manageable annual debt maturities and repayments provides the Corporation and its subsidiaries with flexibility in the timing of access to capital markets. For a discussion of capital resources and liquidity risk, refer to the "Business Risk Management" section of this MD&A.

Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2016 and are expected to remain compliant in 2017.

Credit Facilities

As at December 31, 2016, the Corporation and its subsidiaries had consolidated credit facilities of approximately $6.0 billion, of which approximately $3.7 billion was unused, including $915 million unused under the Corporation's committed revolving corporate credit facility. The credit facilities are syndicated mostly with large banks in Canada and the United States, with no one bank holding more than 20% of these facilities. Approximately $5.1 billion of the total credit facilities are committed facilities with maturities ranging from 2017 through 2021.

The following summary outlines the credit facilities of the Corporation and its subsidiaries.

Credit Facilities

($ millions)	Regulated Utilities	Corporate and Other	**Total as at December 31, 2016**	Total as at December 31, 2015
Total credit facilities [1]	3,823	2,153	**5,976**	3,565
Credit facilities utilized:				
Short-term borrowings [1]	(640)	(515)	**(1,155)**	(511)
Long-term debt (including current portion) [2]	(508)	(465)	**(973)**	(551)
Letters of credit outstanding	(68)	(51)	**(119)**	(104)
Credit facilities unused [1]	2,607	1,122	**3,729**	2,399

[1] Total credit facilities and short-term borrowings as at December 31, 2016 include $195 million (US$145 million) outstanding under ITC's commercial paper program. Outstanding commercial paper does not reduce available capacity under the Corporation's consolidated credit facilities.

[2] As at December 31, 2016, credit facility borrowings classified as long-term debt included $61 million in current installments of long-term debt on the consolidated balance sheet (December 31, 2015 – $71 million).

As at December 31, 2016 and 2015, certain borrowings under the Corporation's and subsidiaries' long-term committed credit facilities were classified as long-term debt. It is management's intention to refinance these borrowings with long-term permanent financing during future periods.

Regulated Utilities

ITC has a total of US$1.0 billion in unsecured committed revolving credit facilities maturing in March 2019. ITC has an ongoing commercial paper program in an aggregate amount of US$400 million, under which US$145 million in commercial paper was outstanding as at December 31, 2016.

UNS Energy has a total of US$350 million in unsecured committed revolving credit facilities, with US$305 million maturing in October 2021, and US$45 million maturing in October 2020.

Central Hudson has a US$200 million unsecured committed revolving credit facility, maturing in October 2020, and an uncommitted credit facility totalling US$25 million.

FortisBC Energy has a $700 million unsecured committed revolving credit facility, maturing in August 2021.

FortisAlberta has a $250 million unsecured committed revolving credit facility, maturing in August 2021, and a $90 million bilateral credit facility, maturing in November 2017.

FortisBC Electric has a $150 million unsecured committed revolving credit facility, maturing in May 2019, and a $10 million unsecured demand overdraft facility.

Newfoundland Power has a $100 million unsecured committed revolving credit facility, maturing in August 2021, and a $20 million demand credit facility. Maritime Electric has a $50 million unsecured committed revolving credit facility, maturing in February 2019. FortisOntario has a $30 million unsecured committed revolving credit facility, maturing in June 2019.

Caribbean Utilities has unsecured credit facilities totalling approximately US$49 million. Fortis Turks and Caicos has short-term unsecured demand credit facilities of US$31 million, maturing in June 2017.

Corporate and Other

Fortis has a $1.3 billion unsecured committed revolving credit facility, maturing in July 2021, and a $500 million non-revolving term senior unsecured equity bridge credit facility, used to finance a portion of the cash purchase price of the acquisition of ITC, maturing in October 2017.

UNS Energy Corporation has a US$150 million unsecured committed revolving credit facility, with US$130 million maturing in October 2021, and US$20 million maturing in October 2020. CH Energy Group has a US$50 million unsecured committed revolving credit facility, maturing in July 2020. FHI has a $50 million unsecured committed revolving credit facility, maturing in April 2019.

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $119 million as at December 31, 2016 (December 31, 2015 – $104 million), the Corporation had no off-balance sheet arrangements that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources.

BUSINESS RISK MANAGEMENT

The following is a summary of the Corporation's principal risks that could materially affect its business, results of operations, financial condition or cash flows. Other risks may arise or risks not currently considered material may become material in the future.

The Corporation's utilities are subject to substantial regulation and its results of operation, financial condition and cash flows may be affected by regulatory or legislative changes.

Regulated utility assets comprised approximately 97% of total assets of Fortis as at December 31, 2016 (December 31, 2015 – 96%). Approximately 97% of the Corporation's operating revenue[1] was derived from regulated utility operations in 2016 (2015 – 96%), and approximately 93% of the Corporation's operating earnings[1] were derived from regulated utility operations in 2016 (2015 – 92% excluding the gains on sale of non-core assets). The Corporation operates utilities in different jurisdictions, including five Canadian provinces, nine U.S. States and three Caribbean countries.

The Corporation's utilities are subject to regulation by various federal, state and provincial regulators that can affect future revenue and earnings. These regulators administer various acts and regulations covering material aspects of the utilities' business, including, among others: electricity and gas tariff rates charged to customers; the allowed ROEs and deemed capital structures of the utilities; electricity and gas infrastructure investments; capacity and ancillary services; the transmission and distribution of energy; the terms and conditions of procurement of electricity for customers; issuances of securities; the provision of services by affiliates and the allocation of those service costs; certain accounting matters; and certain aspects of the siting and construction of transmission and distribution systems. Any decisions made by such regulators could have an adverse effect on the business, results of operations, financial condition and cash flows of the Corporation's utilities. In addition, there is no assurance that the utilities will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement.

For those utilities that follow COS regulation in determining annual revenue requirements and resulting customer rates, with the exception of ITC, the ability of the utility to recover the actual cost of service and earn the approved ROE and/or ROA may depend on achieving the forecasts established in the rate-setting process. Failure of a utility to meet such forecasts could adversely affect the Corporation's results of operations, financial condition and cash flows. When PBR mechanisms are utilized, a formula is generally applied that incorporates inflation and assumed productivity improvements. The use of PBR mechanisms should allow a utility a reasonable opportunity to recover prudent cost of service and earn its allowed ROE, however, in the event that inflationary increases exceed the inflationary factor set by the regulator or the utility is unable to achieve productivity improvements, the Corporation's results of operations, financial condition and cash flows may be adversely impacted. In the case of FortisAlberta's current PBR mechanism, there is a risk that capital expenditures may not qualify, or be approved, for incremental funding where necessary.

The Corporation and its utilities must address the effects of regulation, including compliance costs imposed on operations as a result of such regulation. The political and economic environment has had, and may continue to have, an adverse effect on regulatory decisions with negative consequences for the Corporation's utilities, including the cancellation or delay of planned development activities or other capital expenditures, and the incurrence of costs that may not be recoverable through rates. In addition, the Corporation is unable to predict future legislative or regulatory changes, and there can be no assurance that it will be able to respond adequately or in a timely manner to such changes. Such legislative or regulatory changes may increase costs and competitive pressures on the Corporation and its utilities. Any of these events could have an adverse effect on the Corporation's business, results of operations, financial condition and cash flows.

[1] Operating revenue and operating earnings are non-US GAAP measures and refer to total revenue, excluding Corporate and Other segment revenue and inter-segment eliminations, and net earnings attributable to common equity shareholders, excluding Corporate and Other segment expenses, respectively. Operating revenue and operating earnings are referred to by users of the consolidated financial statements in evaluating the performance of the Corporation's operating subsidiaries.

For additional information on various specific regulatory matters pertaining to the Corporation's utilities, refer to the "Regulatory Highlights" section of this MD&A.

Certain elements of ITC's regulated operating subsidiaries' formula rates can be and have been challenged, which could result in lowered rates and/or refunds of amounts previously collected, and could have an adverse effect on ITC's business, results of operations, financial condition and cash flows.

ITC's regulated operating subsidiaries provide transmission service under rates regulated by FERC. FERC has approved the cost-based formula rate templates used to calculate the annual revenue requirement, but it has not expressly approved the amount of actual capital and operating expenditures to be used in the formula rates. All aspects of ITC's rates approved by FERC, including the formula rate templates, the rates of return on the actual equity portion of capital structure and the approved targeted capital structure, are subject to challenge by interested parties, or by FERC. In addition, interested parties may challenge ITC's annual implementation and calculation of projected rates and formula rate true up pursuant to their approved formula rate templates under their formula rate implementation protocols. End-use customers and entities supplying electricity to end-use customers may also attempt to influence government and/or regulators to change the rate-setting methodologies that apply to ITC, particularly if rates for delivered electricity increase substantially. If it is established that any of these aspects are unjust, unreasonable, unduly discriminatory or preferential, then FERC will make appropriate prospective adjustments to them and/or disallow the inclusion of those aspects in the rate-setting formula. This could result in lowered rates and/or refunds of amounts collected, any of which could have an adverse effect on ITC's business, results of operations, financial condition and cash flows.

For additional information on current third-party complaints with FERC regarding the MISO regional base ROE for certain of ITC's regulated operating subsidiaries, refer to the "Regulatory Highlights" section of this MD&A.

Changes in interest rates could have an adverse effect on the Corporation's results of operations, financial condition and cash flows.

Generally, allowed ROEs for regulated utilities in North America are exposed to changes in long-term interest rates. Such rates affect allowed ROEs as the regulatory process may consider the general level of interest rates as a factor for setting allowed ROEs. The continuation of a low interest rate environment could adversely affect the allowed ROEs at the Corporation's utilities, which could have a negative effect on the results of operations, financial condition and cash flows of the Corporation. Alternatively, if interest rates begin to increase, regulatory lag may cause a delay in any resulting increase in the regulatory allowed ROEs to compensate for higher cost of capital.

The Corporation and its subsidiaries may also be exposed to interest rate risk associated with borrowings under variable-rate credit facilities, variable-rate long-term debt and refinancing of long-term debt. At the utilities, interest expense is generally recovered in customer rates, as approved by the regulators. The inability to flow through interest costs to customers could have an adverse effect on the results of operations, financial condition and cash flows of the utilities. A change in the level of interest rates could affect the measurement and disclosure of the fair value of long-term debt.

If generation, transmission and distribution facilities of the Corporation's utilities do not operate as expected, this could have an adverse effect on the business, results of operations, financial condition and cash flows of Fortis.

The ongoing operation of the utilities' facilities involves risks customary to the electric and gas utility industry, including storms and severe weather conditions, natural disasters, wars, terrorist acts, failure of critical equipment and other catastrophic events occurring both within and outside the service territories of the utilities. Such occurrences could result in service disruptions and the inability to deliver electricity or gas to customers in an efficient manner, resulting in lower earnings and/or cash flows if the situation is not resolved in a timely manner or the financial impacts of restoration are not alleviated through insurance policies or regulated rate recovery.

The operation of the Corporation's electric generating stations involves certain risks, including equipment breakdown or failure, interruption of fuel supply and lower-than-expected levels of efficiency or operational performance. Unplanned outages, including extensions of planned outages due to equipment failure or other complications, occur from time to time and are an inherent risk of the generation business. There can be no assurance that the generation facilities of Fortis will continue to operate in accordance with expectations.

The operation of electricity transmission and distribution assets is also subject to certain risks, including the potential to cause fires, mainly as a result of equipment failure, falling trees and lightning strikes to lines or equipment. In addition, a significant portion of the utilities' infrastructure is located in remote areas, which may make access to perform maintenance and repairs difficult if such assets become damaged. Certain of the Corporation's utilities operate in remote and mountainous terrain with a risk of loss or damage from forest fires, floods, washouts, landslides, earthquakes, avalanches and other acts of nature.

The Corporation's gas utilities are exposed to various operational risks associated with gas, including fires, explosions, pipeline leaks, accidental damage to mains and service lines, corrosion in pipes, pipeline or equipment failure, other issues that can lead to outages and/or leaks, and any other accidents involving gas that could result in significant operational disruptions and/or environmental liability.

The Corporation and its subsidiaries have limited insurance that provides coverage for business interruption, liability and property damage. In the event of a large uninsured loss caused by severe weather conditions, natural disasters and certain other events beyond the control of the utility, an application would be made to the respective regulatory authority for the recovery of these costs through customer rates to offset any loss. However, there can be no assurance that the regulatory authorities would approve any such application in whole or in part. For further detail on the Corporation's insurance coverage, refer to the insurance coverage risk discussion within the "Business Risk Management" section of this MD&A.

The Corporation's electricity and gas systems require ongoing maintenance, improvement and replacement. The utilities could experience service disruptions and increased costs if they are unable to maintain their asset base. The inability to recover, through approved customer rates, the expenditures the utilities believe are necessary to maintain, improve, replace and remove assets; the failure by the utilities to properly implement or complete approved capital expenditure programs; or the occurrence of significant unforeseen equipment failures, despite maintenance programs, could have an adverse effect on the business, results of operations, financial condition and cash flows of the Corporation's utilities.

Generally, the Corporation's utilities have designed their electricity and gas systems to service customers under various contingencies in accordance with good utility practice. The utilities are responsible for operating and maintaining their assets in a safe manner, including the development and application of appropriate standards, processes and/or procedures to ensure the safety of employees and contractors, as well as the general public. Failure to do so may disrupt the ability of the utilities to safely generate, transmit and distribute electricity and gas, which could have an adverse effect on the operations of the utilities, as well as harm the reputation of the Corporation and the respective utility.

Changes in energy laws, regulations or policies could have an adverse effect on the utilities' business, results of operations, financial condition and cash flows.

The political, regulatory and economic environment may have an adverse effect on the regulatory process and limit the ability of the Corporation's utilities to increase earnings or achieve authorized rates of return. The disallowance of the recovery of costs incurred by the Corporation's utilities, or a decrease in the ROE/ROA, could have an adverse effect on the Corporation's business, results of operations, financial condition and cash flows. Fortis cannot predict whether the approved rate methodologies for any of its utilities will be changed. In addition, the U.S. Congress periodically considers enacting energy legislation that could assign new responsibilities to FERC, modify provisions of the U.S. *Federal Power Act*, or the *Natural Gas Act*, as amended, or provide FERC or another entity with increased authority to regulate U.S. federal energy matters. The Corporation cannot predict whether, and to what extent, its utilities may be affected by any such changes in U.S. federal energy laws, regulations or policies in the future.

Failure by the Corporation's applicable subsidiaries to comply with required reliability standards could have an adverse effect on the Corporation's business, results of operations, financial condition and cash flows.

As a result of the *Energy Policy Act* of 2005, owners, operators and users of bulk electricity systems in the United States are subject to mandatory reliability standards developed by the North American Electric Reliability Corporation ("NERC") and its regional entities, which are approved and enforced by FERC. The standards are based on the functions that need to be performed to ensure that the bulk electricity system operates reliably. The Corporation's utilities located in the United States, British Columbia and Alberta have been, and will continue to be, subject to routine audits and monitoring with respect to compliance with applicable NERC reliability standards, including standards approved by FERC that will result in an increase in the number of assets (including cyber-security assets) designated as "critical assets". NERC and FERC can be expected to continue to refine existing reliability standards, as well as develop and adopt new reliability standards. Compliance with modified or new reliability standards may subject the Corporation's utilities located in the United States, British Columbia and Alberta to new requirements, potentially resulting in higher operating costs and/or increased capital expenditures. If any of the Corporation's utilities located in the United States were found not to be in compliance with the mandatory reliability standards, it could be subject to penalties of up to US$1 million per day per violation. Both the costs of regulatory compliance and the costs that may be imposed as a result of any actual or alleged compliance failures could have an adverse effect on the Corporation's business, results of operations, financial condition and cash flows.

Energy sales of the Corporation's utilities may be negatively impacted by changes in general economic, credit and market conditions.

The Corporation's utilities are affected by energy demand in the jurisdictions in which they operate, that may change as a result of fluctuations in general economic conditions, energy prices, employment levels, personal disposable income, and housing starts. Significantly reduced energy demand in the Corporation's service territories could reduce capital spending forecasts, and specifically capital spending related to new customer growth. A reduction in capital spending would, in turn, affect the Corporation's rate base and earnings growth. A severe and prolonged downturn in economic conditions may have an adverse effect on the Corporation's results of operations, financial condition and cash flows despite regulatory measures, where applicable, available to compensate for reduced demand. In addition, an extended decline in economic conditions could make it more difficult for customers to pay for the electricity and gas they consume, thereby affecting the aging and collection of the utilities' trade receivables.

If Fortis and/or its subsidiaries fail to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures, acquisitions and the repayment of maturing debt, the Corporation's financial condition could be adversely impacted.

The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and financial condition of the Corporation and its subsidiaries, the regulatory environment in which the Corporation's utilities operate and the outcome of regulatory decisions regarding capital structure and allowed ROEs, conditions in the capital and bank credit markets, ratings assigned by credit rating agencies, and general economic conditions. Funds generated from operations after payment of expected expenses, including interest payments on any outstanding debt, may not be sufficient to fund the repayment of all outstanding liabilities when due or anticipated capital expenditures. There can be no assurance that sufficient capital will continue to be available on acceptable terms to fund capital expenditures and repay existing debt.

Consolidated fixed-term debt maturities in 2017 are expected to total $190 million. The ability to meet long-term debt repayments when due will be dependent on the Corporation and its subsidiaries obtaining sufficient and cost-effective financing to replace maturing indebtedness. Activity in the global capital markets may impact the cost and timing of issuance of long-term debt by the Corporation and its subsidiaries. Although the Corporation and its subsidiaries have been successful at raising long-term capital at reasonable rates, the cost of raising capital could increase and there can be no assurance that the Corporation and its subsidiaries will continue to have reasonable access to capital in the future.

Generally, the Corporation and its utilities rated by credit rating agencies are subject to financial risk associated with changes in the credit ratings assigned to them by credit rating agencies. Credit ratings affect the level of credit risk spreads on new long-term debt and credit facilities. A change in credit ratings could potentially affect access to various sources of capital and increase or decrease finance charges of the Corporation and its utilities.

In 2016 there were no changes made to debt credit ratings of the Corporation's utilities, with the exception of S&P's downgrade of Central Hudson's senior unsecured debt rating to 'A–' from 'A' and revision of its outlook to stable from negative in June 2016. For details on the Corporation's credit ratings, see the "Credit Ratings" section of this MD&A.

Additional information on the Corporation's consolidated credit facilities, contractual obligations, including long-term debt maturities and repayments, and consolidated cash flow requirements is provided in the "Liquidity and Capital Resources" section of this MD&A.

The Corporation is subject to risks associated with its growth strategy that may adversely affect its business, results of operations, financial condition and cash flows, and actual capital expenditures may be lower than planned.

The Corporation has a history of growth through acquisitions and organic growth from capital expenditures in existing service territories. Acquisitions include inherent risks that some or all of the expected benefits may fail to materialize, or may not occur within the time periods anticipated, and the Corporation may incur material unexpected costs. The Corporation's capital expenditure plan generally consists of a large number of individually small projects, however, the Corporation and its utilities are also involved in a number of major capital projects. Risks related to such major capital projects include schedule delays and project cost overruns. Capital expenditures at the utilities are generally approved by the respective regulators, however, there is no assurance that any project cost overruns would be approved for recovery in customer rates. The failure to realize expected benefits of an acquisition and/or cost overruns on major capital projects could have an adverse effect on the Corporation's business, results of operations, financial condition and cash flows.

Additionally, the Corporation's five-year capital expenditure program and associated rate base growth are key assumptions in the Corporation's targeted dividend growth guidance. Actual capital expenditures may be lower than planned due to factors beyond the Corporation's control, which would result in a lower than anticipated rate base and have an adverse effect on the Corporation's results of operations, financial condition and cash flows. This could limit the Corporation's ability to meet its targeted dividend growth.

Management believes that the acquisition of ITC will provide benefits to the Corporation, including an accretive effect on earnings per common share in the first full year following closing (excluding acquisition-related expenses). However, there is a risk that some or all of the expected benefits of the acquisition may fail to materialize, or may not occur within the time periods anticipated. The realization of such benefits may be impacted by a number of factors, including regulatory considerations and decisions, many of which are beyond the control of the Corporation. Realization of the anticipated benefits of the acquisition will depend, in part, on the Corporation's ability to successfully integrate ITC's business, including the requirement to devote management attention and resources to integrating business practices and support functions. The diversion of management's attention, any delays or difficulties encountered in connection with the integration, or the failure to realize all of the anticipated benefits of the acquisition could have an adverse effect on the Corporation's business, results of operations, financial condition or cash flows.

Cyber-security breaches, acts of war or terrorism, grid disturbances or security breaches involving the misappropriation of sensitive, confidential and proprietary customer, employee, financial or system operating information could significantly disrupt the Corporation's business operations and have an adverse effect on its reputation.

As operators of critical energy infrastructure, the Corporation's utilities face a heightened risk of cyber-attacks. Software and information technology systems may be vulnerable to unauthorized access due to hacking, viruses, acts of war or terrorism, and other causes that can result in service disruptions, system failures, and the disclosure, deliberate or inadvertent, of confidential business and customer information. The ability of the Corporation's utilities to operate effectively is dependent upon developing and maintaining complex information systems and infrastructure that support the operation of generation and T&D facilities; provide customers with billing, consumption and load settlement information, where applicable; and support the financial and general operating aspects of the business.

In the event the Corporation's utilities' information technology systems are breached, service disruptions, property damage, corruption or unavailability of critical data or confidential employee or customer information could result. A material breach could adversely affect the financial performance of the Corporation, its reputation and standing with customers, regulators, financial markets and expose it to claims for third-party damage. The financial impact of a material breach in cyber-security, act of war or terrorism could be material and may not be covered by insurance policies or, in the case of utilities, through regulatory recovery.

The Corporation's utilities are subject to seasonality and their respective operations and electricity generation of the utilities may fall below expectations due to the impact of severe weather or other natural events, which could have an adverse effect on its business, results of operations, financial condition and cash flows.

Fluctuations in the amount of electricity used by customers can vary significantly in response to seasonal changes in weather and could impact the operations, results of operations, financial condition and cash flows of the electric utilities. In Canada, Arizona and New York State, cool summers may reduce the use of air conditioning and other cooling equipment, while less severe winters may reduce electric heating load.

At the Corporation's gas utilities, weather has a significant impact on gas distribution volumes as a major portion of the gas distributed is ultimately used for space heating for residential customers. Because of gas consumption patterns, the gas utilities normally generate quarterly earnings that vary by season and may not be an indicator of annual earnings. The earnings associated with the Corporation's gas utilities are highest in the first and fourth quarters.

Regulatory deferral mechanisms are in place at certain of the Corporation's utilities to minimize the volatility in earnings that would otherwise be caused by variations in weather conditions. The absence of these regulatory deferral mechanisms could have an adverse effect on the results of operations, financial condition and cash flows of the Corporation and its utilities.

Despite preparations for severe weather, ice, wind and snow storms, hurricanes and other natural disasters, weather will always remain a risk to the physical assets of utilities. Global warming and climate change may have the effect of increasing the severity and frequency of weather-related natural disasters that could affect the Corporation's service territories. Although physical utility assets have been constructed and are operated and maintained to withstand severe weather, there can be no assurance that they will successfully do so in all circumstances.

Earnings from non-regulated generation assets in Belize and British Columbia are sensitive to rainfall levels and the related impact on water flows. Hydrologic risk associated with hydroelectric generation at the Waneta Expansion and FortisBC Electric is reduced by the Canal Plant Agreement, under which it will receive fixed energy and capacity entitlements based upon long-term average water flows. Prolonged adverse weather conditions, however, could lead to a significant and sustained loss of precipitation over the headwaters of the Kootenay River system, which could reduce the entitlement of the Waneta Expansion and FortisBC Electric to capacity and energy under the Canal Plant Agreement.

The Corporation's risk management policies cannot fully eliminate the risk associated with commodity price movements, which may result in significant losses.

The Corporation's utilities have exposure to long-term and short-term commodity price volatility, including changes in the market price of gas, world oil prices, which affect the cost of fuel, purchased power and coal. The risk of price volatility is substantially mitigated by the utilities' ability to flow through to customers the cost of gas, fuel and purchased power through base rates and/or the use of rate-stabilization and other mechanisms, as approved by the various regulatory authorities. The ability to flow through to customers the cost of gas, fuel and purchased power alleviates the effect on earnings of commodity price volatility. This risk has also been reduced by entering into various price-risk management strategies to reduce exposure to changing commodity rates, including the use of derivative contracts that effectively fix the price of gas, power and electricity purchases. The inability to utilize such hedging mechanisms in the future could result in increased exposure to market price volatility.

There can be no assurance that the current regulator-approved mechanisms allowing for the flow through of the cost of gas, fuel, coal and purchased power will continue to exist in the future. Also, a severe and prolonged increase in such costs could have an adverse effect on the Corporation's utilities, despite regulatory measures available to compensate for changes in these costs. The inability of the regulated utilities to flow through the full cost of gas, fuel and purchased power could have an adverse effect on the utilities' results of operations, financial condition and cash flows.

Increased foreign exchange exposure may have an adverse effect on the Corporation's earnings and the value of its assets.

A significant portion of the Corporation's assets, earnings and cash flows are denominated in US dollars. The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, Fortis Turks and Caicos and BECOL is the US dollar. The earnings from, and net investments in, foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. Although the Corporation has limited this exposure through the use of US dollar-denominated borrowings at the corporate level, such actions may not completely mitigate this exposure. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange gain or loss on the translation of the Corporation's foreign subsidiaries' earnings. As at December 31, 2016, the Corporation's corporately issued US$3,511 million (December 31, 2015 – US$1,535 million) long-term debt had been designated as an effective hedge of a portion of the Corporation's foreign net investments. As at December 31, 2016, the Corporation had approximately US$7,250 million (December 31, 2015 – US$3,137 million) in foreign net investments that were unhedged.

As a result of the acquisition of ITC, consolidated earnings and cash flows of Fortis are impacted to a greater extent by fluctuations in the US dollar-to-Canadian dollar exchange rate. On an annual basis, it is estimated that a 5 cent increase or decrease in the US dollar relative to the Canadian dollar exchange rate of US$1.00=CAD$1.34 as at December 31, 2016 would increase or decrease earnings per common share of Fortis by approximately 7 cents.

The Corporation may enter into forward foreign exchange contracts and utilize certain derivatives as cash flow hedges of its exposure to foreign currency risk to a greater extent than in the past. There is no guarantee that such hedging strategies, if adopted, will be effective. In addition, currency hedging entails a risk of liquidity and, to the extent that the US dollar depreciates against the Canadian dollar, such hedges could result in losses greater than if hedging had not been used. Hedging arrangements may have the effect of limiting or reducing the Corporation's total returns if management's expectations concerning future events or market conditions prove to be incorrect, in which case the costs associated with the hedging strategies may outweigh their benefits.

Changes in tax laws could have an adverse effect on the Corporation's business, results of operations, financial condition and cash flows.

The Corporation and its subsidiaries are subject to changes in tax legislation and tax rates in Canada, the United States and other international jurisdictions. A change in tax legislation or tax rates could adversely affect the Corporation's business, results of operations, financial condition and cash flows.

The results of the 2016 election in the United States, including the Republican Party securing the Presidency and control of Congress, will likely result in some tax reform, including a change in tax rates. The specific draft legislation proposing tax reform is expected to be submitted to Congress early to mid-2017 and could be enacted by the end of 2017. If the proposed tax reform is passed, this change in legislation could affect the results of operations, financial condition and cash flows of the Corporation's US subsidiaries.

Certain of the Corporation's subsidiaries are subject to counterparty default risks. The Corporation and its subsidiaries are exposed to credit risk associated with amounts owing from customers and counterparties to derivative instruments. Any non-payment or non-performance by customers of the Corporation's subsidiaries or the derivative counterparties could have an adverse effect on the results of operations, financial condition and cash flows of these subsidiaries.

ITC derives approximately 70% of its revenue from the transmission of electricity to three primary customers. While such customers have investment-grade credit ratings, any failure by such customers to make payments for transmission services could have an adverse effect on ITC's business, results of operations, financial condition and cash flows.

FortisAlberta has a concentration of credit risk as a result of its distribution service billings being to a relatively small group of retailers. As required under regulation, FortisAlberta minimizes its gross exposure associated with retailer billings by obtaining from the retailer either a cash deposit, bond, letter of credit or an investment-grade credit rating from a major rating agency, or a financial guarantee from an entity with an investment-grade credit rating.

UNS Energy, Central Hudson, FortisBC Energy and Aitken Creek may be exposed to credit risk in the event of non-performance by counterparties to derivative instruments. These subsidiaries evaluate the creditworthiness of customers in accordance with established credit approval practices. Non-performance by counterparties could have an adverse effect on the results of operations, financial condition and cash flows of these subsidiaries.

The competitiveness of gas relative to alternative energy sources could have an adverse effect on the Corporation's business, results of operations, financial condition and cash flows.

If the gas sector becomes less competitive due to pricing or other factors, this could have an adverse effect on the Corporation's utilities that are involved in gas distribution and sales. In British Columbia, gas primarily competes with electricity for space and hot water heating load. In addition to other price comparisons, upfront capital costs between electric and gas equipment for hot water and space heating applications continue to present challenges for the competitiveness of gas on a full-cost basis.

In the future, if gas becomes less competitive due to pricing or other factors, the ability to add new customers could be impaired, and existing customers could reduce their consumption of gas or eliminate its usage altogether as furnaces, water heaters and other appliances are replaced. The above conditions may result in higher customer rates and, in an extreme case, could ultimately lead to an inability of the Corporation's gas utilities to fully recover COS in rates charged to customers.

Government policy has also impacted the competitiveness of gas in British Columbia. The Government of British Columbia has introduced changes to energy policy, including greenhouse gas emission reduction targets and a consumption tax on carbon-based fuels. The Government of British Columbia has yet to introduce a carbon tax on imported electricity generated through the combustion of carbon-based fuels. The impact of these changes in energy policy may impact the competitiveness of gas relative to non-carbon-based or other energy sources.

There are other competitive challenges impacting the penetration of gas in new housing supply, such as the green attributes of the energy source and the type of housing being built. In addition, municipal and other government policy may regulate or restrict the energy source permitted in new and existing developments. In recent years, there has been a decline in the percentage of new homes installing gas compared with the total number of dwellings being built throughout British Columbia.

A disruption in the wholesale energy markets or failure by an energy or fuel supplier could have an adverse effect on the Corporation and its subsidiaries.

A significant portion of the electricity and gas that the Corporation's utilities sell to full-service customers is purchased through the wholesale energy markets or pursuant to contracts with energy suppliers. A disruption in the wholesale energy markets or a failure on the part of energy or fuel suppliers or operators of energy delivery systems that connect to the utilities could adversely affect such utilities' ability to meet their customers' energy needs and could adversely affect the Corporation's business, results of operations, financial condition and cash flows.

Pension and post-retirement benefit plans could require significant future contributions to such plans.

Fortis and the majority of its subsidiaries maintain a combination of defined benefit pension and/or other post employment benefit ("OPEB") plans for certain of their employees and retirees. The most significant cost drivers of these benefit plans are investment performance and interest rates, which are affected by global financial and capital markets. Financial market disruptions and significant declines in the market values of the investments held to meet the pension and post-retirement obligations, discount rate assumptions, participant demographics and increasing longevity, and changes in laws and regulations may require the Corporation and its utilities to make significant funding contributions to the plans. Large funding requirements or significant increases in expenses could adversely impact the business, results of operations, financial condition and cash flows of the Corporation's utilities.

Certain generation assets of the Corporation's utilities are jointly owned with, or are operated by, third parties. Therefore, the utilities may not have the ability to affect the management or operations at such facilities which could have an adverse effect on their respective businesses, results of operations, financial condition and cash flows.

Certain of the generating facilities from which TEP receives power are jointly owned with, or are operated by, third parties. TEP may not have the sole discretion or any ability to affect the management or operations at such facilities and, therefore, may not be able to ensure the proper management of the operations and maintenance of the generating facilities. Further, TEP may have no or limited ability to make determinations on how best to manage the changing economic conditions or environmental requirements which may affect such facilities. A divergence in the interests of TEP and the co-owners or operators, as applicable, of such generating facilities could negatively impact the business and operations of TEP.

Advances in technology could impair or eliminate the Corporation's utilities' competitive advantage.

The emergence of initiatives designed to reduce greenhouse gas emissions and control or limit the effects of global warming and overall climate change has increased the incentive for the development of new technologies that produce power, enable more efficient storage of energy or reduce power consumption. New technology developments in distributed generation, particularly solar, and energy efficiency products and services, as well as the implementation of renewable energy and energy efficiency standards, will continue to have a significant impact on retail sales, which could negatively impact the business, results of operations, financial condition and cash flows of the Corporation's utilities. Heightened awareness of energy costs and environmental concerns have increased demand for products intended to reduce consumers' use of electricity. The Corporation's utilities are promoting demand-side management programs designed to help customers reduce their energy usage. These technologies include energy derived from renewable energy sources, customer-owned generation, appliances, battery storage, equipment and control systems. Advances in these, or other technologies, could have a significant impact on retail sales, which could have an adverse effect on the business, results of operations, financial condition and cash flows of the Corporation's utilities.

Environmental risks, including effects of climate change, fires, floods, contamination of air, soil or water from hazardous substances, natural gas leaks and hazardous or toxic emissions from the combustion of fuel required in the generation of electricity could cause the Corporation's utilities to incur significant financial losses.

The Corporation's electric and gas utilities are subject to environmental risks. Risks associated with fire damage vary depending on weather, the extent of forestation, habitation and third-party facilities located on or near the land on which the utilities' facilities are situated. The utilities may become liable for fire-suppression costs, regeneration and timber value costs, and third-party claims if it is found that such facilities were responsible for a fire, and such claims, if successful, could be material. Environmental risks also include the responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the utility at the time it was the property owner. The risk of contamination of air, soil and water at the electric utilities primarily relates to: (i) the transportation, handling and storage of large volumes of fuel; (ii) the use of petroleum-based products, mainly transformer and lubricating oil, in the utilities' day-to-day operating and maintenance activities; (iii) hazardous or toxic emissions from the combustion of fuel required in the generation of electricity; and (iv) management and disposal of coal combustion residuals and other wastes. The risk of contamination of air, soil or water at the gas utilities primarily relates to gas and propane leaks and other accidents involving these substances.

Liabilities relating to investigation and remediation of contamination, as well as claims for personal injury or property damage, may arise at many locations, including formerly owned or operated properties and sites where wastes have been treated or disposed of, as well as properties the utilities currently own or operate. Such liabilities may arise even where the contamination does not result from non-compliance with applicable environmental laws. Under a number of environmental laws, such liabilities may also be joint and several, meaning that a party can be held responsible for more than its share of the liability involved, or even the entire liability. Additional risks include accidents resulting in hazardous release at or from coal mines that supply generating facilities in which the Corporation's utilities have an ownership interest. The key environmental hazards related to hydroelectric generation operations include the creation of artificial water flows that may disrupt natural habitats and any failure of containment of large volumes of water for the purpose of electricity generation. Such inherent environmental risks could subject the Corporation and its utilities to litigation and administrative proceedings that could result in substantial monetary judgments for clean-up costs, damages, fines or penalties. To the extent that the occurrence of any of these events is not fully covered by insurance, they could adversely affect the utilities' results of operations, financial condition and cash flows.

Furthermore, the Corporation's electric and gas utilities are subject to U.S. and Canadian federal, state and provincial environmental laws and regulations, including those which impose limitations or restrictions on the discharge of pollutants into the air and water, establish standards for the management, treatment, storage, transportation and disposal of solid and hazardous wastes and hazardous materials, and impose obligations to investigate and remediate contamination in certain circumstances. The Corporation's utilities have incurred expenses in connection with environmental compliance, and they anticipate that they will continue to do so in the future.

In particular, the management of greenhouse gas emissions is a concern for the Corporation's regulated utilities in Canada and the United States, primarily due to new and emerging federal, state and provincial greenhouse gas laws, regulations and guidelines. For example, in 2015, the federal government in the United States issued the Clean Power Plan, which would regulate greenhouse gas emissions from existing fossil fuel-fired generating units. In 2016, the implementation of the Clean Power Plan was stayed pending judicial review. At present, the future of the Clean Power Plan under President Trump's administration is highly uncertain. The utilities continue to assess the impact that such legislative changes may have on future operations, as well as the costs to comply with these new requirements. However, due to the significant current uncertainties related to federal and state regulation of greenhouse gas emissions in the United States, the ultimate financial and operational impact of such regulation cannot be determined at this time. If any of the coal-fired generation plants, or coal-handling facilities, from which the utilities obtain power are closed prior to the end of their useful life in response to recent or future changes in environmental regulation, the utilities could be required to recognize an impairment of their assets and incur additional expenses, relating to accelerated depreciation and amortization, decommissioning and cancellation of long-term coal contracts of such generating plants and facilities. Closure of any such generating facilities may force the Corporation's utilities to incur higher costs for replacement capacity and energy, which may not be recovered in customer rates. Any unrecovered costs, if substantial, could have an adverse effect on the results of operations, financial condition and cash flows of the Corporation's utilities.

The Corporation and its subsidiaries are not able to insure against all potential risks and may become subject to loss of coverage, higher insurance premiums and failure by insurers to satisfy eligible claims.

The Corporation and its subsidiaries maintain insurance with respect to potential liabilities and the accidental loss of value of certain of their physical assets, for amounts and with such insurers as is considered appropriate, taking into account all relevant factors, including practices of owners of similar assets and operations. However, a significant portion of the Corporation's regulated electric utilities' T&D assets are not covered under insurance, as is customary in North America, as the cost of coverage is not considered economically viable. Insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions and there can be no assurance that the types of liabilities that may be incurred by the Corporation and its subsidiaries will be covered by insurance. The Corporation's utilities would likely apply to their respective regulatory authority to recover any loss or liability through increased customer rates. However, there can be no assurance that a regulatory authority would approve any such application in whole, or in part. Any major damage to the physical assets of the Corporation and its subsidiaries could result in repair costs, loss of revenue and customer claims that are substantial in amount and could have an adverse effect on the Corporation's business, results of operations, financial position and cash flows. In addition, the occurrence of significant uninsured claims, claims in excess of the insurance coverage limits maintained by the Corporation and its subsidiaries, or material damage that is self-insured, could have an adverse effect on the Corporation's business, results of operations, financial position and cash flows.

It is anticipated that insurance coverage will be maintained. However, there can be no assurance that the Corporation and its subsidiaries will be able to obtain or maintain adequate insurance in the future at rates considered reasonable, that insurance will continue to be available on terms as favourable as the existing arrangements, or that the insurance companies will meet their obligations to pay claims.

Certain of the Corporation's regulated utilities and non-regulated energy infrastructure operations may not be able to obtain or maintain all required approvals.

The acquisition, ownership and operation of electric and gas utilities and assets require numerous licenses, permits, agreements, orders, approvals and certificates from various levels of government, government agencies and/or third parties. For various reasons, including increased stakeholder participation, the Corporation's regulated utilities and non-regulated energy infrastructure operations may not be able to obtain or maintain all required approvals. If there is a delay in obtaining any required approvals, failure to obtain or maintain any required approvals, failure to comply with any applicable law, regulation or condition of an approval, or there is a material change to any required approval, the operation of the assets and the sale of electricity and gas could be prevented or become subject to additional costs, any of which could have an adverse effect on the Corporation's subsidiaries.

The Corporation's failure to comply with Section 404(a) of the Sarbanes-Oxley Act of 2002 ("Sarbanes-Oxley") commencing for the year ended December 31, 2017, and on an ongoing basis, could adversely affect investor confidence and harm its reputation.

Commencing with the year ended December 31, 2017, the Corporation's internal controls over financial reporting are required to be in compliance with the requirements of Section 404(a) of Sarbanes-Oxley, and the related rules of the SEC and the Public Company Accounting Oversight Board. In addition, the Corporation's independent auditors will be required to attest to the effectiveness of the Corporation's disclosure and internal controls over financial reporting. The Corporation is currently undergoing an assessment of its internal control procedures to determine whether it is in compliance with Section 404(a) of Sarbanes-Oxley. The Corporation's failure to satisfy the requirements of Section 404(a) on an ongoing basis, or any failure in its internal controls, could result in the loss of investor confidence in the reliability of its financial statements, which could have an adverse effect on its results of operations, financial condition and cash flows, as well as harm its reputation. Further, there can be no assurance that the Corporation's independent auditors will be able to provide the required attestation.

Increased external stakeholder activism could have an adverse effect on the Corporation's ability to execute capital programs.

External stakeholders are increasingly challenging investor-owned utilities in the areas of climate change, sustainability, diversity, utility ROEs and executive compensation. In addition, public opposition to larger infrastructure projects is becoming increasingly common, which can challenge a utility's ability to execute capital programs. While the Corporation is actively monitoring activism and is committed to developing stronger relationships with its external stakeholders, failure to effectively respond to public opposition may adversely affect the Corporation's capital expenditure programs, and, therefore, future organic growth, which could adversely affect its results of operations, financial condition and cash flows.

Certain of the Corporation's subsidiaries have facilities and provide limited services on lands that are subject to land claims by various First Nations, which may subject the utilities to various legal, administrative and land use proceedings.

The Corporation's utilities in British Columbia provide service to customers on First Nations' lands and maintain gas facilities and electric generation and T&D facilities on lands that are subject to land claims by various First Nations. A treaty negotiation process involving various First Nations and the Governments of British Columbia and Canada is underway, but the basis upon which settlements might be reached in the Corporation's service territories is not clear. Furthermore, not all First Nations are participating in the process. To date, the policy of the Government of British Columbia has been to structure settlements without prejudicing existing rights held by third parties. However, there can be no certainty that the settlement process will not have an adverse effect on the Corporation's results of operations, financial condition and cash flows.

The Corporation has distribution assets on First Nations' lands in Alberta with access permits to these lands held by TransAlta Utilities Corporation ("TransAlta"). In order for FortisAlberta to acquire these access permits, both the Department of Aboriginal Affairs and Northern Development Canada and the individual First Nations band councils must grant approval. FortisAlberta may be unable to acquire the access permits from TransAlta and may be unable to negotiate land-use agreements with property owners or, if negotiated, such agreements may be on terms that are less than favourable to FortisAlberta and, therefore, may have an adverse effect on FortisAlberta.

The Corporation's subsidiaries face the risk of strikes, work stoppages or an inability to negotiate future collective bargaining agreements on commercially reasonable terms.

Most of the Corporation's subsidiaries employ members of labour unions or associations that have entered into collective bargaining agreements with the subsidiaries. The Corporation considers the relationships of its subsidiaries with their labour unions and associations to be satisfactory but there can be no assurance that current relations will continue in the future or that the terms under the present collective bargaining agreements will be renewed. The inability to maintain or renew the collective bargaining agreements on acceptable terms could result in increased labour costs or service interruptions arising from labour disputes that are not provided for in approved rate orders at the regulated utilities and which could have an adverse effect on the results of operations, financial condition and cash flows of the utilities.

The Corporation's subsidiaries may suffer the loss of key personnel or the inability to hire and retain qualified employees.

The ability of Fortis to deliver service in a cost-effective manner is dependent on the ability of the Corporation's subsidiaries to attract, develop and retain skilled workforces. Like other utilities across Canada, the United States and the Caribbean, the Corporation's utilities are faced with demographic challenges relating to trades, technical staff and engineers. The growing size of the Corporation and a competitive job market present ongoing recruitment challenges. The Corporation's significant consolidated capital expenditure program will present challenges to ensure the Corporation's utilities have the qualified workforce necessary to complete the capital work initiatives.

ITC enters into various agreements and arrangements with third parties to provide services for construction, maintenance and operations of certain aspects of its business, which, if terminated, could result in a shortage of a readily available workforce to provide these services. If any of these agreements or arrangements are terminated for any reason, ITC may face difficulty finding a qualified replacement work force to provide such services, which could have an adverse effect on the ability of ITC to carry on its business and on its results of operations.

The Corporation and its subsidiaries are subject to litigation or administrative proceedings.

The Corporation and its subsidiaries have been and continue to be involved in legal proceedings, administrative proceedings, claims and other litigation that arise in the ordinary course of business. These actions may include environmental claims, employment-related claims, securities-based litigation and contractual disputes or claims for personal injury or property damage that occur in connection with services performed relating to the operation of the utilities, or actions by regulatory or tax authorities. Unfavourable outcomes or developments relating to these proceedings or future proceedings, such as judgments for monetary damages, injunctions or denial or revocation of permits or settlement of claims, could have an adverse effect on the business, results of operations, financial condition and cash flows of the Corporation and its subsidiaries.

CHANGES IN ACCOUNTING POLICIES

The new US GAAP accounting policies that are applicable to, and were adopted by, Fortis in 2016 are described as follows.

Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern: Effective January 1, 2016, the Corporation adopted Accounting Standards Update ("ASU") No. 2014-15, which provides guidance on management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and provide related disclosures. The adoption of this update did not impact the Corporation's consolidated financial statements and related disclosures.

Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items: Effective January 1, 2016, the Corporation prospectively adopted ASU No. 2015-01, which is part of the Financial Accounting Standards Board's ("FASB's") initiative to reduce complexity in accounting standards by eliminating the concept of extraordinary items. The adoption of this update did not impact the Corporation's consolidated financial statements.

Amendments to the Consolidation Analysis: Effective January 1, 2016, the Corporation adopted ASU No. 2015-02, which changes the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. Specifically, the amendments note the following regarding limited partnerships: (i) modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities; and (ii) eliminate the presumption that a general partner should consolidate a limited partnership. The amendments in this update did not materially impact the Corporation's consolidated financial statements, however, did change the Corporation's 51% controlling ownership interest in the Waneta Partnership from a voting interest entity to a variable interest entity, resulting in additional disclosure.

Simplifying the Accounting for Measurement-Period Adjustments: Effective January 1, 2016, the Corporation prospectively adopted ASU No. 2015-16, which requires that in a business combination an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. Under previous guidance, these adjustments were required to be accounted for retrospectively. The adoption of this update did not impact the Corporation's consolidated financial statements.

Improvements to Employee Share-Based Payment Accounting: Effective January 1, 2016, the Corporation early adopted ASU No. 2016-09, which simplifies the accounting for share-based payment transactions, including income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The guidance requires excess tax benefits and tax deficiencies to be recognized as an income tax benefit or expense in the consolidated statement of earnings. On adoption, using the modified retrospective method, the Corporation recognized a cumulative adjustment of $16 million related to prior period unrecognized excess tax benefits at UNS Energy, which increased retained earnings and decreased deferred income tax liabilities. In 2016 the adoption of this update also resulted in a $7 million decrease in income tax expense and decrease in deferred income tax liabilities related to excess tax benefits at ITC from the date of acquisition, largely associated with the accelerated vesting of the Company's stock-based compensation awards as a result of the acquisition. The guidance also allows for an accounting policy election to either estimate forfeitures or account for them when they occur. The Corporation elected to account for forfeitures when they occur. This policy election did not have a material impact on the Corporation's consolidated financial statements.

FUTURE ACCOUNTING PRONOUNCEMENTS

The Corporation considers the applicability and impact of all ASUs issued by FASB. The following updates have been issued by FASB, but have not yet been adopted by Fortis. Any ASUs not included below were assessed and determined to be either not applicable to the Corporation or are not expected to have a material impact on the consolidated financial statements.

Revenue from Contracts with Customers: ASU No. 2014-09 was issued in May 2014 and the amendments in this update create Accounting Standards Codification ("ASC") Topic 606, *Revenue from Contracts with Customers*, and supersede the revenue recognition requirements in ASC Topic 605, *Revenue Recognition*, including most industry-specific revenue recognition guidance throughout the codification. This standard clarifies the principles for recognizing revenue and can be applied consistently across various transactions, industries and capital markets. In 2016 a number of additional ASUs were issued that clarify implementation guidance in ASC Topic 606. This standard, and all related ASUs, is effective for annual and interim periods beginning after December 15, 2017. Early adoption is permitted for annual and interim periods beginning after December 15, 2016. The Corporation has elected not to early adopt.

The new guidance permits two methods of adoption: (i) the full retrospective method, under which comparative periods would be restated, and the cumulative impact of applying the standard would be recognized as at January 1, 2017, the earliest period presented; and (ii) the modified retrospective method, under which comparative periods would not be restated and the cumulative impact of applying the standard would be recognized at the date of initial adoption, January 1, 2018. The Corporation expects to use the modified retrospective approach, however, it continues to monitor industry developments. Any significant industry developments could change the Corporation's expected method of adoption.

The majority of the Corporation's revenue is generated from energy sales to retail customers based on published tariff rates, as approved by the respective regulators, and from transmission services and is considered to be in the scope of ASU No. 2014-09. Fortis does not expect that the adoption of this standard, and all related ASUs, will have a material impact on the recognition of revenue generated from energy sales to retail customers, or on its remaining material revenue streams; however, the Corporation does expect it will impact its required disclosures. Certain industry specific interpretative issues, including contributions in aid of construction, remain outstanding and the conclusions reached, if different than currently anticipated, could have a material impact on the Corporation's consolidated financial statements and related disclosures. Fortis continues to closely monitor industry developments related to the new standard.

Recognition and Measurement of Financial Assets and Financial Liabilities: ASU No. 2016-01, *Recognition and Measurement of Financial Assets and Financial Liabilities*, was issued in January 2016 and the amendments in this update address certain aspects of recognition, measurement, presentation and disclosure of financial instruments. Most notably, the amendments require the following: (i) equity investments in unconsolidated entities (other than those accounted for using the equity method of accounting) to be measured at fair value through earnings; however, entities will be able to elect to record equity investments without readily determinable fair values at cost, less impairment, and plus or minus subsequent adjustments for observable price changes; and (ii) financial assets and financial liabilities to be presented separately in the notes to the consolidated financial statements, grouped by measurement category and form of financial asset. This update is effective for annual and interim periods beginning after December 15, 2017. Fortis is assessing the impact that the adoption of this update will have on its consolidated financial statements and related disclosures.

Leases: ASU No. 2016-02 was issued in February 2016 and the amendments in this update create ASC Topic 842, *Leases*, and supersede lease requirements in ASC Topic 840, *Leases*. The main provision of ASC Topic 842 is the recognition of lease assets and lease liabilities on the balance sheet by lessees for those leases that were previously classified as operating leases. For operating leases, a lessee is required to do the following: (i) recognize a right-of-use asset and a lease liability, initially measured at the present value of the lease payments, on the balance sheet; (ii) recognize a single lease cost, calculated so that the cost of the lease is allocated over the lease term on a generally straight-line basis; and (iii) classify all cash payments within operating activities in the statement of cash flows. These amendments also require qualitative disclosures along with specific quantitative disclosures. This update is effective for annual and interim periods beginning after December 15, 2018 and is to be applied using a modified retrospective approach with practical expedient options. Early adoption is permitted. Fortis is assessing the impact that the adoption of this update will have on its consolidated financial statements and related disclosures.

Measurement of Credit Losses on Financial Instruments: ASU No. 2016-13, *Measurement of Credit Losses on Financial Instruments*, was issued in June 2016 and the amendments in this update require entities to use an expected credit loss methodology and to consider a broader range of reasonable and supportable information to inform credit loss estimates. This update is effective for annual and interim periods beginning after December 15, 2019 and is to be applied on a modified retrospective basis. Early adoption is permitted for annual and interim periods beginning after December 15, 2018. Fortis is assessing the impact that the adoption of this update will have on its consolidated financial statements and related disclosures.

Simplifying the Test for Goodwill Impairment: ASU No. 2017-04, *Simplifying the Test for Goodwill Impairment*, was issued in January 2017 and the amendments in this update simplify the subsequent measurement of goodwill by eliminating step two in the current two-step goodwill impairment test. An entity will apply a one-step quantitative test and record the amount of goodwill impairment as the excess of a reporting unit's carrying amount over its fair value, not to exceed the total amount of goodwill allocated to the reporting unit. The new guidance does not amend the optional qualitative assessment of goodwill impairment. This update is effective for annual and interim periods beginning after December 15, 2019 and is to be applied on a prospective basis. Early adoption is permitted for interim and annual goodwill impairment tests performed on testing dates after January 1, 2017. Fortis expects to early adopt this update in 2017; however, does not expect that it will have a material impact on its consolidated financial statements and related disclosures.

FINANCIAL INSTRUMENTS

The carrying values of the Corporation's consolidated financial instruments approximate their fair values, reflecting the short-term maturity, normal trade credit terms and/or nature of these instruments, except as follows.

Financial Instruments

Liability as at December 31	2016		2015	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt, including current portion	**21,219**	**22,523**	11,244	12,614
Waneta Partnership promissory note	**59**	**61**	56	59

The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, as is the case with the Waneta Partnership promissory note and certain long-term debt, the fair value is determined by either: (i) discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality; or (ii) obtaining from third parties indicative prices for the same or similarly rated issues of debt of the same remaining maturities. Since the Corporation does not intend to settle the long-term debt or promissory note prior to maturity, the excess of the estimated fair value above the carrying value does not represent an actual liability.

The following table presents, by level within the fair value hierarchy, the Corporation's assets and liabilities accounted for at fair value on a recurring basis. These assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement and there were no transfers between the levels in the periods presented. For derivative instruments, the Corporation has elected gross presentation for its derivative contracts under master netting agreements and collateral positions.

Financial Instruments Carried at Fair Value

As at December 31	Fair value		
($ millions)	hierarchy	**2016**	2015
Assets			
Energy contracts subject to regulatory deferral [1][2][3]	Levels 1/2/3	**19**	7
Energy contracts not subject to regulatory deferral [1][2]	Level 3	**3**	2
Interest rate swaps – cash flow hedges [4]	Level 2	**11**	–
Available-for-sale investment	Level 1	**–**	33
Assets held for sale	Level 2	**–**	9
Other investments [5]	Level 1	**69**	12
Total gross assets		**102**	63
Less: Counterparty netting not offset on the balance sheet [6]		**(9)**	(6)
Total net assets		**93**	57
Liabilities			
Energy contracts subject to regulatory deferral [1][2][7]	Levels 2/3	**26**	78
Energy contracts not subject to regulatory deferral [1]	Level 2	**9**	–
Interest rate swaps – cash flow hedges [4]	Level 2	**3**	5
Total gross liabilities		**38**	83
Less: Counterparty netting not offset on the balance sheet [6]		**(9)**	(6)
Total net liabilities		**29**	77

[1] The fair value of the Corporation's energy contracts is recognized in accounts receivable and other current assets, long-term other assets, accounts payable and other current liabilities and long-term other liabilities. Unrealized gains and losses arising from changes in fair value of these contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates as permitted by the regulators, with the exception of long-term wholesale trading contracts and certain gas swap contracts.

[2] Changes in one or more of the unobservable inputs could have a significant impact on the fair value measurement depending on the magnitude and direction of the change for each input. The impacts of changes in fair value are subject to regulatory recovery, with the exception of long-term wholesale trading contracts and certain gas swap contracts.

[3] As at December 31, 2016, includes $1 million – level 1, $13 million – level 2 and $5 million – level 3 (December 31, 2015 – $2 million – level 2 and $5 million – level 3)

[4] The fair value of the Corporation's interest rate swaps is recognized in accounts receivable and other current assets, accounts payable and other current liabilities and long-term other liabilities.

[5] Included in long-term other assets on the consolidated balance sheet

[6] Certain energy contracts are subject to legally enforceable master netting arrangements to mitigate credit risk and are netted by counterparty where the intent and legal right to offset exists.

[7] As at December 31, 2016, includes $21 million – level 2 and $5 million – level 3 (December 31, 2015 – $1 million – level 1, $52 million – level 2 and $25 million – level 3)

Derivative Instruments

The Corporation generally limits the use of derivative instruments to those that qualify as accounting, economic or cash flow hedges, or those that are approved for regulatory recovery. The Corporation records all derivative instruments at fair value, with certain exceptions including those derivatives that qualify for the normal purchase and normal sale exception. The fair value of derivative instruments is the estimate of the amounts that the Corporation would receive or have to pay to terminate the outstanding contracts as at the balance sheet dates.

Energy Contracts Subject to Regulatory Deferral

UNS Energy holds electricity power purchase contracts and gas swap and option contracts to reduce its exposure to energy price risk associated with purchased power and gas requirements. UNS Energy primarily applies the market approach for fair value measurements using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships, transmission costs and line losses. The fair value of gas option contracts is estimated using a Black-Scholes option-pricing model, which includes inputs such as implied volatility, interest rates, and forward price curves. UNS Energy also considers the impact of counterparty credit risk using current and historical default and recovery rates, as well as its own credit risk using credit default swap data.

Central Hudson holds swap contracts for electricity and natural gas to minimize price volatility by fixing the effective purchase price for the defined commodities. The fair value of the swap contracts was calculated using forward pricing provided by independent third parties.

FortisBC Energy holds gas supply contract premiums to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. The fair value of the natural gas derivatives was calculated using the present value of cash flows based on market prices and forward curves for the cost of natural gas.

As at December 31, 2016, these energy contract derivatives were not designated as hedges; however, any unrealized gains or losses associated with changes in the fair value of the derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. These unrealized losses and gains would otherwise be recognized in earnings. As at December 31, 2016, unrealized losses of $19 million (December 31, 2015 – $74 million) were recognized in regulatory assets and unrealized gains of $12 million were recognized in regulatory liabilities (December 31, 2015 – $3 million).

Energy Contracts Not Subject to Regulatory Deferral

UNS Energy holds long-term wholesale trading contracts that qualify as derivative instruments. The unrealized gains and losses on these derivative instruments are recognized in earnings, as they do not qualify for regulatory deferral. Ten percent of any realized gains on these contracts are shared with customers through UNS Energy's rate stabilization accounts.

Aitken Creek holds gas supply contract premiums and gas swap contracts to manage its exposure to changes in natural gas prices, to capture natural gas price spreads, and to manage the financial risk posed by physical transactions. The fair value of the gas swap contracts was calculated using forward pricing provided by third parties. The unrealized gains and losses on these derivative instruments are recognized in earnings. As at December 31, 2016, unrealized losses totalled $9 million ($6 million after tax).

Cash Flow Hedges

UNS Energy holds an interest rate swap, expiring in 2020, to mitigate its exposure to volatility in variable interest rates on capital lease obligations.

ITC holds forward-starting interest rate swaps, effective January 2018 and expiring in 2028, with notional amounts totalling US$100 million. The agreements include a mandatory early termination provision and will be terminated no later than the effective date. The interest rate swaps manage the interest rate risk associated with the forecasted future issuance of fixed-rate debt related to the refinancing of maturing US$385 million long-term debt due in January 2018. As at December 31, 2016, the unrealized gain on the derivatives was $11 million (US$8 million).

The unrealized gains and losses on cash flow hedges are recognized in other comprehensive income and reclassified to earnings as a component of interest expense over the life of the hedged debt. The loss expected to be reclassified to earnings within the next twelve months is estimated to be approximately $5 million. Cash flows associated with the settlement of all derivative instruments are included in operating activities on the Corporation's consolidated statement of cash flows.

Volume of Derivative Activity

As at December 31, 2016, the following notional volumes related to electricity and natural gas derivatives that are expected to be settled are outlined below.

Volume	Maturity (year)	Contracts (#)	2017	2018	2019	2020	2021	There-after
Energy contracts subject to regulatory deferral:								
Electricity swap contracts *(GWh)*	2019	8	**1,089**	657	438	–	–	–
Electricity power purchase contracts *(GWh)*	2017	39	**1,252**	–	–	–	–	–
Gas swap and option contracts *(PJ)*	2019	108	**20**	11	4	–	–	–
Gas supply contract premiums *(PJ)*	2024	85	**82**	45	26	22	22	43
Energy contracts not subject to regulatory deferral:								
Long-term wholesale trading contracts *(GWh)*	2017	18	**2,058**	–	–	–	–	–
Gas supply contract premiums *(PJ)*	2017	226	**15**	–	–	–	–	–
Gas swap contracts *(PJ)*	2017	7	**4**	–	–	–	–	–

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's consolidated financial statements in accordance with US GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Due to changes in facts and circumstances, and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are recognized in earnings in the period in which they become known. The Corporation's critical accounting estimates are discussed as follows.

Regulation: Generally, the accounting policies of the Corporation's regulated utilities are subject to examination and approval by the respective regulatory authority. Regulatory assets and liabilities arise as a result of the rate-setting process at the regulated utilities and have been recognized based on previous, existing or expected regulatory orders or decisions. Certain estimates are necessary since the regulatory environments in which the Corporation's regulated utilities operate often require amounts to be recognized at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. The final amounts approved by the regulatory authorities for deferral as regulatory assets and regulatory liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are recognized in earnings in the period in which they become known. In the event that a regulatory decision is received after the balance sheet date but before the consolidated financial statements are issued, the facts and circumstances are reviewed to determine whether or not it is a recognized subsequent event.

As at December 31, 2016, Fortis recognized a total of $2.9 billion in regulatory assets (December 31, 2015 – $2.5 billion) and $2.2 billion in regulatory liabilities (December 31, 2015 – $1.6 billion). The increase in regulatory assets and liabilities from December 31, 2015 was mainly due to the acquisition of ITC. For a further discussion of the nature of regulatory decisions, refer to the "Regulatory Highlights" section of this MD&A.

Depreciation and Amortization: Depreciation and amortization are estimates based primarily on the useful life of assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical life of the assets. As at December 31, 2016, the Corporation's consolidated capital assets and intangible assets were approximately $30.3 billion, or approximately 63% of total consolidated assets, compared to approximately $20.1 billion, or approximately 70% of total consolidated assets, as at December 31, 2015. Depreciation and amortization was $983 million for 2016 compared to $873 million for 2015.

The majority of the Corporation's regulated utilities accrue estimated non-asset retirement obligation ("ARO") removal costs in depreciation, with the amount provided for in depreciation recorded as a long-term regulatory liability. Actual non-ARO removal costs are recorded against the regulatory liability when incurred. The estimate of non-ARO removal costs is based on historical experience and expected cost trends. The balance of this regulatory liability as at December 31, 2016 was $1.2 billion, an increase of $0.1 billion from $1.1 billion as at December 31, 2015, mainly due to the acquisition of ITC.

Changes in depreciation rates, resulting from a change in the estimated service life or removal costs, could have a significant impact on the Corporation's consolidated depreciation and amortization expense.

As part of the customer rate-setting process at the Corporation's regulated utilities, appropriate depreciation, amortization and removal cost rates, as applicable, are approved by the respective regulatory authority. The depreciation periods used and the associated rates are reviewed on an ongoing basis to ensure they continue to be appropriate. From time to time, third-party depreciation studies are performed at the regulated utilities. Based on the results of these depreciation studies, the impact of any over- or under-depreciation, as a result of actual experience differing from that expected and provided for in previous depreciation rates, is generally reflected in future depreciation rates and depreciation expense, when the differences are refunded or collected in customer rates, as approved by the regulator.

Assessment for Impairment of Goodwill: Goodwill represents the excess of the purchase price over the fair value of the identifiable net assets acquired relating to business acquisitions. The Corporation performs an annual impairment test for goodwill as at October 1, or more frequently if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. No such event or change in circumstances occurred during 2016 or 2015.

As at December 31, 2016, consolidated goodwill totalled approximately $12.4 billion (December 31, 2015 – $4.2 billion). The increase in goodwill was driven by the acquisition of ITC.

Fortis performs an annual internal qualitative and quantitative assessment for each reporting unit to which goodwill has been allocated. The Corporation has a total of 12 reporting units that were allocated goodwill at the respective dates of acquisition by Fortis. As at October 1, 2016, the Corporation completed its assessment of goodwill for 11 reporting units and, upon acquisition of ITC in October 2016, a purchase price allocation and associated goodwill impairment assessment was completed.

For those reporting units where: (i) management's assessment of qualitative and quantitative factors indicates that fair value is not 50% or more likely to be greater than carrying value; or (ii) the excess of estimated fair value over carrying value, as determined by an external consultant as of the date of the immediately preceding impairment test, was not significant, then fair value of the reporting unit will be estimated by an external consultant in the current year. Irrespective of the above-noted approach, a reporting unit to which goodwill has been allocated may have its fair value estimated by an external consultant as at the annual impairment date, as Fortis will, at a minimum, have fair value for each material reporting unit estimated by an external consultant once every five years.

The primary method for estimating fair value of the reporting units is the income approach, whereby net cash flow projections for the reporting units are discounted using an enterprise value method. The income approach uses several underlying estimates and assumptions with varying degrees of uncertainty, including the amount and timing of expected future cash flows, growth rates, and the determination of appropriate discount rates. A secondary valuation method, the market approach, as well as a reconciliation of the total estimated fair value of all reporting units to the Corporation's market capitalization, is also performed as an assessment of the conclusions reached under the income approach.

As a result of the Corporation's annual assessment for impairment of goodwill, the fair value of all of the reporting units exceeded their respective carrying value and, therefore, no impairment provision was required in 2016 or 2015.

Income Taxes: Income taxes are determined based on estimates of the Corporation's current income taxes and estimates of deferred income taxes resulting from temporary differences between the carrying values of assets and liabilities in the consolidated financial statements and their tax values. A deferred income tax asset or liability is determined for each temporary difference based on enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. Deferred income tax assets are assessed for the likelihood that they will be recovered from future taxable income. To the extent recovery is not considered more likely than not, a valuation allowance is recognized against earnings in the period when the allowance is created or revised. Estimates of the provision for current income taxes, deferred income tax assets and liabilities, and any related valuation allowance, might vary from actual amounts incurred.

Employee Future Benefits:

Defined Benefit Pension Plans

The Corporation's and subsidiaries' defined benefit pension plans are subject to judgments utilized in the actuarial determination of the net benefit cost and related obligation. The main assumptions utilized by management in determining the net benefit cost and obligation are the discount rate for the benefit obligation and the expected long-term rate of return on plan assets.

The expected weighted average long-term rate of return on the defined benefit pension plan assets, for the purpose of estimating net pension cost for 2017, is 5.97%, which is down from 6.25% used for 2016. The decrease in the average long-term rate of return reflects shifting of plan assets from equities to fixed income assets and lower expected returns from fixed income investments. The defined benefit pension plan assets experienced total positive returns of approximately $187 million in 2016 compared to expected positive returns of $145 million. The expected long-term rates of return on pension plan assets are developed by management with assistance from independent actuaries using best estimates of expected returns, volatilities and correlations for each class of asset. The best estimates are based on historical performance, future expectations and periodic portfolio re-balancing among the diversified asset classes.

The assumed weighted average discount rate used to measure the projected benefit obligations as at December 31, 2016, and to determine net pension cost for 2017, is 4.00%, compared to the assumed weighted average discount rate used to measure the projected benefit obligations as at December 31, 2015, and to determine net pension cost for 2016, of 4.21%. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments. The methodology in determining the discount rates was consistent with that used to determine the discount rates in the previous year. In 2015, newly acquired ITC, along with UNS Energy, adopted the spot rate methodology for determining net pension cost for future years.

There was a $9 million decrease in consolidated defined benefit net pension cost for 2016 compared to 2015, mainly due to lower amortization of actuarial losses for 2016 compared to 2015, partially offset by additional expenses related to the acquisition of ITC. Any increases or decreases in defined benefit net pension cost at the regulated utilities for 2017 are expected to be recovered from or refunded to customers in rates, subject to regulatory lag and forecast risk at certain of the utilities.

The following table provides the sensitivities associated with a 100 basis point change in the expected long-term rate of return on pension plan assets and the discount rate on 2016 net benefit pension cost, and the related projected benefit obligation recognized in the Corporation's 2016 Audited Consolidated Financial Statements.

Sensitivity Analysis of Changes in Rate of Return on Plan Assets and Discount Rate

Year Ended December 31, 2016

(Decrease) increase *($ millions)*	**Net pension benefit cost**	**Projected benefit obligation** [1]
Impact of increasing the rate of return assumption by 100 basis points	(24)	–
Impact of decreasing the rate of return assumption by 100 basis points	19	(52)
Impact of increasing the discount rate assumption by 100 basis points	(36)	(396)
Impact of decreasing the discount rate assumption by 100 basis points	48	490

[1] At FortisBC Energy and FortisBC Electric, certain defined benefit pension plans have pension indexing provisions which provide for a portion of investment returns to be allocated in order to provide for indexing of pension benefits. Therefore, a change in the expected long-term rate of return on pension plan assets has an impact on the projected benefit obligation. The direction of the impact of a change in the rate of return assumption at FortisBC Energy and FortisBC Electric is also the result of the methodology for determining the pension indexing assumption.

Other assumptions applied in measuring net benefit pension cost and/or the projected benefit obligation include the average rate of compensation increase, average remaining service life of the active employee group, and employee and retiree mortality rates.

As approved by the regulator, the cost of defined benefit pension plans at FortisAlberta is recovered in customer rates based on the cash payments made. Any difference between the cash payments made during the year and the cost incurred during the year is deferred as a regulatory asset or regulatory liability. Therefore, changes in assumptions result in changes in regulatory assets and regulatory liabilities for FortisAlberta. ITC, Central Hudson, FortisBC Energy, FortisBC Electric and Newfoundland Power have regulator-approved mechanisms to defer variations in net pension cost from forecast net pension cost, used to set customer rates, as a regulatory asset or regulatory liability. There can be no assurance, however, that the above-noted deferral mechanisms will continue in the future as they are dependent on future regulatory decisions and orders.

As at December 31, 2016, for all defined benefit pension plans, the Corporation had consolidated projected benefit obligations of $3.0 billion (December 31, 2015 – $2.8 billion) and consolidated plan assets of $2.6 billion (December 31, 2015 – $2.5 billion), for a consolidated funded status in a liability position of $0.4 billion (December 31, 2015 – $0.4 billion). In 2016 the Corporation recognized consolidated net pension benefit cost of $88 million (2015 – $97 million).

OPEB Plans

The OPEB plans of the Corporation and its subsidiaries are also subject to judgments utilized in the actuarial determination of the cost and the accumulated benefit obligation. Similar assumptions as described above, except for the assumption of the expected long-term rate of return on pension plan assets, which is applicable only to the OPEB plans at ITC, UNS Energy and Central Hudson, along with the health care cost trend rate, were also utilized by management in determining net OPEB cost and accumulated benefit obligation.

The OPEB plan assets at ITC, UNS Energy and Central Hudson experienced positive returns of $13 million in 2016 compared to expected positive returns of approximately $12 million.

The following table provides the sensitivities associated with a 100 basis point change in the health care cost trend rate and the discount rate on 2016 net OPEB cost, and the related consolidated accumulated benefit obligation recognized in the Corporation's 2016 Audited Consolidated Financial Statements.

Sensitivity Analysis of Changes in Health Care Cost Trend Rate and Discount Rate

Year Ended December 31, 2016

Increase (decrease) *($ millions)*	**Net OPEB cost**	**Accumulated benefit obligation**
Impact of increasing the health care cost trend rate assumption by 100 basis points	12	89
Impact of decreasing the health care cost trend rate assumption by 100 basis points	(8)	(71)
Impact of increasing the discount rate assumption by 100 basis points	(6)	(91)
Impact of decreasing the discount rate assumption by 100 basis points	9	113

ITC, Central Hudson, FortisBC Energy, FortisBC Electric and Newfoundland Power have regulator-approved mechanisms to defer variations in net OPEB cost from forecast net OPEB cost, used to set customer rates, as a regulatory asset or regulatory liability. There can be no assurance, however, that the above-noted deferral mechanisms will continue in the future as they are dependent on future regulatory decisions and orders.

As at December 31, 2016, for all OPEB plans, the Corporation had consolidated accumulated benefit obligations of $676 million (December 31, 2015 – $574 million) and consolidated plan assets of $252 million (December 31, 2015 – $181 million), for a consolidated funded status in a liability position of $424 million (December 31, 2015 – $393 million). In 2016 the Corporation recognized consolidated net OPEB benefit cost of $30 million (2015 – $27 million).

AROs: The measurement of the fair value of AROs requires making reasonable estimates concerning the method of settlement and settlement dates associated with the legally obligated asset retirement costs. There are uncertainties in estimating future asset retirement costs due to potential external events, such as changing legislation or regulations and advances in remediation technologies. The Corporation has AROs associated with the remediation of hydroelectric generating facilities, interconnection facilities, wholesale energy supply agreements, certain distribution system assets and land.

The nature, amount and timing of costs associated with land and environmental remediation and/or removal of assets cannot be reasonably estimated at this time as the hydroelectric generation and T&D assets are reasonably expected to operate in perpetuity due to the nature of their operation; applicable licences, permits, interconnection facilities agreements, wholesale energy supply agreements and rights-of-way are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the related assets and ensure the continued provision of service to customers; a land-lease agreement is expected to be renewed indefinitely; and the exact nature and amount of land remediation is indeterminable. In the event that environmental issues are known and identified, assets are decommissioned or the applicable licences, permits, agreements or leases are terminated, AROs will be recognized at that time provided the costs can be reasonably estimated and are material.

As at December 31, 2016, the Corporation's total AROs were $58 million (December 31, 2015 – $49 million), and were associated with the removal of polychlorinated biphenyl ("PCB")-contaminated oil from equipment, the remediation of asbestos, and the remediation of certain generation and photovoltaic assets. The total ARO liability as at December 31, 2016 has been classified on the consolidated balance sheet as a long-term other liability with the offset to utility capital assets. All factors used in estimating the Corporation's AROs represent management's best estimate of the fair value of the costs required to meet existing legislation or regulations. It is reasonably possible that volumes of contaminated assets, inflation assumptions, cost estimates to perform the work and the assumed pattern of annual cash flows may differ significantly from current assumptions. The AROs may change from period to period because of changes in the estimates.

Revenue Recognition: Revenue at the Corporation's regulated utilities is generally recognized on an accrual basis. Electricity and gas consumption is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of each reporting period, a certain amount of consumed electricity and gas will not have been billed. Electricity and gas that is consumed but not yet billed to customers is estimated and accrued as revenue at each period end, as approved by the regulator.

The unbilled revenue accrual for the period is based on estimated electricity and gas sales to customers for the period since the last meter reading at the rates approved by the respective regulatory authority. The development of the sales estimates generally requires analysis of consumption on a historical basis in relation to key inputs, such as the current price of electricity and gas, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled electricity and gas consumption will result in adjustments to revenue in the periods they become known, when actual results differ from estimates. As at December 31, 2016, the amount of accrued unbilled revenue recognized in accounts receivable was approximately $551 million (December 31, 2015 – $404 million) on consolidated revenue of $6.8 billion for 2016 (2015 – $6.8 billion). The increase in accrued unbilled revenue from December 31, 2015 was mainly due to the acquisition of ITC.

Capitalized Overhead: Most of the Corporation's utilities capitalize overhead costs that are not directly attributable to specific utility capital assets but relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized general overhead costs to utility capital assets is established by the utilities' respective regulator. Any change in the methodology of calculating and allocating general overhead costs to utility capital assets could have a material impact on the amount recognized as operating expenses versus utility capital assets.

Contingencies: The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with the ordinary course of business operations. Management believes that the amount of liability, if any, from these actions would not have a material adverse effect on the Corporation's consolidated financial position, results of operations or cash flows.

The following describes the nature of the Corporation's contingencies.

Central Hudson

Asbestos Litigation

Prior to and after its acquisition by Fortis, various asbestos lawsuits have been brought against Central Hudson. While a total of 3,363 asbestos cases have been raised, 1,175 remained pending as at December 31, 2016. Of the cases no longer pending against Central Hudson, 2,032 have been dismissed or discontinued without payment by the Company, and Central Hudson has settled the remaining 156 cases. The Company is presently unable to assess the validity of the outstanding asbestos lawsuits; however, based on information known to Central Hudson at this time, including the Company's experience in the settlement and/or dismissal of asbestos cases, Central Hudson believes that the costs which may be incurred in connection with the remaining lawsuits will not have a material effect on its financial position, results of operations or cash flows and, accordingly, no amount has been accrued in the consolidated financial statements.

FHI

In April 2013 FHI and Fortis were named as defendants in an action in the B.C. Supreme Court by the Coldwater Indian Band ("Band"). The claim is in regard to interests in a pipeline right of way on reserve lands. The pipeline on the right of way was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in April 2007. The Band seeks orders cancelling the right of way and claims damages for wrongful interference with the Band's use and enjoyment of reserve lands. In May 2016 the Federal Court entered a decision dismissing the Coldwater Band's application for judicial review of the ministerial consent. The Band has appealed that decision. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Fortis and ITC

Following announcement of the acquisition of ITC in February 2016, complaints which named Fortis and other defendants were filed in the Oakland County Circuit Court in the State of Michigan ("Superior Court") and the United States District Court in and for the Eastern District of Michigan. The complaints generally allege, among other things, that the directors of ITC breached their fiduciary duties in connection with the merger agreement and that ITC, Fortis, FortisUS Inc. and Element Acquisition Sub Inc. aided and abetted those purported breaches. The complaints seek class action certification and a variety of relief including, among other things, unspecified damages, and costs, including attorneys' fees and expenses. In July 2016 the federal actions were voluntarily dismissed by the federal plaintiffs. The federal plaintiffs reserved the right to make certain other claims, and ITC and the individual members of the ITC board of directors reserved the right to oppose any such claim. The federal plaintiffs have sought a mootness fee application and the parties are currently exploring a mutually satisfactory resolution. In June 2016 the Superior Court granted a motion for summary disposition dismissing the aiding and abetting claims asserted against Fortis, FortisUS Inc. and Element Acquisition Sub Inc. In January 2017 the Superior Court issued a revised scheduling order, which, among other things, requires the parties, including ITC, to complete discovery by May 2017, and set a trial date for September 2017. A hearing on the plaintiff's motion for class certification was held on February 9, 2017. A hearing on a motion of the defendants for summary disposition has been scheduled for March 2017. The outcome of these lawsuits cannot be predicted with any certainty and, accordingly, no amount has been accrued in the consolidated financial statements.

RELATED-PARTY AND INTER-COMPANY TRANSACTIONS

Related-party transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. There were no material related-party transactions in 2016 or 2015.

Inter-company balances and inter-company transactions, including any related inter-company profit, are eliminated on consolidation, except for certain inter-company transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. The significant inter-company transactions for 2016 and 2015 are summarized in the following table.

Years Ended December 31 *($ millions)*	**2016**	2015
Sale of capacity from Waneta Expansion to FortisBC Electric	**45**	30
Sale of energy from BECOL to Belize Electricity	**33**	30
Lease of gas storage capacity from Aitken Creek to FortisBC Energy	**17**	–

As at December 31, 2016, accounts receivable on the Corporation's consolidated balance sheet included approximately $16 million due from Belize Electricity (December 31, 2015 – $5 million), in which Fortis holds a 33% equity investment.

From time to time, the Corporation provides short-term financing to certain of its subsidiaries to support capital expenditure programs, acquisitions and seasonal working capital requirements, bearing interest at rates that approximate the Corporation's cost of short-term borrowing, and provides long-term financing to certain of its subsidiaries, bearing interest at rates that approximate the Corporation's cost of long-term debt. There were no inter-segment loans outstanding as at December 31, 2016 (December 31, 2015 – $48 million) and total interest charged in 2016 was less than $1 million (2015 – $17 million).

SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth the annual financial information for the years ended December 31, 2016, 2015 and 2014.

Selected Annual Financial Information

Years Ended December 31 *($ millions, except per share amounts)*	**2016**	2015	2014
Revenue	**6,838**	6,757	5,401
Net earnings	**713**	840	390
Net earnings attributable to common equity shareholders	**585**	728	317
Basic earnings per common share	**1.89**	2.61	1.41
Diluted earnings per common share	**1.89**	2.59	1.40
Total assets	**47,904**	28,804	26,233
Long-term debt (excluding current portion)	**20,817**	10,784	9,911
Preference shares	**1,623**	1,820	1,820
Common shareholders' equity	**12,974**	8,060	6,871
Dividends declared per common share	**1.55**	1.43	1.30
Dividends declared per First Preference Share, Series E[(1)]	**0.6126**	1.2250	1.2250
Dividends declared per First Preference Share, Series F	**1.2250**	1.2250	1.2250
Dividends declared per First Preference Share, Series G	**0.9708**	0.9708	0.9708
Dividends declared per First Preference Share, Series H[(2)]	**0.6250**	0.7344	1.0625
Dividends declared per First Preference Share, Series I[(2)]	**0.4874**	0.3637	–
Dividends declared per First Preference Share, Series J	**1.1875**	1.1875	1.1875
Dividends declared per First Preference Share, Series K	**1.0000**	1.0000	1.0000
Dividends declared per First Preference Share, Series M[(3)]	**1.0250**	1.0250	0.4613

(1) In September 2016 the Corporation redeemed all of the issued and outstanding First Preference Shares, Series E.

(2) On June 1, 2015, 2,975,154 of the 10,000,000 First Preference Shares, Series H were converted on a one-for-one basis into First Preference Shares, Series I. The annual fixed dividend per share for the First Preference Shares, Series H was reset from $1.0625 to $0.6250 for the five-year period from and including June 1, 2015 to but excluding June 1, 2020. The First Preference Shares, Series I are entitled to receive floating rate cumulative dividends, which rate is reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus 1.45%.

(3) The Fixed Rate Reset First Preference Shares, Series M were issued in September 2014 and are entitled to receive cumulative dividends in the amount of $1.0250 per share per annum for the first five years.

2016/2015: Revenue increased $81 million, or 1.2%, from 2015 and net earnings attributable to common equity shareholders were $585 million, or $1.89 per common share, compared to $728 million, or $2.61 per common share, in 2015. For a discussion of the reasons for the changes in revenue, net earnings attributable to common equity shareholders, and earnings per common share, refer to the "Summary Financial Highlights" and "Consolidated Results of Operations" sections of this MD&A.

The growth in total assets was driven by the acquisition of ITC in October 2016 and continued investment in energy infrastructure, driven by capital spending at the regulated utilities and the acquisition of Aitken Creek, partially offset by unfavourable foreign exchange on the translation of US dollar-denominated assets. The increase in long-term debt was primarily due to the financing of the acquisition of ITC, including debt assumed on acquisition, and the financing of energy infrastructure investments.

2015/2014: Revenue increased $1,356 million, or 25.1%, from 2014. The increase in revenue was driven by the acquisition of UNS Energy in August 2014. Favourable foreign exchange associated with the translation of US dollar-denominated revenue, contribution from the Waneta Expansion and higher base electricity rates at the Canadian Regulated Electric Utilities also contributed to the increase. The increase was partially offset by the flow through in customer rates of lower energy supply costs at FortisBC Energy, Central Hudson and the Caribbean Regulated Electric Utilities, and a decrease in non-utility revenue due to the sale of commercial real estate and hotel assets in 2015.

Net earnings attributable to common equity shareholders were $728 million in 2015 compared to $317 million in 2014. Results for both years were impacted by adjusting items, largely associated with the sale of commercial real estate and hotel assets in 2015 and the acquisition of UNS Energy in 2014. Earnings for 2015 were favourably impacted by an after-tax net gain of $133 million on the sale of commercial real estate, hotel and non-regulated generation assets and a positive capital tracker revenue adjustment of $9 million at FortisAlberta, partially offset by the loss on the settlement of expropriation matters in Belize of $9 million. Acquisition-related expenses and fees associated with the acquisition of ITC totalled $7 million in 2015, compared to $39 million related to the acquisition of UNS Energy in 2014. In addition, earnings in 2014 were unfavourably impacted by interest expense of $51 million after tax associated with convertible debentures issued to finance a portion of the acquisition of UNS Energy. A $13 million foreign exchange gain was recognized in 2015 compared to $8 million in 2014. In addition, earnings for 2014 included $5 million associated with discontinued operations.

Excluding the above-noted impacts, adjusted net earnings attributable to common equity shareholders for 2015 were $589 million, an increase of $195 million from $394 million for 2014. The increase was driven by a full year of earnings from UNS Energy. Earnings contribution of $22 million from the Waneta Expansion, which came online in early April 2015, rate base growth associated with capital expenditures and growth in the number of customers at FortisAlberta, a higher AFUDC at FortisBC Energy, the resetting of customer rates at Central Hudson, effective July 1, 2015, and the continued strength of the US dollar relative to the Canadian dollar also increased earnings year over year. The increase in adjusted earnings was partially offset by higher preference share dividends and finance charges in the Corporate and Other segment, largely associated with the acquisition of UNS Energy, and lower earnings contribution from non-utility assets due to the sale of the commercial real estate and hotel assets.

The growth in total assets reflects favourable foreign exchange on the translation of US dollar-denominated assets and continued investment in energy infrastructure, driven by capital spending at the regulated utilities, partially offset by the sale of commercial real estate and hotel assets. The increase in long-term debt was primarily due to the issuance of long-term debt at the Corporation's regulated utilities, largely to finance energy infrastructure investment, and the impact of foreign exchange on the translation of US dollar-denominated long-term debt. The increase was partially offset by regularly scheduled debt repayments and net repayments under committed credit facilities, mainly at the Corporation, using net proceeds from the sale of commercial real estate and hotel assets.

Basic earnings per common share were $2.61 in 2015 compared to $1.41 in 2014. On an adjusted basis, as noted above, basic earnings per common share were $2.11 for 2015, an increase of $0.36 over 2014. The increase was driven by higher adjusted earnings, as discussed above, partially offset by an increase in the weighted average number of common shares outstanding.

FOURTH QUARTER RESULTS

The following tables set forth unaudited financial information for the fourth quarters ended December 31, 2016 and 2015.

Summary of Electricity and Energy Sales and Gas Volumes

Fourth Quarters Ended December 31 *(Unaudited)*	**2016**	2015	Variance
Regulated Electric & Gas Utilities – United States			
UNS Energy – Electricity Sales *(GWh)*	**3,356**	3,562	(206)
UNS Energy – Gas Volumes *(PJ)*	**4**	4	–
Central Hudson – Electricity Sales *(GWh)*	**1,195**	1,160	35
Central Hudson – Gas Volumes *(PJ)*	**6**	5	1
Regulated Gas & Electric Utilities – Canadian			
FortisBC Energy *(PJ)*	**67**	62	5
FortisAlberta *(GWh)*	**4,352**	4,188	164
FortisBC Electric *(GWh)*	**856**	836	20
Eastern Canadian *(GWh)*	**2,207**	2,189	18
Regulated Electric Utilities – Caribbean *(GWh)*	**205**	201	4
Non-Regulated – Energy Infrastructure *(GWh)*	**115**	122	(7)

Electricity and Energy Sales

The increase in electricity sales was driven by higher energy deliveries at FortisAlberta, due to higher average consumption by oil and gas customers, higher average consumption by residential, commercial and farm and irrigation customers due to changes in weather, and growth in the number of customers. Higher electricity sales at most of the other regulated electric utilities, mainly due to changes in weather, were offset by lower electricity sales at UNS Energy due to lower mining retail and short-term wholesale sales.

Gas Volumes

The increase in gas volumes at FortisBC Energy was mainly due to customer growth, higher average consumption by residential and commercial customers due to colder temperatures, and higher gas volumes for transportation customers due to certain customers switching to natural gas compared to alternative fuel sources.

Segmented Revenue and Net Earnings Attributable to Common Equity Shareholders

Fourth Quarters Ended December 31 *(Unaudited)*	Revenue			Net Earnings		
($ millions, except per share amounts)	**2016**	2015	Variance	**2016**	2015	Variance
Regulated Electric & Gas Utilities – United States						
ITC	**334**	–	334	**59**	–	59
UNS Energy	**468**	482	(14)	**29**	26	3
Central Hudson	**207**	202	5	**20**	15	5
	1,009	684	325	**108**	41	67
Regulated Gas & Electric Utilities – Canadian						
FortisBC Energy	**393**	411	(18)	**70**	65	5
FortisAlberta	**143**	140	3	**30**	29	1
FortisBC Electric	**102**	99	3	**13**	8	5
Eastern Canadian	**278**	273	5	**16**	15	1
	916	923	(7)	**129**	117	12
Regulated Electric Utilities – Caribbean	**76**	82	(6)	**12**	9	3
Non-Regulated – Energy Infrastructure	**54**	30	24	**15**	11	4
Non-Regulated – Non-Utility	**–**	6	(6)	**–**	1	(1)
Corporate and Other	**2**	2	–	**(75)**	(44)	(31)
Inter-Segment Eliminations	**(4)**	(4)	–	**–**	–	–
Total	**2,053**	1,723	330	**189**	135	54
Basic Earnings per Common Share *($)*				**0.49**	0.48	0.01
Weighted Average Number of Common Shares Outstanding *(# millions)*				**384.6**	280.7	103.9

Revenue

The increase in revenue was driven by the acquisition of ITC, as well as contribution from Aitken Creek. The increase was partially offset by the flow through in customer rates of lower overall energy supply costs.

Earnings

The increase in earnings was driven by contribution of $59 million from ITC, which was reduced by $22 million in expenses associated with the accelerated vesting of the Company's stock-based compensation awards as a result of the acquisition. Strong performance at most of the Corporation's regulated utilities and contribution of $6 million from Aitken Creek, net of an after-tax $3 million unrealized loss on the mark-to-market of derivatives, also contributed to higher earnings. The increase was partially offset by higher Corporate and Other expenses. Corporate and Other expenses reflected after-tax acquisition-related expenses of $32 million in the fourth quarter of 2016, compared to $7 million in the fourth quarter of 2015, with the remaining increase primarily due to finance charges associated with the acquisition of ITC.

Earnings per Common Share

The impact of higher earnings was offset by an increase in the weighted average number of common shares outstanding, as a result of shares issued to finance a portion of the acquisition of ITC. Excluding the impacts of acquisition-related expenses in the ITC and Corporate and Other segments, as well as the mark-to-market loss at Aitken Creek, adjusted earnings for the fourth quarter of 2016 were $246 million, or $0.64 per common share, compared to $142 million, or $0.51 per common share, for the fourth quarter of 2015. The increase in adjusted earnings per common share was driven by accretion associated with the acquisition of ITC, strong performance at most of the Corporation's regulated utilities and contribution from Aitken Creek.

Summary of Consolidated Cash Flows

Fourth Quarters Ended December 31 *(Unaudited)*

($ millions)	**2016**	2015	Variance
Cash, Beginning of Period	**301**	347	(46)
Cash Provided by (Used in):			
Operating Activities	**475**	397	78
Investing Activities	**(5,187)**	(234)	(4,953)
Financing Activities	**4,685**	(280)	4,965
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**(5)**	12	(17)
Cash, End of Period	**269**	242	27

Cash flow from operating activities was $78 million higher quarter over quarter. The increase was primarily due to higher cash earnings, driven by the acquisition of ITC, partially offset by the Corporation's acquisition-related expenses. Favourable changes in long-term regulatory deferrals were partially offset by unfavourable changes in working capital.

Cash used in investing activities was $4,953 million higher quarter over quarter. The increase was driven by the acquisition of ITC in October 2016 for a net cash consideration of approximately $4.5 billion (US$3.5 billion). Proceeds received from the sale of hotel assets in October 2015 of $365 million and an increase in capital expenditures also contributed to the increase. Capital expenditures at ITC of approximately US$167 million from the date of acquisition were partially offset by lower capital spending at FortisAlberta, FortisBC Energy and UNS Energy.

Cash provided by financing activities was $4,965 million higher quarter over quarter. The increase was driven by financing activities associated with the acquisition of ITC and higher proceeds from the issuance of long-term debt. The increase was partially offset by higher net repayments of committed credit facility borrowings.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2015 through December 31, 2016. The quarterly information has been obtained from the Corporation's interim unaudited consolidated financial statements. These financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Summary of Quarterly Results

(Unaudited)

		Net Earnings Attributable to Common Equity Shareholders	**Earnings per Common Share**	
			Basic	**Diluted**
Quarter Ended	**Revenue** *($ millions)*	*($ millions)*	*($)*	*($)*
December 31, 2016	2,053	189	0.49	0.49
September 30, 2016	1,528	127	0.45	0.45
June 30, 2016	1,485	107	0.38	0.38
March 31, 2016	1,772	162	0.57	0.57
December 31, 2015	1,723	135	0.48	0.48
September 30, 2015	1,579	151	0.54	0.54
June 30, 2015	1,540	244	0.88	0.87
March 31, 2015	1,915	198	0.72	0.71

The summary of the past eight quarters reflects the Corporation's continued organic growth, growth from acquisitions and associated acquisition-related expenses, and the impact of the sale of non-regulated assets, as well as the seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of electricity and gas demand and water flows, as well as the timing and recognition of regulatory decisions. Revenue is also affected by the cost of fuel and purchased power and the cost of natural gas, which are flowed through to customers without markup. Given the diversified nature of the Corporation's subsidiaries, seasonality may vary. Most of the annual earnings of the gas utilities are realized in the first and fourth quarters due to space-heating requirements. Earnings for the electric utilities in the United States are generally highest in the second and third quarters due to the use of air conditioning and other cooling equipment.

December 2016/December 2015: Net earnings attributable to common equity shareholders were $189 million, or $0.49 per common share, for the fourth quarter of 2016 compared to earnings of $135 million, or $0.48 per common share, for the fourth quarter of 2015. A discussion of the variances in financial results for the fourth quarter is provided in the "Fourth Quarter Results" section of this MD&A.

September 2016/September 2015: Net earnings attributable to common equity shareholders were $127 million, or $0.45 per common share, for the third quarter of 2016 compared to earnings of $151 million, or $0.54 per common share, for the third quarter of 2015. The decrease in earnings was primarily due to: $7 million (US$5 million) in FERC ordered transmission refunds at UNS Energy, $19 million in acquisition-related expenses and fees, and a $1 million unrealized loss on the mark-to-market of derivatives in the third quarter of 2016; a $5 million positive tax adjustment on the sale of hotel assets, a $5 million gain on the sale of non-regulated generation assets, and a foreign exchange gain of $5 million in the third quarter of 2015; partially offset by the $9 million loss on the settlement of expropriation matters in Belize in the third quarter of 2015. Excluding these items, the $9 million increase in earnings was mainly due to: (i) strong performance at most of the Corporation's regulated utilities driven by UNS Energy, largely due to the settlement of Springerville Unit 1 matters, and Central Hudson, due to an increase in delivery revenue; (ii) the timing of quarterly earnings at FortisBC Electric compared to the third quarter of 2015; and (iii) contribution of $2 million from Aitken Creek, which was acquired in early April 2016. The increase was partially offset by: (i) lower earnings at FortisAlberta due to higher operating expenses, a negative capital tracker revenue adjustment as a result of the outcome of the 2016 GCOC Proceeding in Alberta, and lower average energy consumption; (ii) the sale of hotel assets in 2015; and (iii) an increase in Corporate and Other expenses.

June 2016/June 2015: Net earnings attributable to common equity shareholders were $107 million, or $0.38 per common share, for the second quarter of 2016 compared to earnings of $244 million, or $0.88 per common share, for the second quarter of 2015. The decrease in earnings was primarily due to: $22 million in acquisition-related expenses and fees and a $2 million unrealized loss on the mark-to-market of derivatives in the second quarter of 2016, and a net gain of $123 million on the sale of commercial real estate, hotel and non-regulated generation assets in the second quarter of 2015. Excluding these items, the $10 million increase in earnings was mainly due to: (i) strong performance at most of the Corporation's regulated utilities; (ii) contribution of $4 million from Aitken Creek, which was acquired in early April 2016; (iii) favourable foreign exchange associated with US dollar-denominated earnings; and (iv) the timing of quarterly earnings at FortisBC Electric compared to the second quarter of 2015. The increase was partially offset by lower earnings at FortisAlberta, due to higher operating expenses and lower average energy consumption, and the sale of commercial real estate and hotel assets in 2015.

March 2016/March 2015: Net earnings attributable to common equity shareholders were $162 million, or $0.57 per common share, for the first quarter of 2016 compared to earnings of $198 million, or $0.72 per common share, for the first quarter of 2015. The decrease in earnings was primarily due to: $17 million in acquisition-related expenses and $11 million (US$8 million) in FERC ordered transmission refunds in the first quarter of 2016, and a positive capital tracker revenue adjustment of $10 million and a foreign exchange gain of $9 million in the first quarter of 2015. Excluding these items, the $11 million increase in net earnings was mainly due to: (i) contribution of $4 million from the Waneta Expansion, which came online in early April 2015, and increased production in Belize due to higher rainfall; (ii) favourable foreign exchange associated with US dollar-denominated earnings; (iii) a higher AFUDC at FortisBC Energy; and (iv) strong performance from the utilities in the Caribbean. The increase was partially offset by the timing of quarterly earnings at FortisBC Electric compared to the first quarter of 2015, and higher Corporate and Other expenses.

MANAGEMENT'S EVALUATON OF DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Disclosure Controls and Procedures: The President and Chief Executive Officer ("CEO") and the Executive Vice President, Chief Financial Officer ("CFO") of Fortis, together with management, have established and maintain disclosure controls and procedures for the Corporation in order to provide reasonable assurance that material information relating to the Corporation is made known to them in a timely manner, particularly during the period in which the annual filings are being prepared. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's disclosure controls and procedures as of December 31, 2016 and, based on that evaluation, have concluded that these controls and procedures are effective in providing such reasonable assurance.

Internal Controls over Financial Reporting: The CEO and CFO of Fortis, together with management, are also responsible for establishing and maintaining internal controls over financial reporting ("ICFR") within the Corporation in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements for external purposes in accordance with US GAAP. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's ICFR as of December 31, 2016 and, based on that evaluation, have concluded that the controls are effective in providing such reasonable assurance. During the fourth quarter of 2016, there was no change in the Corporation's ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR. Given that Fortis became an SEC registrant in 2016, it has until the year ended December 31, 2017 to ensure that its ICFR are in compliance with the requirements of Section 404(a) of Sarbanes-Oxley, and the related rules of the SEC and the Public Company Accounting Oversight Board.

OUTLOOK

The Corporation's results for 2017 will benefit from the impact of ITC, the outcome of the TEP general rate case and continued growth of the underlying business. Over the long term, Fortis is well positioned to enhance value for shareholders through the execution of its capital plan, the balance and strength of its diversified portfolio of utility businesses, as well as growth opportunities within its franchise regions.

Over the five-year period through 2021, the Corporation's capital program is expected to be approximately $13 billion, allowing rate base to reach almost $30 billion in 2021. Fortis expects this long-term sustainable growth in rate base to support continuing growth in earnings and dividends.

Fortis has targeted average annual dividend growth of approximately 6% through 2021. This dividend guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at the Corporation's utilities, the successful execution of the five-year capital expenditure program, and management's continued confidence in the strength of the Corporation's diversified portfolio of utilities and record of operational excellence.

OUTSTANDING SHARE DATA

As at February 15, 2017, the Corporation had issued and outstanding 401.6 million common shares; 5.0 million First Preference Shares, Series F; 9.2 million First Preference Shares, Series G; 7.0 million First Preference Shares, Series H; 3.0 million First Preference Shares, Series I; 8.0 million First Preference Shares, Series J; 10.0 million First Preference Shares, Series K; and 24.0 million First Preference Shares, Series M. Only the common shares of the Corporation have voting rights. The Corporation's First Preference Shares do not have voting rights unless and until Fortis fails to pay eight quarterly dividends, whether or not consecutive and whether such dividends have been declared.

The number of common shares of Fortis that would be issued if all outstanding stock options were converted as at February 15, 2017 is approximately 4.1 million.

Additional information can be accessed at www.fortisinc.com, www.sedar.com, or www.sec.gov.

Financials

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MANAGEMENT'S REPORT

The accompanying Annual Consolidated Financial Statements of Fortis Inc. have been prepared by management, who is responsible for the integrity of the information presented including the amounts that must, of necessity, be based on estimates and informed judgments. These Annual Consolidated Financial Statements were prepared in accordance with accounting principles generally accepted in the United States.

In meeting its responsibility for the reliability and integrity of the Annual Consolidated Financial Statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to ensure transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Corporation and its subsidiaries focus on the need for training of qualified and professional staff and the effective communication of management guidelines and policies. The effectiveness of the internal controls of Fortis Inc. is evaluated on an ongoing basis.

The Board of Directors oversees management's responsibilities for financial reporting through an Audit Committee which is composed entirely of outside independent directors. The Audit Committee oversees the external audit of the Corporation's Annual Consolidated Financial Statements and the accounting and financial reporting and disclosure processes and policies of the Corporation. The Audit Committee meets with management, the shareholders' auditors and the internal auditor to discuss the results of the external audit, the adequacy of the internal accounting controls and the quality and integrity of financial reporting. The Corporation's Annual Consolidated Financial Statements are reviewed by the Audit Committee with each of management and the shareholders' auditors before the statements are recommended to the Board of Directors for approval. The shareholders' auditors have full and free access to the Audit Committee. The Audit Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Corporation's Annual Consolidated Financial Statements and to review and report to the Board of Directors on policies relating to the accounting and financial reporting and disclosure processes.

The Audit Committee has the duty to review financial reports requiring Board of Directors' approval prior to the submission to securities commissions or other regulatory authorities, to assess and review management judgments material to reported financial information and to review shareholders' auditors' independence and auditors' fees. The 2016 Annual Consolidated Financial Statements were reviewed by the Audit Committee and, on their recommendation, were approved by the Board of Directors of Fortis Inc. Ernst & Young LLP, independent auditors appointed by the shareholders of Fortis Inc. upon recommendation of the Audit Committee, have performed an audit of the 2016 Annual Consolidated Financial Statements and their report follows.



Barry V. Perry
President and Chief Executive Officer, Fortis Inc.



Karl W. Smith
Executive Vice President, Chief Financial Officer, Fortis Inc.

St. John's, Canada

INDEPENDENT AUDITORS' REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders of Fortis Inc.

We have audited the accompanying consolidated financial statements of Fortis Inc., which comprise the consolidated balance sheets as at December 31, 2016 and 2015, and the consolidated statements of earnings, comprehensive income, cash flows and changes in equity for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements, evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Fortis Inc. as at December 31, 2016 and 2015, and its financial performance and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States.



Chartered Professional Accountants

St. John's, Canada
February 15, 2017

CONSOLIDATED BALANCE SHEETS

FORTIS INC.

As at December 31 (in millions of Canadian dollars)

ASSETS	2016	2015
Current assets		
Cash and cash equivalents	**$ 269**	$ 242
Accounts receivable and other current assets *(Note 6)*	**1,127**	964
Prepaid expenses	**85**	68
Inventories *(Note 7)*	**372**	337
Regulatory assets *(Note 8)*	**313**	246
	2,166	1,857
Other assets *(Note 9)*	**406**	352
Regulatory assets *(Note 8)*	**2,620**	2,286
Utility capital assets *(Note 10)*	**29,337**	19,595
Intangible assets *(Note 11)*	**1,011**	541
Goodwill *(Note 12)*	**12,364**	4,173
	$ 47,904	$ 28,804
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings *(Note 32)*	**$ 1,155**	$ 511
Accounts payable and other current liabilities *(Note 13)*	**1,970**	1,419
Regulatory liabilities *(Note 8)*	**492**	298
Current installments of long-term debt *(Note 14)*	**251**	384
Current installments of capital lease and finance obligations *(Note 15)*	**76**	26
	3,944	2,638
Other liabilities *(Note 16)*	**1,279**	1,152
Regulatory liabilities *(Note 8)*	**1,691**	1,340
Deferred income taxes *(Note 25)*	**3,263**	2,050
Long-term debt *(Note 14)*	**20,817**	10,784
Capital lease and finance obligations *(Note 15)*	**460**	487
	31,454	18,451
Shareholders' equity		
Common shares [1] *(Note 17)*	**10,762**	5,867
Preference shares *(Note 19)*	**1,623**	1,820
Additional paid-in capital	**12**	14
Accumulated other comprehensive income *(Note 20)*	**745**	791
Retained earnings	**1,455**	1,388
Total Fortis Inc. shareholders' equity	**14,597**	9,880
Non-controlling interests *(Note 21)*	**1,853**	473
	16,450	10,353
	$ 47,904	$ 28,804

[1] No par value. Unlimited authorized shares; 401.5 million and 281.6 million issued and outstanding as at December 31, 2016 and 2015, respectively

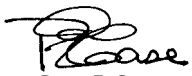
Commitments *(Note 33)*
Contingencies *(Note 34)*

See accompanying Notes to Consolidated Financial Statements

Approved on Behalf of the Board



Douglas J. Haughey, Director



Peter E. Case, Director

CONSOLIDATED STATEMENTS OF EARNINGS

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except per share amounts)	2016	2015
Revenue	**$ 6,838**	$ 6,757
Expenses		
Energy supply costs	**2,341**	2,591
Operating	**2,031**	1,874
Depreciation and amortization	**983**	873
	5,355	5,338
Operating income	**1,483**	1,419
Other income (expenses), net *(Note 23)*	**53**	197
Finance charges *(Note 24)*	**678**	553
Earnings before income taxes	**858**	1,063
Income tax expense *(Note 25)*	**145**	223
Net earnings	**$ 713**	$ 840
Net earnings attributable to:		
Non-controlling interests	**$ 53**	$ 35
Preference equity shareholders	**75**	77
Common equity shareholders	**585**	728
	$ 713	$ 840
Earnings per common share *(Note 18)*		
Basic	**$ 1.89**	$ 2.61
Diluted	**$ 1.89**	$ 2.59

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	2016	2015
Net earnings	**$ 713**	$ 840
Other comprehensive (loss) income *(Note 20)*		
Unrealized foreign currency translation (losses) gains, net of hedging activities and tax	**(50)**	660
Reclassification to earnings of foreign currency translation loss on disposal of investment in foreign operations, net of tax	**–**	2
Net change in available-for-sale investment, net of tax	**2**	(2)
Net change in fair value of cash flow hedges, net of tax	**3**	1
Net change in employee future benefits, net of tax	**(1)**	1
	(46)	662
Comprehensive income	**$ 667**	$ 1,502
Comprehensive income attributable to:		
Non-controlling interests	**$ 53**	$ 35
Preference equity shareholders	**75**	77
Common equity shareholders	**539**	1,390
	$ 667	$ 1,502

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2016**	2015
Operating activities		
Net earnings	**$ 713**	$ 840
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation – capital assets	**873**	785
Amortization – intangible assets	**79**	64
Amortization – other	**31**	24
Deferred income tax expense *(Note 25)*	**98**	164
Accrued employee future benefits	**58**	(19)
Equity component of allowance for funds used during construction *(Note 23)*	**(37)**	(23)
Gain on sale of non-utility capital assets *(Note 23)*	**–**	(131)
Gain on sale of non-regulated generation assets *(Note 23)*	**–**	(62)
Other	**64**	79
Change in long-term regulatory assets and liabilities	**(17)**	(89)
Change in non-cash operating working capital *(Note 29)*	**22**	41
	1,884	1,673
Investing activities		
Change in other assets and other liabilities	**(89)**	(36)
Capital expenditures – capital assets	**(1,912)**	(2,131)
Capital expenditures – intangible assets	**(149)**	(112)
Contributions in aid of construction	**50**	59
Purchase of assets held for sale *(Note 6)*	**–**	(32)
Proceeds on sale of assets *(Note 28)*	**50**	922
Business acquisitions, net of cash acquired *(Note 27)*	**(4,841)**	(38)
	(6,891)	(1,368)
Financing activities		
Change in short-term borrowings	**392**	148
Proceeds from long-term debt, net of issue costs *(Note 14)*	**4,136**	1,002
Repayments of long-term debt and capital lease and finance obligations	**(336)**	(602)
Net borrowings (repayments) under committed credit facilities	**93**	(622)
Advances from non-controlling interests *(Notes 21 and 27)*	**1,361**	20
Issue of common shares, net of costs and dividends reinvested *(Note 17)*	**45**	40
Redemption of preference shares *(Note 19)*	**(200)**	–
Dividends		
Common shares, net of dividends reinvested	**(316)**	(232)
Preference shares	**(72)**	(77)
Subsidiary dividends paid to non-controlling interests	**(53)**	(23)
	5,050	(346)
Effect of exchange rate changes on cash and cash equivalents	**(16)**	53
Change in cash and cash equivalents	**27**	12
Cash and cash equivalents, beginning of year	**242**	230
Cash and cash equivalents, end of year	**$ 269**	$ 242

Supplementary Information to Consolidated Statements of Cash Flows *(Note 29)*

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

FORTIS INC.

For the years ended December 31, 2016 and 2015 (in millions of Canadian dollars)	Common Shares	Preference Shares	Additional Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-Controlling Interests	Total Equity
	(Note 17)	*(Note 19)*		*(Note 20)*		*(Note 21)*	
As at January 1, 2016	**$ 5,867**	**$ 1,820**	**$ 14**	**$ 791**	**$ 1,388**	**$ 473**	**$ 10,353**
Net earnings	**–**	**–**	**–**	**–**	**660**	**53**	**713**
Other comprehensive loss	**–**	**–**	**–**	**(46)**	**–**	**–**	**(46)**
Common share issues	**4,895**	**–**	**(4)**	**–**	**–**	**–**	**4,891**
Stock-based compensation	**–**	**–**	**2**	**–**	**–**	**–**	**2**
Advances from non-controlling interests	**–**	**–**	**–**	**–**	**–**	**1,361**	**1,361**
Foreign currency translation impacts	**–**	**–**	**–**	**–**	**–**	**19**	**19**
Subsidiary dividends paid to non-controlling interests	**–**	**–**	**–**	**–**	**–**	**(53)**	**(53)**
Redemption of preference shares	**–**	**(197)**	**–**	**–**	**–**	**–**	**(197)**
Dividends declared on common shares ($1.55 per share)	**–**	**–**	**–**	**–**	**(534)**	**–**	**(534)**
Dividends declared on preference shares	**–**	**–**	**–**	**–**	**(75)**	**–**	**(75)**
Adoption of new accounting policy *(Note 3)*	**–**	**–**	**–**	**–**	**16**	**–**	**16**
As at December 31, 2016	**$ 10,762**	**$ 1,623**	**$ 12**	**$ 745**	**$ 1,455**	**$ 1,853**	**$ 16,450**
As at January 1, 2015	$ 5,667	$ 1,820	$ 15	$ 129	$ 1,060	$ 421	$ 9,112
Net earnings	–	–	–	–	805	35	840
Other comprehensive income	–	–	–	662	–	–	662
Common share issues	200	–	(4)	–	–	–	196
Stock-based compensation	–	–	3	–	–	–	3
Advances from non-controlling interests	–	–	–	–	–	20	20
Foreign currency translation impacts	–	–	–	–	–	20	20
Subsidiary dividends paid to non-controlling interests	–	–	–	–	–	(23)	(23)
Dividends declared on common shares ($1.43 per share)	–	–	–	–	(400)	–	(400)
Dividends declared on preference shares	–	–	–	–	(77)	–	(77)
As at December 31, 2015	$ 5,867	$ 1,820	$ 14	$ 791	$ 1,388	$ 473	$ 10,353

See accompanying Notes to Consolidated Financial Statements

For the years ended December 31, 2016 and 2015

1. DESCRIPTION OF BUSINESS

Fortis Inc. ("Fortis" or the "Corporation") is principally an international electric and gas utility holding company. Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated energy infrastructure, which is treated as a separate segment. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each entity within the reporting segments operates with substantial autonomy, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following summary describes the operations included in each of the Corporation's reportable segments.

Regulated Utilities

Electric & Gas Utilities – United States

a. *ITC:* Primarily comprised of ITC Holdings Corp. ("ITC Holdings") and the electric transmission operations of its regulated operating subsidiaries, which include International Transmission Company ("ITCTransmission"), Michigan Electric Transmission Company, LLC ("METC"), ITC Midwest LLC ("ITC Midwest"), and ITC Great Plains, LLC ("ITC Great Plains"), (collectively "ITC"). ITC was acquired by Fortis in October 2016, with Fortis owning 80.1% of ITC and an affiliate of GIC Private Limited ("GIC") owning a 19.9% minority interest (Notes 21 and 27).

   ITC owns and operates high-voltage transmission lines serving a system peak load exceeding 26,000 megawatts ("MW") along approximately 25,000 kilometres in Michigan's lower peninsula and portions of Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma that transmit electricity from approximately 570 generating stations to local distribution facilities connected to ITC's systems.

b. *UNS Energy:* Primarily comprised of Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas"), (collectively "UNS Energy").

   TEP, UNS Energy's largest operating subsidiary, is a vertically integrated regulated electric utility. TEP generates, transmits and distributes electricity to retail customers in southeastern Arizona, including the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP also sells wholesale electricity to other entities in the western United States. UNS Electric is a vertically integrated regulated electric utility, which generates, transmits and distributes electricity to retail customers in Arizona's Mohave and Santa Cruz counties. TEP and UNS Electric currently own generation resources with an aggregate capacity of 2,994 MW, including 54 MW of solar capacity. Several of the generating assets in which TEP and UNS Electric have an interest are jointly owned. As at December 31, 2016, approximately 47% of the generating capacity was fuelled by coal.

   UNS Gas is a regulated gas distribution utility, serving retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties.

c. *Central Hudson:* Central Hudson Gas & Electric Corporation ("Central Hudson") is a regulated transmission and distribution ("T&D") utility, serving eight counties of New York State's Mid-Hudson River Valley. The Company owns gas-fired and hydroelectric generating capacity totalling 64 MW.

Gas & Electric Utilities – Canadian

a. *FortisBC Energy:* FortisBC Energy Inc. ("FortisBC Energy" or "FEI") is the largest distributor of natural gas in British Columbia, serving more than 135 communities. Major areas served by the Company are the Mainland, Vancouver Island and Whistler regions of British Columbia. FEI provides T&D services to customers, and obtains natural gas supplies on behalf of most residential, commercial and industrial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through FEI's Southern Crossing pipeline, from Alberta.

b. *FortisAlberta:* FortisAlberta Inc. ("FortisAlberta") owns and operates the electricity distribution system in a substantial portion of southern and central Alberta. The Company does not own or operate generation or transmission assets and is not involved in the direct sale of electricity.

c. *FortisBC Electric:* Includes FortisBC Inc. ("FortisBC Electric"), an integrated electric utility operating in the southern interior of British Columbia. FortisBC Electric owns four hydroelectric generating facilities with a combined capacity of 225 MW. Also included in the FortisBC Electric segment are the operating, maintenance and management services relating to five hydroelectric generating facilities in British Columbia primarily owned by third parties, one of which is the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion"), owned by Fortis and Columbia Power Corporation and Columbia Basin Trust ("CPC/CBT").

1. *DESCRIPTION OF BUSINESS (cont'd)*

Gas & Electric Utilities – Canadian (cont'd)

d. *Eastern Canadian:* Comprised of Newfoundland Power Inc. ("Newfoundland Power"), Maritime Electric Company, Limited ("Maritime Electric") and FortisOntario Inc. ("FortisOntario"). Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador. Newfoundland Power has an installed generating capacity of 139 MW, of which 97 MW is hydroelectric generation. Maritime Electric is an integrated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI"). Maritime Electric also maintains on-Island generating facilities with a combined capacity of 145 MW. FortisOntario is comprised of three electric utilities that provide service to customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario.

Electric Utilities – Caribbean

The Electric Utilities – Caribbean segment includes the Corporation's approximate 60% controlling ownership interest in Caribbean Utilities Company, Ltd. ("Caribbean Utilities") (December 31, 2015 – 60%), Fortis Turks and Caicos, and the Corporation's 33% equity investment in Belize Electricity Limited ("Belize Electricity") (Note 9). Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands. The Company has an installed diesel-powered generating capacity of 161 MW. Caribbean Utilities is a public company traded on the Toronto Stock Exchange ("TSX") (TSX:CUP.U). Fortis Turks and Caicos is comprised of two integrated electric utilities that provide electricity to certain islands in Turks and Caicos. The utilities have a combined diesel-powered generating capacity of 82 MW. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize.

Non-Regulated – Energy Infrastructure

Non-Regulated – Energy Infrastructure is primarily comprised of long-term contracted generation assets in British Columbia and Belize, and the Aitken Creek natural gas storage facility ("Aitken Creek"). Generating assets in British Columbia include the Corporation's 51% controlling ownership interest in the 335-MW Waneta Expansion, conducted through the Waneta Expansion Limited Partnership ("Waneta Partnership"), with CPC/CBT holding the remaining 49% interest. The output is sold to BC Hydro and FortisBC Electric under 40-year contracts. Generating assets in Belize are comprised of three hydroelectric generating facilities with a combined capacity of 51 MW, conducted through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL"). The output is sold to Belize Electricity under 50-year power purchase agreements ("PPAs"). Aitken Creek Gas Storage ULC ("ACGS"), acquired by Fortis in April 2016, owns 93.8% of Aitken Creek, with the remaining share owned by BP Canada Energy Company (Note 27). Aitken Creek is the only underground natural gas storage facility in British Columbia and has a total working gas capacity of 77 billion cubic feet.

In 2016 the Corporation sold its 16-MW run-of-river Walden hydroelectric generating facility ("Walden") and in 2015 the Corporation sold its non-regulated generation assets in Upstate New York and Ontario (Note 28).

Non-Regulated – Non-Utility

The Non-Utility segment previously included Fortis Properties Corporation ("Fortis Properties"). Fortis Properties completed the sale of its commercial real estate and hotel assets in 2015 (Note 28).

Corporate and Other

The Corporate and Other segment captures expense and revenue items not specifically related to any reportable segment and those business operations that are below the required threshold for reporting as separate segments. The Corporate and Other segment includes net corporate expenses of Fortis and non-regulated holding company expenses of FortisBC Holdings Inc. ("FHI"), CH Energy Group, Inc. ("CH Energy Group"), and UNS Energy Corporation. Also included in the Corporate and Other segment are the financial results of FortisBC Alternative Energy Services Inc. ("FAES"). FAES is a wholly owned subsidiary of FHI that provides alternative energy solutions, including thermal-energy and geo-exchange systems.

2. NATURE OF REGULATION

The earnings of the Corporation's utilities are primarily determined under cost of service ("COS") regulation and, in certain jurisdictions, performance-based rate-setting ("PBR") mechanisms. Generally, under COS regulation the respective regulatory authority sets customer electricity and/or gas rates to permit a reasonable opportunity for the utility to recover, on a timely basis, estimated costs of providing service to customers, including a fair rate of return on a regulatory deemed or targeted capital structure applied to an approved regulatory asset value ("rate base"). The ability of a regulated utility to recover prudently incurred costs of providing service and earn the regulator-approved rate of return on common shareholders' equity ("ROE") and/or rate of return on rate base assets ("ROA") may depend on the utility achieving the forecasts established in the rate-setting processes. If a historical test year is used to set customer rates, there may be regulatory lag between when costs are incurred and when they are reflected in customer rates. When PBR mechanisms are utilized in determining annual revenue requirements and resulting customer rates, a formula is generally applied that incorporates inflation and assumed productivity improvements. The use of PBR mechanisms should allow a utility a reasonable opportunity to recover prudently incurred costs and earn its allowed ROE or ROA.

The Corporation's regulated utilities, where applicable, are permitted by their respective regulatory authority to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms (Note 8).

The nature of regulation at the Corporation's utilities is as follows.

ITC

ITC is regulated by the U.S. Federal Energy Regulatory Commission ("FERC") under the *Federal Power Act* (United States) and operates under COS regulation. Rates are set annually, using FERC-approved cost-based formula rate templates, and remain in effect for one year, which provides timely cost recovery and reduces regulatory lag. The formula rates include an annual true-up mechanism, and any over- or under-collections are accrued and reflected in future rates within a two-year period. The formula rates do not require annual FERC approvals, although inputs remain subject to legal challenge with FERC. The common equity component of capital structure for ITC was 60% for 2015 and 2016.

Since 2013 two third-party complaints were filed with FERC requesting that FERC find the Midcontinent Independent System Operator ("MISO") regional base ROE for all MISO transmission owners, including ITCTransmission, METC and ITC Midwest, for the periods November 2013 through February 2015 (the "Initial Refund Period") and February 2015 through May 2016 (the "Second Refund Period") to no longer be just or reasonable. In September 2016 FERC issued an order affirming the presiding Administrative Law Judge's ("ALJ's") initial decision for the Initial Refund Period and setting the base ROE for the Initial Refund Period at 10.32%, with a maximum ROE of 11.35%. Additionally, the rates established in the September 2016 order will be used prospectively from the date of the order until a new approved rate is established for the Second Refund Period. In June 2016 the presiding ALJ issued an initial decision for the Second Refund Period, which recommended a base ROE of 9.70%, with a maximum ROE of 10.68%, which is a recommendation to FERC. A decision from FERC for the Second Refund Period is expected in 2017. The base ROE for the three effected utilities for the period of May 2016 through September 2016 was 12.38% and any authorized adders that were approved prior to the filing of the complaints were collected during this time, up to a maximum of 13.88%. As at December 31, 2016, the estimated range of refunds for both periods was between US$221 million and US$258 million and ITC has recognized an aggregate estimated regulatory liability of US$258 million (Note 8 *(xii)*). In February 2017 ITC provided refunds totalling US$119 million, including interest, for the initial complaint. The estimated regulatory liability was accrued by ITC before its acquisition by Fortis. It is possible that the outcome of these matters could differ materially from the estimated range of refunds.

UNS Energy

UNS Energy is regulated by the Arizona Corporation Commission ("ACC") and certain activities are subject to regulation by FERC under the *Federal Power Act* (United States). UNS Energy operates under COS regulation as administered by the ACC, which provides for the use of a historical test year in the establishment of retail electric and gas rates. Retail electric and gas rates are set to provide the utilities with an opportunity to recover their COS and earn a reasonable rate of return on rate base, including an adjustment for the fair value of rate base as required under the laws of the State of Arizona.

TEP's allowed ROE is set at 10.0% on a capital structure of 43.5% common equity, effective from July 1, 2013. In February 2017 the ACC approved an allowed ROE of 9.75% on a capital structure of 50%, effective on or before March 1, 2017. UNS Electric's allowed ROE is set at 9.50% on a capital structure of 52.8% common equity, effective from August 1, 2016, prior to which its allowed ROE was set at 9.50% on a capital structure of 52.6%, effective from January 1, 2014. UNS Gas' allowed ROE is set at 9.75% on a capital structure of 50.8% common equity, effective from May 1, 2012.

2. NATURE OF REGULATION (cont'd)

Central Hudson

Central Hudson is regulated by the New York State Public Service Commission ("PSC") and certain activities are subject to regulation by FERC under the *Federal Power Act* (United States). Central Hudson operates under COS regulation as administered by the PSC with the use of a future test year in the establishment of rates.

Central Hudson's allowed ROE is set at 9.0% on a capital structure of 48% common equity, effective July 1, 2015 for a three-year term. Prior to July 1, 2015, Central Hudson was operating under a three-year rate order issued by the PSC effective July 1, 2010 with an allowed ROE set at 10.0% on a deemed capital structure of 48% common equity, which was extended for two years, through June 30, 2015, as part of the regulatory approval of the acquisition of Central Hudson by Fortis.

Effective July 1, 2015, Central Hudson is also subject to an earnings sharing mechanism, whereby the Company and customers share equally earnings in excess of 50 basis points above the allowed ROE up to an achieved ROE that is 100 basis points above the allowed ROE. Earnings in excess of 100 basis points above the allowed ROE are shared primarily with the customer. Prior to July 1, 2015, an earnings sharing mechanism was in place whereby the Company and customers shared equally earnings in excess of the allowed ROE up to an achieved ROE that is 50 basis points above the allowed ROE, and shared 10%/90% (Company/customers) earnings in excess of 50 basis points above the allowed ROE.

FortisBC Energy and FortisBC Electric

FortisBC Energy and FortisBC Electric are regulated by the British Columbia Utilities Commission ("BCUC") pursuant to the *Utilities Commission Act* (British Columbia). The Companies primarily operate under COS regulation and, from time to time, PBR mechanisms for establishing customer rates.

FEI is the benchmark utility in British Columbia, as designated by the BCUC, and the established allowed ROE for the benchmark utility was 8.75% on a 38.5% common equity component of capital structure, both effective January 1, 2013 through December 31, 2015. In August 2016 the BCUC issued its decision on the Generic Cost of Capital ("GCOC") Proceeding which established that the ROE and common equity component of capital structure for the benchmark utility would remain unchanged at 8.75% and 38.5%, respectively, effective January 1, 2016. FortisBC Electric's allowed ROE of 9.15% on a 40% common equity component of capital structure, effective since January 1, 2013, also remained unchanged, effective January 1, 2016.

FEI and FortisBC Electric are subject to Multi-Year PBR Plans for 2014 through 2019. The PBR Plans, as approved by the BCUC, incorporate incentive mechanisms for improving operating and capital expenditure efficiencies. Operation and maintenance expenses and base capital expenditures during the PBR period are subject to an incentive formula reflecting incremental costs for inflation and half of customer growth, less a fixed productivity adjustment factor of 1.1% for FEI and 1.03% for FortisBC Electric each year. The approved PBR Plans also include a 50%/50% sharing of variances from the formula-driven operation and maintenance expenses and capital expenditures over the PBR period, and a number of service quality measures designed to ensure FEI and FortisBC Electric maintain specified service levels. It also sets out the requirements for an annual review process which provides a forum for discussion between the utilities and interested parties regarding current performance and future activities.

FortisAlberta

FortisAlberta is regulated by the Alberta Utilities Commission ("AUC") pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Act* (Alberta), the *Hydro and Electric Energy Act* (Alberta) and the *Alberta Utilities Commission Act* (Alberta). FortisAlberta is subject to a Multi-Year PBR plan for 2013 through 2017. Under PBR, each year the prescribed formula is applied to the preceding year's distribution rates, with 2012 used as the going-in distribution rates.

The PBR plan includes mechanisms for the recovery or settlement of items determined to flow through directly to customers ("Y factor") and the recovery of costs related to capital expenditures that are not being recovered through the formula ("K factor" or "capital tracker"). The AUC also approved a Z factor, a PBR re-opener and an ROE efficiency carry-over mechanism. The Z factor permits an application for recovery of costs related to significant unforeseen events. The PBR re-opener permits an application to re-open and review the PBR plan to address specific problems with the design or operation of the PBR plan. The use of the Z factor and PBR re-opener mechanisms is associated with certain thresholds. The ROE efficiency carry-over mechanism provides an efficiency incentive by permitting the Company to continue to benefit from any efficiency gains achieved during the PBR term for two years following the end of that term.

For 2013 through 2015, FortisAlberta's allowed ROE was set at 8.30% with a common equity component of capital structure at 40%. In October 2016 the AUC issued its decision related to FortisAlberta's 2016 and 2017 GCOC Proceeding, establishing that FortisAlberta's allowed ROE remain unchanged at 8.30%, for 2016 and increase to 8.50% for 2017. The decision also set the common equity component of capital structure at 37%, effective January 1, 2016, down from 40% approved on an interim basis. Changes in FortisAlberta's allowed ROE and common equity component of capital structure impact only the portion of rate base that is funded by capital tracker revenue.

Eastern Canadian Electric Utilities

Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") under the *Public Utilities Act* (Newfoundland and Labrador). Newfoundland Power operates under COS regulation with the use of a future test year in the establishment of rates. In June 2016 the PUB set the allowed ROE at 8.50%, effective January 1, 2016, down from 8.80% in effect since January 1, 2013. The decision also established that Newfoundland Power's common equity component of capital structure of 45%, effective January 1, 2013, remain unchanged. The June 2016 rate order will remain in effect for 2016 through 2018.

Maritime Electric is regulated by the Island Regulatory and Appeals Commission ("IRAC") under the provisions of the *Electric Power Act* (PEI), the *Renewable Energy Act* (PEI), the *Electric Power (Electricity Rate-Reduction) Amendment Act* (PEI), and the former *Electric Power (Energy Accord Continuation) Amendment Act* (PEI) ("Accord Continuation Act"), which expired in February 2016. Maritime Electric operates under COS regulation with the use of a future test year for the establishment of rates. In March 2016 IRAC set the Company's allowed ROE at 9.35%, effective March 1, 2016 for a three-year period, down from 9.75% in effect since March 1, 2013, and established that Maritime Electric's targeted minimum capital structure of 40% remain unchanged.

FortisOntario's three electric utilities operate under the *Electricity Act* (Ontario) and the *Ontario Energy Board Act* (Ontario), as administered by the Ontario Energy Board ("OEB"). FortisOntario's utilities operate under COS regulation with the use of a future test year in the establishment of rates. Earnings are regulated on the basis of rate of return on rate base, plus a recovery of allowable distribution costs. In non-rebasing years, customer electricity distribution rates are set using inflationary factors less an efficiency target as prescribed by the OEB. The allowed ROE for distribution assets for FortisOntario's utilities ranged from 8.93% to 9.30% for 2015 and 2016, both on a deemed capital structure of 40% common equity, with the exception of one of its utilities which is subject to a rate-setting mechanism under a 35-year Franchise Agreement expiring in 2033, based on a price cap with commodity cost flow through. The base revenue requirement is adjusted annually for inflation, load growth and customer growth.

Regulated Electric Utilities – Caribbean

Caribbean Utilities operates under T&D and generation licences from the Government of the Cayman Islands. The exclusive T&D licence is for an initial period of 20 years, expiring April 2028, with a provision for automatic renewal. A non-exclusive generation licence was issued for a term of 25 years, expiring November 2039. The licences detail the role of the Electricity Regulatory Authority, which oversees all licences, establishes and enforces licence standards, reviews the rate-cap adjustment mechanism ("RCAM"), and annually approves capital expenditures. The licences contain the provision for an RCAM based on published consumer price indices. Caribbean Utilities' targeted allowed ROA for 2016 was in the range of 6.75% to 8.75%, compared to a range of 7.25% to 9.25% for 2015.

Fortis Turks and Caicos operates under two 50-year licences expiring in 2036 and 2037. Among other matters, the licences describe how electricity rates are set by the Government of the Turks and Caicos Islands, using a historical test year, in order to provide the utilities with an allowed ROA of between 15.0% and 17.5% (the "Allowable Operating Profit"). The Allowable Operating Profit is based on a calculated rate base, including interest on the amounts by which actual operating profits fall short of the Allowable Operating Profits on a cumulative basis (the "Cumulative Shortfall"). Annual submissions are made to the Government of the Turks and Caicos Islands calculating the amount of the Allowable Operating Profit and the Cumulative Shortfall. The submissions for 2016 calculated the Allowable Operating Profit to be $58 million (US$44 million) and the Cumulative Shortfall as at December 31, 2016 to be $317 million (US$236 million). The recovery of the Cumulative Shortfall is, however, dependent on future sales volumes and expenses. The achieved ROAs at the utilities have been significantly lower than those allowed under the licences as a result of the inability, due to economic and political factors, to increase base electricity rates associated with significant capital investment in recent years.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States ("US GAAP"), which for regulated utilities include specific accounting guidance for regulated operations, as outlined in Note 2, and the following summary of significant accounting policies.

All amounts presented are in Canadian dollars unless otherwise stated.

Basis of Presentation

The consolidated financial statements reflect the Corporation's investments in its subsidiaries and variable interest entity, where Fortis is the primary beneficiary, on a consolidated basis, with the equity method used for entities in which Fortis has significant influence, but not control, and proportionate consolidation for generation and transmission assets that are jointly owned with non-affiliated entities. All material intercompany transactions have been eliminated in the consolidated financial statements, except for transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. For further details on the Corporation's variable interest entity refer to Note 31.

An evaluation of subsequent events through to February 15, 2017, the date these consolidated financial statements were approved by the Board of Directors of Fortis ("Board of Directors"), was completed to determine whether the circumstances warranted recognition and disclosure of events or transactions in the consolidated financial statements as at December 31, 2016.

For the years ended December 31, 2016 and 2015

3. *SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)*

Cash and Cash Equivalents

Cash and cash equivalents include cash, cash held in margin accounts and short-term deposits with initial maturities of three months or less from the date of deposit.

Allowance for Doubtful Accounts

Fortis and each of its subsidiaries, with the exception of ITC, maintain an allowance for doubtful accounts that is estimated based on a variety of factors including accounts receivable aging, historical experience and other currently available information, including events such as customer bankruptcy and economic conditions. ITC recognizes losses for uncollectible accounts based upon specific identification of such items. Accounts receivable are written-off in the period in which the receivable is deemed uncollectible.

Inventories

Inventories, consisting of materials and supplies, gas, fuel and coal in storage, are measured at the lower of weighted average cost and market value.

Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate-setting process at the Corporation's utilities. Regulatory assets represent future revenues and/or receivables associated with certain costs incurred that will be, or are expected to be, recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that will be, or are expected to be, refunded to customers through the rate-setting process.

All amounts deferred as regulatory assets and liabilities are subject to regulatory approval. As such, the regulatory authorities could alter the amounts subject to deferral, at which time the change would be reflected in the consolidated financial statements. Certain remaining recovery and settlement periods are those expected by management and the actual recovery or settlement periods could differ based on regulatory approval.

Investments

Portfolio investments are accounted for on the cost basis. Declines in value considered to be other than temporary are recorded in the period in which such determinations are made. Investments in which the Corporation exercises significant influence are accounted for on the equity basis. The Corporation reviews its investments on an annual basis for potential impairment in investment value. Should an impairment be identified, it will be recognized in the period in which such impairment is identified.

Available-for-Sale Assets

The Corporation's assets designated as available-for-sale are measured at fair value based on quoted market prices. Unrealized gains or losses resulting from changes in fair value are recognized in accumulated other comprehensive income and are reclassified to earnings when the assets are sold.

Utility Capital Assets

Utility capital assets are recorded at cost less accumulated depreciation. Contributions in aid of construction represent amounts contributed by customers and governments for the cost of utility capital assets. These contributions are recorded as a reduction in the cost of utility capital assets and are being amortized annually by an amount equal to the charge for depreciation provided on the related assets.

The majority of the Corporation's regulated utilities accrue non-asset retirement obligation ("ARO") removal costs in depreciation, with the amount provided for in depreciation recorded as a long-term regulatory liability (Note 8 *(xi)*). Actual non-ARO removal costs are recorded against the regulatory liability when incurred.

For the majority of the Corporation's regulated utilities, utility capital assets are derecognized on disposal or when no future economic benefits are expected from their use. Upon retirement or disposal of utility capital assets, any difference between the cost and accumulated depreciation of the asset, net of salvage proceeds, is charged to accumulated depreciation, with no gain or loss recognized in earnings. It is expected that any gains or losses charged to accumulated depreciation will be reflected in future depreciation expense when they are refunded or collected in customer rates.

The majority of the Corporation's regulated utilities capitalize overhead costs that are not directly attributable to specific utility capital assets but relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized overhead costs to utility capital assets is established by the respective regulator.

The majority of the Corporation's regulated utilities include in the cost of utility capital assets both a debt and an equity component of the allowance for funds used during construction ("AFUDC"). The debt component of AFUDC is reported as a reduction of finance charges (Note 24) and the equity component of AFUDC is reported as other income (Note 23). Both components of AFUDC are charged to earnings through depreciation expense over the estimated service lives of the applicable utility capital assets. AFUDC is calculated in a manner as prescribed by the respective regulator.

At FortisAlberta the cost of utility capital assets also includes Alberta Electric System Operator ("AESO") contributions, which are investments required by FortisAlberta to partially fund the construction of transmission facilities.

Utility capital assets include inventories held for the development, construction and betterment of other utility capital assets. As required by its regulator, UNS Energy recognizes inventories held for the development and construction of other utility capital assets in inventories until consumed. When put into service, the inventories are reclassified to utility capital assets.

Maintenance and repairs of utility capital assets are charged to earnings in the period incurred, while replacements and betterments which extend the useful lives are capitalized.

The majority of the Corporation's utility capital assets are depreciated using the straight-line method based on the estimated service lives of the utility capital assets. Depreciation rates for regulated utility capital assets are approved by the respective regulator. Depreciation rates for 2016 ranged from 0.9% to 34.6% (2015 – 1.3% to 43.2%). The weighted average composite rate of depreciation, before reduction for amortization of contributions in aid of construction, for 2016 was 2.8% (2015 – 3.1%).

The service life ranges and weighted average remaining service life of the Corporation's distribution, transmission, generation and other assets as at December 31 were as follows.

	2016		2015	
(Years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Distribution				
Electric	**5–80**	**32**	5–80	30
Gas	**7–95**	**33**	4–95	33
Transmission				
Electric	**20–80**	**41**	20–80	29
Gas	**7–80**	**34**	7–80	36
Generation	**5–85**	**26**	5–85	27
Other	**3–70**	**14**	3–70	8

Leases

Leases that transfer to the Corporation substantially all of the risks and benefits incidental to ownership of the leased item are capitalized at the present value of the minimum lease payments. Included as capital leases are any arrangements that qualify as leases by conveying the right to use a specific asset.

Capital leases are depreciated over the lease term, except where ownership of the asset is transferred at the end of the lease term, in which case capital leases are depreciated over the estimated service life of the underlying asset. Where the regulator has approved recovery of the arrangements as operating leases for rate-setting purposes that would otherwise qualify as capital leases for financial reporting purposes, the timing of the expense recognition related to the lease is modified to conform with the rate-setting process.

Operating lease payments are recognized as an expense in earnings on a straight-line basis over the lease term.

Intangible Assets

Intangible assets are recorded at cost less accumulated amortization. The useful lives of intangible assets are assessed to be either indefinite or finite. Intangible assets with indefinite useful lives are tested for impairment annually, either individually or at the reporting unit level. Such intangible assets are not amortized. An intangible asset with an indefinite useful life is reviewed annually to determine whether the indefinite life assessment continues to be supportable. If not, the change in the useful life assessment from indefinite to finite is made on a prospective basis.

Intangible assets with finite lives are amortized using the straight-line method based on the estimated service lives of the assets. Amortization rates for regulated intangible assets are approved by the respective regulator. Amortization rates for 2016 ranged from 1.0% to 50.0% (2015 – 1.0% to 50.0%).

For the years ended December 31, 2016 and 2015

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Intangible Assets (cont'd)

The service life ranges and weighted average remaining service life of finite-life intangible assets as at December 31 were as follows.

	2016		2015	
(Years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	**3–10**	**4**	3–10	4
Land, transmission and water rights	**30–80**	**57**	30–80	37
Other	**10–104**	**15**	10–104	15

For the majority of the Corporation's regulated utilities, intangible assets are derecognized on disposal or when no future economic benefits are expected from their use. Upon retirement or disposal of intangible assets, any difference between the cost and accumulated amortization of the asset, net of salvage proceeds, is charged to accumulated amortization, with no gain or loss recognized in earnings. It is expected that any gains or losses charged to accumulated amortization will be reflected in future amortization costs when they are refunded or collected in customer rates.

The majority of indefinite-lived intangible assets are held in the Corporation's regulated utilities that also have goodwill. For its annual testing of impairment for indefinite-lived intangible assets, Fortis includes these assets as part of the respective reporting units, which are tested on an annual basis for goodwill impairment, as disclosed in this Note under "Goodwill".

Impairment of Long-Lived Assets

The Corporation reviews the valuation of utility capital assets, intangible assets with finite lives and other long-term assets when events or changes in circumstances indicate that the assets' carrying value may not be recoverable. If the carrying amount of the asset exceeds the expected total undiscounted cash flows generated by the asset, the asset is written down to estimated fair value and an impairment loss is recognized in earnings in the period in which it is identified.

Asset-impairment testing is carried out at the reporting unit level to determine if assets are impaired. The net cash flows for reporting units are not asset-specific but are pooled for the entire reporting unit. The recovery of regulated assets' carrying value, including a fair rate of return, is provided through customer rates approved by the respective regulatory authority.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of the identifiable net assets acquired relating to business acquisitions. The Corporation performs an annual impairment test for goodwill as at October 1, or more frequently if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. No such event or change in circumstances occurred during 2016 or 2015.

Fortis performs an annual internal qualitative and quantitative assessment for each reporting unit to which goodwill has been allocated. The Corporation has a total of 12 reporting units that were allocated goodwill at the respective dates of acquisition by Fortis. For those reporting units where: (i) management's assessment of qualitative and quantitative factors indicates that fair value is not 50% or more likely to be greater than carrying value; or (ii) the excess of estimated fair value over carrying value, as determined by an external consultant as of the date of the immediately preceding impairment test, was not significant, then fair value of the reporting unit will be estimated by an external consultant in the current year. Irrespective of the above-noted approach, a reporting unit to which goodwill has been allocated may have its fair value estimated by an external consultant as at the annual impairment date, as Fortis will, at a minimum, have fair value for each material reporting unit estimated by an external consultant once every five years.

In calculating goodwill impairment, the estimated fair value of the reporting unit is compared to its carrying value. If the fair value of the reporting unit is less than the carrying value, a second measurement step is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill, and then comparing that amount to the carrying value of the reporting unit's goodwill. Any excess of the carrying value of the goodwill over the implied fair value is the impairment amount recognized.

The primary method for estimating fair value of the reporting units is the income approach, whereby net cash flow projections for the reporting units are discounted using an enterprise value method. The income approach uses several underlying estimates and assumptions with varying degrees of uncertainty, including the amount and timing of expected future cash flows, growth rates, and the determination of appropriate discount rates. A secondary valuation method, the market approach, as well as a reconciliation of the total estimated fair value of all reporting units to the Corporation's market capitalization, is also performed as an assessment of the conclusions reached under the income approach.

As a result of the Corporation's annual assessment for impairment of goodwill, the fair value of all of the reporting units exceeded their respective carrying value and, therefore, no impairment provision was required in 2016 or 2015.

Deferred Financing Costs

Any costs, debt discounts and premiums related to the issuance of long-term debt are recognized against long-term debt and are amortized over the life of the related long-term debt.

Employee Future Benefits

Defined Benefit and Defined Contribution Pension Plans

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, including retirement allowances and supplemental retirement plans for certain executive employees, and defined contribution pension plans, including group Registered Retirement Savings Plans and group 401(k) plans for employees. The projected benefit obligation and the value of pension cost associated with the defined benefit pension plans are actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan investment performance, salary escalation and expected retirement ages of employees. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments.

With the exception of FortisBC Energy and Newfoundland Power, pension plan assets are valued at fair value for the purpose of determining pension cost. At FortisBC Energy and Newfoundland Power, pension plan assets are valued using the market-related value for the purpose of determining pension cost, where investment returns in excess of, or below, expected returns are recognized in the asset value over a period of three years.

The excess of any cumulative net actuarial gain or loss over 10% of the greater of the projected benefit obligation and the fair value of plan assets (the market-related value of plan assets at FortisBC Energy and Newfoundland Power) at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

The net funded or unfunded status of defined benefit pension plans, measured as the difference between the fair value of the plan assets and the projected benefit obligation, is recognized on the Corporation's consolidated balance sheet.

For the majority of the Corporation's regulated utilities, any difference between pension cost recognized under US GAAP and that recovered from customers in current rates for defined benefit pension plans, which is expected to be recovered from, or refunded to, customers in future rates, is subject to deferral account treatment (Note 8 *(ii)*).

With the exception of Fortis and FHI, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with defined benefit pension plans, which would otherwise be recognized in accumulated other comprehensive income, are subject to deferral account treatment (Note 8 *(ii)*). At Fortis and FHI, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with defined benefit pension plans are recognized in accumulated other comprehensive income.

The costs of the defined contribution pension plans are expensed as incurred.

Other Post-Employment Benefits Plans

The Corporation and its subsidiaries also offer other post-employment benefits ("OPEB") plans, including certain health and dental coverage and life insurance benefits, for qualifying members. The accumulated benefit obligation and the cost associated with OPEB plans are actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan performance, salary escalation, expected retirement ages of employees and health care costs. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected OPEB payments.

The excess of any cumulative net actuarial gain or loss over 10% of the accumulated benefit obligation and the fair value of plan assets at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

The net funded or unfunded status of OPEB plans, measured as the difference between the fair value of the plan assets and the accumulated benefit obligation, is recognized on the Corporation's consolidated balance sheet.

For the majority of the Corporation's regulated utilities, any difference between the cost of OPEB plans recognized under US GAAP and that recovered from customers in current rates, which is expected to be recovered from, or refunded to, customers in future rates, is subject to deferral account treatment (Note 8 *(ii)*).

At FortisAlberta, the difference between the cost of OPEB plans recognized under US GAAP and that recovered from customers in current rates does not meet the criteria for deferral account treatment and, therefore, FortisAlberta recognizes in earnings the cost associated with its OPEB plan as actuarially determined, rather than as approved by the regulator. Unamortized OPEB plan balances at FortisAlberta related to net actuarial gains and losses and past service costs are recognized in accumulated other comprehensive income.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Stock-Based Compensation

The Corporation records compensation expense related to stock options granted under its 2002 Stock Option Plan ("2002 Plan"), 2006 Stock Option Plan ("2006 Plan") and 2012 Stock Option Plan ("2012 Plan") (Note 22). Compensation expense is measured at the date of grant using the Black-Scholes fair value option-pricing model and each grant is amortized as a single award evenly over the four-year vesting period of the options granted. The offsetting entry is an increase to additional paid-in capital for an amount equal to the annual compensation expense related to the issuance of stock options. The stock options become exercisable once time vesting requirements have been met. Upon exercise, the proceeds of the options are credited to capital stock at the option prices and the fair value of the options, as previously recognized, is reclassified from additional paid-in capital to capital stock. An exercise of options below the current market price of the Corporation's common shares has a dilutive effect on the Corporation's consolidated capital stock and shareholders' equity. Fortis satisfies stock option exercises by issuing common shares from treasury.

The Corporation also records liabilities associated with its Directors' Deferred Share Unit ("DSU"), Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") Plans, all representing cash settled awards, at fair value at each reporting date until settlement. Compensation expense is recognized on a straight-line basis over the vesting period, which, for the PSU and RSU Plans, is over the shorter of three years or the period to retirement eligibility. The fair value of the DSU, PSU and RSU liabilities is based on the five-day volume weighted average price ("VWAP") of the Corporation's common shares at the end of each reporting period. The VWAP of the Corporation's common shares as at December 31, 2016 was $41.46 (December 31, 2015 – $37.72). The fair value of the PSU liability is also based on the expected payout probability, based on historical performance in accordance with the defined metrics of each grant and management's best estimate.

Foreign Currency Translation

The assets and liabilities of the Corporation's foreign operations, all of which have a US dollar functional currency, are translated at the exchange rate in effect as at the balance sheet date. The exchange rate in effect as at December 31, 2016 was US$1.00=CAD$1.34 (December 31, 2015 – US$1.00=CAD$1.38). The resulting unrealized translation gains and losses are excluded from the determination of earnings and are recognized in accumulated other comprehensive income until the foreign subsidiary is sold, substantially liquidated or evaluated for impairment in anticipation of disposal. Revenue and expenses of the Corporation's foreign operations are translated at the average exchange rate in effect during the reporting period, which was US$1.00=CAD$1.33 for 2016 (2015 – US$1.00=CAD$1.28).

Foreign exchange translation gains and losses on foreign currency-denominated long-term debt that is designated as an effective hedge of foreign net investments are accumulated as a separate component of shareholders' equity within accumulated other comprehensive income and the current period change is recorded in other comprehensive income.

Monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate prevailing at the balance sheet date. Revenue and expenses denominated in foreign currencies are translated at the exchange rate prevailing at the transaction date. Gains and losses on translation are recognized in earnings.

Derivative Instruments and Hedging Activities

Non-Designated Derivatives

Derivatives not designated as hedging contracts are used by UNS Energy to meet forecast load and reserve requirements and Aitken Creek to manage exposure to commodity price risk, to capture natural gas price spreads, and to manage the financial risk posed by physical transactions. These non-designated derivatives are measured at fair value with changes in fair value recognized in earnings.

Derivatives not designated as hedging contracts are also used by UNS Energy, Central Hudson and FortisBC Energy to reduce exposure to energy price risk associated with purchased power and gas requirements. The settled amounts of these derivatives are generally included in regulated rates, as permitted by the respective regulators. These non-designated derivatives are measured at fair value and the net unrealized gains and losses associated with changes in fair value of the derivative contracts are recorded as regulatory assets or liabilities for recovery from, or refund to, customers in future rates (Note 8 *(ix)*).

Derivative instruments that meet the normal purchase or normal sale scope exception are not measured at fair value and settled amounts are recognized as energy supply costs on the consolidated statements of earnings.

Derivatives in Designated Hedging Relationships

For derivatives designated as hedging contracts, the Corporation and its utilities formally assess, at inception and thereafter, whether the hedging contract is highly effective in offsetting changes in the hedged item. The hedging strategy by transaction type and risk management strategy is formally documented. As at December 31, 2016, the Corporation's hedging relationships primarily consisted of cash flow hedges and net investment hedges.

The Corporation, ITC and UNS Energy use cash flow hedges to manage its exposure to interest rate risk. Unrealized gains or losses on these derivatives are initially recognized in accumulated other comprehensive income and reclassified to earnings when the underlying hedged transaction affects earnings. Any hedge ineffectiveness is recognized in net income immediately at the time the gain or loss on the derivatives is calculated.

The Corporation's earnings from, and net investments in, foreign subsidiaries and significant influence investments are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has decreased a portion of the above-noted exposure through the use of US dollar-denominated borrowings at the corporate level. The Corporation has designated its corporately issued US dollar long-term debt as a hedge of a portion of the foreign exchange risk related to its foreign net investments. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar-denominated borrowings designated as hedges are recognized in accumulated other comprehensive income and help offset unrealized foreign currency exchange gains and losses on the foreign net investments, which gains and losses are also recognized in accumulated other comprehensive income.

Presentation of Derivatives

The fair value of derivative instruments are recognized on the Corporation's consolidated balance sheet as current or long-term assets and liabilities depending on the timing of the settlements and the resulting cash flows associated with the instruments. Derivative contracts under master netting agreements and collateral positions are presented on a gross basis. Cash flows associated with the settlement of all derivative instruments are included in operating activities on the Corporation's consolidated statement of cash flows.

Income Taxes

The Corporation and its subsidiaries follow the asset and liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are more likely than not to be realized. Valuation allowances are recognized against deferred tax assets when it is more likely than not that a portion of, or the entire amount of, the deferred income tax asset will not be realized. Deferred income tax assets and liabilities are measured using enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. The effect of a change in income tax rates on deferred income tax assets and liabilities is recognized in earnings in the period that the change occurs. Current income tax expense or recovery is recognized for the estimated income taxes payable or receivable in the current year.

As approved by the respective regulator, ITC, UNS Energy, Central Hudson and Maritime Electric recover current and deferred income tax expense in customer rates. As approved by the regulator, FortisAlberta recovers income tax expense in customer rates based only on income taxes that are currently payable. FortisBC Energy, FortisBC Electric, Newfoundland Power and FortisOntario recover income tax expense in customer rates based only on income taxes that are currently payable, except for certain regulatory balances for which deferred income tax expense is recovered from, or refunded to, customers in current rates, as prescribed by the respective regulator. Therefore, with the exception of certain deferred tax balances of FortisBC Energy, FortisBC Electric, Newfoundland Power and FortisOntario, current customer rates do not include the recovery of deferred income taxes related to temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes, as these taxes are expected to be collected in customer rates when they become payable. These utilities recognize an offsetting regulatory asset or liability for the amount of deferred income taxes that are expected to be collected from or refunded to customers in rates once income taxes become payable or receivable (Note 8 *(i)*).

For regulatory reporting purposes, the capital cost allowance pool for certain utility capital assets at FortisAlberta is different from that for legal entity corporate income tax filing purposes. In a future reporting period, yet to be determined, the difference may result in higher income tax expense than that recognized for regulatory rate-setting purposes and collected in customer rates.

Caribbean Utilities and Fortis Turks and Caicos are not subject to income tax as they operate in tax-free jurisdictions. BECOL is not subject to income tax as it was granted tax-exempt status by the Government of Belize ("GOB") for the terms of its 50-year PPAs.

For the years ended December 31, 2016 and 2015

3. *SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)*

Income Taxes (cont'd)

Any difference between the income tax expense recognized under US GAAP and that recovered from customers in current rates that is expected to be recovered from customers in future rates, is subject to deferral account treatment (Note 8 *(i)*).

The Corporation intends to indefinitely reinvest earnings from certain foreign operations. Accordingly, the Corporation does not provide for deferred income taxes on temporary differences related to investments in foreign subsidiaries. The difference between the carrying values of these foreign investments and their tax bases, resulting from unrepatriated earnings and currency translation adjustments, is approximately $525 million as at December 31, 2016 (December 31, 2015 – $565 million). If such earnings are repatriated, in the form of dividends or otherwise, the Corporation may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is impractical.

Tax benefits associated with income tax positions taken, or expected to be taken, in an income tax return are recognized only when the more likely than not recognition threshold is met. The tax benefits are measured at the largest amount of benefit that is greater than 50% likely to be realized upon settlement. The difference between a tax position taken, or expected to be taken, and the benefit recognized and measured pursuant to this guidance represents an unrecognized tax benefit.

Income tax interest and penalties are expensed as incurred and included in income tax expense.

Sales Taxes

In the course of its operations, the Corporation's subsidiaries collect sales taxes from their customers. When customers are billed, a current liability is recognized for the sales taxes included on customers' bills. The liability is settled when the taxes are remitted to the appropriate government authority. The Corporation's revenue excludes sales taxes.

Revenue Recognition

Revenue from the sale and delivery of electricity and gas by the Corporation's regulated utilities is generally recognized on an accrual basis. Electricity and gas consumption is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Revenue at the regulated utilities is billed at rates approved by the applicable regulatory authority. Meters are read periodically and bills are issued to customers based on these readings. At the end of each reporting period, a certain amount of consumed electricity and gas will not have been billed, which is estimated and accrued as revenue.

ITC's transmission revenue is recognized as services are provided based on FERC-approved cost-based formula rate templates. A reserve for revenue subject to refund is recognized as a reduction to revenue when such refund is probable and can be reasonably estimated (Note 8 *(iii)*).

In certain circumstances, UNS Energy enters into purchased power and wholesale sales contracts that are not settled with energy. The net sales contracts and power purchase contracts are reflected at the net amount in revenue.

As stipulated by the regulator, FortisAlberta is required to arrange and pay for transmission services with AESO and collect transmission revenue from its customers, which is achieved through invoicing the customers' retailers through FortisAlberta's transmission component of its regulator-approved rates. FortisAlberta is solely a distribution company and, as such, does not operate or provide any transmission or generation services. The Company is a conduit for the flow through of transmission costs to end-use customers, as the transmission provider does not have a direct relationship with these customers. As a result, FortisAlberta reports revenue and expenses related to transmission services on a net basis. The rates collected are based on forecast transmission expenses. FortisAlberta is not subject to any forecast risk with respect to transmission costs, as all differences between actual expenses related to transmission services and actual revenue collected from customers are deferred to be recovered from, or refunded to, customers in future rates.

FortisBC Electric has entered into contracts to sell surplus capacity that may be available after it meets its load requirements. This revenue is recognized on an accrual basis at rates established in the sales contract.

All of the Corporation's non-regulated generation operations record revenue on an accrual basis and revenue is recognized on delivery of output at rates fixed under contract or based on observed market prices as stipulated in contractual arrangements.

Revenue at Aitken Creek is generated from long-term lease storage, park and loan activities, and storage optimization activities and is generally recognized on an accrual basis over the term of the related contracts. Optimization revenue results from the purchase of natural gas and its forward sale through financial and physical trading contracts and consists of realized and unrealized gains and losses on the financial and physical energy trading contracts, not designated as derivatives, used to manage commodity price risk (Note 30).

Asset Retirement Obligations

AROs, including conditional AROs, are recorded as a liability at fair value and are classified as long-term other liabilities, with a corresponding increase to utility capital assets. The Corporation recognizes AROs in the periods in which they are incurred if a reasonable estimate of fair value can be determined. Fair value is based on an estimate of the present value of expected future cash outlays, discounted at a credit-adjusted risk-free interest rate. The increase in the liability due to the passage of time is recorded through accretion, and the capitalized cost is depreciated over the useful life of the asset. Actual costs incurred upon the settlement of AROs are recorded as a reduction in the liabilities.

The Corporation has AROs associated with the remediation of hydroelectric generation facilities, interconnection facilities, wholesale energy supply agreements, and certain electricity distribution system assets. While each of the foregoing will have legal AROs, including land and environmental remediation and/or removal of assets, the final date and cost of remediation and/or removal of the related assets cannot be reasonably determined at this time. These assets are reasonably expected to operate in perpetuity due to the nature of their operations. The licences, permits, interconnection facilities agreements, wholesale energy supply agreements and rights-of-way are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the assets and ensure the continued provision of service to customers. In the event that environmental issues are identified, assets are decommissioned or the applicable licences, permits or agreements are terminated, AROs will be recognized at that time provided the costs can be reasonably estimated.

New Accounting Policies

Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern
Effective January 1, 2016, the Corporation adopted ASU No. 2014-15, which provides guidance on management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and provide related disclosures. The adoption of this update did not impact the Corporation's consolidated financial statements and related disclosures.

Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items
Effective January 1, 2016, the Corporation prospectively adopted ASU No. 2015-01, which is part of the Financial Accounting Standards Board's ("FASB's") initiative to reduce complexity in accounting standards by eliminating the concept of extraordinary items. The adoption of this update did not impact the Corporation's consolidated financial statements.

Amendments to the Consolidation Analysis
Effective January 1, 2016, the Corporation adopted ASU No. 2015-02, which changes the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. Specifically, the amendments note the following regarding limited partnerships: (i) modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities; and (ii) eliminate the presumption that a general partner should consolidate a limited partnership. The amendments in this update did not materially impact the Corporation's consolidated financial statements, however, did change the Corporation's 51% controlling ownership interest in the Waneta Partnership from a voting interest entity to a variable interest entity, resulting in additional disclosure (Note 31).

Simplifying the Accounting for Measurement-Period Adjustments
Effective January 1, 2016, the Corporation prospectively adopted ASU No. 2015-16, which requires that in a business combination an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. Under previous guidance, these adjustments were required to be accounted for retrospectively. The adoption of this update did not impact the Corporation's consolidated financial statements.

Improvements to Employee Share-Based Payment Accounting
Effective January 1, 2016, the Corporation early adopted ASU No. 2016-09, which simplifies the accounting for share-based payment transactions, including income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The guidance requires excess tax benefits and tax deficiencies to be recognized as an income tax benefit or expense in the consolidated statement of earnings. On adoption, using the modified retrospective method, the Corporation recognized a cumulative adjustment of $16 million related to prior period unrecognized excess tax benefits at UNS Energy, which increased retained earnings and decreased deferred income tax liabilities. In 2016 the adoption of this update also resulted in a $7 million decrease in income tax expense and decrease in deferred income tax liabilities related to excess tax benefits at ITC from the date of acquisition, largely associated with the accelerated vesting of the Company's stock-based compensation awards as a result of the acquisition. The guidance also allows for an accounting policy election to either estimate forfeitures or account for them when they occur. The Corporation elected to account for forfeitures when they occur. This policy election did not have a material impact on the Corporation's consolidated financial statements.

For the years ended December 31, 2016 and 2015

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Use of Accounting Estimates

The preparation of the consolidated financial statements in accordance with US GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances.

Additionally, certain estimates and judgments are necessary since the regulatory environments in which the Corporation's utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances, and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are recognized in earnings in the period in which they become known. In the event that a regulatory decision is received after the balance sheet date but before the consolidated financial statements are issued, the facts and circumstances are reviewed to determine whether or not it is a recognized subsequent event.

The Corporation's critical accounting estimates are described above in Note 3 under the headings Regulatory Assets and Liabilities, Utility Capital Assets, Intangible Assets, Goodwill, Employee Future Benefits, Income Taxes, Revenue Recognition, Asset Retirement Obligations and Contingencies, and in the respective notes to the consolidated financial statements.

4. FUTURE ACCOUNTING PRONOUNCEMENTS

The Corporation considers the applicability and impact of all ASUs issued by the FASB. The following updates have been issued by FASB, but have not yet been adopted by Fortis. Any ASUs not included below were assessed and determined to be either not applicable to the Corporation or are not expected to have a material impact on the consolidated financial statements.

Revenue from Contracts with Customers

ASU No. 2014-09 was issued in May 2014 and the amendments in this update create Accounting Standards Codification ("ASC") Topic 606, *Revenue from Contracts with Customers*, and supersede the revenue recognition requirements in ASC Topic 605, *Revenue Recognition*, including most industry-specific revenue recognition guidance throughout the codification. This standard clarifies the principles for recognizing revenue and can be applied consistently across various transactions, industries and capital markets. In 2016 a number of additional ASUs were issued that clarify implementation guidance in ASC Topic 606. This standard, and all related ASUs, is effective for annual and interim periods beginning after December 15, 2017. Early adoption is permitted for annual and interim periods beginning after December 15, 2016. The Corporation has elected not to early adopt.

The new guidance permits two methods of adoption: (i) the full retrospective method, under which comparative periods would be restated, and the cumulative impact of applying the standard would be recognized as at January 1, 2017, the earliest period presented; and (ii) the modified retrospective method, under which comparative periods would not be restated and the cumulative impact of applying the standard would be recognized at the date of initial adoption, January 1, 2018. The Corporation expects to use the modified retrospective approach, however, it continues to monitor industry developments. Any significant industry developments could change the Corporation's expected method of adoption.

The majority of the Corporation's revenue is generated from energy sales to retail customers based on published tariff rates, as approved by the respective regulators, and from transmission services and is considered to be in the scope of ASU No. 2014-09. Fortis does not expect that the adoption of this standard, and all related ASUs, will have a material impact on the recognition of revenue generated from energy sales to retail customers, or on its remaining material revenue streams; however, the Corporation does expect it will impact its required disclosures. Certain industry specific interpretative issues, including contributions in aid of construction, remain outstanding and the conclusions reached, if different than currently anticipated, could have a material impact on the Corporation's consolidated financial statements and related disclosures. Fortis continues to closely monitor industry developments related to the new standard.

Recognition and Measurement of Financial Assets and Financial Liabilities

ASU No. 2016-01, *Recognition and Measurement of Financial Assets and Financial Liabilities*, was issued in January 2016 and the amendments in this update address certain aspects of recognition, measurement, presentation and disclosure of financial instruments. Most notably, the amendments require the following: (i) equity investments in unconsolidated entities (other than those accounted for using the equity method of accounting) to be measured at fair value through earnings; however, entities will be able to elect to record equity investments without readily determinable fair values at cost, less impairment, and plus or minus subsequent adjustments for observable price changes; and (ii) financial assets and financial liabilities to be presented separately in the notes to the consolidated financial statements, grouped by measurement category and form of financial asset. This update is effective for annual and interim periods beginning after December 15, 2017. Fortis is assessing the impact that the adoption of this update will have on its consolidated financial statements and related disclosures.

Leases

ASU No. 2016-02 was issued in February 2016 and the amendments in this update create ASC Topic 842, *Leases*, and supersede lease requirements in ASC Topic 840, *Leases*. The main provision of ASC Topic 842 is the recognition of lease assets and lease liabilities on the balance sheet by lessees for those leases that were previously classified as operating leases. For operating leases, a lessee is required to do the following: (i) recognize a right-of-use asset and a lease liability, initially measured at the present value of the lease payments, on the balance sheet; (ii) recognize a single lease cost, calculated so that the cost of the lease is allocated over the lease term on a generally straight-line basis; and (iii) classify all cash payments within operating activities in the statement of cash flows. These amendments also require qualitative disclosures along with specific quantitative disclosures. This update is effective for annual and interim periods beginning after December 15, 2018 and is to be applied using a modified retrospective approach with practical expedient options. Early adoption is permitted. Fortis is assessing the impact that the adoption of this update will have on its consolidated financial statements and related disclosures.

Measurement of Credit Losses on Financial Instruments

ASU No. 2016-13, *Measurement of Credit Losses on Financial Instruments*, was issued in June 2016 and the amendments in this update require entities to use an expected credit loss methodology and to consider a broader range of reasonable and supportable information to inform credit loss estimates. This update is effective for annual and interim periods beginning after December 15, 2019 and is to be applied on a modified retrospective basis. Early adoption is permitted for annual and interim periods beginning after December 15, 2018. Fortis is assessing the impact that the adoption of this update will have on its consolidated financial statements and related disclosures.

Simplifying the Test for Goodwill Impairment

ASU No. 2017-04, *Simplifying the Test for Goodwill Impairment*, was issued in January 2017 and the amendments in this update simplify the subsequent measurement of goodwill by eliminating step two in the current two-step goodwill impairment test. An entity will apply a one-step quantitative test and record the amount of goodwill impairment as the excess of a reporting unit's carrying amount over its fair value, not to exceed the total amount of goodwill allocated to the reporting unit. The new guidance does not amend the optional qualitative assessment of goodwill impairment. This update is effective for annual and interim periods beginning after December 15, 2019 and is to be applied on a prospective basis. Early adoption is permitted for interim and annual goodwill impairment tests performed on testing dates after January 1, 2017. Fortis expects to early adopt this update in 2017; however, does not expect that it will have a material impact on its consolidated financial statements and related disclosures.

For the years ended December 31, 2016 and 2015

5. SEGMENTED INFORMATION

Information by reportable segment is as follows:

	REGULATED									NON-REGULATED				
	United States			Canada										
Year Ended December 31, 2016 *($ millions)*	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Eastern Canadian	Caribbean Electric	**Total**	**Energy Infra-structure**	**Non-Utility**	**Corporate and Other**	**Inter-segment eliminations**	**Total**
Revenue	334	2,002	849	1,151	572	377	1,063	301	**6,649**	**193**	**–**	**9**	**(13)**	**6,838**
Energy supply costs	–	740	253	347	–	132	698	137	**2,307**	**35**	**–**	**–**	**(1)**	**2,341**
Operating expenses	151	605	387	295	189	88	136	45	**1,896**	**39**	**–**	**108**	**(12)**	**2,031**
Depreciation and amortization	46	264	61	198	180	57	91	54	**951**	**28**	**–**	**4**	**–**	**983**
Operating income (loss)	137	393	148	311	203	100	138	65	**1,495**	**91**	**–**	**(103)**	**–**	**1,483**
Other income (expenses), net	9	7	5	17	3	–	2	9	**52**	**2**	**–**	**–**	**(1)**	**53**
Finance charges	54	102	40	125	85	37	55	15	**513**	**4**	**–**	**162**	**(1)**	**678**
Income tax expense (recovery)	20	99	43	51	–	9	21	–	**243**	**3**	**–**	**(101)**	**–**	**145**
Net earnings (loss)	72	199	70	152	121	54	64	59	**791**	**86**	**–**	**(164)**	**–**	**713**
Non-controlling interests	13	–	–	1	–	–	–	13	**27**	**26**	**–**	**–**	**–**	**53**
Preference share dividends	–	–	–	–	–	–	–	–	**–**	**–**	**–**	**75**	**–**	**75**
Net earnings (loss) attributable to common equity shareholders	59	199	70	151	121	54	64	46	**764**	**60**	**–**	**(239)**	**–**	**585**
Goodwill	8,246	1,854	605	913	227	235	67	190	**12,337**	**27**	**–**	**–**	**–**	**12,364**
Identifiable assets	9,754	7,081	2,609	5,317	3,830	1,908	2,327	1,154	**33,980**	**1,475**	**–**	**130**	**(45)**	**35,540**
Total assets	18,000	8,935	3,214	6,230	4,057	2,143	2,394	1,344	**46,317**	**1,502**	**–**	**130**	**(45)**	**47,904**
Gross capital expenditures	223	524	233	336	375	74	161	106	**2,032**	**19**	**–**	**10**	**–**	**2,061**
Year Ended December 31, 2015 *($ millions)*														
Revenue	–	2,034	880	1,295	563	360	1,033	321	**6,486**	**107**	**171**	**24**	**(31)**	**6,757**
Energy supply costs	–	820	315	498	–	116	673	169	**2,591**	**1**	**–**	**–**	**(1)**	**2,591**
Operating expenses	–	573	381	292	183	89	143	46	**1,707**	**19**	**124**	**36**	**(12)**	**1,874**
Depreciation and amortization	–	242	56	190	168	57	82	47	**842**	**18**	**11**	**2**	**–**	**873**
Operating income (loss)	–	399	128	315	212	98	135	59	**1,346**	**69**	**36**	**(14)**	**(18)**	**1,419**
Other income (expenses), net	–	5	8	11	3	–	2	2	**31**	**56**	**109**	**2**	**(1)**	**197**
Finance charges	–	98	38	134	78	39	56	14	**457**	**3**	**18**	**94**	**(19)**	**553**
Income tax expense (recovery)	–	111	40	51	(1)	9	19	–	**229**	**24**	**13**	**(43)**	**–**	**223**
Net earnings (loss)	–	195	58	141	138	50	62	47	**691**	**98**	**114**	**(63)**	**–**	**840**
Non-controlling interests	–	–	–	1	–	–	–	13	**14**	**21**	**–**	**–**	**–**	**35**
Preference share dividends	–	–	–	–	–	–	–	–	**–**	**–**	**–**	**77**	**–**	**77**
Net earnings (loss) attributable to common equity shareholders	–	195	58	140	138	50	62	34	**677**	**77**	**114**	**(140)**	**–**	**728**
Goodwill	–	1,912	624	913	227	235	67	195	**4,173**	**–**	**–**	**–**	**–**	**4,173**
Identifiable assets	–	6,977	2,601	5,116	3,592	1,872	2,219	1,084	**23,461**	**1,025**	**–**	**352**	**(207)**	**24,631**
Total assets	–	8,889	3,225	6,029	3,819	2,107	2,286	1,279	**27,634**	**1,025**	**–**	**352**	**(207)**	**28,804**
Gross capital expenditures	–	669	181	460	452	103	175	137	**2,177**	**38**	**9**	**19**	**–**	**2,243**

Related-party and inter-company transactions

Related-party transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. There were no material related-party transactions in 2016 or 2015.

Inter-company balances and inter-company transactions, including any related inter-company profit, are eliminated on consolidation, except for certain inter-company transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. The significant inter-company transactions for 2016 and 2015 are summarized in the following table.

(in millions)	**2016**	2015
Sale of capacity from Waneta Expansion to FortisBC Electric *(Note 35)*	**$ 45**	$ 30
Sale of energy from BECOL to Belize Electricity	**33**	30
Lease of gas storage capacity from Aitken Creek to FortisBC Energy	**17**	–

As at December 31, 2016, accounts receivable on the Corporation's consolidated balance sheet included approximately $16 million due from Belize Electricity (December 31, 2015 – $5 million), in which Fortis holds a 33% equity investment.

From time to time, the Corporation provides short-term financing to certain of its subsidiaries to support capital expenditure programs, acquisitions and seasonal working capital requirements, bearing interest at rates that approximate the Corporation's cost of short-term borrowing, and provides long-term financing to certain of its subsidiaries, bearing interest at rates that approximate the Corporation's cost of long-term debt. There were no inter-segment loans outstanding as at December 31, 2016 (December 31, 2015 – $48 million) and total interest charged in 2016 was less than $1 million (2015 – $17 million).

6. ACCOUNTS RECEIVABLE AND OTHER CURRENT ASSETS

(in millions)	**2016**	2015
Trade accounts receivable	**$ 507**	$ 517
Unbilled accounts receivable	**551**	404
Allowance for doubtful accounts	**(33)**	(66)
Income tax receivable	**26**	–
Assets held for sale	**–**	38
Other	**76**	71
	$ 1,127	$ 964

The decrease in the allowance for doubtful accounts was due to the settlement and release of a reserve at UNS Energy in relation to billings to third-party owners of Springerville Unit 1.

Assets held for sale as at December 31, 2015 included utility capital assets of approximately $29 million (US$21 million) purchased by UNS Energy upon expiration of the Springerville Coal Handling Facilities lease in April 2015. UNS Energy has an agreement with a third party whereby they can purchase a 17.05% interest or continue to make payments to UNS Energy for the use of the facility. In March 2016 the third party notified UNS Energy that it was exercising its option to purchase, however, as at December 31, 2016, it was no longer probable that the sale would be completed and UNS Energy reclassified the assets held for sale to utility capital assets (Note 10). As at December 31, 2015, assets held for sale also included the non-regulated Walden hydroelectric power plant assets of approximately $9 million, which were sold in February 2016 (Note 28).

Other consisted of customer billings for non-core services, collateral deposits for gas purchases at FortisBC Energy and advances on coal purchases at UNS Energy, as well as the fair value of derivative instruments (Note 30).

7. INVENTORIES

(in millions)	**2016**	2015
Materials and supplies	**$ 244**	$ 194
Gas and fuel in storage	**98**	101
Coal inventory	**30**	42
	$ 372	$ 337

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8. REGULATORY ASSETS AND LIABILITIES

Based on previous, existing or expected regulatory orders or decisions, the Corporation's regulated utilities have recognized the following amounts that are expected to be recovered from, or refunded to, customers in future periods.

(in millions)	**2016**	2015	Remaining recovery period *(Years)*
Regulatory assets			
Deferred income taxes *(i)*	**$ 1,260**	$ 936	To be determined
Employee future benefits *(ii)*	**576**	627	Various
Rate stabilization accounts *(iii)*	**183**	119	Various
Deferred energy management costs *(iv)*	**178**	145	1–10
Manufactured gas plant ("MGP") site remediation deferral *(v)*	**107**	121	To be determined
Deferred lease costs *(vi)*	**97**	90	Various
Deferred operating overhead costs *(vii)*	**78**	66	Various
Natural gas for transportation incentives *(viii)*	**40**	25	10
Derivative instruments *(ix)*	**19**	74	Various
Other regulatory assets *(x)*	**395**	329	Various
Total regulatory assets	**2,933**	2,532	
Less: current portion	**(313)**	(246)	1
Long-term regulatory assets	**$ 2,620**	$ 2,286	
Regulatory liabilities			
Non-ARO removal cost provision *(xi)*	**$ 1,194**	$ 1,060	To be determined
ROE refund liability *(xii)*	**346**	–	2
Rate stabilization accounts *(iii)*	**230**	212	Various
Electric and gas moderator account *(xiii)*	**71**	88	To be determined
Renewable energy surcharge *(xiv)*	**53**	47	To be determined
Energy efficiency liability *(xv)*	**49**	20	Various
Employee future benefits *(ii)*	**42**	44	Various
Other regulatory liabilities *(xvi)*	**198**	167	Various
Total regulatory liabilities	**2,183**	1,638	
Less: current portion	**(492)**	(298)	1
Long-term regulatory liabilities	**$ 1,691**	$ 1,340	

Description of the Nature of Regulatory Assets and Liabilities

(i) *Deferred Income Taxes*

The Corporation's regulated utilities recognize deferred income tax assets and liabilities and related regulatory liabilities and assets for the amount of deferred income taxes expected to be refunded to, or recovered from, customers in future rates. As at December 31, 2016, $596 million (December 31, 2015 – $351 million) in regulatory assets for deferred income taxes was not subject to a regulatory return.

(ii) *Employee Future Benefits*

The regulatory asset and liability associated with employee future benefits includes the actuarially determined unamortized net actuarial losses, past service costs and credits, and transitional obligations associated with defined benefit pension and OPEB plans maintained by the Corporation's regulated utilities, which are expected to be recovered from, or refunded to, customers in future rates (Note 26). At the Corporation's regulated utilities, as approved by the respective regulators, differences between defined benefit pension and OPEB plan costs recognized under US GAAP and those which are expected to be recovered from, or refunded to, customers in future rates are subject to deferral account treatment and have been recognized as a regulatory asset or liability. These amounts would otherwise be recognized in accumulated other comprehensive income on the consolidated balance sheet.

As at December 31, 2016, regulatory assets of approximately $346 million associated with employee future benefits were not subject to a regulatory return (December 31, 2015 – $367 million). As at December 31, 2016, regulatory liabilities of approximately $31 million associated with employee future benefits were not subject to a regulatory return (December 31, 2015 – $36 million).

(iii) Rate Stabilization Accounts

Rate stabilization accounts associated with the Corporation's regulated utilities are recovered from, or refunded to, customers in future rates, as approved by the respective regulators. Electric rate stabilization accounts primarily mitigate the effect on earnings of variability in the cost of fuel and/or purchased power above or below a forecast or predetermined level and, at certain utilities, revenue decoupling mechanisms minimize the earnings impact resulting from reduced energy consumption as energy efficiency programs are implemented. Gas rate stabilization accounts primarily mitigate the effect on earnings of unpredictable and uncontrollable factors, namely volume volatility caused principally by weather, and natural gas cost volatility.

At ITC, transmission revenue requirements are set annually using cost-based formula rates that remain in effect for a one-year period. The formula rates include a true-up mechanism, whereby the actual revenue requirement is compared to billed revenue for each year to determine any over- or under-collection of revenue requirement. Revenue is recognized based on the actual revenue requirement, and revenue accrual and deferral accounts represent the difference between the actual revenue requirement and billed revenue, and are collected from, or refunded to, customers within a two-year period. Included in the rate stabilization accounts at ITC is US$29 million related to regional cost allocation recovery for refunds ITC paid to other regional transmission organizations, which will be recovered from network customers in 2017.

As at December 31, 2016, approximately $135 million and $173 million of the rate stabilization accounts are expected to be recovered from, or refunded to, customers within one year and, as a result, are classified as current regulatory assets and liabilities, respectively (December 31, 2015 – approximately $49 million and $142 million, respectively).

As at December 31, 2016, regulatory assets of approximately $139 million associated with rate stabilization accounts were not subject to a regulatory return (December 31, 2015 – $44 million). As at December 31, 2016, regulatory liabilities of approximately $180 million associated with rate stabilization accounts were not subject to a regulatory return (December 31, 2015 – $123 million).

(iv) Deferred Energy Management Costs

FortisBC Energy, FortisBC Electric, Central Hudson and Newfoundland Power provide energy management services to promote energy efficiency programs to their customers. As required by their respective regulator, these regulated utilities have capitalized related expenditures and are amortizing these expenditures on a straight-line basis over periods ranging from 1 to 10 years. This regulatory asset represents the unamortized balance of the energy management costs.

UNS Energy is required to implement cost-effective Demand-Side Management ("DSM") programs to comply with the ACC's energy efficiency standards. The energy efficiency standards provide for a DSM surcharge to recover the costs of implementing DSM programs, as well as an annual performance incentive. The existing rate orders provide for a lost fixed-cost recovery mechanism to recover certain non-fuel costs that were previously unrecoverable, due to reduced electricity sales as a result of energy efficiency programs and distributed generation.

As at December 31, 2016, $42 million of the regulatory asset balance associated with deferred energy management costs was not subject to a regulatory return (December 31, 2015 – $25 million).

(v) MGP Site Remediation Deferral

As approved by the regulator, Central Hudson is permitted to defer for future recovery from its customers the difference between actual costs for MGP site investigation and remediation and the associated rate allowances (Notes 13 and 16). Central Hudson's MGP site remediation costs are not subject to a regulatory return.

(vi) Deferred Lease Costs

Deferred lease costs at FortisBC Electric primarily relate to the Brilliant Power Purchase Agreement ("BPPA"), which ends in 2056. The depreciation of the asset under capital lease and interest expense associated with the capital lease obligation are not being fully recovered in current customer rates, since those rates include only the cash payments set out under the BPPA. The deferred lease costs are expected to be recovered from customers in future rates over the term of the lease and are not subject to a regulatory return.

In 2016, of the $31 million (2015 – $30 million) of interest expense related to the capital lease obligations and the $6 million (2015 – $6 million) of depreciation expense related to the assets under capital lease, $27 million (2015 – $26 million) was recognized in energy supply costs and $3 million (2015 – $3 million) was recognized in operating expenses, as approved by the regulator, with the balance of $7 million (2015 – $7 million) deferred as a regulatory asset (Note 15).

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8. REGULATORY ASSETS AND LIABILITIES (cont'd)

Description of the Nature of Regulatory Assets and Liabilities (cont'd)

(vii) Deferred Operating Overhead Costs

As approved by the regulator, FortisAlberta has deferred certain operating overhead costs. The deferred costs are expected to be collected in future customer rates over the lives of the related utility capital and intangible assets.

(viii) Natural Gas for Transportation Incentives

The deferral for natural gas transportation incentives at FortisBC Energy is comprised of subsidy payments to assist customers in purchasing natural gas vehicles in lieu of vehicles fueled by diesel as part of the incentive program pursuant to the greenhouse gas reductions regulations under the *Clean Energy Act* (British Columbia). The regulator has approved recovery in rates over a 10-year period.

(ix) Derivative Instruments

As approved by the respective regulators, unrealized gains or losses associated with changes in the fair value of certain derivative instruments at UNS Energy, Central Hudson and FortisBC Energy are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates. These unrealized losses and gains would otherwise be recognized in earnings. UNS Energy and Central Hudson's regulatory asset balance totalling $6 million as at December 31, 2016 was not subject to a regulatory return (December 31, 2015 – $57 million).

(x) Other Regulatory Assets

Other regulatory assets relate to all of the Corporation's regulated utilities and are comprised of various items, each individually less than $40 million. As at December 31, 2016, $296 million (December 31, 2015 – $265 million) of the balance was approved to be recovered from customers in future rates, with the remaining balance expected to be approved. As at December 31, 2016, $217 million (December 31, 2015 – $168 million) of the balance was not subject to a regulatory return.

(xi) Non-ARO Removal Cost Provision

As required by the respective regulators, depreciation rates include an amount allowed for regulatory purposes to accrue for non-ARO removal costs. Actual non-ARO removal costs are recorded against the regulatory liability when incurred. This regulatory liability represents amounts collected in customer rates at the respective utilities in excess of incurred non-ARO removal costs.

(xii) ROE Refund Liability

The ROE refund liability at ITC relates to two third-party complaints filed with FERC dating back to 2013, requesting that FERC find the MISO regional base ROE for all MISO transmission owners, including ITC for the periods November 2013 through February 2015 and February 2015 through May 2016, to no longer be just and reasonable (Note 2). As at December 31, 2016, the estimated range of refunds for both periods was between US$221 million and US$258 million and ITC has recognized an aggregate estimated regulatory liability of US$258 million, of which US$119 million has been classified as current regulatory liabilities.

(xiii) Electric and Gas Moderator Account

Under the terms of Central Hudson's three-year Rate Order issued in June 2015, certain of the Company's regulatory assets and liabilities were identified and approved by the PSC for offset and a net regulatory liability electric and gas moderator account was established, which will be used for future customer rate moderation. This electric and gas moderator account is not subject to a regulatory return.

(xiv) Renewable Energy Surcharge

As ordered by the regulator under its Renewable Energy Standard ("RES"), UNS Energy is required to increase its use of renewable energy each year until it represents at least 15% of its total annual retail energy requirements in 2025, with distributed generation accounting for 30% of the annual renewable energy requirement. The Company must file an annual RES implementation plan for review and approval by the ACC. The approved cost of carrying out the plan is recovered from retail customers through the RES surcharge until such costs are reflected in TEP and UNS Electric's non-fuel base rates. Any RES surcharge collections above or below the costs incurred to implement the plans are deferred as a regulatory asset or liability and is not subject to a regulatory return.

The ACC measures compliance with its RES requirements through Renewable Energy Credits ("REC"). Each REC represents one kilowatt hour generated from renewable resources. When UNS Energy purchases renewable energy, the premium paid above the market cost of conventional power equals the REC recoverable through the RES surcharge. When RECs are purchased, UNS Energy records the cost of the RECs as long-term other assets and a corresponding regulatory liability, to reflect the obligation to use the RECs for future RES compliance. When RECs are reported to the ACC for compliance with RES requirements, energy supply costs and revenue are recognized in an equal amount (Note 9).

(xv) *Energy Efficiency Liability*

The energy efficiency regulatory liability primarily relates to Central Hudson's Energy Efficiency Program established to fund the costs of environmental policies associated with energy conservation programs and megawatt hour reduction goals, as approved by its regulator, and was not subject to a regulatory return.

(xvi) *Other Regulatory Liabilities*

Other regulatory liabilities relate to all of the Corporation's regulated utilities and are comprised of various items, each individually less than $40 million. As at December 31, 2016, $190 million (December 31, 2015 – $156 million) of the balance was approved for refund to customers or reduction in future rates, with the remaining balance expected to be approved. As at December 31, 2016, $51 million (December 31, 2015 – $80 million) of the balance was not subject to a regulatory return.

9. OTHER ASSETS

(in millions)	**2016**	2015
Supplemental Executive Retirement Plan assets	**$ 115**	$ 58
Equity investment – Belize Electricity	**78**	79
Renewable Energy Credits *(Note 8 (xiv))*	**39**	17
Defined benefit pension plan assets *(Note 26)*	**32**	11
Deferred compensation plan assets *(Note 16)*	**24**	25
Other investments	**21**	13
Available-for-sale investment *(Notes 28 and 30)*	**–**	33
Deposit on acquisition of Aitken Creek *(Note 27)*	**–**	38
Other	**97**	78
	$ 406	$ 352

ITC, UNS Energy and Central Hudson provide additional post-employment benefits through both deferred compensation plans for Directors and Officers of the Companies, as well as Supplemental Executive Retirement Plans ("SERP") and the assets held to support these plans are reported separately from the related liabilities (Note 16). Most of the plan assets are held in trust and funded mainly through the use of trust-owned life insurance policies and mutual funds. Assets held in mutual and money market funds are recorded at fair value on a recurring basis (Note 30). Included in SERP assets are available-for-sale-securities at ITC of US$42 million, for which gains and losses are recorded in other comprehensive income.

In August 2015 the Corporation agreed to terms of a settlement with the GOB regarding the GOB's expropriation of the Corporation's approximate 70% interest in Belize Electricity in June 2011. The terms of the settlement included a one-time US$35 million cash payment to Fortis from the GOB and an approximate 33% equity investment in Belize Electricity. As a result of the settlement, the Corporation recognized an approximate $9 million loss in 2015 (Note 23).

Other assets are recorded at cost and are recovered or amortized over the estimated period of future benefit, where applicable. Other assets also includes the fair value of derivative instruments (Note 30).

For the years ended December 31, 2016 and 2015

10. UTILITY CAPITAL ASSETS

2016

(in millions)	Cost	Accumulated Depreciation	Net Book Value
Distribution			
Electric	**$ 9,616**	**$ (2,752)**	**$ 6,864**
Gas	**3,956**	**(1,096)**	**2,860**
Transmission			
Electric	**12,616**	**(2,876)**	**9,740**
Gas	**1,776**	**(562)**	**1,214**
Generation	**6,884**	**(2,474)**	**4,410**
Other	**3,497**	**(1,096)**	**2,401**
Assets under construction	**1,559**	**–**	**1,559**
Land	**289**	**–**	**289**
	$ 40,193	**$ (10,856)**	**$ 29,337**

2015

(in millions)	Cost	Accumulated Depreciation	Net Book Value
Distribution			
Electric	$ 9,245	$ (2,634)	$ 6,611
Gas	3,829	(1,021)	2,808
Transmission			
Electric	3,093	(997)	2,096
Gas	1,735	(531)	1,204
Generation	6,465	(2,241)	4,224
Other	2,429	(849)	1,580
Assets under construction	886	–	886
Land	186	–	186
	$ 27,868	$ (8,273)	$ 19,595

Electric distribution assets are those used to distribute electricity at lower voltages (generally below 69 kilovolt ("kV")). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment. Gas distribution assets are those used to transport natural gas at low pressures (generally below 2,070 kilopascal ("kPa")) or a hoop stress of less than 20% of standard minimum yield strength. These assets include distribution stations, telemetry, distribution pipe for mains and services, meter sets and other related equipment.

Electric transmission assets are those used to transmit electricity at higher voltages (generally at 69 kV and higher). These assets include poles, wires, switching equipment, transformers, support structures and other related equipment. Gas transmission assets are those used to transport natural gas at higher pressures (generally at 2,070 kPa and higher) or a hoop stress of 20% or more of standard minimum yield strength. These assets include transmission stations, telemetry, transmission pipe and other related equipment.

Generation assets are those used to generate electricity. These assets include hydroelectric and thermal generation stations, gas and combustion turbines, coal-fired generating stations, dams, reservoirs, photovoltaic systems and other related equipment.

Other assets include buildings, equipment, vehicles, inventory, information technology assets and the Aitken Creek natural gas storage facility (Note 27).

As at December 31, 2016, assets under construction were primarily associated with FortisBC Energy's Tilbury liquefied natural gas facility expansion and ongoing transmission projects at ITC to upgrade or replace existing transmission assets to improve system reliability and transmission infrastructure to support generator interconnections and investments that provide regional benefits, such as the Multi-Value Projects.

The cost of utility capital assets under capital lease as at December 31, 2016 was $539 million (December 31, 2015 – $496 million) and related accumulated depreciation was $231 million (December 31, 2015 – $221 million).

Jointly Owned Facilities

UNS Energy and ITC hold undivided interests in jointly owned generating facilities and transmission systems, are entitled to their pro rata share of the utility capital assets, and are proportionately liable for the associated operating costs and liabilities. As at December 31, 2016, interests in jointly owned facilities consisted of the following.

2016

(in millions)	Ownership *(%)*	Cost	Accumulated Depreciation	Net Book Value
San Juan Units 1 and 2	50.0	**$ 670**	**$ (352)**	**$ 318**
Navajo Units 1, 2 and 3	7.5	**206**	**(153)**	**53**
Four Corners Units 4 and 5	7.0	**185**	**(103)**	**82**
Luna Energy Facility	33.3	**73**	**(3)**	**70**
Gila River Common Facilities	25.0	**44**	**(15)**	**29**
Springerville Coal Handling Facilities [1]	83.0	**270**	**(108)**	**162**
Transmission Facilities	1.0–80.0	**750**	**(236)**	**514**
		$ 2,198	**$ (970)**	**$ 1,228**

[1] In 2016 UNS Energy reclassified an additional 17.05% undivided interest in the Springerville Coal Handling Facilities from assets held for sale (Note 6).

11. INTANGIBLE ASSETS

2016

(in millions)	Cost	Accumulated Amortization	Net Book Value
Computer software	**$ 748**	**$ (447)**	**$ 301**
Land, transmission and water rights	**700**	**(108)**	**592**
Other	**128**	**(56)**	**72**
Assets under construction	**46**	**–**	**46**
	$ 1,622	**$ (611)**	**$ 1,011**

2015

(in millions)	Cost	Accumulated Amortization	Net Book Value
Computer software	$ 685	$ (436)	$ 249
Land, transmission and water rights	328	(76)	252
Other	17	(13)	4
Assets under construction	36	–	36
	$ 1,066	$ (525)	$ 541

Included in the cost of land, transmission and water rights as at December 31, 2016 was $138 million (December 31, 2015 – $106 million) not subject to amortization.

Amortization expense related to intangible assets was $79 million for 2016 (2015 – $64 million). Amortization is estimated to average approximately $96 million annually for each of the next five years.

12. GOODWILL

(in millions)	2016	2015
Balance, beginning of year	**$ 4,173**	$ 3,732
Acquisition of ITC *(Note 27)*	**8,106**	–
Acquisition of Aitken Creek *(Note 27)*	**27**	–
Foreign currency translation impacts	**58**	441
Balance, end of year	**$ 12,364**	$ 4,173

Goodwill associated with the acquisitions of ITC, UNS Energy, Central Hudson, Caribbean Utilities and Fortis Turks and Caicos is denominated in US dollars, as the functional currency of these companies is the US dollar. Foreign currency translation impacts are the result of the translation of US dollar-denominated goodwill and the impact of the movement of the Canadian dollar relative to the US dollar.

13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

(in millions)	2016	2015
Trade accounts payable	**$ 554**	$ 414
Customer and other deposits	**287**	160
Interest payable	**218**	127
Employee compensation and benefits payable	**178**	137
Gas and fuel cost payable	**175**	153
Accrued taxes other than income taxes	**168**	108
Dividends payable	**166**	113
Fair value of derivative instruments *(Note 30)*	**28**	69
Defined benefit pension and OPEB liabilities *(Note 26)*	**26**	13
MGP site remediation *(Notes 8 (v) and 16)*	**21**	32
Other	**149**	93
	$ 1,970	$ 1,419

Customer and other deposits include $64 million at FortisBC Energy related to the pipeline expansion to the proposed Woodfibre LNG export facility, and US$17 million associated with refundable deposits from generators for transmission network upgrades at ITC.

14. LONG-TERM DEBT

(in millions)	Maturity Date	**2016**	2015
Regulated Utilities			
ITC			
Secured US First Mortgage Bonds –			
4.81% weighted average fixed rate	2017 – 2055	**$ 1,994**	$ –
Secured US Senior Notes –			
4.19% weighted average fixed rate	2040 – 2046	**638**	–
Unsecured US Senior Notes –			
4.80% weighted average fixed rate	2017 – 2043	**3,160**	–
Unsecured US Shareholder Note –			
6.00% fixed rate *(Note 27)*	2028	**267**	–
UNS Energy			
Unsecured US Tax-Exempt Bonds – 3.87% weighted average fixed and variable rate (2015 – 3.83%)	2020 – 2040	**827**	852
Unsecured US Fixed Rate Notes –			
4.26% weighted average fixed rate (2015 – 4.26%)	2021 – 2045	**1,511**	1,557
Central Hudson			
Unsecured US Promissory Notes – 4.25% weighted average fixed and variable rate (2015 – 4.30%)	2017 – 2046	**768**	728
FortisBC Energy			
Secured Purchase Money Mortgages –			
10.30% weighted average fixed rate (2015 – 10.30%)	n/a	**–**	200
Unsecured Debentures –			
5.24% weighted average fixed rate (2015 – 5.73%)	2026 – 2047	**2,220**	1,770
Government loan	n/a	**–**	5
FortisAlberta			
Unsecured Debentures –			
4.82% weighted average fixed rate (2015 – 4.95%)	2024 – 2052	**1,834**	1,684
FortisBC Electric			
Secured Debentures –			
8.80% fixed rate (2015 – 8.80%)	2023	**25**	25
Unsecured Debentures –			
5.22% weighted average fixed rate (2015 – 5.36%)	2021 – 2050	**635**	660
Eastern Canadian			
Secured First Mortgage Sinking Fund Bonds –			
6.48% weighted average fixed rate (2015 – 6.72%)	2020 – 2045	**516**	553
Secured First Mortgage Bonds –			
6.19% weighted average fixed rate (2015 – 7.18%)	2018 – 2061	**195**	167
Unsecured Senior Notes –			
6.11% weighted average fixed rate (2015 – 6.11%)	2018 – 2041	**104**	104
Caribbean Electric			
Unsecured US Senior Loan Notes and Bonds – 4.92% weighted average fixed and variable rate (2015 – 4.89%)	2018 – 2046	**499**	467
Corporate			
Unsecured US Senior Notes and Promissory Notes –			
3.43% weighted average fixed rate (2015 – 4.43%)	2019 – 2044	**4,353**	1,720
Unsecured Debentures –			
6.50% weighted average fixed rate (2015 – 6.49%)	2039	**200**	201
Unsecured Senior Notes – 2.85% fixed rate	2023	**500**	–
Long-term classification of credit facility borrowings *(Note 32)*		**973**	551
Total long-term debt *(Note 30)*		**21,219**	11,244
Less: Deferred financing costs and debt discounts		**(151)**	(76)
Less: Current installments of long-term debt		**(251)**	(384)
		$ 20,817	$ 10,784

For the years ended December 31, 2016 and 2015

14. LONG-TERM DEBT (cont'd)

Certain long-term debt instruments at the Corporation's regulated utilities are secured. When security is provided, it is typically a fixed or floating first charge on the specific assets of the Company to which the long-term debt is associated.

Covenants

Certain of the Corporation's long-term debt obligations have covenants restricting the issuance of additional debt such that consolidated debt cannot exceed 70% of the Corporation's consolidated capital structure, as defined by the long-term debt agreements. In addition, one of the Corporation's long-term debt obligations contains a covenant which provides that Fortis shall not declare or pay any dividends, other than stock dividends or cumulative preferred dividends on preference shares not issued as stock dividends, or make any other distribution on its shares or redeem any of its shares or prepay subordinated debt if, immediately thereafter, its consolidated funded obligations would be in excess of 75% of its total consolidated capitalization.

As at December 31, 2016, the Corporation and its subsidiaries were in compliance with their debt covenants.

Regulated Utilities

The majority of the long-term debt instruments at the Corporation's regulated utilities are redeemable at the option of the respective utilities, at any time, at the greater of par or a specified price as defined in the respective long-term debt agreements, together with accrued and unpaid interest.

In April 2016 FortisBC Energy issued $300 million of unsecured debentures in a dual tranche of 10-year $150 million unsecured debentures at 2.58% and 30-year $150 million unsecured debentures at 3.67%. In December 2016 FortisBC Energy issued 30-year $150 million unsecured debentures at 3.78%. The net proceeds from the issuances were used to repay short-term borrowings and to finance capital expenditures.

In May and September 2016, Fortis Turks and Caicos issued 15-year US$45 million unsecured notes in a dual tranche of US$22.5 million at 5.14% and 5.29%, respectively. In July 2016 Fortis Turks and Caicos issued 15-year US$5 million unsecured bonds at 5.14%. The net proceeds were used to finance capital expenditures and for general corporate purposes.

In June 2016 Central Hudson issued 4-year US$24 million unsecured notes at 2.16%. The net proceeds were used to finance capital expenditures and for general corporate purposes. In October 2016 Central Hudson issued US$30 million of unsecured notes in a dual tranche of 10-year US$10 million unsecured notes at 2.56% and 30-year US$20 million unsecured debentures at 3.63%. The net proceeds were used to finance capital expenditures and for general corporate purposes.

In August 2016 Maritime Electric issued 40-year $40 million secured first mortgage bonds at 3.657%. The net proceeds were primarily used to repay long-term debt and short-term borrowings.

In September 2016 FortisAlberta issued 30-year $150 million unsecured debentures at 3.34%. The net proceeds were used to repay credit facility borrowings, to finance capital expenditures and for general corporate purposes.

In October 2016 a 12-year shareholder note of US$199 million at 6.00% was issued to an affiliate of GIC as part of its minority investment in ITC. The proceeds were used to finance a portion of the cash purchase price of the acquisition of ITC (Note 27).

Corporate

The unsecured debentures and senior notes are redeemable at the option of Fortis at a price calculated as the greater of par or a specified price as defined in the respective long-term debt agreements, together with accrued and unpaid interest.

In October 2016 the Corporation issued 5-year US$500 million unsecured notes at 2.100% and 10-year US$1.5 billion unsecured notes at 3.055%. The net proceeds were used to finance a portion of the cash purchase price of the acquisition of ITC (Note 27). In December 2016 the Corporation issued 7-year $500 million unsecured notes at 2.85%. The net proceeds were used to repay credit facility borrowings, mainly related to the financing of the acquisition of Aitken Creek in April 2016 and the redemption of First Preference Shares, Series E in September 2016, and for general corporate purposes.

Repayment of Long-Term Debt

The consolidated annual requirements to meet principal repayments and maturities in each of the next five years and thereafter are as follows.

Year	Subsidiaries *(in millions)*	Corporate *(in millions)*	Total *(in millions)*
2017	$ 249	$ 2	$ 251
2018	929	2	931
2019	556	123	679
2020	544	181	725
2021	460	1,296	1,756
Thereafter	12,963	3,914	16,877
	$ 15,701	$ 5,518	$ 21,219

15. CAPITAL LEASE AND FINANCE OBLIGATIONS

Capital Lease Obligations

UNS Energy

TEP is party to three Springerville Common Facilities leases, which have a fixed purchase price of US$38 million and an initial term to December 2017 for one lease and a fixed purchase price of US$68 million and an initial term to January 2021 for the other two leases. In December 2016 TEP notified the owner participant and the lessor that TEP has elected to purchase a 17.8% undivided ownership interest in the Springerville Common Facilities at the fixed purchase price of US$38 million upon the expiration of the lease term in December 2017. Under the remaining two leases, TEP has the option to renew the leases for periods of two or more years or exercise the purchase options under these contracts. In addition, TEP has entered into agreements with third parties that if the Springerville Common Facilities leases are not renewed, TEP will exercise the purchase options under these contracts. The third parties would be obligated to buy a portion of these facilities or continue to make payments to TEP for the use of these facilities.

TEP entered into an interest rate swap that hedges a portion of the floating interest rate risk associated with the Springerville Common Facilities lease obligation. As at December 31, 2016, interest on the lease obligation is payable at a six-month LIBOR plus a spread of 1.88% (December 31, 2015 – 1.88%). The swap has the effect of fixing the interest rate on a portion of the amortizing principal balance of US$23 million (December 31, 2015 – US$29 million). The interest rate swap expires in 2020 and is recorded as a cash flow hedge (Note 30).

The Springerville Common Facilities capital lease obligation bears interest at a rate of 5.08%. For 2016 $4 million (2015 – $5 million) of interest expense and $7 million (2015 – $8 million) of depreciation expense was recognized related to the Springerville capital lease obligations and for 2015 $3 million of depreciation expense was recognized in energy supply costs.

FortisBC Electric

FortisBC Electric has a capital lease obligation with respect to the operation of the Brilliant hydroelectric plant ("Brilliant Plant") located in British Columbia. FortisBC Electric operates and maintains the Brilliant Plant, under the BPPA which expires in 2056, in return for a management fee. In exchange for the specified take-or-pay amounts of power, the BPPA requires semi-annual payments based on a return on capital, comprised of the original plant capital charge and periodic upgrade capital charges, which are both subject to fixed annual escalators, as well as sustaining capital charges and operating expenses. The BPPA includes a market-related price adjustment in 2026. Approximately 94% of the output from the Brilliant Plant is being purchased by FortisBC Electric through the BPPA. The BPPA capital lease obligation bears interest at a composite rate of 5.00%. Included in energy supply costs for 2016 was $27 million (2015 – $26 million) recognized in accordance with the BPPA, as approved by the BCUC.

FortisBC Electric also has a capital lease obligation with respect to the operation of the Brilliant Terminal Station ("BTS"), under an agreement which expires in 2056. The agreement provides that FortisBC Electric will pay a charge related to the recovery of the capital cost of the BTS and related operating costs. The obligation bears interest at a composite rate of 9.00%. Included in operating expenses for 2016 was $3 million (2015 – $3 million) recognized in accordance with the BTS agreement, as approved by the BCUC.

Finance Obligations

Between 2000 and 2005 FEI entered into arrangements whereby certain natural gas distribution assets were leased to certain municipalities and then leased back by FEI. The natural gas distribution assets are considered to be integral equipment to real estate assets and, as such, the transactions have been accounted for as finance transactions. The proceeds from these transactions have been recognized as finance obligations on the consolidated balance sheet. Lease payments, net of the portion considered to be interest expense, reduce the finance obligations.

Obligations under the above-noted lease-in lease-out transactions have implicit interest at rates ranging from 6.78% to 8.40% and are being repaid over a 35-year period. Each of the lease-in lease-out arrangements allows FEI, at its option, to terminate the lease arrangement early, after 17 years. If the Company exercises this option, FEI would pay the municipality an early termination payment which is equal to the carrying value of the obligation at that point in time.

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15. CAPITAL LEASE AND FINANCE OBLIGATIONS (cont'd)

Repayment of Capital Lease and Finance Obligations

The present value of the minimum lease payments required for the capital lease and finance obligations over the next five years and thereafter are as follows:

Year	Capital Leases *(in millions)*	Finance Obligations *(in millions)*	Total *(in millions)*
2017	$ 116	$ 5	$ 121
2018	60	32	92
2019	61	15	76
2020	70	3	73
2021	46	35	81
Thereafter	1,976	3	1,979
	$ 2,329	$ 93	$ 2,422
Less: Amounts representing imputed interest and executory costs on capital lease and finance obligations			(1,886)
Total capital lease and finance obligations			536
Less: Current installments			(76)
			$ 460

16. OTHER LIABILITIES

(in millions)	2016	2015
OPEB plan liabilities *(Note 26)*	**$ 411**	$ 385
Defined benefit pension plan liabilities *(Note 26)*	**410**	368
MGP site remediation *(Notes 8 (v) and 13)*	**77**	96
Customer and other deposits	**69**	38
Waneta Partnership promissory note *(Notes 30, 31 and 33)*	**59**	56
Asset retirement obligations	**58**	49
Mine reclamation and retiree health care liabilities	**40**	39
Deferred compensation plan liabilities *(Note 9)*	**27**	25
DSU, PSU and RSU liabilities *(Note 22)*	**24**	20
Fair value of derivative instruments *(Note 30)*	**10**	13
Other	**94**	63
	$ 1,279	$ 1,152

Central Hudson has been notified by the New York State Department of Environmental Conservation to investigate MGPs at sites that the Company or its predecessors once owned and/or operated and, if necessary, remediate these sites. Central Hudson accrues for remediation costs based on the amounts that can be reasonably estimated. As at December 31, 2016, an obligation of US$73 million was recognized, including a current portion of US$16 million included in accounts payable and other current liabilities. It is estimated that total costs to remediate these sites over the next 30 years will not exceed US$169 million. Central Hudson has notified its insurers and intends to seek reimbursement, where coverage exists. Further, as authorized by the PSC, Central Hudson is currently permitted to defer, for future recovery from customers, differences between actual costs for MGP site investigation and remediation and the associated rate allowances.

The Waneta Partnership promissory note is non-interest bearing with a face value of $72 million. As at December 31, 2016, its discounted net present value was $59 million (December 31, 2015 – $56 million). The promissory note is payable on April 1, 2020, the fifth anniversary of the commercial operation date of the Waneta Expansion.

TEP pays ongoing reclamation costs related to three coal mines that supply generating stations in which the Company has an ownership interest but does not operate. TEP's share of the reclamation costs is expected to be US$61 million (December 31, 2015 – US$43 million) upon expiry of the coal agreements, which expire between 2019 and 2031. The mine reclamation liability recognized as at December 31, 2016 was US$25 million (December 31, 2015 – US$25 million), which represents the present value of the estimated future liability. TEP is permitted to recover these costs from customers and, accordingly, these costs are deferred and included in other regulatory assets.

Customer and other deposits include US$27 million of refundable deposits from generators for transmission network upgrades at ITC. These deposits are to be refunded under generator interconnection agreements at a future date.

Other liabilities primarily include long-term accrued liabilities, deferred lease revenue, funds received in advance of expenditures and unrecognized tax benefits.

17. COMMON SHARES

Common shares issued during the year were as follows.

	2016		2015	
	Number of Shares *(in thousands)*	**Amount** *(in millions)*	Number of Shares *(in thousands)*	Amount *(in millions)*
Balance, beginning of year	**281,562**	**$ 5,867**	275,997	$ 5,667
Public Offering	**114,364**	**4,684**	–	–
Dividend Reinvestment Plan	**4,100**	**163**	4,272	157
Consumer Share Purchase Plan	**31**	**1**	28	1
Employee Share Purchase Plan	**377**	**15**	356	13
Stock Option Plans	**1,042**	**32**	885	28
Conversion of Convertible Debentures	**10**	**–**	24	1
Balance, end of year	**401,486**	**$ 10,762**	281,562	$ 5,867

Public Offering

To finance a portion of the acquisition of ITC, in October 2016 Fortis issued approximately 114.4 million common shares to shareholders of ITC, representing share consideration of approximately $4.7 billion (US$3.5 billion), based on the closing price for Fortis common shares of $40.96 and the closing foreign exchange rate of US$1.00=CAD$1.32 on October 13, 2016 (Note 27).

18. EARNINGS PER COMMON SHARE

The Corporation calculates earnings per common share ("EPS") on the weighted average number of common shares outstanding. The weighted average number of common shares outstanding was 308.9 million for 2016 and 278.6 million for 2015.

Diluted EPS was calculated using the treasury stock method for options and the "if-converted" method for convertible securities.

	2016			2015		
	Net Earnings to Common Shareholders *($ millions)*	**Weighted Average Shares** *(# millions)*	**EPS**	Net Earnings to Common Shareholders *($ millions)*	Weighted Average Shares *(# millions)*	EPS
Basic EPS	**$ 585**	**308.9**	**$ 1.89**	$ 728	278.6	$ 2.61
Effect of potential dilutive securities:						
Stock Options	**–**	**0.7**		–	0.7	
Preference Shares	**7**	**3.8**		10	5.4	
Diluted EPS	**$ 592**	**313.4**	**$ 1.89**	$ 738	284.7	$ 2.59

19. PREFERENCE SHARES

Authorized

(a) an unlimited number of First Preference Shares, without nominal or par value
(b) an unlimited number of Second Preference Shares, without nominal or par value

Issued and Outstanding	2016		2015	
First Preference Shares	**Number of Shares** *(in thousands)*	**Amount** *(in millions)*	Number of Shares *(in thousands)*	Amount *(in millions)*
Series E	**–**	**$ –**	7,994	$ 197
Series F	**5,000**	**122**	5,000	122
Series G	**9,200**	**225**	9,200	225
Series H	**7,025**	**172**	7,025	172
Series I	**2,975**	**73**	2,975	73
Series J	**8,000**	**196**	8,000	196
Series K	**10,000**	**244**	10,000	244
Series M	**24,000**	**591**	24,000	591
	66,200	**$ 1,623**	74,194	$ 1,820

In September 2016 the Corporation redeemed all of the issued and outstanding $200 million 4.9% First Preference Shares, Series E at a redemption price of $25.3063 per share, being equal to $25.00 plus the amount of accrued and unpaid dividends per share. Upon redemption, approximately $3 million of after-tax issuance costs associated with the First Preference Shares, Series E were recognized in net earnings attributable to preference equity shareholders.

In June 2015, 2,975,154 of the 10,000,000 First Preference Shares, Series H were converted on a one-for-one basis into First Preference Shares, Series I.

Characteristics of the First Preference Shares are as follows.

First Preference Shares [1] [2]	**Initial Yield** *(%)*	**Annual Dividend** *($)*	**Reset Dividend Yield** *(%)*	**Earliest Redemption and/or Conversion Option Date**	**Redemption Value** *($)*	**Right to Convert on a One for One Basis**
Perpetual fixed rate						
Series F	4.90	1.2250	–	December 1, 2011	25.00	–
Series J [3]	4.75	1.1875	–	December 1, 2017	26.00	–
Fixed rate reset [4] [5]						
Series G	5.25	0.9708	2.13	September 1, 2013	25.00	–
Series H [6]	4.25	0.6250	1.45	June 1, 2015	25.00	Series I
Series K	4.00	1.0000	2.05	March 1, 2019	25.00	Series L
Series M	4.10	1.0250	2.48	December 1, 2019	25.00	Series N
Floating rate reset [5] [7]						
Series I [3]	2.10	–	1.45	June 1, 2015	25.50	Series H
Series L	–	–	2.05	March 1, 2024	–	Series K
Series N	–	–	2.48	December 1, 2024	–	Series M

[1] Holders are entitled to receive a fixed or floating cumulative quarterly cash dividend as and when declared by the Board of Directors of the Corporation, payable in equal quarterly installments on the first day of each quarter.

[2] On or after the specified redemption dates, the Corporation has the option to redeem for cash the outstanding First Preference Shares, in whole or in part, at the specified per share redemption value plus all accrued and unpaid dividends up to but excluding the dates fixed for redemption, and in the case of the Cumulative Redeemable Five-Year Fixed Rate Reset First Preference Shares, on every fifth anniversary date, thereafter.

[3] First Preference Shares, Series J are redeemable at $26.00 to December 1, 2018, decreasing $0.25 each year until December 1, 2021 and $25.00 per share thereafter. First Preference Shares, Series I are redeemable at $25.50 per share, up to and excluding June 1, 2020, and $25.00 per share on June 1, 2020, and on every fifth anniversary date, thereafter.

[4] On the redemption and/or conversion option date, and each five-year anniversary thereafter, the reset annual dividend per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date, plus the applicable reset dividend yield.

[5] On each conversion option date, the holders have the option, subject to certain conditions, to convert any or all of their Shares into an equal number of Cumulative Redeemable First Preference Shares of a specified series.

[6] The annual fixed dividend per share for First Preference Shares, Series H was reset from $1.0625 to $0.6250 for the five-year period from and including June 1, 2015 to but excluding June 1, 2020.

[7] The floating quarterly dividend rate will be reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus the applicable reset dividend yield.

On the liquidation, dissolution or winding-up of Fortis, holders of Common Shares are entitled to participate ratably in any distribution of assets of Fortis, subject to the rights of holders of First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive the assets of the Corporation on such a distribution in priority to or ratably with the holders of the Common Shares.

20. ACCUMULATED OTHER COMPREHENSIVE INCOME

Other comprehensive income or loss results from items deferred from recognition in the consolidated statement of earnings. The change in accumulated other comprehensive income by category is provided as follows.

	2016		
(in millions)	**Opening balance January 1**	**Net Change**	**Ending balance December 31**
Net unrealized foreign currency translation gains (losses):			
Unrealized foreign currency translation gains (losses) on net investments in foreign operations	**$ 1,281**	**$ (54)**	**$ 1,227**
(Losses) gains on hedges of net investments in foreign operations	**(476)**	**4**	**(472)**
Income tax recovery	**1**	**–**	**1**
	806	**(50)**	**756**
Available-for-sale investment: *(Notes 9, 28 and 30)*			
Realized gain on available-for-sale investment	**(2)**	**2**	**–**
Cash flow hedges: *(Note 30)*			
Net change in fair value of cash flow hedges	**3**	**5**	**8**
Income tax expense	**(1)**	**(2)**	**(3)**
	2	**3**	**5**
Unrealized employee future benefits (losses) gains: *(Note 26)*			
Unamortized net actuarial (losses) gains	**(20)**	**1**	**(19)**
Unamortized past service costs	**(1)**	**(2)**	**(3)**
Income tax recovery	**6**	**–**	**6**
	(15)	**(1)**	**(16)**
Accumulated other comprehensive income	**$ 791**	**$ (46)**	**$ 745**

	2015		
(in millions)	Opening balance January 1	Net Change	Ending balance December 31
Net unrealized foreign currency translation gains (losses):			
Unrealized foreign currency translation gains on net investments in foreign operations	$ 273	$ 1,008	$ 1,281
Losses on hedges of net investments in foreign operations	(131)	(345)	(476)
Income tax recovery	2	(1)	1
	144	662	806
Available-for-sale investment: *(Notes 9, 28 and 30)*			
Unrealized loss on available-for-sale investment	–	(2)	(2)
Cash flow hedges: *(Note 30)*			
Net change in fair value of cash flow hedges	1	2	3
Income tax expense	–	(1)	(1)
	1	1	2
Unrealized employee future benefits (losses) gains: *(Note 26)*			
Unamortized net actuarial losses	(20)	–	(20)
Unamortized past service costs	(2)	1	(1)
Income tax recovery	6	–	6
	(16)	1	(15)
Accumulated other comprehensive income	$ 129	$ 662	$ 791

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21. NON-CONTROLLING INTERESTS

(in millions)	**2016**	2015
ITC *(Note 27)*	**$ 1,385**	$ –
Waneta Partnership	**330**	335
Caribbean Utilities	**122**	122
Other	**16**	16
	$ 1,853	$ 473

22. STOCK-BASED COMPENSATION PLANS

Stock Options

The Corporation is authorized to grant officers and certain key employees of Fortis and its subsidiaries options to purchase common shares of the Corporation. As at December 31, 2016, the Corporation had the following stock option plans: the 2012 Plan and the 2006 Plan. The 2012 Plan was approved at the May 4, 2012 Annual General Meeting and will ultimately replace the 2006 Plan. The 2006 Plan will cease to exist when all outstanding options are exercised or expire in or before 2018. The former 2002 Plan expired in February 2016. The Corporation has ceased the granting of options under the 2006 Plan and all new options granted after 2011 are being made under the 2012 Plan.

Options granted under the 2006 Plan are exercisable for a period not to exceed seven years from the date of grant, expire no later than three years after the termination, death or retirement of the optionee and vest evenly over a four-year period on each anniversary of the date of grant.

Options granted under the 2012 Plan are exercisable for a period not to exceed ten years from the date of grant, expire no later than three years after the termination, death or retirement of the optionee and vest evenly over a four-year period on each anniversary of the date of grant.

The following options were granted in 2016 and 2015. The fair values of the options were estimated at the date of grant using the Black-Scholes fair value option-pricing model and the following assumptions:

	2016	2015
Options granted *(#)*	**788,188**	667,244
Exercise price *($)* [1]	**37.30**	39.25
Grant date fair value *($)*	**2.41**	2.46
Assumptions:		
Dividend yield *(%)* [2]	**3.9**	3.6
Expected volatility *(%)* [3]	**16.4**	14.6
Risk-free interest rate *(%)* [4]	**0.7**	0.9
Weighted average expected life *(years)* [5]	**5.5**	5.5

[1] Five-day VWAP immediately preceding the date of grant

[2] Based on average annual dividend yield up to the date of grant and the weighted average expected life of the options

[3] Based on historical experience over a period equal to the weighted average expected life of the options

[4] Government of Canada benchmark bond yield in effect at the date of grant that covers the weighted average expected life of the options

[5] Based on historical experience

The Corporation records compensation expense upon the issuance of stock options granted under its 2002, 2006 and 2012 Plans. Using the fair value method, each grant is treated as a single award, the fair value of which is amortized to compensation expense evenly over the four-year vesting period of the options.

The following table summarizes information related to stock options for 2016.

	Total Options		Non-vested Options [1]	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Grant Date Fair Value
Options outstanding, January 1, 2016	**4,416,454**	**$ 32.12**	**1,936,532**	**$ 3.30**
Granted	**788,188**	**$ 37.30**	**788,188**	**$ 2.41**
Exercised	**(1,041,450)**	**$ 26.74**	**n/a**	**n/a**
Vested	**n/a**	**n/a**	**(906,702)**	**$ 3.57**
Cancelled/Forfeited	**(3,000)**	**$ 31.68**	**(3,000)**	**$ 3.66**
Options outstanding, December 31, 2016	**4,160,192**	**$ 34.45**	**1,815,018**	**$ 2.78**
Options vested, December 31, 2016 [2]	**2,345,174**	**$ 33.14**		

[1] As at December 31, 2016, there was $5 million of unrecognized compensation expense related to stock options not yet vested, which is expected to be recognized over a weighted average period of approximately three years.

[2] As at December 31, 2016, the weighted average remaining term of vested options was six years with an aggregate intrinsic value of $20 million.

The following table summarizes additional 2016 and 2015 stock option information.

(in millions)	2016	2015
Stock option expense recognized	**$ 2**	$ 3
Stock options exercised:		
Cash received for exercise price	**28**	24
Intrinsic value realized by employees	**15**	10
Fair value of options that vested	**3**	3

Directors' DSU Plan

Under the Corporation's Directors' DSU Plan, directors who are not officers of the Corporation are eligible for grants of DSUs representing the equity portion of directors' annual compensation. In addition, directors can elect to receive credit for their quarterly cash retainer in a notional account of DSUs in lieu of cash. The Corporation may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled.

Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors. The DSUs are fully vested at the date of grant.

Number of DSUs	2016	2015
DSUs outstanding, beginning of year	**167,762**	176,124
Granted	**30,165**	28,737
Granted – notional dividends reinvested	**6,994**	7,037
DSUs paid out	**(5,510)**	(44,136)
DSUs outstanding, end of year	**199,411**	167,762

For 2016 expense of $2 million (2015 – $1 million) was recognized in earnings with respect to the DSU Plan.

In 2016, 5,510 DSUs were paid out to a deceased director at a price of $40.05 per DSU for a total of less than $1 million.

As at December 31, 2016, the liability related to outstanding DSUs has been recorded at the VWAP of the Corporation's common shares for the last five trading days of 2016 of $41.46, for a total of $8 million (December 31, 2015 – $6 million), and is included in long-term other liabilities (Note 16).

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22. STOCK-BASED COMPENSATION PLANS (cont'd)

PSU Plans

The Corporation's PSU Plans represent a component of long-term compensation awarded to senior management of the Corporation and its subsidiaries. As at December 31, 2016, the Corporation had the following PSU plans: the 2013 PSU Plan, the 2015 PSU Plan, and certain subsidiaries of the Corporation have also adopted similar share unit plans that are modelled after the Corporation's plans. Each PSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

The PSUs are subject to a three-year vesting and performance period, at which time a cash payment may be made, as determined by the Human Resources Committee of the Board of Directors. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by the VWAP of the Corporation's common shares for five trading days prior to the maturity of the grant and by a payout percentage that may range from 0% to 150%.

The payout percentage for the PSU Plans is based on the Corporation's performance over the three-year period, mainly determined by: (i) the Corporation's total shareholder return as compared to a pre-defined peer group of companies; and (ii) the Corporation's cumulative compound annual growth rate in earnings per common share, or for certain subsidiaries the Company's cumulative net income, as compared to the target established at the time of the grant. As at December 31, 2016, the estimated payout percentages for the grants under the 2013 and 2016 PSU Plans range from 88% to 113%.

The following table summarizes information related to the PSUs for 2016 and 2015.

Number of PSUs	**2016**	2015
PSUs outstanding, beginning of year	**694,386**	481,700
Granted	**351,737**	276,381
Granted – notional dividends reinvested	**34,439**	25,687
PSUs paid out [(1)]	**(148,168)**	(83,637)
PSUs cancelled/forfeited	**(443)**	(5,745)
PSUs outstanding, end of year	**931,951**	694,386

(1) Includes 2,432 PSUs paid to senior management on retirement in accordance with the PSU plan

In 2016, 145,736 PSUs were paid out to senior management of the Corporation and its subsidiaries at $37.72 per PSU, for a total of approximately $5 million. The payout was made in respect of the PSUs granted in 2013 at a payout percentage of 96% based on the Corporation's performance over the three-year period, as determined by the Human Resources Committee of the Board of Directors.

For 2016 expense of approximately $16 million (2015 – $12 million) was recognized in earnings with respect to the PSU Plans and there was $9 million of unrecognized compensation expense related to PSUs not yet vested, which is expected to be recognized over a weighted average period of approximately two years.

As at December 31, 2016, the aggregate intrinsic value of the outstanding PSUs was $39 million, with a weighted average contractual life of approximately one year. The liability related to outstanding PSUs has been recorded at the VWAP of the Corporation's common shares for the last five trading days of 2016 of $41.46, for a total of $30 million (December 31, 2015 – $19 million), and is included in accounts payable and other current liabilities and long-term other liabilities (Notes 13 and 16).

RSU Plans

The Corporation's 2015 RSU Plan represents a component of long-term compensation awarded to senior management of the Corporation and its subsidiaries. Each RSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is subject to a three-year vesting period, at which time a cash payment may be made. Each RSU is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

Number of RSUs	**2016**	2015
RSUs outstanding, beginning of year	**58,740**	–
Granted	**70,393**	59,462
Granted – notional dividends reinvested	**4,709**	2,150
RSUs paid out [(1)]	**(10,201)**	–
RSUs cancelled/forfeited	**(29)**	(2,872)
RSUs outstanding, end of year	**123,612**	58,740

(1) Reflects RSUs paid to senior management on retirement in accordance with the RSU plan

For 2016 expense of approximately $2 million (2015 – $1 million) was recognized in earnings with respect to the RSU Plan and there was approximately $2 million of unrecognized compensation expense related to RSUs not yet vested, which is expected to be recognized over a weighted average period of approximately two years.

As at December 31, 2016, the aggregate intrinsic value of the outstanding RSUs was $5 million, with a weighted average contractual life of approximately two years. The liability related to outstanding RSUs was recorded at the VWAP of the Corporation's common shares for the last five trading days of 2016 of $41.46, for a total of $3 million (December 31, 2015 – $1 million), and is included in long-term other liabilities (Note 16).

23. OTHER INCOME (EXPENSES), NET

(in millions)	**2016**	2015
Equity component of AFUDC	**$ 37**	$ 23
Interest income	**7**	8
Equity income – Belize Electricity	**7**	–
Net gain on sale of commercial real estate and hotel assets *(Note 28)* [1]	**–**	109
Gain on sale of non-regulated generation assets *(Note 28)* [2]	**–**	56
Net foreign exchange gain	**–**	13
Loss on settlement of expropriation matters *(Note 9)*	**–**	(9)
Other	**2**	(3)
	$ 53	$ 197

[1] Net of $23 million of expenses associated with the sale

[2] Net of $6 million of expenses and foreign exchange impacts associated with the sale

The net foreign exchange gain relates to the translation into Canadian dollars of the Corporation's previous US dollar-denominated long-term other asset, representing the book value of the Corporation's expropriated investment in Belize Electricity, up to the date of settlement of expropriation matters in August 2015 (Note 9). As a result of the settlement, the Corporation recognized an approximate $9 million loss in 2015. Unrealized foreign exchange gains and losses associated with the Corporation's 33% equity investment in Belize Electricity are recognized on the balance sheet in accumulated other comprehensive income.

24. FINANCE CHARGES

(in millions)	**2016**	2015
Interest – Long-term debt and capital lease and finance obligations	**$ 658**	$ 572
– Short-term borrowings	**10**	8
Acquisition credit facilities *(Notes 27 and 32)*	**39**	–
Debt component of AFUDC	**(29)**	(27)
	$ 678	$ 553

25. INCOME TAXES

Deferred Income Taxes

Deferred income taxes are provided for temporary differences. The significant components of deferred income tax assets and liabilities consist of the following.

(in millions)	**2016**	2015
Gross deferred income tax assets		
Tax loss and credit carryforwards	**$ 675**	$ 387
Regulatory liabilities	**292**	210
Employee future benefits	**155**	116
Fair value of long-term debt adjustment	**88**	–
Unrealized foreign exchange losses on long-term debt	**56**	65
Other	**57**	58
	1,323	836
Deferred income tax assets valuation allowance	**(56)**	(73)
Net deferred income tax assets	**$ 1,267**	$ 763
Gross deferred income tax liabilities		
Utility capital assets	**$ (4,213)**	$ (2,575)
Regulatory assets	**(242)**	(201)
Intangible assets	**(75)**	(37)
	(4,530)	(2,813)
Net deferred income tax liability	**$ (3,263)**	$ (2,050)

The deferred income tax asset associated with unrealized foreign exchange losses on long-term debt reflects $56 million of unrealized capital losses as at December 31, 2016 (December 31, 2015 – $65 million). The deferred income tax asset can only be used if the Corporation has capital gains to offset the losses once realized. Management believes that it is more likely than not that Fortis will not be able to generate future capital gains and, as a result, the Corporation recorded a $56 million valuation allowance against the deferred income tax asset as at December 31, 2016 (December 31, 2015 – $65 million). Management believes that based on its historical pattern of taxable income, Fortis will produce sufficient income in the future to realize all other deferred income tax assets.

Unrecognized Tax Benefits

The following table summarizes the change in unrecognized tax benefits during 2016 and 2015.

(in millions)	**2016**	2015
Total unrecognized tax benefits, beginning of year	**$ 13**	$ 11
Additions related to the current year	**10**	1
Adjustments related to prior years	**–**	1
Total unrecognized tax benefits, end of year	**$ 23**	$ 13

Unrecognized tax benefits, if recognized, would reduce income tax expense by $1 million in 2016. Fortis has not recognized interest expense in 2016 and 2015 related to unrecognized tax benefits.

The components of the income tax expense were as follows.

(in millions)	**2016**	2015
Canadian		
Earnings before income taxes	**$ 357**	$ 544
Current income taxes	**66**	59
Deferred income taxes	**54**	113
Less: regulatory adjustments	**(77)**	(100)
	(23)	13
Total Canadian	**$ 43**	$ 72
Foreign		
Earnings before income taxes	**$ 501**	$ 519
Current income taxes	**(19)**	–
Deferred income taxes	**121**	151
Total Foreign	**$ 102**	$ 151
Income tax expense	**$ 145**	$ 223

Income taxes differ from the amount that would be expected to be generated by applying the enacted combined Canadian federal and provincial statutory income tax rate to earnings before income taxes. The following is a reconciliation of consolidated statutory taxes to consolidated effective taxes.

(in millions, except as noted)	**2016**	2015
Earnings before income taxes	**$ 858**	$ 1,063
Combined Canadian federal and provincial statutory income tax rate	**28.0%**	27.5%
Statutory income tax rate applied to earnings before income taxes	**$ 240**	$ 292
Difference between Canadian statutory income tax rate and rates applicable to foreign subsidiaries	**(28)**	(7)
Difference in Canadian provincial statutory income tax rates applicable to subsidiaries in different Canadian jurisdictions	**(4)**	(4)
Items capitalized for accounting purposes but expensed for income tax purposes	**(40)**	(39)
Difference between gain on sale of assets for accounting and amounts calculated for tax purposes	**–**	(18)
Change in tax rates and legislation	**(6)**	13
Difference between capital cost allowance and amounts claimed for accounting purposes	**(25)**	(15)
Other	**8**	1
Income tax expense	**$ 145**	$ 223
Effective tax rate	**16.9%**	21.0%

For the years ended December 31, 2016 and 2015

25. INCOME TAXES (cont'd)

As at December 31, 2016, the Corporation had the following tax carryforward amounts.

(in millions)	Expiring Year	Amount
Canadian		
Capital loss	n/a	**$ 76**
Non-capital loss	2025 – 2036	**244**
Other tax credits	2026 – 2035	**2**
		322
Unrecognized in the consolidated financial statements		**(76)**
		$ 246
Foreign		
Capital loss	2020 – 2021	**$ 3**
Federal and state net operating loss	2031 – 2036	**862**
Other tax credits	2032 – 2036	**126**
		991
Unrecognized in the consolidated financial statements		**(2)**
		$ 989
Total tax carryforwards		**$ 1,235**

As at December 31, 2016, the Corporation had approximately $1,235 million in tax carryforward amounts recognized in the consolidated financial statements (December 31, 2015 – $912 million).

The Corporation and one or more of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Corporation is subject to potential examinations include the United States (Federal, Arizona, Kansas, Iowa, Michigan, Minnesota and New York) and Canada (Federal and British Columbia). The Corporation's 2011 to 2016 taxation years are still open for audit in the Canadian jurisdictions and 2012 to 2016 taxation years are still open for audit in the United States jurisdictions. The Corporation is not currently under examination for income tax matters in any of these jurisdictions.

26. EMPLOYEE FUTURE BENEFITS

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, OPEB plans, and defined contribution pension plans. For the defined benefit pension and OPEB plan arrangements, the benefit obligation and the fair value of plan assets are measured for accounting purposes as at December 31 of each year.

Actuarial valuations are required to determine funding contributions for pension plans, at least, every three years for Fortis' Canadian and Caribbean subsidiaries. The most recent valuations were as of December 31, 2013 for FortisBC Electric, FortisBC Energy (plans covering unionized employees) and Caribbean Utilities; December 31, 2014 for Newfoundland Power, FortisOntario and the Corporation; and December 31, 2015 for FortisAlberta and FortisBC Energy (plan covering non-unionized employees).

ITC, UNS Energy and Central Hudson perform annual actuarial valuations, as their funding contribution requirements are based on maintaining annual target fund percentages. ITC, UNS Energy and Central Hudson have all met the minimum funding requirements.

The Corporation's investment policy is to ensure that the defined benefit pension and OPEB plan assets, together with expected contributions, are invested in a prudent and cost-effective manner to optimally meet the liabilities of the plans for its members. The investment objective of the defined benefit pension and OPEB plans is to maximize return in order to manage the funded status of the plans and minimize the Corporation's cost over the long term, as measured by both cash contributions and defined benefit pension and OPEB expense for consolidated financial statement purposes.

The Corporation's consolidated defined benefit pension and OPEB plan weighted average asset allocations were as follows.

Plan assets as at December 31 *(%)*	**2016 Target Allocation**	**2016**	2015
Equities	**50**	**50**	51
Fixed income	**46**	**45**	44
Real estate	**4**	**4**	4
Cash and other	**–**	**1**	1
	100	**100**	100

The fair value measurements of defined benefit pension and OPEB plan assets by fair value hierarchy, as defined in Note 30, were as follows.

Fair value of plan assets as at December 31, 2016

(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Equities	**$ 507**	**$ 942**	**$ –**	**$ 1,449**
Fixed income	**124**	**1,180**	**–**	**1,304**
Real estate	**–**	**13**	**103**	**116**
Private equities	**–**	**–**	**10**	**10**
Cash and other	**6**	**13**	**–**	**19**
	$ 637	**$ 2,148**	**$ 113**	**$ 2,898**

Fair value of plan assets as at December 31, 2015

(in millions)	Level 1	Level 2	Level 3	Total
Equities	$ 417	$ 922	$ –	$ 1,339
Fixed income	–	1,166	–	1,166
Real estate	–	14	97	111
Private equities	–	–	10	10
Cash and other	3	18	–	21
	$ 420	$ 2,120	$ 107	$ 2,647

The following table is a reconciliation of changes in the fair value of pension plan assets that have been measured using Level 3 inputs for the years ended December 31, 2016 and 2015.

(in millions)	**2016**	2015
Balance, beginning of year	**$ 107**	$ 93
Actual return on plan assets held at end of year	**8**	9
Foreign currency translation impacts	**(1)**	5
Purchases, sales and settlements	**(1)**	–
Balance, end of year	**$ 113**	$ 107

For the years ended December 31, 2016 and 2015

26. EMPLOYEE FUTURE BENEFITS (cont'd)

The following is a breakdown of the Corporation's and subsidiaries' defined benefit pension and OPEB plans and their respective funded status.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2016**	2015	**2016**	2015
Change in benefit obligation [1]				
Balance, beginning of year	**$ 2,828**	$ 2,604	**$ 574**	$ 564
Liabilities assumed on acquisition	**167**	–	**111**	–
Service costs	**66**	68	**18**	17
Employee contributions	**17**	17	**2**	1
Interest costs	**112**	109	**23**	23
Benefits paid	**(119)**	(118)	**(23)**	(21)
Actuarial losses (gains)	**45**	(102)	**(1)**	(50)
Past service credits/plan amendments	**(10)**	–	**–**	(10)
Foreign currency translation impacts	**(69)**	250	**(28)**	50
Balance, end of year [2]	**$ 3,037**	$ 2,828	**$ 676**	$ 574
Change in value of plan assets				
Balance, beginning of year	**$ 2,466**	$ 2,216	**$ 181**	$ 154
Assets assumed on acquisition	**85**	–	**65**	–
Actual return on plan assets	**187**	30	**13**	–
Benefits paid	**(119)**	(118)	**(23)**	(21)
Employee contributions	**17**	17	**2**	1
Employer contributions	**47**	99	**18**	17
Foreign currency translation impacts	**(37)**	222	**(4)**	30
Balance, end of year	**$ 2,646**	$ 2,466	**$ 252**	$ 181
Funded status	**$ (391)**	$ (362)	**$ (424)**	$ (393)

[1] Amounts reflect projected benefit obligation for defined benefit pension plans and accumulated benefit obligation for OPEB plans.

[2] The accumulated benefit obligation for defined benefit pension plans, excluding assumptions about future salary levels, was $2,741 million as at December 31, 2016 (December 31, 2015 – $2,595 million).

The following table summarizes the employee future benefit assets and liabilities and their classifications on the consolidated balance sheet.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2016**	2015	**2016**	2015
Assets				
Defined benefit pension assets:				
Long-term other assets *(Note 9)*	**$ 32**	$ 11	**$ –**	$ –
Liabilities				
Defined benefit pension liabilities:				
Current *(Note 13)*	**13**	5	**–**	–
Long-term other liabilities *(Note 16)*	**410**	368	**–**	–
OPEB plan liabilities:				
Current *(Note 13)*	**–**	–	**13**	8
Long-term other liabilities *(Note 16)*	**–**	–	**411**	385
Net liabilities	**$ 391**	$ 362	**$ 424**	$ 393

The net benefit cost for the Corporation's defined benefit pension plans and OPEB plans were as follows.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2016**	2015	**2016**	2015
Components of net benefit cost				
Service costs	**$ 66**	$ 68	**$ 18**	$ 17
Interest costs	**112**	109	**23**	23
Expected return on plan assets	**(145)**	(140)	**(12)**	(12)
Amortization of actuarial losses	**48**	57	**2**	5
Amortization of past service credits/plan amendments	**1**	2	**(10)**	(12)
Regulatory adjustments	**6**	1	**9**	6
Net benefit cost	**$ 88**	$ 97	**$ 30**	$ 27

The following table provides the components of accumulated other comprehensive loss and regulatory assets and liabilities, which would otherwise have been recognized as accumulated other comprehensive loss, for the years ended December 31, 2016 and 2015, which have not been recognized as components of net benefit cost.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2016**	2015	**2016**	2015
Unamortized net actuarial losses	**$ 19**	$ 16	**$ –**	$ 4
Unamortized past service costs	**1**	1	**2**	–
Income tax recovery	**(5)**	(5)	**(1)**	(1)
Accumulated other comprehensive loss *(Note 20)*	**$ 15**	$ 12	**$ 1**	$ 3
Net actuarial losses	**$ 479**	$ 513	**$ 53**	$ 41
Past service credits	**(11)**	–	**(31)**	(33)
Amount deferred due to actions of regulators	**12**	23	**32**	39
	$ 480	$ 536	**$ 54**	$ 47
Regulatory assets *(Note 8 (ii))*	**$ 480**	$ 536	**$ 96**	$ 91
Regulatory liabilities *(Note 8 (ii))*	**–**	–	**(42)**	(44)
Net regulatory assets	**$ 480**	$ 536	**$ 54**	$ 47

The following table provides the components recognized in comprehensive income or as regulatory assets, which would otherwise have been recognized in comprehensive income.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2016**	2015	**2016**	2015
Current year net actuarial losses (gains)	**$ 4**	$ –	**$ (2)**	$ (1)
Past service credits/plan amendments	**–**	–	**–**	(1)
Amortization of actuarial gains	**–**	1	**–**	–
Income tax recovery	**(1)**	–	**–**	–
Total recognized in comprehensive income	**$ 3**	$ 1	**$ (2)**	$ (2)
Assets assumed on acquisition	**$ 23**	$ –	**$ 3**	$ –
Current year net actuarial (gains) losses	**(1)**	8	**–**	(28)
Past service credits/plan amendments	**(10)**	–	**–**	(10)
Amortization of actuarial losses	**(47)**	(56)	**(4)**	(5)
Amortization of past service costs	**(1)**	(1)	**13**	(2)
Foreign currency translation impacts	**(9)**	49	**1**	(6)
Regulatory adjustments	**(11)**	5	**(6)**	7
Total recognized in regulatory assets	**$ (56)**	$ 5	**$ 7**	$ (44)

For the years ended December 31, 2016 and 2015

26. EMPLOYEE FUTURE BENEFITS (cont'd)

Net actuarial losses of $1 million are expected to be amortized from accumulated other comprehensive income into net benefit cost in 2017 related to defined benefit pension plans.

Net actuarial losses of $43 million, past service credits of $1 million and regulatory adjustments of $2 million are expected to be amortized from regulatory assets into net benefit cost in 2017 related to defined benefit pension plans. Net actuarial losses of $1 million, past service credits of $10 million and regulatory adjustments of $8 million are expected to be amortized from regulatory assets into net benefit cost in 2017 related to OPEB plans.

Significant weighted average assumptions	**Defined Benefit Pension Plans**		**OPEB Plans**	
(%)	**2016**	2015	**2016**	2015
Discount rate during the year [1]	**4.08**	4.00	**4.14**	3.95
Discount rate as at December 31	**4.00**	4.21	**4.00**	4.12
Expected long-term rate of return on plan assets [2]	**6.25**	6.25	**6.25**	6.95
Rate of compensation increase	**3.36**	3.48	**–**	–
Health care cost trend increase as at December 31 [3]	**–**	–	**4.70**	4.67

[1] ITC and UNS use the split discount rate methodology for determining current service and interest costs. All other subsidiaries use the single discount rate approach.

[2] Developed by management with assistance from external actuaries using best estimates of expected returns, volatilities and correlations for each class of asset. The best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes.

[3] The projected 2017 weighted average health care cost trend rate is 6.62% for OPEB plans and is assumed to decrease over the next 12 years by 2028 to the weighted average ultimate health care cost trend rate of 4.70% and remain at that level thereafter.

For 2016 the effects of changing the health care cost trend rate by 1% were as follows.

(in millions)	**1% increase in rate**	**1% decrease in rate**
Increase (decrease) in accumulated benefit obligation	**$ 89**	**$ (71)**
Increase (decrease) in service and interest costs	**19**	**(13)**

The following table provides the amount of benefit payments expected to be made over the next 10 years.

Year	**Defined Benefit Pension Payments** *(in millions)*	**OPEB Payments** *(in millions)*
2017	$ 133	$ 24
2018	135	25
2019	140	27
2020	146	28
2021	152	30
2022 – 2026	848	173

During 2017 the Corporation expects to contribute $63 million for defined benefit pension plans and $31 million for OPEB plans.

In 2016 the Corporation expensed $31 million (2015 – $28 million) related to defined contribution pension plans.

27. BUSINESS ACQUISITIONS

ITC

On October 14, 2016, Fortis and GIC acquired all of the outstanding common shares of ITC for an aggregate purchase price of approximately US$11.8 billion ($15.7 billion) on closing, including approximately US$4.8 billion ($6.3 billion) of ITC consolidated indebtedness. ITC is now a subsidiary of Fortis, with an affiliate of GIC owning a 19.9% minority interest in ITC.

Under the terms of the transaction, ITC shareholders received US$22.57 in cash and 0.7520 of a Fortis common share per ITC share, representing total consideration of approximately US$7.0 billion ($9.4 billion). The net cash consideration totalled approximately US$3.5 billion ($4.7 billion) and was financed using: (i) net proceeds from the issuance of US$2.0 billion unsecured notes in October 2016 (Note 14); (ii) net proceeds from GIC's US$1.228 billion minority investment (Note 21), which includes a shareholder note of US$199 million (Note 14); and (iii) drawings of approximately US$404 million ($535 million) under the Corporation's non-revolving term senior unsecured equity bridge credit facility (Note 32). On October 14, 2016, approximately 114.4 million common shares of Fortis were issued to shareholders of ITC, representing share consideration of approximately US$3.5 billion ($4.7 billion), based on the closing price for Fortis common shares of $40.96 and the closing foreign exchange rate of US$1.00=CAD$1.32 on October 13, 2016 (Note 17). The financing of the acquisition was structured to allow Fortis to maintain investment-grade credit ratings.

ITC is the largest independent electric transmission company in the United States. Based in Novi, Michigan, ITC invests in the electrical transmission grid to improve reliability, expand access to markets, allow new generating resources to interconnect to its transmission systems and lower the overall cost of delivered energy. Through its regulated operating subsidiaries ITCTransmission, METC, ITC Midwest and ITC Great Plains, ITC owns and operates high-voltage transmission lines serving a combined peak load exceeding 26,000 MW along approximately 25,000 kilometres in Michigan's lower peninsula and portions of Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma that transmit electricity from approximately 570 generating stations to local distribution facilities connected to ITC's systems.

Each of the ITC regulated operating subsidiaries is an electric transmission utility subject to rate regulation by FERC (Note 2). The determination of revenue and earnings is based on regulated rates of return that are applied to historic values, which do not change with a change of ownership. Therefore, with the exception of a fair market value adjustment for long-term debt at the ITC parent company level outside of regulated operations, which debt does not form part of the rate-making process, along with the related impact on deferred income taxes, no other fair market value adjustments to ITC's assets and liabilities have been recognized because all of the economic benefits and obligations associated with regulated assets and liabilities beyond regulated rates of return accrue to ITC's customers.

The following table summarizes the preliminary allocation of the purchase consideration to the assets and liabilities acquired as at October 14, 2016 based on their fair values, using an exchange rate of US$1.00=$CAD$1.32. The purchase price allocation is preliminary pending final assessment of fair value estimates, income taxes, consideration transferred, and identification of assets and liabilities.

(in millions)	**Total**
Share consideration	**$ 4,684**
Cash consideration	**4,658**
Total consideration	**$ 9,342**
Purchase consideration for 80.1% of ITC common shares	**$ 7,721**
19.9% minority shareholder investment and shareholder note *(Notes 14 and 21)*	**1,621**
	$ 9,342
Fair value assigned to net assets:	
Current assets	**$ 319**
Long-term regulatory assets	**319**
Utility capital assets	**8,345**
Intangible assets	**392**
Other long-term assets	**71**
Current liabilities	**(625)**
Assumed short-term borrowings	**(311)**
Assumed long-term debt (including current portion)	**(5,989)**
Long-term regulatory liabilities	**(327)**
Deferred income taxes	**(926)**
Other long-term liabilities	**(166)**
	1,102
Cash and cash equivalents	**134**
Fair value of net assets acquired	**1,236**
Goodwill *(Note 12)*	**$ 8,106**

The acquisition has been accounted for using the acquisition method, whereby financial results of the business acquired have been consolidated in the financial statements of Fortis commencing on October 14, 2016.

For the years ended December 31, 2016 and 2015

27. *BUSINESS ACQUISITIONS (cont'd)*

ITC (cont'd)

Acquisition-related expenses totalled approximately $118 million ($90 million after tax) in 2016 (2015 – $10 million ($7 million after tax)). Acquisition-related expenses included: (i) investment banking, legal, consulting and other fees totalling approximately $79 million ($62 million after tax) in 2016 (2015 – $10 million ($7 million after tax)), which were included in operating expenses; and (ii) fees associated with the Corporation's acquisition credit facilities and deal-contingent interest rate swap contracts totalling approximately $39 million ($28 million after tax) in 2016 (2015 – nil), which were included in finance charges (Note 24). From the date of acquisition, ITC also recognized US$21 million ($27 million) in after-tax expenses associated with the accelerated vesting of the Company's stock-based compensation awards as a result of the acquisition, of which the Corporation's share was US$17 million ($22 million).

Supplemental Pro Forma Data

The unaudited pro forma financial information below gives effect to the acquisition of ITC as if the transaction had occurred at the beginning of 2015. This pro forma data is presented for information purposes only, and does not necessarily represent the results that would have occurred had the acquisition taken place at the beginning of 2015, nor is it necessarily indicative of the results that may be expected in future periods.

(in millions)	**2016**	2015
Pro forma revenue	**$ 7,995**	$ 8,093
Pro forma net earnings attributable to common equity shareholders [1]	**919**	937

[1] Pro forma net earnings attributable to common equity shareholders exclude all after-tax acquisition-related expenses incurred by ITC and the Corporation. A pro forma adjustment has been made to net earnings for the years presented to reflect the Corporation's after-tax financing costs associated with the acquisition.

Aitken Creek

On April 1, 2016, Fortis acquired ACGS from Chevron Canada Properties Ltd. for approximately $349 million (US$266 million), plus the cost of working gas inventory. The net cash purchase price was initially financed through US dollar-denominated borrowings under the Corporation's committed revolving credit facility. In December 2015 the Corporation paid a deposit of $38 million (US$29 million) as part of the purchase consideration for the transaction (Note 9).

ACGS owns 93.8% of Aitken Creek, with the remaining share owned by BP Canada Energy Company. Aitken Creek is the only underground natural gas storage facility in British Columbia and has a total working gas capacity of 77 billion cubic feet. The facility is an integral part of western Canada's natural gas transmission network. ACGS also owns 100% of the North Aitken Creek gas storage site which offers future expansion potential.

The preliminary allocation of purchase consideration to the assets and liabilities acquired as at April 1, 2016, based on their fair values, resulted in the recognition of approximately $27 million in goodwill, which is associated with deferred income tax liabilities. The purchase price allocation is preliminary pending final assessment of deferred income tax liabilities and working capital. The acquisition has been accounted for using the acquisition method, whereby financial results of the business acquired have been consolidated in the financial statements of Fortis commencing on April 1, 2016.

28. DISPOSITIONS

Walden

In February 2016 FortisBC Electric sold the non-regulated Walden hydroelectric power plant assets for gross proceeds of approximately $9 million, and as a result recognized a gain on sale of less than $1 million, after tax and transaction costs.

Sale of Commercial Real Estate and Hotel Assets

In June 2015 the Corporation completed the sale of the commercial real estate assets of Fortis Properties for gross proceeds of $430 million. As a result of the sale, the Corporation recognized a gain on sale of $129 million ($109 million after tax), net of expenses (Note 23). As part of the transaction, Fortis subscribed to $35 million in trust units of Slate Office REIT in conjunction with the REIT's public offering. The Corporation sold the trust units of Slate Office REIT in November 2016 for gross proceeds of $37 million.

In October 2015 the Corporation completed the sale of the hotel assets of Fortis Properties for gross proceeds of $365 million. As a result of the sale, the Corporation recognized a loss of approximately $20 million ($8 million after tax), which reflected an impairment loss and expenses associated with the sale transaction (Note 23).

Net proceeds from the sales were used by the Corporation to repay credit facility borrowings, the majority of which were used to finance a portion of the acquisition of UNS Energy, and for other general corporate purposes.

Earnings before taxes related to Fortis Properties of approximately $18 million were recognized in 2015, excluding the net gain on sale.

Sale of Non-Regulated Generation Assets in New York and Ontario

In June 2015 the Corporation sold its non-regulated generation assets in Upstate New York for gross proceeds of approximately $77 million (US$63 million). As a result of the sale, the Corporation recognized a gain on sale of $51 million (US$41 million) ($27 million (US$22 million) after tax), net of expenses and foreign exchange impacts (Note 23).

In July 2015 the Corporation sold its non-regulated generation assets in Ontario for gross proceeds of approximately $16 million. As a result of the sale, the Corporation recognized a gain on sale of $5 million ($5 million after tax) (Note 23).

Earnings before taxes of less than $1 million were recognized in 2015, excluding the gain on sale.

29. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	**2016**	2015
Cash paid for:		
Interest	**$ 644**	$ 561
Income taxes	**62**	109
Change in non-cash operating working capital:		
Accounts receivable and other current assets	**$ 43**	$ 14
Prepaid expenses	**(4)**	(1)
Inventories	**17**	15
Regulatory assets – current portion	**(58)**	57
Accounts payable and other current liabilities	**25**	(82)
Regulatory liabilities – current portion	**(1)**	38
	$ 22	$ 41
Non-cash investing and financing activities:		
Common share dividends reinvested	**$ 162**	$ 156
Common shares issued on business acquisition *(Notes 17 and 27)*	**4,684**	–
Additions to utility capital assets and intangible assets included in current and long-term liabilities	**296**	187
Commitment to purchase capital lease interest *(Note 15)*	**48**	–
Transfer of deposit on business acquisition *(Note 27)*	**38**	–
Contributions in aid of construction included in current assets	**9**	4
Exercise of stock options into common shares	**4**	4

30. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS

Fair value is the price at which a market participant could sell an asset or transfer a liability to an unrelated party. A fair value measurement is required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. A fair value hierarchy exists that prioritizes the inputs used to measure fair value.

The three levels of the fair value hierarchy are defined as follows:

Level 1: Fair value determined using unadjusted quoted prices in active markets;
Level 2: Fair value determined using pricing inputs that are observable; and
Level 3: Fair value determined using unobservable inputs only when relevant observable inputs are not available.

The fair values of the Corporation's financial instruments, including derivatives, reflect point-in-time estimates based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flows.

The following table presents, by level within the fair value hierarchy, the Corporation's assets and liabilities accounted for at fair value on a recurring basis. These assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement and there were no transfers between the levels in the periods presented. For derivative instruments, the Corporation has elected gross presentation for its derivative contracts under master netting agreements and collateral positions.

(in millions)	**Fair value hierarchy**	**2016**	2015
Assets			
Energy contracts subject to regulatory deferral [1][2][3]	Levels 1/2/3	**$ 19**	$ 7
Energy contracts not subject to regulatory deferral [1][2]	Level 3	**3**	2
Interest rate swaps – cash flow hedges [4]	Level 2	**11**	–
Available-for-sale investment *(Notes 9 and 28)*	Level 1	**–**	33
Assets held for sale	Level 2	**–**	9
Other investments [5]	Level 1	**69**	12
Total gross assets		**102**	63
Less: Counterparty netting not offset on the balance sheet [6]		**(9)**	(6)
Total net assets		**$ 93**	$ 57
Liabilities			
Energy contracts subject to regulatory deferral [1][2][7]	Levels 2/3	**$ 26**	$ 78
Energy contracts not subject to regulatory deferral [1]	Level 2	**9**	–
Interest rate swaps – cash flow hedges [4]	Level 2	**3**	5
Total gross liabilities		**38**	83
Less: Counterparty netting not offset on the balance sheet [6]		**(9)**	(6)
Total net liabilities		**$ 29**	$ 77

[1] The fair value of the Corporation's energy contracts is recognized in accounts receivable and other current assets, long-term other assets, accounts payable and other current liabilities and long-term other liabilities. Unrealized gains and losses arising from changes in fair value of these contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates as permitted by the regulators, with the exception of long-term wholesale trading contracts and certain gas swap contracts.

[2] Changes in one or more of the unobservable inputs could have a significant impact on the fair value measurement depending on the magnitude and direction of the change for each input. The impacts of changes in fair value are subject to regulatory recovery, with the exception of long-term wholesale trading contracts and certain gas swap contracts.

[3] As at December 31, 2016, includes $1 million – level 1, $13 million – level 2 and $5 million – level 3 (December 31, 2015 – $2 million – level 2 and $5 million – level 3)

[4] The fair value of the Corporation's interest rate swaps is recognized in accounts receivable and other current assets, accounts payable and other current liabilities and long-term other liabilities.

[5] Included in long-term other assets on the consolidated balance sheet (Note 9).

[6] Certain energy contracts are subject to legally enforceable master netting arrangements to mitigate credit risk and are netted by counterparty where the intent and legal right to offset exists.

[7] As at December 31, 2016, includes $21 million – level 2 and $5 million – level 3 (December 31, 2015 – $1 million – level 1, $52 million – level 2 and $25 million – level 3)

Derivative Instruments

The Corporation generally limits the use of derivative instruments to those that qualify as accounting, economic or cash flow hedges, or those that are approved for regulatory recovery. The Corporation records all derivative instruments at fair value, with certain exceptions including those derivatives that qualify for the normal purchase and normal sale exception. The fair value of derivative instruments is the estimate of the amounts that the Corporation would receive or have to pay to terminate the outstanding contracts as at the balance sheet dates.

Energy Contracts Subject to Regulatory Deferral

UNS Energy holds electricity power purchase contracts and gas swap and option contracts to reduce its exposure to energy price risk associated with purchased power and gas requirements. UNS Energy primarily applies the market approach for fair value measurements using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships, transmission costs and line losses. The fair value of gas option contracts is estimated using a Black-Scholes option-pricing model, which includes inputs such as implied volatility, interest rates, and forward price curves. UNS Energy also considers the impact of counterparty credit risk using current and historical default and recovery rates, as well as its own credit risk using credit default swap data.

Central Hudson holds swap contracts for electricity and natural gas to minimize price volatility by fixing the effective purchase price for the defined commodities. The fair value of the swap contracts was calculated using forward pricing provided by independent third parties.

FortisBC Energy holds gas supply contract premiums to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. The fair value of the natural gas derivatives was calculated using the present value of cash flows based on market prices and forward curves for the cost of natural gas.

As at December 31, 2016, these energy contract derivatives were not designated as hedges; however, any unrealized gains or losses associated with changes in the fair value of the derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. These unrealized losses and gains would otherwise be recognized in earnings. As at December 31, 2016, unrealized losses of $19 million (December 31, 2015 – $74 million) were recognized in regulatory assets and unrealized gains of $12 million were recognized in regulatory liabilities (December 31, 2015 – $3 million) (Note 8 *(ix)*).

Energy Contracts Not Subject to Regulatory Deferral

UNS Energy holds long-term wholesale trading contracts that qualify as derivative instruments. The unrealized gains and losses on these derivative instruments are recognized in earnings, as they do not qualify for regulatory deferral. Ten percent of any realized gains on these contracts are shared with customers through UNS Energy's rate stabilization accounts.

Aitken Creek holds gas supply contract premiums and gas swap contracts to manage its exposure to changes in natural gas prices, to capture natural gas price spreads, and to manage the financial risk posed by physical transactions. The fair value of the gas swap contracts was calculated using forward pricing provided by third parties. The unrealized gains and losses on these derivative instruments are recognized in earnings. As at December 31, 2016, unrealized losses totalled $9 million ($6 million after tax).

Cash Flow Hedges

UNS Energy holds an interest rate swap, expiring in 2020, to mitigate its exposure to volatility in variable interest rates on capital lease obligations (Note 15).

ITC holds forward-starting interest rate swaps, effective January 2018 and expiring in 2028, with notional amounts totalling US$100 million. The agreements include a mandatory early termination provision and will be terminated no later than the effective date. The interest rate swaps manage the interest rate risk associated with the forecasted future issuance of fixed-rate debt related to the refinancing of maturing US$385 million long-term debt due in January 2018. As at December 31, 2016, the unrealized gain on the derivatives was $11 million (US$8 million).

The unrealized gains and losses on cash flow hedges are recognized in other comprehensive income and reclassified to earnings as a component of interest expense over the life of the hedged debt (Note 20). The loss expected to be reclassified to earnings within the next twelve months is estimated to be approximately $5 million. Cash flows associated with the settlement of all derivative instruments are included in operating activities on the Corporation's consolidated statement of cash flows.

For the years ended December 31, 2016 and 2015

30. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS (cont'd)

Volume of Derivative Activity

As at December 31, 2016, the following notional volumes related to electricity and natural gas derivatives that are expected to be settled are outlined below.

Volume [1]	Maturity (year)	Contracts (#)	2017	2018	2019	2020	2021	There-after
Energy contracts subject to regulatory deferral:								
Electricity swap contracts *(GWh)*	2019	8	**1,089**	657	438	–	–	–
Electricity power purchase contracts *(GWh)*	2017	39	**1,252**	–	–	–	–	–
Gas swap and option contracts *(PJ)*	2019	108	**20**	11	4	–	–	–
Gas supply contract premiums *(PJ)*	2024	85	**82**	45	26	22	22	43
Energy contracts not subject to regulatory deferral:								
Long-term wholesale trading contracts *(GWh)*	2017	18	**2,058**	–	–	–	–	–
Gas supply contract premiums *(PJ)*	2017	226	**15**	–	–	–	–	–
Gas swap contracts *(PJ)*	2017	7	**4**	–	–	–	–	–

[1] GWh means gigawatt hours and PJ means petajoules

Financial Instruments Not Carried At Fair Value

The following table discloses the estimated fair value measurements of the Corporation's financial instruments not carried at fair value. The fair values were measured using Level 2 pricing inputs, except as noted. The carrying values of the Corporation's consolidated financial instruments approximate their fair values, reflecting the short-term maturity, normal trade credit terms and/or nature of these instruments, except as follows:

	2016		2015	
(in millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt, including current portion *(Note 14)* [1]	**$ 21,219**	**$ 22,523**	$ 11,244	$ 12,614
Waneta Partnership promissory note *(Note 16)* [2]	**59**	**61**	56	59

[1] The Corporation's $200 million unsecured debentures due 2039, $500 million unsecured senior notes due 2023, and consolidated borrowings under credit facilities classified as long-term debt of $973 million (December 31, 2015 – $551 million) are valued using Level 1 inputs. All other long-term debt is valued using Level 2 inputs.

[2] Included in long-term other liabilities on the consolidated balance sheet (Note 16).

The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, as is the case with the Waneta Partnership promissory note and certain long-term debt, the fair value is determined by either: (i) discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality; or (ii) obtaining from third parties indicative prices for the same or similarly rated issues of debt of the same remaining maturities. Since the Corporation does not intend to settle the long-term debt or promissory note prior to maturity, the excess of the estimated fair value above the carrying value does not represent an actual liability.

31. VARIABLE INTEREST ENTITY

On adoption of ASU No. 2015-02, *Amendments to the Consolidation Analysis*, effective January 1, 2016, Fortis was required to reassess its limited partnerships under the voting interest model. As a result, the Corporation's ownership interest in the Waneta Partnership is considered to be a variable interest entity ("VIE") based on an assessment of the rights of the limited partners and the general partner. It was determined under the VIE model that the Corporation is the primary beneficiary of the Waneta Partnership and should, therefore, continue to consolidate its investment. As the primary beneficiary, the Corporation has the power to direct the activities of the partnership and the obligation to absorb losses or the right to receive benefits that could potentially be significant to the partnership, as discussed below.

The purpose of the Waneta Partnership was to construct, own and operate the Waneta Expansion on the Pend d'Oreille River south of Trail, British Columbia, which was completed in April 2015. The Corporation has a 51% controlling ownership interest in the Waneta Partnership, with CPC/CBT holding the remaining 49% interest. The general partner, which is owned by the Corporation and CPC/CBT in the same proportion as the Waneta Partnership, has a 0.01% interest in the Waneta Partnership. Each partner pays its proportionate share of the costs and is entitled to a proportionate share of the net revenue and expenses. The construction of the Waneta Expansion was financed and managed by the Corporation and CPC/CBT. The Waneta Expansion is operated and maintained by a wholly owned subsidiary of the Corporation and output is sold to BC Hydro and FortisBC Electric under 40-year contracts.

The following table details the Waneta Partnership assets, liabilities, revenue, expenses, and cash flow, included in the Corporation's consolidated financial statements.

(in millions)	**2016**	2015
Assets		
Cash and cash equivalents	**$ 15**	$ 23
Accounts receivable and other current assets	**14**	14
Utility capital assets	**696**	708
Intangible assets	**30**	30
	$ 755	$ 775
Liabilities		
Accounts payable and other current liabilities	**$ (3)**	$ (18)
Other liabilities	**(79)**	(74)
	(82)	(92)
Net assets before partners' equity	**$ 673**	$ 683

(in millions)	**2016**	2015
Revenue	**$ 91**	$ 70
Expenses		
Operating	**17**	10
Depreciation and amortization	**18**	14
Finance charges	**3**	2
	38	26
Net earnings	**$ 53**	$ 44

Cash used in investing activities at the Waneta Partnership for 2016 included capital expenditures of $18 million (2015 – $32 million). Cash flow related to financing activities for 2016 included dividends paid by the Waneta Partnership to non-controlling interests of $31 million (2015 – $11 million) and for 2015 included advances from non-controlling interests of $9 million.

32. FINANCIAL RISK MANAGEMENT

The Corporation is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit risk Risk that a counterparty to a financial instrument might fail to meet its obligations under the terms of the financial instrument.

Liquidity risk Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.

Market risk Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices. The Corporation is exposed to foreign exchange risk, interest rate risk and commodity price risk.

Credit Risk

For cash equivalents, trade and other accounts receivable, and long-term other receivables, the Corporation's credit risk is generally limited to the carrying value on the consolidated balance sheet. The Corporation generally has a large and diversified customer base, which minimizes the concentration of credit risk. The Corporation and its subsidiaries have various policies to minimize credit risk, which include requiring customer deposits, prepayments and/or credit checks for certain customers and performing disconnections and/or using third-party collection agencies for overdue accounts.

ITC has a concentration of credit risk as a result of approximately 70% of its revenue being derived from three primary customers. Credit risk is limited as such customers have investment-grade credit ratings. ITC further reduces its exposure to credit risk by requiring a letter of credit or cash deposit equal to the credit exposure, which is determined by a credit-scoring model and other factors.

FortisAlberta has a concentration of credit risk as a result of its distribution service billings being to a relatively small group of retailers. As at December 31, 2016, FortisAlberta's gross credit risk exposure was approximately $123 million, representing the projected value of retailer billings over a 37-day period. The Company has reduced its exposure to $1 million by obtaining from the retailers either a cash deposit, bond, letter of credit, an investment-grade credit rating from a major rating agency, or a financial guarantee from an entity with an investment-grade credit rating.

UNS Energy, Central Hudson, FortisBC Energy and Aitken Creek may be exposed to credit risk in the event of non-performance by counterparties to derivative instruments. The Companies use netting arrangements to reduce credit risk and net settle payments with counterparties where net settlement provisions exist. They also limit credit risk by only dealing with counterparties that have investment-grade credit ratings. At UNS Energy, contractual arrangements also contain certain provisions requiring counterparties to derivative instruments to post collateral under certain circumstances.

Liquidity Risk

The Corporation's consolidated financial position could be adversely affected if it, or one of its subsidiaries, fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures, acquisitions and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the consolidated results of operations and financial position of the Corporation and its subsidiaries, conditions in capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To help mitigate liquidity risk, the Corporation and its regulated utilities have secured committed credit facilities to support short-term financing of capital expenditures, seasonal working capital requirements, and for general corporate purposes. In addition to its credit facilities, ITC uses commercial paper to finance its short-term cash requirements, and may use credit facility borrowings, from time to time, to repay borrowings under its commercial paper program.

The Corporation's committed corporate credit facility is used for interim financing of acquisitions and for general corporate purposes. Depending on the timing of cash payments from subsidiaries, borrowings under the Corporation's committed corporate credit facility may be required from time to time to support the servicing of debt and payment of dividends. As at December 31, 2016, over the next five years, average annual consolidated fixed-term debt maturities and repayments are expected to be approximately $680 million. The combination of available credit facilities and reasonable annual debt maturities and repayments provides the Corporation and its subsidiaries with flexibility in the timing of access to capital markets.

As at December 31, 2016, the Corporation and its subsidiaries had consolidated credit facilities of approximately $6.0 billion, of which approximately $3.7 billion was unused, including $915 million unused under the Corporation's committed revolving corporate credit facility. The credit facilities are syndicated mostly with large banks in Canada and the United States, with no one bank holding more than 20% of these facilities. Approximately $5.1 billion of the total credit facilities are committed facilities with maturities ranging from 2017 through 2021.

The following summary outlines the credit facilities of the Corporation and its subsidiaries.

(in millions)	Regulated Utilities	Corporate and Other	**Total as at December 31, 2016**	Total as at December 31, 2015
Total credit facilities [1]	$ 3,823	$ 2,153	**$ 5,976**	$ 3,565
Credit facilities utilized:				
Short-term borrowings [1][2]	(640)	(515)	**(1,155)**	(511)
Long-term debt *(Note 14)* [3]	(508)	(465)	**(973)**	(551)
Letters of credit outstanding	(68)	(51)	**(119)**	(104)
Credit facilities unused [1]	$ 2,607	$ 1,122	**$ 3,729**	$ 2,399

[1] Total credit facilities and short-term borrowings as at December 31, 2016 include $195 million (US$145 million) outstanding under ITC's commercial paper program. Outstanding commercial paper does not reduce available capacity under the Corporation's consolidated credit facilities.

[2] The weighted average interest rate on short-term borrowings was approximately 1.7% as at December 31, 2016 (December 31, 2015 – 1.0%).

[3] As at December 31, 2016, credit facility borrowings classified as long-term debt included $61 million in current installments of long-term debt on the consolidated balance sheet (December 31, 2015 – $71 million). The weighted average interest rate on credit facility borrowings classified as long-term debt was approximately 1.8% as at December 31, 2016 (December 31, 2015 – 1.5%).

As at December 31, 2016 and 2015, certain borrowings under the Corporation's and subsidiaries' long-term committed credit facilities were classified as long-term debt. It is management's intention to refinance these borrowings with long-term permanent financing during future periods.

Regulated Utilities

ITC has a total of US$1.0 billion in unsecured committed revolving credit facilities maturing in March 2019. ITC has an ongoing commercial paper program in an aggregate amount of US$400 million, under which US$145 million in commercial paper was outstanding as at December 31, 2016.

UNS Energy has a total of US$350 million in unsecured committed revolving credit facilities, with US$305 million maturing in October 2021, and US$45 million maturing in October 2020.

Central Hudson has a US$200 million unsecured committed revolving credit facility, maturing in October 2020, and an uncommitted credit facility totalling US$25 million.

FortisBC Energy has a $700 million unsecured committed revolving credit facility, maturing in August 2021.

FortisAlberta has a $250 million unsecured committed revolving credit facility, maturing in August 2021, and a $90 million bilateral credit facility, maturing in November 2017.

FortisBC Electric has a $150 million unsecured committed revolving credit facility, maturing in May 2019, and a $10 million unsecured demand overdraft facility.

Newfoundland Power has a $100 million unsecured committed revolving credit facility, maturing in August 2021, and a $20 million demand credit facility. Maritime Electric has a $50 million unsecured committed revolving credit facility, maturing in February 2019. FortisOntario has a $30 million unsecured committed revolving credit facility, maturing in June 2019.

Caribbean Utilities has unsecured credit facilities totalling approximately US$49 million. Fortis Turks and Caicos has short-term unsecured demand credit facilities of US$31 million, maturing in June 2017.

Corporate and Other

Fortis has a $1.3 billion unsecured committed revolving credit facility, maturing in July 2021, and a $500 million non-revolving term senior unsecured equity bridge credit facility, used to finance a portion of the cash purchase price of the acquisition of ITC, maturing in October 2017.

UNS Energy Corporation has a US$150 million unsecured committed revolving credit facility, with US$130 million maturing in October 2021, and US$20 million maturing in October 2020. CH Energy Group has a US$50 million unsecured committed revolving credit facility, maturing in July 2020. FHI has a $50 million unsecured committed revolving credit facility, maturing in April 2019.

For the years ended December 31, 2016 and 2015

32. *FINANCIAL RISK MANAGEMENT (cont'd)*

Liquidity Risk (cont'd)

The Corporation and its currently rated utilities target investment-grade credit ratings to maintain capital market access at reasonable interest rates. As at December 31, 2016, the Corporation's credit ratings were as follows.

Rating Agency	Credit Rating	Type of Rating	Outlook
Standard & Poor's ("S&P")	A–	Corporate	Stable
	BBB+	Unsecured debt	Stable
DBRS	BBB (high)	Unsecured debt	Stable
Moody's Investor Service ("Moody's")	Baa3	Issuer	Stable
	Baa3	Unsecured debt	Stable

The above-noted credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, and the level of debt at the holding company. In September 2016 Moody's commenced rating Fortis. In October 2016, following the completion of the acquisition of ITC, DBRS revised the Corporation's unsecured debt credit rating to BBB (high) from A (low) and revised its outlook to stable from under review with negative implications, and S&P affirmed the Corporation's long-term corporate and unsecured debt credit ratings as A– and BBB+, respectively, and revised its outlook to stable from negative.

Market Risk

Foreign Exchange Risk

The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, Fortis Turks and Caicos and BECOL is the US dollar. The Corporation's earnings from, and net investments in, foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has decreased the above-noted exposure through the use of US dollar-denominated borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange gain or loss on the translation of the Corporation's foreign subsidiaries' earnings.

As at December 31, 2016, the Corporation's corporately issued US$3,511 million (December 31, 2015 – US$1,535 million) long-term debt had been designated as an effective hedge of a portion of the Corporation's foreign net investments. As at December 31, 2016, the Corporation had approximately US$7,250 million (December 31, 2015 – US$3,137 million) in foreign net investments that were unhedged. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar-denominated borrowings designated as effective hedges are recorded on the consolidated balance sheet in accumulated other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the net investments in foreign subsidiaries, which gains and losses are also recorded on the consolidated balance sheet in accumulated other comprehensive income.

As a result of the acquisition of ITC, consolidated earnings and cash flows of Fortis are impacted to a greater extent by fluctuations in the US dollar-to-Canadian dollar exchange rate. On an annual basis, it is estimated that a 5 cent increase or decrease in the US dollar relative to the Canadian dollar exchange rate of US$1.00=CAD$1.34 as at December 31, 2016 would increase or decrease earnings per common share of Fortis by approximately 7 cents. Management will continue to hedge future exchange rate fluctuations related to the Corporation's foreign net investments and US dollar-denominated earnings streams, where possible, through future US dollar-denominated borrowings, and will continue to monitor the Corporation's exposure to foreign currency fluctuations on a regular basis.

Interest Rate Risk

The Corporation and most of its subsidiaries are exposed to interest rate risk associated with borrowings under variable-rate credit facilities, variable-rate long-term debt and the refinancing of long-term debt. The Corporation and its subsidiaries may enter into interest rate swap agreements to help reduce this risk (Note 30).

Commodity Price Risk

UNS Energy is exposed to commodity price risk associated with changes in the market price of gas, purchased power and coal. Central Hudson is exposed to commodity price risk associated with changes in the market price of electricity and gas. FortisBC Energy is exposed to commodity price risk associated with changes in the market price of gas. The risks have been reduced by entering into derivative contracts that effectively fix the price of natural gas, power and electricity purchases. Aitken Creek is exposed to commodity price risk associated with changes in the market price of gas and enters into derivative contracts to manage the financial risk posed by physical transactions. These derivative instruments are recorded on the consolidated balance sheet at fair value and any change in the fair value is deferred as a regulatory asset or liability, as permitted by the regulators, for recovery from, or refund to, customers in future rates, except at Aitken Creek where the changes in fair value are recorded in earnings (Note 30).

33. COMMITMENTS

As at December 31, 2016, the Corporation's consolidated commitments in each of the next five years and for periods thereafter, excluding repayments of long-term debt and capital lease and finance obligations separately disclosed in Notes 14 and 15, respectively, are as follows.

($ in millions)	**Total**	Due within 1 year	Due in year 2	Due in year 3	Due in year 4	Due in year 5	Due after 5 years
Interest obligations on long-term debt	**14,586**	892	854	837	817	793	10,393
Power purchase obligations [(1)]	**2,295**	290	200	119	107	107	1,472
Renewable power purchase obligations [(2)]	**1,625**	100	99	99	98	97	1,132
Gas purchase obligations [(3)]	**1,329**	411	290	177	141	110	200
Long-term contracts – UNS Energy [(4)]	**1,146**	192	161	161	127	85	420
ITC easement agreement [(5)]	**453**	13	13	13	13	13	388
Operating lease obligations	**175**	13	13	11	8	7	123
Renewable energy credit purchase agreements [(6)]	**154**	20	15	12	12	12	83
Purchase of Springerville Common Facilities [(7)]	**91**	–	–	–	–	91	–
Waneta Partnership promissory note *(Note 16)*	**72**	–	–	–	72	–	–
Joint-use asset and shared service agreements	**53**	3	3	3	3	3	38
Other [(8)]	**156**	93	18	19	–	–	26
Total	**22,135**	2,027	1,666	1,451	1,398	1,318	14,275

(1) Power purchase obligations include various power purchase contracts held by the Corporation's regulated utilities, of which the most significant contracts are described below.

FortisOntario: Power purchase obligations for FortisOntario, totalling $743 million as at December 31, 2016, include a contract with Hydro-Quebec for the supply of up to 145 MW of capacity and a minimum of 537 GWh of associated energy annually from January 2020 through to December 2030. This contract will replace FortisOntario's existing long-term take-or-pay contracts with Hydro-Quebec to supply 145 MW of capacity expiring in 2019.

FortisBC Energy: FortisBC Energy is party to an electricity supply agreement with BC Hydro for the purchase of electricity supply to the Tilbury LNG Facility Expansion, with purchase obligations totalling $486 million as at December 31, 2016.

FortisBC Electric: Power purchase obligations for FortisBC Electric, totalling $288 million as at December 31, 2016, include a PPA with BC Hydro to purchase up to 200 MW of capacity and 1,752 GWh of associated energy annually for a 20-year term. FortisBC Electric is also party to the Waneta Expansion Capacity Agreement ("WECA"), allowing it to purchase 234 MW of capacity for 40 years, effective April 2015, as approved by the BCUC. Amounts associated with the WECA have not been included in the Commitments table as they will be paid by FortisBC Electric to a related party.

Maritime Electric: Maritime Electric's power purchase obligations include two take-or-pay contracts for the purchase of either capacity or energy, expiring in February 2019, as well as an Energy Purchase Agreement with New Brunswick Power ("NB Power"). Maritime Electric has entitlement to approximately 4.55% of the output from NB Power's Point Lepreau nuclear generating station for the life of the unit. As part of its entitlement, Maritime Electric is required to pay its share of the capital and operating costs of the unit, and as at December 31, 2016, had commitments of $480 million under this arrangement.

(2) TEP and UNS Electric are party to long-term renewable PPAs totalling approximately US$1,210 million as at December 31, 2016, which require TEP and UNS Electric to purchase 100% of the output of certain renewable energy generating facilities once commercial operation is achieved. While TEP and UNS Electric are not required to make payments under these contracts if power is not delivered, the Commitments table includes estimated future payments. These agreements have various expiry dates from 2030 through 2036.

(3) Certain of the Corporation's subsidiaries, mainly FortisBC Energy, enter into contracts for the purchase of gas, gas transportation and storage services. FortisBC Energy's gas purchase obligations are based on gas commodity indices that vary with market prices and the obligations are based on index prices as at December 31, 2016.

(4) UNS Energy enters into various long-term contracts for the purchase and delivery of coal to fuel its generating facilities, the purchase of gas transportation services to meet its load requirements, and the purchase of transmission services for purchased power, with obligations totalling US$496 million, US$244 million and US$113 million, respectively, as at December 31, 2016. Amounts paid under contracts for the purchase and delivery of coal depend on actual quantities purchased and delivered. Certain of these contracts also have price adjustment clauses that will affect future costs under the contracts.

For the years ended December 31, 2016 and 2015

33. COMMITMENTS (cont'd)

(5) ITC is party to an easement agreement with Consumers Energy, the primary customer of METC, which provides the Company with an easement for transmission purposes and rights-of-way, leasehold interests, fee interests and licenses associated with the land over which its transmission lines cross. The agreement expires in December 2050, subject to 10 additional 50-year renewals thereafter.

(6) UNS Energy and Central Hudson are party to renewable energy credit purchase agreements. UNS Energy's renewable energy credit purchase agreements totalled approximately US$107 million as at December 31, 2016 for the purchase of environmental attributions from retail customers with solar installations. Payments for the renewable energy credit purchase agreements are paid in contractually agreed-upon intervals based on metered renewable energy production.

(7) UNS Energy has an obligation to purchase an undivided 32.2% leased interest in the Springerville Common Facilities if the related two leases are not renewed, for a total purchase price of US$68 million (Note 15).

(8) Other contractual obligations include various other commitments entered into by the Corporation and its subsidiaries, including PSU, RSU and DSU plan obligations, asset retirement obligations, and defined benefit pension plan funding obligations.

Other Commitments

Capital Expenditures: The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by the need to ensure continued and enhanced performance, reliability and safety of the electricity and gas systems and to meet customer growth. The Corporation's consolidated capital expenditure program, including capital spending at its non-regulated operations, is forecast to be approximately $3.0 billion for 2017. Over the five years 2017 through 2021, the Corporation's consolidated capital expenditure program is expected to be approximately $13 billion, which has not been included in the Commitments table.

Other: CH Energy Group is party to an investment to develop, own and operate electric transmission projects in New York State. In December 2014 an application was filed with FERC for the recovery of the cost of and return on five high-voltage transmission projects totalling US$1.7 billion, of which CH Energy Group's maximum commitment is US$182 million. CH Energy Group issued a parental guarantee to assure the payment of the maximum commitment of US$182 million. As at December 31, 2016, there was no obligation under this guarantee.

In 2016 FHI issued a parental guarantee of $77 million to secure the storage optimization transactions of Aitken Creek.

The Corporation's long-term regulatory liabilities of $2,183 million as at December 31, 2016 have been excluded from the Commitments table, as the final timing of settlement of many of the liabilities is subject to further regulatory determination or the settlement periods are not currently known (Note 8).

34. CONTINGENCIES

The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with the ordinary course of business operations. Management believes that the amount of liability, if any, from these actions would not have a material adverse effect on the Corporation's consolidated financial position, results of operations or cash flows. The following describes the nature of the Corporation's contingencies.

Central Hudson

Prior to and after its acquisition by Fortis, various asbestos lawsuits have been brought against Central Hudson. While a total of 3,363 asbestos cases have been raised, 1,175 remained pending as at December 31, 2016. Of the cases no longer pending against Central Hudson, 2,032 have been dismissed or discontinued without payment by the Company, and Central Hudson has settled the remaining 156 cases. The Company is presently unable to assess the validity of the outstanding asbestos lawsuits; however, based on information known to Central Hudson at this time, including the Company's experience in the settlement and/or dismissal of asbestos cases, Central Hudson believes that the costs which may be incurred in connection with the remaining lawsuits will not have a material effect on its financial position, results of operations or cash flows and, accordingly, no amount has been accrued in the consolidated financial statements.

FHI

In April 2013 FHI and Fortis were named as defendants in an action in the B.C. Supreme Court by the Coldwater Indian Band ("Band"). The claim is in regard to interests in a pipeline right of way on reserve lands. The pipeline on the right of way was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in April 2007. The Band seeks orders cancelling the right of way and claims damages for wrongful interference with the Band's use and enjoyment of reserve lands. In May 2016 the Federal Court entered a decision dismissing the Coldwater Band's application for judicial review of the ministerial consent. The Band has appealed that decision. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Fortis and ITC

Following announcement of the acquisition of ITC in February 2016, complaints which named Fortis and other defendants were filed in the Oakland County Circuit Court in the State of Michigan ("Superior Court") and the United States District Court in and for the Eastern District of Michigan. The complaints generally allege, among other things, that the directors of ITC breached their fiduciary duties in connection with the merger agreement and that ITC, Fortis, FortisUS Inc. and Element Acquisition Sub Inc. aided and abetted those purported breaches. The complaints seek class action certification and a variety of relief including, among other things, unspecified damages, and costs, including attorneys' fees and expenses. In July 2016 the federal actions were voluntarily dismissed by the federal plaintiffs. The federal plaintiffs reserved the right to make certain other claims, and ITC and the individual members of the ITC board of directors reserved the right to oppose any such claim. The federal plaintiffs have sought a mootness fee application and the parties are currently exploring a mutually satisfactory resolution. In June 2016 the Superior Court granted a motion for summary disposition dismissing the aiding and abetting claims asserted against Fortis, FortisUS Inc. and Element Acquisition Sub Inc. In January 2017 the Superior Court issued a revised scheduling order, which, among other things, requires the parties, including ITC, to complete discovery by May 2017, and set a trial date for September 2017. A hearing on the plaintiff's motion for class certification was held on February 9, 2017. A hearing on a motion of the defendants for summary disposition has been scheduled for March 2017. The outcome of these lawsuits cannot be predicted with any certainty and, accordingly, no amount has been accrued in the consolidated financial statements.

35. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to comply with current period presentation. Acquisition-related expenses of $10 million in 2015 were previously included in other income, net of expenses, on the consolidated statement of earnings and have been reclassified to operating expenses (Note 27). Related-party transactions for the sale of energy from the Waneta Expansion to FortisBC Electric totalling $30 million in 2015 were previously eliminated on consolidation. Fortis no longer eliminates related-party transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities and, as a result, revenue and energy supply costs each increased by $30 million (Note 5).

Historical Financial Summary

Statements of Earnings *(in $ millions)*	**2016** [1][2]	2015 [1][2][3]	2014 [1][2]
Revenue	**6,838**	6,757	5,401
Energy supply costs and operating expenses	**4,372**	4,465	3,690
Depreciation and amortization	**983**	873	688
Other income (expenses), net	**53**	197	(25)
Finance charges	**678**	553	547
Income tax expense	**145**	223	66
Earnings from continuing operations	**713**	840	385
Earnings from discontinued operations, net of tax	**–**	–	5
Extraordinary gain, net of tax	**–**	–	–
Net earnings	**713**	840	390
Net earnings attributable to non-controlling interests	**53**	35	11
Net earnings attributable to preference equity shareholders	**75**	77	62
Net earnings attributable to common equity shareholders	**585**	728	317
Balance Sheets *(in $ millions)*			
Current assets	**2,166**	1,857	1,787
Goodwill	**12,364**	4,173	3,732
Other long-term assets	**3,026**	2,638	2,410
Utility capital assets, non-utility capital assets and intangible assets	**30,348**	20,136	18,304
Total assets	**47,904**	28,804	26,233
Current liabilities	**3,944**	2,638	2,676
Other long-term liabilities	**6,693**	5,029	4,534
Long-term debt (excluding current portion)	**20,817**	10,784	9,911
Preference shares (classified as debt)	**–**	–	–
Total liabilities	**31,454**	18,451	17,121
Shareholders' equity	**16,450**	10,353	9,112
Cash Flows *(in $ millions)*			
Operating activities	**1,884**	1,673	982
Investing activities	**(6,891)**	(1,368)	(4,199)
Financing activities, excluding dividends	**5,491**	(14)	3,627
Dividends, excluding dividends on preference shares classified as debt	**(441)**	(332)	(266)
Financial Statistics			
Return on average book common shareholders' equity *(%)*	**5.56**	9.75	5.45
Capitalization Ratios *(%)* (year end)			
Total debt and capital lease and finance obligations (net of cash)	**60.6**	54.8	56.4
Preference shares (classified as debt and equity)	**4.4**	8.3	9.1
Common shareholders' equity	**35.0**	36.9	34.5
Interest Coverage *(x)*			
Debt	**2.1**	2.7	1.6
All fixed charges	**2.1**	2.7	1.6
Total gross capital expenditures *(in $ millions)*	**2,061**	2,243	1,725
Common share data			
Book value per share (year end) *($)*	**32.31**	28.62	24.89
Average common shares outstanding *(in millions)*	**308.9**	278.6	225.6
Basic earnings per common share *($)*	**1.89**	2.61	1.41
Dividends declared per common share *($)*	**1.55**	1.43	1.30
Dividends paid per common share *($)*	**1.53**	1.40	1.28
Dividend payout ratio *(%)*	**81.0**	53.6	90.8
Price earnings ratio *(x)*	**21.9**	14.3	27.6
Share trading summary (TSX)			
High price *($)*	**44.87**	42.23	40.83
Low price *($)*	**35.53**	34.16	29.78
Closing price *($)*	**41.46**	37.41	38.96
Volume *(in thousands)*	**293,991**	172,038	174,566

[1] Financial information for the years 2010 through 2016 prepared under US generally accepted accounting principles ("GAAP"); prior to 2010 prepared under Canadian GAAP.

[2] Results were impacted by non-operating items, largely associated with the acquisition of ITC in 2016, the sale of non-core assets in 2015, the acquisition of UNS Energy in 2014, and the acquisition of Central Hudson in 2013.

[3] Certain 2015 comparative figures have been reclassified to comply with current period classifications.

Historical Financial Summary

2013 [1][2]	2012 [1]	2011 [1]	2010 [1]	2009	2008	2007
4,047	3,654	3,738	3,647	3,641	3,907	2,718
2,654	2,390	2,547	2,448	2,577	2,859	1,904
541	470	416	406	364	348	273
(31)	4	38	13	10	–	8
389	366	363	359	369	363	299
32	61	84	72	49	65	36
400	371	366	375	292	272	214
–	–	–	–	–	–	–
20	–	–	–	–	–	–
420	371	366	375	292	272	214
10	9	9	10	12	13	15
57	47	46	45	18	14	6
353	315	311	320	262	245	193
1,296	1,093	1,132	1,205	1,124	1,150	1,038
2,075	1,568	1,565	1,561	1,560	1,575	1,544
1,925	1,715	1,580	1,309	917	487	424
12,612	10,574	9,937	9,336	8,538	7,954	7,276
17,908	14,950	14,214	13,411	12,139	11,166	10,282
2,084	1,350	1,305	1,491	1,592	1,697	1,804
3,024	2,449	2,281	1,977	1,325	763	732
6,424	5,741	5,685	5,616	5,239	4,848	4,588
–	–	–	–	320	320	320
11,532	9,540	9,271	9,084	8,476	7,628	7,444
6,376	5,410	4,943	4,327	3,663	3,538	2,838
899	992	915	742	681	661	373
(2,164)	(1,096)	(1,115)	(980)	(1,045)	(852)	(2,033)
1,434	396	386	451	563	387	1,826
(248)	(225)	(206)	(189)	(176)	(191)	(146)
8.06	8.06	8.79	10.06	8.41	8.70	10.00
56.2	55.3	57.1	60.4	60.2	59.5	64.3
9.0	9.7	8.3	8.7	6.9	7.3	5.2
34.8	35.0	34.6	30.9	32.9	33.2	30.5
1.9	2.0	2.0	2.0	1.9	1.9	1.9
1.9	2.0	2.0	2.0	1.8	1.8	1.7
1,175	1,146	1,171	1,071	1,024	935	803
22.38	20.84	20.25	18.65	18.61	17.97	16.69
202.5	190.0	181.6	172.9	170.2	157.4	137.6
1.74	1.66	1.71	1.85	1.54	1.56	1.40
1.25	1.21	1.17	1.41	0.78	1.01	0.88
1.24	1.20	1.16	1.12	1.04	1.00	0.82
71.3	72.3	67.8	60.5	67.5	64.1	58.6
17.5	20.6	19.5	18.4	18.6	15.8	20.7
35.14	34.98	35.45	34.54	29.24	29.94	30.00
29.51	31.70	28.24	21.60	21.52	20.70	24.50
30.45	34.22	33.37	33.98	28.68	24.59	28.99
120,470	115,962	126,341	120,855	121,162	132,108	100,920

Investor Information

Expected Dividend* and Earnings Release Dates

Dividend Record Dates

May 19, 2017	August 21, 2017
November 20, 2017	February 15, 2018

Dividend Payment Dates

June 1, 2017	September 1, 2017
December 1, 2017	March 1, 2018

Earnings Release Dates

May 2, 2017	July 28, 2017
November 3, 2017	February 15, 2018

* *The setting of dividend record dates and the declaration and payment of dividends are subject to the Board of Directors' approval.*

Transfer Agent and Registrar

Computershare Trust Company of Canada ("Computershare" or "Transfer Agent") is responsible for the maintenance of shareholder records and the issuance, transfer and cancellation of stock certificates. Transfers can be effected at its Halifax, Montreal and Toronto offices in Canada and at the co-transfer agent's Canton, MA, Jersey City, NJ, and College Station, TX offices in the United States. Computershare also distributes dividends and shareholder communications. Inquiries with respect to these matters and corrections to shareholder information should be addressed to the Transfer Agent.

Computershare Trust Company of Canada
8th Floor, 100 University Avenue, Toronto, ON M5J 2Y1
T: 514.982.7555 or 1.866.586.7638
F: 416.263.9394 or 1.888.453.0330
W: www.investorcentre.com/fortisinc

Computershare Trust Company N.A.
Attn: Stock Transfer Department
Overnight Mail Delivery: 250 Royall Street, Canton, MA 02021
Regular Mail Delivery: P.O. Box 43078, Providence, RI 02940-3070

Direct Deposit of Dividends

Shareholders may arrange for automatic electronic deposit of dividends to their designated Canadian and U.S. financial institutions by contacting the Transfer Agent.

Duplicate Annual Reports

While every effort is made to avoid duplications, some shareholders may receive extra reports as a result of multiple share registrations. Shareholders wishing to consolidate these accounts should contact the Transfer Agent.

Eligible Dividend Designation

For purposes of the enhanced dividend tax credit rules contained in the *Income Tax Act* (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on common and preferred shares after December 31, 2005 by Fortis to Canadian residents are designated as "eligible dividends". Unless stated otherwise, all dividends paid by Fortis hereafter are designated as "eligible dividends" for the purposes of such rules.

Annual Meeting

Thursday, May 4, 2017 – 10:30 a.m.
Holiday Inn St. John's, 180 Portugal Cove Road, St. John's, NL, Canada

Dividend Reinvestment Plan and Consumer Share Purchase Plan

Fortis offers a Dividend Reinvestment Plan ("DRIP")[(1)] and a Consumer Share Purchase Plan ("CSPP")[(2)] as a convenient method for Common Shareholders to increase their investments in Fortis. Participants have dividends plus any optional contributions (DRIP: minimum of $100, maximum of $30,000 annually; CSPP: minimum of $25, maximum of $20,000 annually) automatically deposited in the plans to purchase additional Common Shares. Shares can be purchased quarterly on March 1, June 1, September 1 and December 1 at the average market price then prevailing on the Toronto Stock Exchange. The DRIP currently offers a 2% discount on the purchase of Common Shares, issued from treasury, with the reinvested dividends. Inquiries should be directed to the Transfer Agent.

(1) *All registered holders of Common Shares who are residents of Canada are eligible to participate in the DRIP. Shareholders residing outside Canada may also participate unless participation is not allowed in that jurisdiction. Residents of the United States, its territories or possessions are not eligible to participate.*

(2) *The CSPP is offered to residents of the provinces of Newfoundland and Labrador and Prince Edward Island.*

Share Listings

The Common Shares; First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series I; First Preference Shares, Series J; First Preference Shares, Series K; and First Preference Shares, Series M of Fortis Inc. are listed on the Toronto Stock Exchange and trade under the ticker symbols FTS, FTS.PR.F, FTS.PR.G, FTS.PR.H, FTS.PR.I, FTS.PR.J, FTS.PR.K and FTS.PR.M, respectively. The Common Shares are also listed on the New York Stock Exchange and trade under the ticker symbol FTS.

Valuation Day

For capital gains purposes, the valuation day prices are as follows:

December 22, 1971	$1.531
February 22, 1994	$7.156

Analyst and Investor Inquiries

T: 709.737.2900 **F:** 709.737.5307
E: investorrelations@fortisinc.com

Fortis Inc. Executive

Barry V. Perry
President and Chief Executive Officer

Karl W. Smith
Executive Vice President, Chief Financial Officer

Nora M. Duke
Executive Vice President,
Corporate Services and Chief Human Resource Officer

Earl A. Ludlow
Executive Vice President,
Eastern Canadian and Caribbean Operations

James P. Laurito
Executive Vice President, Business Development

David C. Bennett
Executive Vice President,
Chief Legal Officer and Corporate Secretary

Janet A. Craig
Vice President, Investor Relations

Karen J. Gosse
Vice President, Planning and Forecasting

James D. Roberts
Vice President, Controller

James D. Spinney
Vice President, Treasurer

Photography:
David Howells, St. John's, NL
Brendon Meadows, Vancouver, BC

Photos: Cover: ITC Transmission; **Inside Front Cover:** Fortis Place, St. John's, NL; **Page 1:** FortisBC Burnaby Call Centre, ITC Transmission, ITC Control Room, Tucson Electric Power's Solar, Newfoundland Power's Petty Harbour Hydroelectric Generating Facility; **Page 3:** FortisBC; **Page 4:** Solar Zone at University of Arizona's Tech Park, Tucson, AZ; **Page 7:** ITC Control Room, Novi, MI; **Page 10–11:** UNS Energy's Tortolita Substation, southeast of Red Rock, AZ; **Page 12:** Waneta Expansion Hydroelectric Generating Facility, near Trail, BC; **Page 14:** New York Stock Exchange, New York, NY; **Page 15:** The Rooms, St. John's, NL

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✻ Audit Committee ✷ Human Resources Committee
★ Governance and Nominating Committee

For Board of Directors' biographies, please visit www.fortisinc.com.



FORTIS INC.

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Consolidated Financial Statements

FortisOntario Inc.

December 31, 2015



Building a better working world

INDEPENDENT AUDITORS' REPORT

To the Shareholder of
FortisOntario Inc.

We have audited the accompanying consolidated financial statements of **FortisOntario Inc.**, which comprise the consolidated balance sheet as at December 31, 2015, and the consolidated statements of earnings and retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian accounting standards for private enterprises, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audit is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of **FortisOntario Inc.** as at December 31, 2015, and the results of its operations and its cash flows for the year then ended in accordance with Canadian accounting standards for private enterprises.

Ernst & Young LLP

Chartered Professional Accountants
Licensed Public Accountants

Toronto, Canada
February 3, 2016

FortisOntario Inc.

CONSOLIDATED BALANCE SHEET

[in thousands of dollars]

As at December 31

	2015	2014
	$	$
ASSETS		
Current		
Cash	**5,107**	5,527
Accounts receivable *[note 14]*	**24,623**	26,658
Income taxes recoverable	**333**	510
Due from related parties *[note 8]*	**—**	138
Materials and supplies	**164**	239
Regulatory assets *[note 16]*	**671**	1,606
Prepaid expenses	**613**	740
Total current assets	**31,511**	35,418
Utility capital assets, net *[note 3]*	**238,460**	222,383
Intangible assets, net *[note 4]*	**29,040**	27,653
Long-term investments *[note 5]*	**4,121**	3,821
Accrued pension benefits *[note 6]*	**8,477**	6,677
Other assets	**284**	157
Regulatory assets *[note 16]*	**19,726**	20,763
Goodwill	**46,094**	46,094
	377,713	362,966
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable and accrued liabilities *[note 16]*	**23,880**	21,469
Regulatory liabilities *[note 16]*	**1,948**	1,616
Due to related parties *[note 8]*	**3,930**	—
Short-term loan payable *[note 14]*	**—**	—
Total current liabilities	**29,758**	23,085
Long-term payable *[notes 14 and 16]*	**—**	125
Promissory notes due to parent *[note 8]*		
Long-term debt *[notes 9 and 14]*	**103,426**	103,355
Future tax liabilities, net *[note 7]*	**5,553**	3,496
Accrued other retirement benefits *[note 6]*	**17,457**	17,704
Accrued pension benefits *[note 6]*	**2,083**	1,971
Contributions in aid of construction	**22,647**	21,196
Regulatory liabilities *[note 16]*	**5,520**	7,957
Total liabilities	**186,444**	178,889
Commitments and contingencies *[note 13]*		
Shareholder's equity		
Capital stock *[note 10]*	**2**	2
Contributed surplus	**108,606**	108,606
Retained earnings	**82,661**	75,469
Total shareholder's equity	**191,269**	184,077
	377,713	362,966

See accompanying notes

Approved on behalf of the Board:

Director Director

FortisOntario Inc.

CONSOLIDATED STATEMENT OF EARNINGS AND RETAINED EARNINGS

[in thousands of dollars]

Year ended December 31

	2015	2014
	$	$
REVENUE		
Sale of energy	**138,219**	133,250
Distribution	**53,432**	50,728
Transmission	**4,347**	4,854
Other	**3,478**	3,621
	199,476	192,453
EXPENSES		
Cost of power purchased	**137,577**	132,659
Operating	**30,262**	29,675
Amortization *[note 11]*	**9,689**	9,783
	177,528	172,117
Operating earnings before the following	**21,948**	20,336
Dividend income *[note 8]*	**104**	115
Other regulatory adjustments *[note 16]*	**(1,343)**	(710)
Interest expense *[notes 9 and 14]*	**(6,642)**	(6,660)
Earnings before income taxes	**14,067**	13,081
Provision for income taxes *[note 7]*	**2,875**	2,192
Net earnings for the year	**11,192**	10,889
Retained earnings, beginning of year	**75,469**	68,580
Dividends paid *[note 8]*	**(4,000)**	(4,000)
Retained earnings, end of year	**82,661**	75,469

See accompanying notes

FortisOntario Inc.

CONSOLIDATED STATEMENT OF CASH FLOWS

[in thousands of dollars]

Year ended December 31

	2015 $	2014 $
OPERATING ACTIVITIES		
Net earnings for the year	**11,192**	10,889
Add (deduct) items not affecting cash		
Amortization	**10,716**	10,783
Future income taxes	**2,056**	6,776
Gain on disposal of utility capital assets	**(105)**	(161)
Accrued pension benefits	**—**	(3,719)
Accrued other retirement benefits	**457**	1,253
Long-term regulatory assets and liabilities	**(1,400)**	1,848
Accrued pension benefits	**(1,687)**	(2,574)
Accrued other retirement benefits	**(703)**	(675)
	20,526	24,420
Net change in non-cash working capital balances related to operations *[note 12]*	**10,163**	771
Cash provided by operating activities	**30,689**	25,191
INVESTING ACTIVITIES		
Additions to utility capital assets	**(26,295)**	(19,469)
Investment in Niagara Power Incorporated	**(300)**	—
Additions to intangible assets	**(3,188)**	(1,327)
Proceeds on sale of utility capital assets	**784**	227
Change in other assets	**(60)**	25
Cash used in investing activities	**(29,059)**	(20,544)
FINANCING ACTIVITIES		
Decrease in long-term payable	**(125)**	(250)
Repayment of short-term loan payable	**—**	(3,000)
Dividends paid	**(4,000)**	(4,000)
Increase in contributions in aid of construction	**2,075**	2,733
Cash used in financing activities	**(2,050)**	(4,517)
Net increase (decrease) in cash during the year	**(420)**	130
Cash, beginning of year	**5,527**	5,397
Cash, end of year	**5,107**	5,527

See accompanying notes

FortisOntario Inc.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

[in thousands of dollars]

December 31, 2015

1. BASIS OF PRESENTATION

The consolidated financial statements include the accounts of FortisOntario Inc. [the "Corporation"] and its wholly-owned subsidiaries, Canadian Niagara Power Inc. ["CNPI"], FortisOntario District Heating Inc. [formerly 1161557 Ontario Inc.], Cornwall Street Railway, Light and Power Company Limited ["Cornwall Electric"] and Algoma Power Inc. ["API"].

The principal businesses of the Corporation are the generation of electricity and the transmission and distribution of electricity to customers within Ontario. Certain of these businesses are regulated by the Ontario Energy Board ["OEB"].

2. BASIS OF ACCOUNTING AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. BASIS OF ACCOUNTING

These consolidated financial statements have been prepared in accordance with Canadian accounting standards for private enterprises ["ASPE"], as per Part II of the CPA Handbook – Accounting, which constitutes generally accepted accounting principles for non-publicly accountable enterprises in Canada.

B. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Regulation

CNPI distribution

The distribution rates of CNPI are based upon cost of service rate regulation by the OEB. Earnings are regulated on the basis of a rate of return on rate base plus a recovery of all allowable distribution costs of CNPI.

On August 16, 2013, CNPI filed its 2014 4th Generation Incentive Rate-setting Application ["4GIRM"] for electricity distribution rates effective January 1, 2014. This application was based on the OEB's guidelines for 4th Generation Incentive Regulation Mechanism. On January 9, 2014, the OEB issued its Decision and Order for CNPI; the final 4th Generation Incentive Price Index was 1.25% comprising 1.7% inflation, a 0% productivity factor and a 0.45% stretch factor [i.e. 1.7% - (0% + 0.45%)]. Rates were effective January 1, 2014. The overall bill impact for the average residential consumer in Fort Erie is a 0.9% increase, a 0.8% increase for the average residential consumer in Gananoque, and a 0.2% increase for the average residential consumer in Port Colborne.

On August 13, 2014, CNPI submitted its 2015 4GIRM for electricity distribution rates effective January 1, 2015. This application was a second in a series of rate applications to fully harmonize electricity distribution rates in Port Colborne with those of Fort Erie and Gananoque. The OEB issued its Decision and Order on December 4, 2014, and the net price cap index adjustment for 2015 is 1.15% [i.e. 1.6% - (0% + 0.45%)]. The overall bill impact for the average residential consumer in Fort Erie was a 1.4% decrease, a 1.5% decrease for the average residential consumer in Gananoque, and a 3.2% decrease for the average residential consumer in Port Colborne. These overall decreases include the impact of the disposition of regulatory deferral and variance accounts.

On August 14, 2015, CNPI submitted its 2016 4GIRM for electricity distribution rates effective January 1, 2016. The OEB has calculated the value of the inflation factor for incentive rate setting, for rate changes effective in 2016, to be 2.1%. The OEB assigned a stretch factor of 0.45% based on the updated benchmarking study for use for rates effective in 2016. As a result, the net price cap index adjustment for CNPI is 1.65% [i.e. 2.1% - (0% + 0.45%)]. The 1.65% adjustment applies to distribution rates [fixed and variable charges] uniformly across all customer classes.

Beginning with electricity distribution rates effective in 2016, decoupling of electricity distribution rates for the Residential customer class is being introduced; complete decoupling is expected to take four consecutive years to implement fully.

CNPI transmission
The transmission rates of CNPI are based upon cost of service rate regulation by the OEB. Earnings are regulated on the basis of a rate of return on rate base plus a recovery of all allowable transmission costs of CNPI.

On November 17, 2014, CNPI submitted a Revenue Requirement Application for its Transmission business. The Application sought approval of CNPI's 2015 and 2016 Transmission Revenue Requirement.

On June 25, 2015, the OEB issued its Decision and Order. The Decision and Order approves final revenue requirements of $4,246,478 and $4,647,201 for 2015 and 2016 respectively, and provides a 9.30% ROE with a 60%/40% debt equity structure. On January 14, 2016, the OEB issued its Decision and Order approving an adjusted 2016 revenue requirement of $4,457,953.

API distribution
The distribution rates of API are based upon cost of service rate regulation by the OEB. Earnings are regulated on the basis of a rate of return on rate base plus a recovery of all allowable distribution costs of API.

API is subject to Ontario Regulation 335/07, which is the Rural and Remote Rate Protection subsidy program ["RRRP"]. The RRRP is calculated as the deficiency between the approved revenue requirement from the OEB and current customer distribution rates adjusted for the average rate increase across the Province of Ontario. API qualifies for this subsidy because it has fewer than seven customers per kilometre and a service area that extends beyond 10,000 kilometres. All general service and large customer classes have been reclassified as residential class under Ontario Regulation 445/07.

On August 16, 2013, API filed an application with the OEB seeking approval to change distribution rates effective January 1, 2014 based on 4GIRM. The OEB issued its Decision and Order on February 20, 2014, and the 2014 net price cap index adjustment for API is 1.4% [i.e. 1.7% - (0% + 0.3%)]. The 2014 electricity distribution rates were effective January 1, 2014 and implemented on March 1, 2014, and a provision was made to collect foregone revenue through a rate rider. As a result of the OEB's Decision and Order, the average residential customer of API experienced a 3.6% reduction in their electricity charges. The reduction includes the impact of the elimination of certain deferral and variance account rate riders for 2014.

In May 2014, API filed a cost of service electricity distribution rate application for rates effective January 1, 2015 based on a 2015 test year. The OEB issued its Decision and Order on January 8, 2015. The Decision and Order approves a 2015 Base Revenue Requirement of $22,816,180 and provides a 9.30% ROE with a 60%/40% debt equity structure.

On August 14, 2015, API filed an application with the OEB seeking approval to change electricity distribution rates, effective January 1, 2016, based on 4GIRM. The OEB has calculated the value of the inflation factor for incentive rate setting, for rate changes effective in 2016, to be 2.1%. The OEB assigned a stretch factor of 0.60% based on the updated benchmarking study for use for rates effective in 2016. The resulting net price cap index adjustment for API is 1.50% [i.e. 2.1% - (0% + 0.60%)]. The 1.50% adjustment applies to distribution rates [fixed and variable charges] uniformly for the Seasonal and Street Lighting customer classes. The OEB approved the application of the 1.8% RRRP adjustment factor to the distribution rates for the Residential R-1 and Residential R-2 classes. The OEB found that the amount of RRRP of $13,678,440 for the year commencing January 1, 2016 accurately reflects the OEB's findings pursuant to the applicable regulations and approved a monthly payment of $1,139,870 effective January 1, 2016.

Beginning with electricity distribution rates effective in 2016, decoupling of electricity distribution rates for the Residential customer class is being introduced; complete decoupling is expected to take four consecutive years to fully implement.

Cornwall Electric
Cornwall Electric is subject to a rate-setting mechanism under the Franchise Agreement, which is the retail rate and service agreement between Cornwall Electric and The Corporation of the City of

Cornwall. The rate-setting mechanism is based on a price cap with commodity cost flow-through. The base revenue requirement is adjusted annually for inflation, load growth, number of customers and premises vacancies. The rate years covering the operations for 2015 are from July 1, 2014 to June 30, 2015 and from July 1, 2015 to June 30, 2016.

Materials and supplies

Materials and supplies are recorded at average cost. Materials and supplies expensed to operating expenses in 2015 were $125 [2014 – $202].

Utility capital assets, capitalization policy and service life of utility capital assets

[a] Nature of distribution, transmission and generation assets

Distribution assets
Distribution assets are those used to distribute electricity at lower voltages [generally below 50 kilovolts]. These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Transmission assets
Transmission assets are those used to transmit electricity at higher voltages [generally at 50 kilovolts and above]. These assets include poles, wires and conductors, substations, support structures and other related equipment.

Generation assets
Generation assets are those used to generate electricity. These assets include thermal generating stations, gas turbines and other related equipment.

[b] Service life ranges and average remaining service life of utility capital assets

The service life range and average remaining service life of the utility capital assets are as follows:

	Service life range [years]	Average remaining service life [years]
Distribution	10 to 50	34.2
Transmission	25 to 50	35.3
Generation	25 to 50	12.9

Utility capital assets are stated at cost less accumulated amortization. Amortization is provided over their estimated useful lives using the straight-line method at a composite rate of 2.3% [2014 – 2.5%].

Contributions in aid of construction represent funding of utility capital assets contributed by customers. These accounts are being reduced annually by an amount equal to the charge for amortization provided on the contributed portion of the utility capital assets involved.

[c] Capitalization policy

The Corporation's capitalization policy is in accordance with the OEB's requirements to use a "modified IFRS" accounting basis. API, as permitted by the OEB, has recognized the financial differences arising as a result of the 2013 accounting changes to amortization expense and capitalization policies *[note 16]*.

Intangible assets

Intangible assets are stated at cost less accumulated amortization. Amortization is provided over their estimated useful lives using the straight-line method.

The service life range and average remaining service life of the intangible assets are as follows:

	Service life range [years]	Average remaining service life [years]
Software costs	5 to 10	5.7
Land and transmission rights	40	29.9
Other	50	28.3

Asset retirement obligations

ASPE requires the recognition of an asset retirement obligation in the period during which a legal obligation associated with the retirement of a tangible long-lived asset is incurred and when a reasonable estimate of this amount can be made.

The Corporation has determined that there are asset retirement obligations associated with some parts of its transmission, distribution and generation systems; however, none of these are material or require recognition under Section 3110 of the CPA Handbook.

Long-term investments

The Corporation accounts for its long-term investments using the cost method.

Goodwill

Goodwill represents the excess of the acquisition cost of the shares of CNPI, Cornwall Electric and Eastern Ontario Power Inc. [amalgamated with CNPI as of January 1, 2004] over the assigned value of identifiable net assets acquired, as well as the excess of the purchase price of the remaining utility capital assets of Port Colborne Hydro Inc. over the fair value of these assets.

ASPE requires that goodwill be tested for impairment whenever events or changes in circumstances indicate that the carrying amount of the reporting unit to which the goodwill is assigned may exceed the fair value of the reporting unit. Any impairment in value is charged to earnings during the year.

Other assets

Other assets are amortized over their useful lives.

Revenue recognition

Revenue from the sale, transmission and distribution of electricity is recognized on the accrual basis. Electricity is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of the year, a certain amount of consumed electricity will not have been billed. Electricity that is consumed, but not yet billed to the customers, is estimated and accrued as revenue in the current year. Unbilled revenue included in accounts receivable as at December 31, 2015 is $14,378 [2014 – $14,995].

The Corporation of the City of Cornwall Franchise Agreement provides that Cornwall Electric sets electricity rates such that Cornwall Electric is guaranteed an annual gross margin on power sold of $13,127 [2014 – $12,956]. This guaranteed gross margin covers the rate years from July 1, 2014 to June 30, 2015 and from July 1, 2015 to June 30, 2016. The guaranteed gross margin is accrued on a prorated basis over the course of the year.

Foreign currency translation

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing at the consolidated balance sheet date. Gains and losses on

translation are included in earnings for the year. Revenue and expenses are translated at the exchange rate prevailing on the transaction date.

Employee benefit plans

Effective January 1, 2014, the Corporation adopted new CPA Handbook Section 3462, *Employee Future Benefits,* for its accounting of pension benefits and other retirement benefits. As allowed under new Section 3462, the Corporation made an accounting policy choice to measure its defined benefit plan obligations using the funding valuation approach. This approach uses the most recent completed actuarial valuations prepared for funding purposes as the basis of measuring defined benefit plan obligations. Even though other retirement benefits are not funded, Section 3462 allows that such liabilities be measured on a basis consistent with funded plans. As well, the Corporation is using a roll-forward technique in the years between valuations to estimate the defined benefit obligations. Pension plan assets are valued at fair value as at the consolidated balance sheet date.

In 2013, the Corporation made an application to the OEB to allow recognition of regulatory assets related to unamortized amounts, and restatement of prior years' pension and other retirement benefit expenses, in CNPI and API that would otherwise be collected from customers through rates in subsequent years. In December 2013, the OEB issued a Decision and Order approving the establishment of specific deferral accounts for CNPI and API to recognize these amounts as long-term regulatory assets, which will be disposed of in the future cost of service proceedings, subject to the OEB's prudence review at that time. As well, the Corporation reversed previously recognized future income tax liabilities related to the changes in the pension and other retirement benefit liabilities as of January 1, 2014. For CNPI and API, the Corporation recognized offsetting regulatory liabilities related to the future income taxes expected to be recovered from customers in future electricity rates as of January 1, 2014.

The Corporation made an application to the OEB for CNPI and API to continue to account for pension and other retirement benefits under the former Section 3461. In December 2013, the OEB issued a Decision and Order approving the establishment of specific variance accounts for CNPI and API as of January 1, 2013, to recognize the difference in expense between Sections 3461 and 3462 as long-term regulatory assets or liabilities for 2013 and future years, which will be disposed of in the future cost of service proceedings, subject to the OEB's prudence review at that time.

Income taxes

The Corporation follows the asset and liability method of accounting for income taxes. Under this method, future tax assets and liabilities are recognized for the temporary differences between the tax and accounting bases of assets and liabilities. Future tax assets and liabilities are measured

using the enacted and substantively enacted tax rates expected to apply to taxable income in the period in which the temporary differences are expected to be recovered or settled. The Corporation recognizes regulatory assets and liabilities related to future tax assets and liabilities for the amount of future income taxes expected to be recovered from customers in future electricity rates for CNPI and API.

Use of estimates

The preparation of consolidated financial statements in conformity with ASPE 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 consolidated financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results may vary from the current estimates. These estimates are reviewed periodically and, as adjustments become necessary, they are reported in earnings in the period in which they become known.

3. UTILITY CAPITAL ASSETS

Utility capital assets consist of the following:

	2015		
	Cost	**Accumulated amortization**	**Net book value**
	$	$	$
Transmission	**32,536**	**13,272**	**19,264**
Distribution	**337,137**	**141,473**	**195,664**
Generation	**16,050**	**10,746**	**5,304**
Other	**47,635**	**29,407**	**18,228**
	433,358	**194,898**	**238,460**

	2014		
	Cost	**Accumulated amortization**	**Net book value**
	$	$	$
Transmission	28,621	12,983	15,638
Distribution	318,338	136,220	182,118
Generation	15,999	10,224	5,775
Other	47,835	28,983	18,852
	410,793	188,410	222,383

The amounts above include assets under construction of $5,340 [2014 – $10,198], which are not subject to amortization.

4. INTANGIBLE ASSETS

Intangible assets consist of the following:

	2015		
	Cost	**Accumulated amortization**	**Net book value**
	$	$	$
Software costs	**17,105**	**10,899**	**6,206**
Land and transmission rights	**29,848**	**7,298**	**22,550**
Other	**406**	**122**	**284**
	47,359	**18,319**	**29,040**

	2014		
	Cost	**Accumulated amortization**	**Net book value**
	$	$	$
Software costs	15,686	9,818	5,868
Land and transmission rights	28,079	6,589	21,490
Other	406	111	295
	44,171	16,518	27,653

5. LONG-TERM INVESTMENTS

The Corporation's long-term investments are summarized as follows:

	2015	**2014**
	$	$
Investment in common shares of Westario Power Holdings Inc.	**2,076**	2,076
Investment in common shares of Rideau St. Lawrence Holdings Inc.	**452**	452
Investment in Class B preferred shares of Niagara Power Incorporated	**1,593**	1,293
	4,121	3,821

Through the ownership of the Class B preferred shares of Niagara Power Incorporated, the Corporation holds a 10% economic interest in Grimsby Power Inc.

6. EMPLOYEE BENEFIT PLANS

The Corporation maintains three defined benefit pension plans and two defined contribution pension plans providing pension benefits, and three defined benefit plans providing other retirement benefits to most of its employees. The Corporation also makes contributions to the Ontario Municipal Employees' Retirement System ["OMERS"] plan on behalf of some of its employees. OMERS is a multi-employer defined benefit pension plan providing pension benefits and is accounted for as a defined contribution pension plan.

Information about the defined benefit plans for the Corporation, CNPI and Cornwall Electric is as follows:

	Pension benefit plans		**Other retirement plans**	
	2015	**2014**	**2015**	**2014**
	$	$	$	$
Accrued benefit obligation				
Balance, beginning of year	**24,511**	24,552	**10,568**	10,413
Current service costs	**404**	386	**111**	107
Finance costs	**1,164**	1,166	**502**	497
Benefits paid	**(1,430)**	(1,556)	**(559)**	(549)
Actuarial losses (gains)	**(594)**	(37)	**225**	100
Balance, end of year	**24,055**	24,511	**10,847**	10,568
Plan assets				
Fair value, beginning of year	**29,899**	25,938	**—**	—
Interest income	**1,420**	1,225	**—**	—
Return on plan assets	**143**	2,556	**—**	—
Contributions	**902**	1,736	**559**	549
Benefits paid	**(1,430)**	(1,556)	**(559)**	(549)
Fair value, end of year	**30,934**	29,899	**—**	—
Funded status – plan surplus (deficit)	**6,879**	5,388	**(10,847)**	(10,568)

The measurement date for the plan assets and the accrued benefit obligation is December 31, 2015. The effective date of the most recent actuarial valuation was as at December 31, 2014, and the date of the next required valuation for funding purposes is as at December 31, 2017.

The plan assets held at the measurement date are represented by the following categories:

	%
Canadian equity funds	**13**
US equity funds	**13**
EAFE equity funds	**13**
Canadian fixed income funds	**60**
Cash and short-term investments	**1**

As at December 31, 2015, one of the two defined benefit pension plans had a net accrued benefit liability of $370 [2014 – $354]. This plan had no plan assets in 2015 or 2014.

Included in the accrued pension benefit liability as at December 31, 2015 is an unfunded defined contribution plan pension liability of $1,337 [2014 – $1,189] relating to the supplementary employee retirement plan.

	Pension benefit plans		**Other retirement plans**	
	2015	**2014**	**2015**	**2014**
	$	$	$	$
Significant assumptions used				
Discount rate – beginning of year	**4.75%**	4.75%	**4.75%**	4.75%
Discount rate – end of year	**4.75%**	4.75%	**4.75%**	4.75%
Rate of compensation increase	**3.50%**	4.00%	**—**	—
Initial health care trend rate	**—**	—	**5.57%**	5.93%
Average remaining service life of active employees [years]	**5**	5	**14 – 16**	9 – 16
Net benefit expense (credit) for the year				
Current service costs	**404**	386	**111**	107
Finance costs	**(256)**	(59)	**502**	497
Remeasurement costs	**(737)**	(2,594)	**225**	100
Regulatory adjustments	**802**	2,004	**(453)**	26
Net benefit expense (credit)	**213**	(263)	**385**	730

Information about the Corporation's defined benefit plans for API is as follows:

	Pension benefit plans		Other retirement plans	
	2015	**2014**	**2015**	**2014**
	$	$	$	$
Accrued benefit obligation				
Balance, beginning of year	**24,111**	23,646	**7,136**	6,713
Current service costs	**463**	465	**288**	276
Finance costs	**1,145**	1,123	**339**	319
Employee contributions	**196**	191	**—**	—
Benefits paid	**(945)**	(1,279)	**(145)**	(127)
Actuarial losses (gains)	**480**	(35)	**(1,008)**	(45)
Balance, end of year	**25,450**	24,111	**6,610**	7,136
Plan assets				
Fair value, beginning of year	**24,618**	21,712	**—**	—
Interest income	**1,168**	1,030	**—**	—
Return on plan assets	**480**	2,127	**—**	—
Contributions	**981**	1,028	**145**	127
Benefits paid	**(945)**	(1,279)	**(145)**	(127)
Fair value, end of year	**26,302**	24,618	**—**	—
Funded status – plan surplus (deficit)	**852**	507	**(6,610)**	(7,136)

The measurement date for the plan assets and the accrued benefit obligation is December 31, 2015. The effective date of the most recent actuarial valuation was as at December 31, 2014 and the date of the next required valuation for funding purposes is as at December 31, 2017.

The plan assets held at the measurement date are represented by the following categories:

	%
Canadian equity funds	**15**
US equity funds	**19**
EAFE equity funds	**16**
Canadian fixed income funds	**48**
Cash and short-term investments	**2**

As at December 31, 2015, one of the defined benefit pension plans had a net accrued benefit liability of $376 [2014 – $428]. This plan had no plan assets in 2015 or 2014.

	Pension benefit plans		**Other retirement plans**	
	2015	**2014**	**2015**	**2014**
	$	$	$	$
Significant assumptions used				
Discount rate – beginning of year	**4.75%**	4.75%	**4.75%**	4.75%
Discount rate – end of year	**4.75%**	4.75%	**4.75%**	4.75%
Rate of compensation increase	**3.50%**	4.00%	**—**	—
Initial health care trend rate	**—**	—	**5.83%**	6.41%
Average remaining service year of active employees [years]	**16**	14	**16**	16
Net benefit expense for the year				
Current service cost	**463**	465	**288**	276
Finance cost	**(23)**	93	**339**	319
Remeasurement costs	**—**	(2,162)	**(1,008)**	(46)
Regulatory adjustments	**126**	2,007	**1,200**	75
Net benefit expense	**566**	403	**819**	624

The total expense for the Corporation's defined contribution pension plans for the year amounted to $483 [2014 – $446]. The pension cost associated with the OMERS plan was $506 [2014 – $495].

7. INCOME TAXES

The following is a reconciliation of the combined statutory income tax rate to the effective income tax rate:

	2015 %	2014 %
Statutory income tax rate	**26.50**	26.50
Future income taxes transferred to regulatory assets	**(7.47)**	(9.08)
Other	**1.41**	(0.66)
Effective income tax rate	**20.44**	16.76

The provision for income taxes consists of the following:

	2015 $	2014 $
Current income taxes	**2,000**	1,678
Future income taxes	**2,056**	6,766
Future income taxes transferred to regulatory assets	**(1,181)**	(6,252)
	2,875	2,192

Future income taxes are provided for temporary differences. Future tax assets and liabilities as at December 31 comprise the following:

	2015 $	2014 $
Future tax assets (liabilities)		
Utility capital assets	**(6,700)**	(5,110)
Employee future benefits	**1,943**	1,948
Rate mitigation accrual	**1,848**	1,987
Regulatory assets	**(2,690)**	(2,377)
Other assets	**46**	56
Net future tax liabilities	**(5,553)**	(3,496)

8. RELATED PARTY TRANSACTIONS

During the year, the Corporation entered into transactions with related parties summarized as follows:

	2015 $	2014 $
Receipts		
Dividends on common shares of		
Westario Power Holdings Inc.	**74**	71
Rideau St. Lawrence Holdings Inc.	**16**	16
Niagara Power Incorporated	**14**	28
Services provided to		
Westario Power Holdings Inc.	**344**	367
FortisAlberta Inc.	**5**	16
Maritime Electric Company Limited	**—**	39
CH Energy Group Inc.	**3**	35
Fortis Inc.	**957**	**—**
Fortis Generation East Limited Partnership	**358**	485
Grimsby Power Inc.	**94**	98
Wataynikaneyap Power LP	**196**	**—**
Payments		
Dividends to Fortis Inc.	**4,000**	4,000
Purchased power from Fortis Generation East Limited Partnership	**662**	1,679
Interest on promissory notes to Fortis Inc.	**—**	36
Services provided by		
Fortis Inc.	**648**	700
Newfoundland Power Inc.	**15**	11
Maritime Electric Company Limited	**45**	2
Wataynikaneyap Power LP	**363**	**—**

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

[in thousands of dollars]

December 31, 2015

As at December 31, the amounts due from (to) related parties are summarized as follows:

	2015 $	2014 $
Fortis Inc.	**(3,805)**	(23)
Wataynikaneyap Power LP	**(167)**	—
Grimsby Power Inc.	**11**	8
Westario Power Holdings Inc.	**31**	52
Fortis Generation East Limited Partnership	**—**	67
CH Energy Group Inc.	**—**	35
Newfoundland Power Inc.	**—**	(1)
	(3,930)	138

Details of the relationships with related parties are as follows:

- Fortis Inc. owns a 100% interest in the capital stock of the Corporation.
- Maritime Electric Company Limited is a wholly-owned subsidiary of FortisWest Inc., which itself is a wholly-owned subsidiary of Fortis Inc.
- Newfoundland Power Inc. is a wholly-owned subsidiary of Fortis Inc.
- Westario Power Holdings Inc. is 10% owned by the Corporation.
- FortisAlberta Inc. is a wholly-owned subsidiary of Fortis Inc.
- The Corporation owns 10 Class B preferred shares of Niagara Power Incorporated.
- The Corporation indirectly owns 10% of Grimsby Power Inc. through the ownership of the Class B preferred shares in Niagara Power Incorporated.
- Fortis Generation East Limited Partnership was formally a wholly-owned subsidiary of Fortis Inc.
- Rideau St. Lawrence Holdings Inc. is 10% owned by the Corporation.
- CH Energy Group Inc. is a wholly-owned subsidiary of Fortis Inc.
- Wataynikaneyap Power LP is indirectly owned 25% by Fortis Inc.

9. LONG-TERM DEBT

Long-term debt consists of the following:

	2015 $	2014 $
7.092% senior unsecured notes due on August 14, 2018		
Canadian Niagara Power Inc.	**30,000**	30,000
Cornwall Street Railway, Light and Power Company Limited	**22,000**	22,000
5.118% senior unsecured notes due on December 16, 2041		
Algoma Power Inc.	**52,000**	52,000
Unamortized debt issue costs	**(574)**	(645)
	103,426	103,355

The senior unsecured notes of CNPI and Cornwall Electric bear interest at 7.092% and are repayable at maturity on August 14, 2018. Interest expense on long-term debt for the year was $3,688 [2014 – $3,688].

The senior unsecured notes of API bear interest at 5.118% and are repayable at maturity on December 16, 2041. Interest expense for the year was $2,661 [2014 – $2,661].

10. CAPITAL STOCK

The authorized and issued capital stock consists of 1,001 common shares without par value.

11. AMORTIZATION

The amortization of utility capital assets and other assets consist of the following:

	2015 $	2014 $
Amortization of utility capital assets	**9,539**	9,600
Amortization of intangible assets	**1,801**	1,738
Amortization of contributions in aid of construction	**(624)**	(555)
	10,716	10,783
Vehicle amortization allocated	**(1,027)**	(1,000)
	9,689	9,783

12. CONSOLIDATED STATEMENT OF CASH FLOWS

The net change in non-cash working capital balances related to operations consists of the following:

	2015 $	2014 $
Accounts receivable	**2,035**	213
Due from/to related parties	**4,068**	(224)
Materials and supplies	**75**	(35)
Prepaid expenses	**128**	(20)
Accounts payable and accrued liabilities	**2,413**	(1,447)
Regulatory assets/liabilities	**1,267**	2,193
Income taxes recoverable	**177**	91
	10,163	771

Supplemental cash flow information:

	2015 $	2014 $
Interest paid	**6,561**	6,696
Income taxes paid	**2,672**	2,288

13. COMMITMENTS AND CONTINGENCIES

The Corporation has a building lease agreement until December 2019 with annual rent, operating costs and municipal taxes of $600.

The Corporation has gas purchase obligations until October 2019 at approximately $730 per year.

The Corporation is contingently liable under certain issued letters of credit amounting to $14,300.

14. FINANCIAL RISK MANAGEMENT

The Corporation is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit risk:	Risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument.
Liquidity risk:	Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.
Market risk:	Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices.

Credit risk

For cash, trade and other accounts receivable due from customers, the Corporation's credit risk is limited to the carrying values on the consolidated balance sheet.

The Corporation is exposed to credit risk from its distribution customers, but has various policies to minimize this risk. These policies include requiring customer deposits, performing disconnections and using third-party collection agencies for overdue accounts. The Corporation has a large and diversified distribution customer base, which minimizes the concentration of credit risk.

The aging of the Corporation's consolidated trade and other receivables due from customers is as follows:

	2015 $
Not past due	**23,261**
Past due 0 – 30 days	**583**
Past due 31 – 60 days	**229**
Past due 61 days and over	**815**
	24,888
Less allowance for doubtful accounts	**265**
	24,623

Liquidity risk

The Corporation's exposure to liquidity risk is minimal. Financing of regulated capital and other expenditures is done through internally generated funds. These funds are a result of allowable rate-regulated returns and recoveries under the OEB rate regulation mechanism and the Cornwall Electric Franchise Agreement as described in note 2.

The Corporation is a subsidiary of Fortis Inc., a large investor-owned utility that has had the ability to raise sufficient and cost-effective financing. However, the ability to arrange financing on a go-forward basis is subject to numerous factors, including the results of operations and financial position of Fortis Inc. and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

Also, to mitigate any liquidity risk, certain subsidiaries of the Corporation have committed revolving credit facilities and letters of credit facilities totalling $30,000, of which $15,700 is unused. The revolving credit facilities and letters of credit facilities are renewed on an annual basis. The following summary outlines the credit facilities of the Corporation:

	2015	**2014**
	$	$
Total credit facilities	**30,000**	30,000
Letters of credit outstanding	**(14,300)**	(14,300)
Credit facilities available	**15,700**	15,700

The facilities of the subsidiaries are guaranteed by the Corporation. The credit facilities bear interest at the bankers' acceptance rate plus 1.20% in the case of bankers' acceptances, and at the bank's prime lending rate plus 0.20% in the case of bank loans.

The following is an analysis of the contractual maturities of the Corporation's financial liabilities as at December 31, 2015:

	< 1 year	**1 – 3 years**	**4 – 5 years**	**> 5 years**	**Total**
	$	$	$	$	$
Accounts payable and accrued liabilities	**21,821**	**—**	**—**	**—**	**21,821**
Government remittances payable	**223**	**—**	**—**	**—**	**223**
Customer deposits	**605**	**467**	**764**	**—**	**1,836**
Long-term debt	**—**	**52,000**	**—**	**52,000**	**104,000**
	22,649	**52,467**	**764**	**52,000**	**127,880**

Market risk

Interest rate risk

Long-term debt is at fixed interest rates, thereby minimizing cash flow and interest rate fluctuation exposure. The Corporation is primarily subject to risks associated with fluctuating interest rates on its short-term borrowings. As at December 31, 2015, the Corporation's short-term borrowings are nil [2014 – nil].

15. CAPITAL MANAGEMENT

The Corporation manages the capital of CNPI and API to approximate the deemed capital structure reflected in the utility's customer rates or anticipated future rates. For CNPI, effective on January 1, 2013, the distribution rates are based on a deemed capital structure of 60% debt and 40% equity. CNPI's capital structure consists of third-party debt, affiliated debt and common equity, but excludes unamortized debt issue costs. API's distribution rates effective on January 1, 2015 are also based on a deemed capital structure of 60% debt and 40% equity. API's debt consists of third-party debt, excluding unamortized debt issue costs.

The managed capital of CNPI and API, combined, is as follows:

	2015 Actual		**2014 Actual**	
	$	%	$	%
Debt	**102,000**	**51**	102,000	53
Equity	**97,470**	**49**	90,056	47
	199,470	**100**	192,056	100

Certain of the Corporation's long-term debt obligations and credit facility agreements have covenants that restrict the issuance of additional debt such that subsidiary debt cannot exceed 75% of their respective capital structures as defined in the agreements. As at December 31, 2015, the subsidiaries were in compliance with their debt covenants.

16. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of regulatory requirements.

CNPI and API pay the cost of power on behalf of their customers and recover these costs through retail billings to their customers. The cost of power includes charges for transmission, wholesale market operations and the power itself from Ontario's Independent Electricity System Operator. The balance of the retail settlement variance account represents the costs that have not been recovered from, or settled through, customers as at the consolidated balance sheet date. The OEB's Distribution Rate Handbook and Accounting Procedures Handbook allow these costs to be deferred and recovered through future rate adjustments, as discussed in note 2B. In the absence of rate regulation, these costs would be expensed in the period they are incurred.

The seasonal revenue accrual is related to previous shortfalls in revenue for API's contributions from the seasonal customer class. The total cost allocated to the seasonal customer class was significantly higher than the total revenue generated through rates by that class. In order to recover the full cost, significant rate shock would have been incurred. In API's 2008 OEB Decision and Order, the OEB had accepted API's proposal to mitigate significant rate impacts to the seasonal customer class by limiting the rate increase to 10%. As a result of the new 2010 Decision and Order, API will collect the past amounts due from the seasonal customer class over a five-year period through specific rate adders. Effective with the new rates on December 1, 2010, the seasonal customer class rates are now designed to recover the full cost associated with this rate class. In API's 2015 cost of service proceeding, the OPEB approved the recovery of the additional $760, and this will be collected from the seasonal customer class by extending the 2010 Decision and Order rate rider expiration date out to June 2019.

The OEB has the general power to include or exclude costs, revenue, gains or losses in the rates of a specific period, resulting in the timing of revenue and expense recognition that may differ in the Corporation's regulated operations from those otherwise expected in non-regulated businesses. This change in timing gives rise to the recognition of regulatory assets and liabilities. The Corporation continually assesses the likelihood of recovery of its regulatory assets and believes that its regulatory assets and liabilities will be factored into the setting of future rates, as discussed in note 2B. If future recovery through rates is no longer considered probable, the appropriate carrying amount will be written off in the period that the assessment is made.

The Corporation of the City of Cornwall Franchise Agreement provides that Cornwall Electric is guaranteed an annual gross margin on energy sold subject to regulatory adjustments. The cost of power is a flow-through to the customers and the retail rates include an estimate of that power for the upcoming rate year. Variances occur as a result of actual gross margins differing from guaranteed gross margins. Gross margins will differ due to differences in the actual cost of power and electric usage by customers from expected levels. In the absence of rate regulation, there

would be no guaranteed gross margin and Cornwall Electric's revenue would have been higher by $1,398 in 2015.

In 2010, Cornwall Electric was subject to back charges in the amount of $1,250 as a result of previous errors in the billing of cost of power by its electricity provider HQ Energy Marketing, Inc. ["MEHQ"]. As per agreement, MEHQ is billing and collecting these amounts from Cornwall Electric effective July 1, 2011 over a five-year period. For 2015, an amount of $125 has been recorded as current accounts payable, which represents the balance of the back charges owing to MEHQ. Since the cost of power is a flow-through to the customers, an equal offsetting amount of $125 is recognized as a regulatory asset to be recovered from customers through future rate adjustments until July 2016.

In 2013, upon approval by the OEB, the Corporation integrated smart meters into rate base from amounts previously held as regulatory assets in CNPI of $4,365 and API of $3,262, as well as removing stranded meter assets of $1,238 in CNPI from utility capital assets and recognizing these amounts as regulatory assets. On January 8, 2015, API received approval from the OEB to remove stranded meter assets of $278 from utility capital assets and recognize these amounts as regulatory assets.

In 2014, as discussed in note 2 under "Capitalization policy", API has recorded a regulatory liability of $710 in OEB account 1576 for a total cumulative regulatory liability of $1,379. These are transitional adjustments related to accounting changes to amortization and capitalization policy. As a result of the 2015 OEB Decision and Order, API recorded an additional regulatory liability of $93 in 2015 relating to the regulatory return calculated on the approved cumulative regulatory liability of $1,379. A reduction of the regulatory liability of $344 occurred during 2015 due to a repayment to API's customers in the form of a rate rider, which is set to expire in December 2019. The cumulative regulatory liability balance as at December 31, 2015 is $1,128, of which $375 has been reported as current.

In 2015, as a result of the Transmission OEB Decision and Order, the corporation expensed certain disallowed capital project costs in the amount of $1,250. These amounts were previously recorded as capital assets under construction.

The following table summarizes the costs associated with these regulatory adjustments:

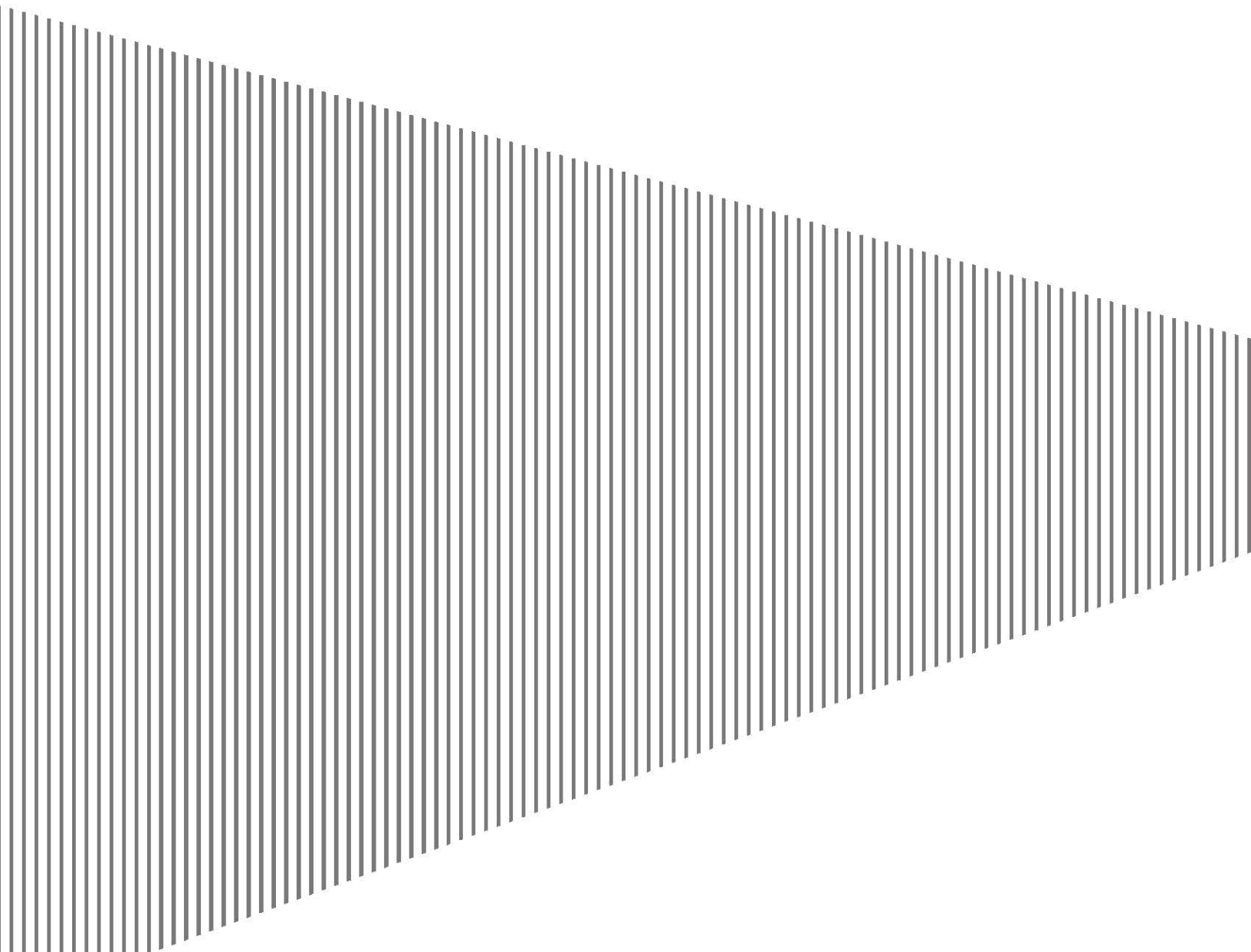
	2015 $	**2014** $
Disallowed capital project costs	**(1,250)**	**—**
Transitional adjustments for API related to accounting changes to amortization expense and capitalization policy	**(93)**	(710)
Other regulatory adjustments	**(1,343)**	(710)

Regulatory assets and liabilities are not subject to a regulatory return; however, the balances include an accrual for interest recoverable/payable as permitted by the regulators. The purpose of the following table is to provide reconciliation between the regulatory assets and liabilities and the remaining rebate period:

	2015 $	2014 $	Remaining rebate period
Current regulatory assets			
Amounts approved in current rates	**368**	597	**1 year**
The Corporation of the City of Cornwall franchise revenue variances	**303**	1,009	**1 year**
	671	1,606	
Long-term regulatory assets			
Amounts approved in current rates	**1,933**	798	**2 years**
Retail settlement and other variance accounts	**3,511**	4,368	**2 years**
Seasonal revenue accrual	**—**	760	
Smart meter variance account	**7**	41	
Future income taxes to be recovered from customers	**10,150**	8,968	**Life of assets**
Pension and other retirement benefits	**4,125**	5,828	**EARSL**
	19,726	20,763	
Current regulatory liabilities			
Amounts approved in current rates	**175**	6	**1 year**
Ontario clean energy benefits	**1,332**	1,546	**1 month**
Other	**441**	64	
	1,948	1,616	
Long-term regulatory liabilities			
The Corporation of the City of Cornwall franchise revenue variances	**1,186**	465	**2 years**
Retail settlement and other variance accounts	**3,580**	6,029	**2 years**
Other	**754**	1,463	
	5,520	7,957	

17. COMPARATIVE CONSOLIDATED FINANCIAL STATEMENTS

The comparative consolidated financial statements have been reclassified from statements previously presented to conform to the presentation of the 2015 consolidated financial statements.



Consolidated financial statements

FortisOntario Inc.

December 31, 2016



Building a better working world

Independent auditors' report

To the Shareholder of
FortisOntario Inc.

We have audited the accompanying consolidated financial statements of **FortisOntario Inc.**, which comprise the consolidated balance sheet as at December 31, 2016, and the consolidated statements of earnings and retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian accounting standards for private enterprises, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of **FortisOntario Inc.** as at December 31, 2016, and the results of its operations and its cash flows for the year then ended in accordance with Canadian accounting standards for private enterprises.

Ernst & Young LLP

Toronto, Canada
February 9, 2017

Chartered Professional Accountants
Licensed Public Accountants

A member firm of Ernst & Young Global Limited

FortisOntario Inc.

Consolidated balance sheet

[in thousands of dollars]

As at December 31

	2016	2015
	$	$
Assets		
Current		
Cash	**6,891**	5,107
Accounts receivable *[note 14]*	**25,322**	24,623
Income taxes recoverable	**411**	333
Due from related parties *[note 8]*	**754**	—
Materials and supplies	**156**	164
Regulatory assets *[note 16]*	**540**	671
Prepaid expenses	**824**	613
Total current assets	**34,898**	31,511
Utility capital assets, net *[note 3]*	**250,314**	238,460
Intangible assets, net *[note 4]*	**28,472**	29,040
Long-term investments *[note 5]*	**4,121**	4,121
Future tax assets [note 7]	**2,902**	3,057
Accrued pension benefits *[note 6]*	**8,206**	8,477
Other assets	**81**	284
Regulatory assets *[note 16]*	**19,429**	19,726
Goodwill	**46,094**	46,094
	394,517	380,770
Liabilities and shareholder's equity		
Current		
Accounts payable and accrued liabilities *[note 14]*	**21,964**	23,880
Regulatory liabilities *[note 16]*	**452**	1,948
Due to related parties *[note 8]*	**—**	3,930
Short-term loan payable *[note 14]*	**9,000**	—
Total current liabilities	**31,416**	29,758
Long-term debt *[notes 9 and 14]*	**103,498**	103,426
Future tax liabilities, net *[note 7]*	**10,433**	8,610
Accrued other retirement benefits *[note 6]*	**18,040**	17,457
Accrued pension benefits *[note 6]*	**2,863**	2,083
Contributions in aid of construction	**24,912**	22,647
Regulatory liabilities *[note 16]*	**4,804**	5,520
Total liabilities	**195,966**	189,501
Commitments and contingencies *[note 13]*		
Shareholder's equity		
Capital stock *[note 10]*	**2**	2
Contributed surplus	**108,606**	108,606
Retained earnings	**89,943**	82,661
Total shareholder's equity	**198,551**	191,269
	394,517	380,770

See accompanying notes

Approved on behalf of the Board:

Director Director

FortisOntario Inc.

Consolidated statement of earnings and retained earnings

[in thousands of dollars]

Year ended December 31

	2016	2015
	$	$
Revenue		
Sale of energy	**145,885**	138,219
Distribution	**53,836**	53,432
Transmission	**4,652**	4,347
Other	**3,836**	3,478
	208,209	199,476
Expenses		
Cost of power purchased	**145,053**	137,577
Operating	**32,468**	30,262
Amortization *[note 11]*	**10,242**	9,689
	187,763	177,528
Operating earnings before the following	**20,446**	21,948
Dividend income *[note 8]*	**103**	104
Other regulatory adjustments *[note 16]*	**(93)**	(1,343)
Interest expense *[notes 9 and 14]*	**(6,674)**	(6,642)
Earnings before income taxes	**13,782**	14,067
Provision for income taxes *[note 7]*	**2,500**	2,875
Net earnings for the year	**11,282**	11,192
Retained earnings, beginning of year	**82,661**	75,469
Dividends paid *[note 8]*	**(4,000)**	(4,000)
Retained earnings, end of year	**89,943**	82,661

See accompanying notes

FortisOntario Inc.

Consolidated statement of cash flows

[in thousands of dollars]

Year ended December 31

	2016 $	2015 $
Operating activities		
Net earnings for the year	**11,282**	11,192
Add (deduct) items not affecting cash		
Amortization	**11,268**	10,716
Future income taxes	**1,978**	2,056
Gain on disposal of utility capital assets	**(156)**	(105)
Accrued pension benefits	**1,578**	—
Accrued other retirement benefits	**1,234**	457
Long-term regulatory assets and liabilities	**(419)**	(1,400)
Accrued pension benefits	**(527)**	(1,687)
Accrued other retirement benefits	**(651)**	(703)
	25,587	20,526
Net change in non-cash working capital balances related to operations *[note 12]*	**(8,945)**	10,163
Cash provided by operating activities	**16,642**	30,689
Investing activities		
Additions to utility capital assets	**(21,918)**	(26,295)
Investment in Niagara Power Incorporated	**—**	(300)
Additions to intangible assets	**(1,327)**	(3,188)
Proceeds on sale of utility capital assets	**180**	784
Change in other assets	**274**	(60)
Cash used in investing activities	**(22,790)**	(29,059)
Financing activities		
Decrease in long-term payable	**—**	(125)
Short-term loan payable	**9,000**	—
Dividends paid	**(4,000)**	(4,000)
Increase in contributions in aid of construction	**2,932**	2,075
Cash used in financing activities	**7,932**	(2,050)
Net increase (decrease) in cash during the year	**1,784**	(420)
Cash, beginning of year	**5,107**	5,527
Cash, end of year	**6,891**	5,107

See accompanying notes

FortisOntario Inc.

Notes to consolidated financial statements

[in thousands of dollars, unless where otherwise noted]

December 31, 2016

1. Basis of presentation

The consolidated financial statements include the accounts of FortisOntario Inc. [the "Corporation"] and its wholly-owned subsidiaries, Canadian Niagara Power Inc. ["CNPI"], FortisOntario District Heating Inc. [formerly 1161557 Ontario Inc.], Cornwall Street Railway, Light and Power Company Limited ["Cornwall Electric"] and Algoma Power Inc. ["API"].

The principal businesses of the Corporation are the generation of electricity and the transmission and distribution of electricity to customers within Ontario. Certain of these businesses are regulated by the Ontario Energy Board ["OEB"].

2. Basis of accounting and summary of significant accounting policies

Basis of accounting

These consolidated financial statements have been prepared in accordance with Canadian accounting standards for private enterprises ["ASPE"], as per Part II of the CPA Handbook – Accounting, which constitutes generally accepted accounting principles for non-publicly accountable enterprises in Canada.

Summary of significant accounting policies

Regulation

CNPI distribution rates

The distribution rates of CNPI are based upon Cost of Service ["CoS"] rate regulation by the OEB. Earnings are regulated on the basis of a rate of return on rate base plus a recovery of all allowable distribution costs of CNPI.

On August 13, 2014, CNPI submitted its 2015 4th Generation Incentive Rate-setting Application ["4GIRM"] for electricity distribution rates effective January 1, 2015. This application was a second in a series of rate applications to fully harmonize electricity distribution rates in Port Colborne with those of Fort Erie and Gananoque. The OEB issued its Decision and Order on December 4, 2014, and the net price cap index adjustment for 2015 was 1.15% [i.e. 1.6% - (0% + 0.45%)]. The overall bill impact for the average residential consumer in Fort Erie was a 1.4% decrease, a 1.5% decrease for the average residential consumer in Gananoque, and a 3.2% decrease for the average residential consumer in Port Colborne. These overall decreases include the impact of the disposition of regulatory deferral and variance accounts.

On August 14, 2015, CNPI submitted its 2016 4GIRM for electricity distribution rates effective January 1, 2016. The OEB calculated the value of the inflation factor for incentive rate setting, for rate changes effective in 2016, to be 2.1%. The OEB assigned a stretch factor of 0.45% based on the updated benchmarking study for use for rates effective in 2016. As a result, the net price cap index adjustment for CNPI was 1.65% [i.e. 2.1% - (0% + 0.45%)]. The 1.65% adjustment applies to distribution rates [fixed and variable charges] uniformly across all customer classes.

Beginning with electricity distribution rates effective in 2016, decoupling of electricity distribution rates for the Residential customer class was introduced; complete decoupling is expected to take five consecutive years to implement fully.

CNPI filed its 2017 CoS Application on April 29, 2016. The application contained CNPI's first Integrated Distribution System Plan ["DSP"], which outlined a comprehensive five-year plan for capital investment and asset management. The key areas of investment in the DSP are replacement of end-of-life assets and elimination of legacy 3-wire delta systems through ongoing voltage conversion and substation replacement programs. The application also contained a significant focus on customer engagement activities in recognition of the increasing levels of scrutiny associated with this outcome.

The CoS Application proposed an increase in approved revenue requirement to approximately $22.3 million [17.6% over 2013 approved] and an increase in rate base to approximately $89.9 million [22% over 2013 approved]. The allowed Return on Equity ["ROE"] and deemed debt rates will be determined as the OEB publishes revised cost of capital parameters during the course of the proceeding.

Total monthly bill impacts are $1.96, or 0.9%, for a typical Residential customer [750 kWh] and $6.59, or 1.8% for a typical GS<50 customer [2,000 kWh].

OEB held community day meetings on September 13 and 14, 2016. At those meetings, Board staff presented the regulatory rate-setting process and CNPI presented its rate application request. Interrogatory responses for Board staff and Intervenors were filed on October 19, 2016. A technical conference was held November 2, 2016, and a settlement conference was held November 8 and 9, 2016. A partial settlement was achieved excluding operating, maintenance, and administrative expenses, cost of debt, pension & OPEB accounting, and rate change effective date. An oral hearing was held on January 4, 2017. Argument in Chief and Response arguments are due in January or early February 2017 with a Board Decision and Order expected by the end of the first quarter.

CNPI transmission rates

The transmission rates of CNPI are based upon CoS rate regulation by the OEB. Earnings are regulated on the basis of a rate of return on rate base plus a recovery of all allowable transmission costs of CNPI.

On November 17, 2014, CNPI submitted a Revenue Requirement Application for its Transmission business. The Application sought approval of CNPI's 2015 and 2016, Transmission Revenue Requirement.

On June 25, 2015, the OEB issued its Decision and Order. The Decision and Order approved final revenue requirements of $4,246,478 and $4,647,201 for 2015 and 2016, respectively, and provided a 9.3% ROE with a 60%/40% debt equity structure. On January 14, 2016, the OEB issued its Decision and Order approving an adjusted 2016 revenue requirement of $4,457,953.

API distribution rates

The distribution rates of API are based upon CoS rate regulation by the OEB. Earnings are regulated on the basis of a rate of return on rate base plus a recovery of all allowable distribution costs of API.

API is subject to Ontario Regulation 335/07, which is the Rural and Remote Rate Protection subsidy program ["RRRP"]. The RRRP is calculated as the deficiency between the approved revenue requirement from the OEB and current customer distribution rates adjusted for the average rate increase across the Province of Ontario.

API qualifies for this subsidy because it has fewer than seven customers per kilometre and a service area that extends beyond 10,000 kilometres. All general service and large customer classes have been reclassified as residential class under Ontario Regulation 445/07.

In May 2014, API filed a CoS electricity distribution rate application for rates effective January 1, 2015 based on a 2015 test year. The OEB issued its Decision and Order on January 8, 2015. The Decision and Order approved a 2015 Base Revenue Requirement of $22,816,180 and provided a 9.3% ROE with a 60%/40% debt equity structure.

On August 14, 2015, API filed an application with the OEB seeking approval to change electricity distribution rates, effective January 1, 2016, based on 4GIRM. The OEB calculated the value of the inflation factor for incentive rate setting, for rate changes effective in 2016, to be 2.1%. The OEB assigned a stretch factor of 0.6% based on the updated benchmarking study for use for rates effective in 2016. The resulting net price cap index adjustment for API was 1.5% [i.e. 2.1% - (0% + 0.6%)]. The 1.5% adjustment applies to distribution rates [fixed and variable charges] uniformly for the Seasonal and Street Lighting customer classes. The OEB approved the application of the 1.8% RRRP adjustment factor to the distribution rates for the Residential R-1 and Residential R-2 classes. The OEB found that the amount of RRRP of $13,678,440 for the year commencing January 1, 2016 accurately reflected the OEB's findings pursuant to the applicable regulations and approved a monthly payment of $1,139,870 effective January 1, 2016.

Beginning with electricity distribution rates effective in 2016, decoupling of electricity distribution rates for the Residential customer class was being introduced; complete decoupling is expected to take eight consecutive years to fully implement for residential, and nine consecutive years to fully implement for seasonal customers.

On August 12, 2016, API filed an application with the OEB seeking approval to change electricity distribution rates, effective January 1, 2017, based on 4GIRM. On October 27, 2016, the OEB updated its inflation factor for 2017 Price Cap IR applications, and subsequently provided API with a calculation of the RRRP rate adjustment applicable to API's Residential customer classes. The net price cap index adjustments for API was updated to be 1.3% [i.e. 1.9% - (0% + 0.6%)]. This was based on a province-wide inflation factor of 1.9%, less productivity factor of 0% and stretch factor of 0.6%. The assignment of the stretch factors was determined by the OEB as a result of updates to its benchmarking analysis research. The rate increase applicable to Residential classes, based on the OEB's RRRP calculation is 2.96%. The OEB found that the amount of RRRP of $13,498,952 for the year commencing January 1, 2017 accurately reflects the OEB's findings pursuant to the applicable regulations and approved a monthly payment of $1,124,913 effective January 1, 2017.

Cornwall Electric

Cornwall Electric is subject to a rate-setting mechanism under the Franchise Agreement, which is the retail rate and service agreement between Cornwall Electric and The Corporation of the City of Cornwall. The rate-setting mechanism is based on a price cap with commodity cost flow-through. The base revenue requirement is adjusted annually for inflation, load growth, number of customers and premises vacancies. The rate years covering the operations for 2016 are from July 1, 2015 to June 30, 2016 and from July 1, 2016 to June 30, 2017.

Materials and supplies

Materials and supplies are recorded at average cost. Materials and supplies expensed to operating expenses in 2016 were $110 [2015 – $125].

Utility capital assets, capitalization policy and service life of utility capital assets

[a] Nature of distribution, transmission and generation assets

Distribution assets

Distribution assets are those used to distribute electricity at lower voltages [generally below 50 kilovolts]. These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Transmission assets

Transmission assets are those used to transmit electricity at higher voltages [generally at 50 kilovolts and above]. These assets include poles, wires and conductors, substations, support structures and other related equipment.

Generation assets

Generation assets are those used to generate electricity. These assets include thermal generating stations, gas turbines and other related equipment.

[b] Service life range and average remaining service life of utility capital assets

The service life range and average remaining service life of the utility capital assets are as follows:

	Service life range [years]	Average remaining service life [years]
Distribution	10 to 50	33.7
Transmission	25 to 50	35.8
Generation	25 to 50	12.3

Utility capital assets are stated at cost less accumulated amortization. Amortization is provided over their estimated useful lives using the straight-line method at a composite rate of 2.3% [2015 – 2.3%].

Contributions in aid of construction represent funding of utility capital assets contributed by customers. These accounts are being reduced annually by an amount equal to the charge for amortization provided on the contributed portion of the utility capital assets involved.

[c] Capitalization policy

The Corporation's capitalization policy is in accordance with the OEB's requirements to use a "modified IFRS" accounting basis. API, as permitted by the OEB, has recognized the financial differences arising as a result of the 2013 accounting changes to amortization expense and capitalization policies *[note 16]*.

Intangible assets

Intangible assets are stated at cost less accumulated amortization. Amortization is provided over their estimated useful lives using the straight-line method.

The service life range and average remaining service life of the intangible assets are as follows:

	Service life range [years]	Average remaining service life [years]
Software costs	5 to 10	5.6
Land and transmission rights	40	29.2
Other	50	27.3

Asset retirement obligations

ASPE requires the recognition of an asset retirement obligation in the period during which a legal obligation associated with the retirement of a tangible long-lived asset is incurred and when a reasonable estimate of this amount can be made.

The Corporation has determined that there are asset retirement obligations associated with some parts of its transmission, distribution and generation systems; however, none of these are material or require recognition under Section 3110 of the CPA Handbook.

Long-term investments

The Corporation accounts for its long-term investments using the cost method.

Goodwill

Goodwill represents the excess of the acquisition cost of the shares of CNPI, Cornwall Electric and Eastern Ontario Power Inc. [amalgamated with CNPI as of January 1, 2004] over the assigned value of identifiable net assets acquired, as well as the excess of the purchase price of the remaining utility capital assets of Port Colborne Hydro Inc. over the fair value of these assets.

ASPE requires that goodwill be tested for impairment whenever events or changes in circumstances indicate that the carrying amount of the reporting unit to which the goodwill is assigned may exceed the fair value of the reporting unit. Any impairment in value is charged to earnings during the year.

Other assets

Other assets are amortized over their useful lives.

Revenue recognition

Revenue from the sale, transmission and distribution of electricity is recognized on the accrual basis. Electricity is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of the year, a certain amount of consumed electricity will not have been billed. Electricity that is consumed, but not yet billed to the customers, is estimated and accrued as revenue in the current year. Unbilled revenue included in accounts receivable as at December 31, 2016 was $14,809 [2015 – $14,378].

The Corporation of the City of Cornwall Franchise Agreement provides that Cornwall Electric sets electricity rates such that Cornwall Electric is guaranteed an annual gross margin on power sold of $13,317 [2015 – $13,127]. This guaranteed gross margin covers the rate years from July 1, 2015 to June 30, 2016 and from July 1, 2016 to June 30, 2017. The guaranteed gross margin is accrued on a prorated basis over the course of the year.

Foreign currency translation

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing at the consolidated balance sheet date. Gains and losses arising from foreign currency transactions are included in earnings for the year. Revenue and expenses are translated at the exchange rate prevailing on the transaction date.

Employee benefit plans

Effective January 1, 2014, the Corporation adopted new CPA Handbook Section 3462, Employee Future Benefits, for its accounting of pension benefits and other retirement benefits. As allowed under new Section 3462, the Corporation made an accounting policy choice to measure its defined benefit plan obligations using the funding valuation approach. This approach uses the most recent completed actuarial valuations prepared for funding purposes as the basis of measuring defined benefit plan obligations. Even though other retirement benefits are not funded, Section 3462 allows that such liabilities be measured on a basis consistent with funded plans. As well, the Corporation is using a roll-forward technique in the years between valuations to estimate the defined benefit plan obligations. Pension plan assets are valued at fair value as at the consolidated balance sheet date.

In 2013, the Corporation made an application to the OEB to allow recognition of regulatory assets related to unamortized amounts, and restatement of prior years' pension and other retirement benefit expenses, in CNPI and API that would otherwise be collected from customers through rates in subsequent years. In December 2013, the OEB issued a Decision and Order approving the establishment of specific deferral accounts for CNPI and API to recognize these amounts as long-term regulatory assets, which will be disposed of in future CoS proceedings, subject to the OEB's prudence review at that time. As well, the Corporation reversed previously recognized future income tax liabilities related to the changes in the pension and other retirement benefit liabilities as of January 1, 2014. For CNPI and API, the Corporation recognized offsetting regulatory liabilities related to the future income taxes expected to be recovered from customers in future electricity rates as of January 1, 2014.

The Corporation made an application to the OEB for CNPI and API to continue to account for pension and other retirement benefits under the former Section 3461. In December 2013, the OEB issued a Decision and Order approving the establishment of specific variance accounts for CNPI and API as of January 1, 2013, to recognize the difference in expense between Sections 3461 and 3462 as long-term regulatory assets or liabilities for 2013 and future years, which will be disposed of in future CoS proceedings, subject to the OEB's prudence review at that time.

Income taxes

The Corporation follows the asset and liability method of accounting for income taxes. Under this method, future tax assets and liabilities are recognized for the temporary differences between the tax and accounting bases of assets and liabilities. Future tax assets and liabilities are measured using the enacted and substantively enacted tax rates expected to apply to taxable income in the period in which the temporary differences are expected to be recovered or settled. The Corporation recognizes regulatory assets and liabilities related to future tax assets and liabilities for the amount of future income taxes expected to be recovered from customers in future electricity rates for CNPI and API.

Use of estimates

The preparation of consolidated financial statements in conformity with ASPE 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 consolidated financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results may vary from the current estimates. These estimates are reviewed periodically and, as adjustments become necessary, they are reported in earnings in the period in which they become known.

3. Utility capital assets

Utility capital assets consist of the following:

	2016		
	Cost	**Accumulated amortization**	**Net book value**
	$	$	$
Transmission	**33,348**	**13,822**	**19,526**
Distribution	**355,633**	**147,948**	**207,685**
Generation	**16,076**	**11,269**	**4,807**
Other	**45,781**	**27,485**	**18,296**
	450,838	**200,524**	**250,314**

	2015		
	Cost	Accumulated amortization	Net book value
	$	$	$
Transmission	32,536	13,272	19,264
Distribution	337,137	141,473	195,664
Generation	16,050	10,746	5,304
Other	47,635	29,407	18,228
	433,358	194,898	238,460

The amounts above include assets under construction of $4,213 [2015 – $5,340], which are not subject to amortization.

4. Intangible assets

Intangible assets consist of the following:

	2016		
	Cost	Accumulated amortization	Net book value
	$	$	$
Software costs	**15,707**	**9,425**	**6,282**
Land and transmission rights	**29,969**	**8,053**	**21,916**
Other	**406**	**132**	**274**
	46,082	**17,610**	**28,472**

	2015		
	Cost	Accumulated amortization	Net book value
	$	$	$
Software costs	17,105	10,899	6,206
Land and transmission rights	29,848	7,298	22,550
Other	406	122	284
	47,359	18,319	29,040

5. Long-term investments

The Corporation's long-term investments are summarized as follows:

	2016	2015
	$	$
Investment in common shares of Westario Power Inc.	**2,076**	2,076
Investment in common shares of Rideau St. Lawrence Holdings Inc.	**452**	452
Investment in Class B preferred shares of Niagara Power Incorporated	**1,593**	1,593
	4,121	4,121

Through the ownership of the Class B preferred shares of Niagara Power Incorporated, the Corporation holds a 10% economic interest in Grimsby Power Inc.

6. Employee benefit plans

The Corporation maintains three defined benefit pension plans and two defined contribution pension plans providing pension benefits, and three defined benefit plans providing other retirement benefits to most of its employees. The Corporation also makes contributions to the Ontario Municipal Employees' Retirement System ["OMERS"] plan on behalf of some of its employees. OMERS is a multi-employer defined benefit pension plan providing pension benefits and is accounted for as a defined contribution pension plan.

Information about the defined benefit plans for the Corporation, CNPI and Cornwall Electric is as follows:

	Pension benefit plans		Other retirement plans	
	2016	**2015**	**2016**	**2015**
	$	$	$	$
Accrued benefit obligation				
Balance, beginning of year	**24,055**	24,511	**10,847**	10,568
Current service costs	**341**	404	**95**	111
Finance costs	**1,143**	1,164	**515**	502
Benefits paid	**(1,424)**	(1,430)	**(577)**	(559)
Actuarial losses (gains)	**(34)**	(594)	**149**	225
Balance, end of year	**24,081**	24,055	**11,029**	10,847
Plan assets				
Fair value, beginning of year	**30,934**	29,899	**—**	—
Interest income	**1,469**	1,420	**—**	—
Return on plan assets	**(279)**	143	**—**	—
Contributions	**30**	902	**577**	559
Benefits paid	**(1,424)**	(1,430)	**(577)**	(559)
Fair value, end of year	**30,730**	30,934	**—**	—
Funded status – plan surplus (deficit)	**6,649**	6,879	**(11,029)**	(10,847)

The measurement date for the plan assets and the accrued benefit obligation was as at December 31, 2016. The effective date of the most recent actuarial valuation was as at December 31, 2014, and the date of the next required valuation for funding purposes is as at December 31, 2017.

The plan assets held at the measurement date are represented by the following categories:

	%
Canadian equity funds	**9**
Foreign equity funds	**33**
Canadian fixed income funds	**58**

As at December 31, 2016, one of the two defined benefit pension plans had a net accrued benefit liability of $357 [2015 – $370]. This plan had no plan assets in 2016 or 2015.

Included in the accrued pension benefits liability as at December 31, 2016 was an unfunded defined contribution plan pension liability of $2,157 [2015 – $1,337] relating to the supplementary employee retirement plan.

Notes to consolidated financial statements

[in thousands of dollars, unless where otherwise noted]

December 31, 2016

	Pension benefit plans		Other retirement plans	
	2016	**2015**	**2016**	**2015**
	$	$	$	$
Significant assumptions used				
Discount rate – beginning of year	**4.75%**	4.75%	**4.75%**	4.75%
Discount rate – end of year	**4.75%**	4.75%	**4.75%**	4.75%
Rate of compensation increase	**3.50%**	3.50%	**—**	—
Initial health care trend rate	**—**	—	**5.54%**	5.57%
Average remaining service life of active employees [years]	**5**	5	**14 - 17**	14 – 16
Net benefit expense for the year				
Current service costs	**341**	404	**95**	111
Finance costs	**(326)**	(256)	**515**	502
Remeasurement costs	**245**	(737)	**59**	225
Regulatory adjustments	**202**	802	**95**	(453)
Net benefit expense	**462**	213	**764**	385

Information about the Corporation's defined benefit plans for API is as follows:

	Pension benefit plans		Other retirement plans	
	2016	**2015**	**2016**	**2015**
	$	$	$	$
Accrued benefit obligation				
Balance, beginning of year	**25,450**	24,111	**6,610**	7,136
Current service costs	**533**	463	**248**	288
Finance costs	**1,209**	1,145	**314**	339
Employee contributions	**234**	196	**—**	—
Benefits paid	**(1,029)**	(945)	**(164)**	(145)
Actuarial losses (gains)	**(35)**	480	**3**	(1,008)
Balance, end of year	**26,362**	25,450	**7,011**	6,610
Plan assets				
Fair value, beginning of year	**26,302**	24,618	**—**	—
Interest income	**1,245**	1,168	**—**	—
Return on plan assets	**(36)**	480	**—**	—
Contributions	**730**	981	**164**	145
Benefits paid	**(1,029)**	(945)	**(164)**	(145)
Fair value, end of year	**27,212**	26,302	**—**	—
Funded status – plan surplus (deficit)	**850**	852	**(7,011)**	(6,610)

Notes to consolidated financial statements

[in thousands of dollars, unless where otherwise noted]

December 31, 2016

The measurement date for the plan assets and the accrued benefit obligation was as at December 31, 2016. The effective date of the most recent actuarial valuation was as at December 31, 2014 and the date of the next required valuation for funding purposes is as at December 31, 2017.

The plan assets held at the measurement date are represented by the following categories:

	%
Canadian equity funds	**11**
Foreign equity funds	**41**
Canadian fixed income funds	**47**
Cash and short-term investments	**1**

As at December 31, 2016, one of the defined benefit pension plans had a net accrued benefit liability of $350 [2015 – $376]. This plan had no plan assets in 2016 or 2015.

	Pension benefit plans		**Other retirement plans**	
	2016	**2015**	**2016**	**2015**
	$	$	$	$
Significant assumptions used				
Discount rate – beginning of year	**4.75%**	4.75%	**4.75%**	4.75%
Discount rate – end of year	**4.75%**	4.75%	**4.75%**	4.75%
Rate of compensation increase	**3.50%**	3.50%	**—**	—
Initial health care trend rate	**—**	—	**5.76%**	5.83%
Average remaining service year of active employees [years]	**16**	16	**16**	16
Net benefit expense for the year				
Current service costs	**533**	463	**248**	288
Finance costs	**(36)**	(23)	**314**	339
Remeasurement costs	**1**	—	**3**	(1,008)
Regulatory adjustments	**(254)**	126	**53**	1,200
Net benefit expense	**244**	566	**618**	819

The total expense for the Corporation's defined contribution pension plans for the year amounted to $464 [2015 – $483]. The pension cost associated with the OMERS plan was $488 [2015 –$506].

7. Income taxes

The following is a reconciliation of the combined statutory income tax rate to the effective income tax rate:

	2016 %	2015 %
Statutory income tax rate	**26.50**	26.50
Future income taxes transferred to regulatory assets	**(8.70)**	(7.47)
Other	**0.34**	1.41
Effective income tax rate	**18.14**	20.44

The provision for income taxes consists of the following:

	2016 $	2015 $
Current income taxes	**2,157**	2,000
Future income taxes	**1,978**	2,056
Future income taxes transferred to regulatory assets	**(1,635)**	(1,181)
	2,500	2,875

Future income taxes are provided for temporary differences. Future tax assets and liabilities as at December 31 comprise the following:

	2016 $	2015 $
Future tax assets (liabilities)		
Utility capital assets	**(8,434)**	(6,700)
Employee future benefits	**2,297**	1,943
Rate mitigation accrual	**1,718**	1,848
Regulatory assets	**(3,122)**	(2,690)
Other assets	**10**	46
Net future tax liabilities	**(7,531)**	(5,553)

8. Related party transactions

During the year, the Corporation entered into transactions with related parties summarized as follows:

	2016 $	2015 $
Receipts		
Dividends on common shares of		
Westario Power Inc.	**80**	74
Rideau St. Lawrence Holdings Inc.	**16**	16
Niagara Power Incorporated	**7**	14
Services provided to		
Westario Power Inc.	**270**	344
FortisAlberta Inc.	**—**	5
Maritime Electric Company Limited	**1**	—
CH Energy Group Inc.	**—**	3
Fortis Inc.	**3,255**	957
Fortis Generation East Limited Partnership	**—**	358
Grimsby Power Inc.	**105**	94
Wataynikaneyap Power LP	**714**	196
Fortis-RES PM Inc.	**260**	80
Payments		
Dividends to Fortis Inc.	**4,000**	4,000
Purchased power from Fortis Generation East Limited Partnership	**—**	662
Interest on promissory notes to Fortis Inc.	**46**	—
Services provided by		
Fortis Inc.	**677**	648
Newfoundland Power Inc.	**28**	15
Maritime Electric Company Limited	**14**	45
Wataynikaneyap Power LP	**—**	363
CH Energy Group Inc.	**3**	—

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Notes to consolidated financial statements

[in thousands of dollars, unless where otherwise noted]

December 31, 2016

As at December 31, the amounts due from (to) related parties are summarized as follows:

	2016 $	2015 $
Fortis Inc.	**(161)**	(3,805)
Wataynikaneyap Power LP	**545**	(247)
Fortis-RES PM Inc.	**341**	80
Grimsby Power Inc.	**14**	11
Westario Power Inc.	**30**	31
CH Energy Group Inc.	**(2)**	—
Newfoundland Power Inc.	**(13)**	—
	754	(3,930)

Details of the relationships with related parties are as follows:

- Fortis Inc. owns a 100% interest in the capital stock of the Corporation.
- Maritime Electric Company Limited is a wholly-owned subsidiary of FortisWest Inc., which itself is a wholly-owned subsidiary of Fortis Inc.
- Newfoundland Power Inc. is a wholly-owned subsidiary of Fortis Inc.
- Westario Power Inc. is 10% owned by the Corporation.
- FortisAlberta Inc. is a wholly-owned subsidiary of Fortis Inc.
- The Corporation owns 10 Class B preferred shares of Niagara Power Incorporated.
- The Corporation indirectly owns 10% of Grimsby Power Inc. through the ownership of the Class B preferred shares in Niagara Power Incorporated.
- Fortis Generation East Limited Partnership was formerly a wholly-owned subsidiary of Fortis Inc.
- Rideau St. Lawrence Holdings Inc. is 10% owned by the Corporation.
- CH Energy Group Inc. is a wholly-owned subsidiary of Fortis Inc.
- Wataynikaneyap Power LP is indirectly owned 25% by Fortis Inc.

9. Long-term debt

Long-term debt consists of the following:

	2016 $	2015 $
7.092% senior unsecured notes due on August 14, 2018		
Canadian Niagara Power Inc.	**30,000**	30,000
Cornwall Street Railway, Light and Power Company Limited	**22,000**	22,000
5.118% senior unsecured notes due on December 16, 2041		
Algoma Power Inc.	**52,000**	52,000
Unamortized debt issue costs	**(502)**	(574)
	103,498	103,426

The senior unsecured notes of CNPI and Cornwall Electric bear interest at 7.092% and are repayable at maturity on August 14, 2018. Interest expense on long-term debt for the year was $3,688 [2015 – $3,688].

The senior unsecured notes of API bear interest at 5.118% and are repayable at maturity on December 16, 2041. Interest expense for the year was $2,661 [2015 – $2,661].

10. Capital stock

The authorized and issued capital stock consists of 1,001 common shares without par value.

11. Amortization

The amortization of utility capital assets and other assets consist of the following:

	2016 $	2015 $
Amortization of utility capital assets	**10,040**	9,539
Amortization of intangible assets	**1,894**	1,801
Amortization of contributions in aid of construction	**(666)**	(624)
	11,268	10,716
Vehicle amortization allocated	**(1,026)**	(1,027)
	10,242	9,689

12. Consolidated statement of cash flows

The net change in non-cash working capital balances related to operations consists of the following:

	2016 $	2015 $
Accounts receivable	**(699)**	2,035
Due from/to related parties	**(4,684)**	4,068
Materials and supplies	**8**	75
Prepaid expenses	**(211)**	128
Income taxes recoverable	**(78)**	177
Accounts payable and accrued liabilities	**(1,916)**	2,413
Regulatory assets/liabilities	**(1,365)**	1,267
	(8,945)	10,163

Supplemental cash flow information:

	2016 $	2015 $
Interest paid	**6,552**	6,561
Income taxes paid	**5,183**	2,672

13. Commitments and contingencies

The Corporation has a building lease agreement until December 2019 with annual rent, operating costs and municipal taxes of $600.

The Corporation has gas purchase obligations until October 2019 at approximately $730 per year.

The Corporation is contingently liable under certain issued letters of credit amounting to $14,300.

14. Financial risk management

The Corporation is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit risk:	Risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument.
Liquidity risk:	Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.
Market risk:	Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices.

Credit risk

For cash, trade and other receivables due from customers, the Corporation's credit risk is limited to the carrying values on the consolidated balance sheet.

The Corporation is exposed to credit risk from its distribution customers, but has various policies to minimize this risk. These policies include requiring customer deposits, performing disconnections and using third-party collection agencies for overdue accounts. The Corporation has a large and diversified distribution customer base, which minimizes the concentration of credit risk.

The aging of the Corporation's consolidated trade and other receivables due from customers was as follows:

	2016 $
Not past due	**23,810**
Past due 0 – 30 days	**558**
Past due 31 – 60 days	**269**
Past due 61 days and over	**973**
	25,610
Less allowance for doubtful accounts	**288**
	25,322

Liquidity risk

The Corporation's exposure to liquidity risk is minimal. Financing of regulated capital and other expenditures is done through internally generated funds. These funds are a result of allowable rate-regulated returns and recoveries under the OEB rate regulation mechanism and the Cornwall Electric Franchise Agreement as described in note 2.

The Corporation is a subsidiary of Fortis Inc., a large investor-owned utility that has had the ability to raise sufficient and cost-effective financing. However, the ability to arrange financing on a go-forward basis is subject to numerous factors, including the results of operations and financial position of Fortis Inc. and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

Also, to mitigate any liquidity risk, certain subsidiaries of the Corporation have committed revolving credit facilities and letters of credit facilities totalling $30,000, of which $6,700 was unused. The revolving credit facilities and letters of credit facilities are renewed on an annual basis. The following summary outlines the credit facilities of the Corporation:

	2016	**2015**
	$	$
Total credit facilities	**30,000**	30,000
Letters of credit outstanding	**(14,300)**	(14,300)
Short-term loan payable	**(9,000)**	—
Credit facilities available	**6,700**	15,700

The facilities of the subsidiaries are guaranteed by the Corporation. The credit facilities bear interest at the bankers' acceptance rate plus 1.20% in the case of bankers' acceptances, and at the bank's prime lending rate plus 0.20% in the case of bank loans.

The following is an analysis of the contractual maturities of the Corporation's financial liabilities as at December 31, 2016:

	< 1 year	**1 – 3 years**	**4 – 5 years**	**> 5 years**	**Total**
	$	$	$	$	$
Accounts payable and accrued liabilities	**19,750**	**—**	**—**	**—**	**19,750**
Government remittances payable	**410**	**—**	**—**	**—**	**410**
Customer deposits	**592**	**676**	**536**	**—**	**1,804**
Long-term debt	**—**	**52,000**	**—**	**52,000**	**104,000**
	20,752	**52,676**	**536**	**52,000**	**125,964**

Market risk

Interest rate risk

Long-term debt is at fixed interest rates, thereby minimizing cash flow and interest rate fluctuation exposure. The Corporation is primarily subject to risks associated with fluctuating interest rates on its short-term borrowings. As at December 31, 2016, the Corporation's short-term borrowings are $9,000 [2015 – nil].

15. Capital management

The Corporation manages the capital of CNPI and API to approximate the deemed capital structure reflected in the utility's customer rates or anticipated future rates. For CNPI, effective on January 1, 2013, the distribution rates are based on a deemed capital structure of 60% debt and 40% equity. CNPI's capital structure consists of third-party debt, affiliated debt and common equity, but excludes unamortized debt issue costs. API's distribution rates effective on January 1, 2015 are also based on a deemed capital structure of 60% debt and 40% equity. API's debt consists of third-party debt, excluding unamortized debt issue costs.

The managed capital of CNPI and API, combined, is as follows:

	2016 Actual		**2015 Actual**	
	$	%	$	%
Debt	**102,000**	**49**	102,000	51
Equity	**105,861**	**51**	97,470	49
	207,861	**100**	199,470	100

Certain of the Corporation's long-term debt obligations and credit facility agreements have covenants that restrict the issuance of additional debt such that subsidiary debt cannot exceed 75% of their respective capital structures as defined in the agreements. As at December 31, 2016, the subsidiaries were in compliance with their debt covenants.

16. Regulatory assets and liabilities

Regulatory assets and liabilities arise as a result of regulatory requirements.

CNPI and API pay the cost of power on behalf of their customers and recover these costs through retail billings to their customers. The cost of power includes charges for transmission, wholesale market operations and the power itself from Ontario's Independent Electricity System Operator. The balance of the retail settlement variance account represents the costs that have not been recovered from, or settled through, customers as at the consolidated balance sheet date. The OEB's Distribution Rate Handbook and Accounting Procedures Handbook allow these costs to be deferred and recovered through future rate adjustments, as discussed in Note 2. In the absence of rate regulation, these costs would be expensed in the period they are incurred.

The seasonal revenue accrual is related to previous shortfalls in revenue for API's contributions from the seasonal customer class. The total cost allocated to the seasonal customer class was significantly higher than the total revenue generated through rates by that class. In order to recover the full cost, significant rate shock would have been incurred. In API's 2008 OEB Decision, the OEB had accepted API's proposal to mitigate significant rate impacts to the seasonal customer class by limiting the rate increase to 10%. As a result of the OEB's 2010 Decision, API was to collect the past amounts due from the seasonal customer class over a five-year period through specific rate adders. Effective with the new rates on December 1, 2010, the seasonal customer class rates were designed to recover the full cost associated with this rate class. In API's 2015 CoS proceeding, the Board approved the recovery of the additional $760, and this will be collected from the seasonal customer class by extending the 2010 Decision rate rider expiration date to June 30, 2019.

The OEB has the general power to include or exclude costs, revenue, gains or losses in the rates of a specific period, resulting in the timing of revenue and expense recognition that may differ in the Corporation's regulated operations from those otherwise expected in non-regulated businesses. This change in timing gives rise to the recognition of regulatory assets and liabilities. The Corporation continually assesses the likelihood of recovery of its regulatory assets and believes that its regulatory assets and liabilities will be factored into the setting of future rates, as discussed in note 2. If future recovery through rates is no longer considered probable, the appropriate carrying amount would be written off in the period that the assessment is made.

The Corporation of the City of Cornwall Franchise Agreement provides that Cornwall Electric is guaranteed an annual gross margin on energy sold subject to regulatory adjustments. The cost of power is a flow-through to the customers and the retail rates include an estimate of that power for the upcoming rate year. Variances occur as a result of actual gross margins differing from guaranteed gross margins. Gross margins will differ due to differences in the actual cost of power and electric usage by customers from expected levels. In the absence of rate regulation, there would be no guaranteed gross margin and Cornwall Electric's revenue would have been higher by $247 in 2016.

In 2013, upon approval by the OEB, the Corporation integrated smart meters into the rate base from amounts previously held as regulatory assets in CNPI of $4,365 and API of $3,262, as well as removing stranded meter assets of $1,238 in CNPI from utility capital assets and recognizing these amounts as regulatory assets. On January 8, 2015, API received approval from the OEB to remove stranded meter assets of $278 from utility capital assets and recognize these amounts as regulatory assets.

As of December 31, 2015, as discussed in note 2 under “Capitalization policy”, API had a regulatory liability in OEB account 1576 of $1,128. These were transitional adjustments related to accounting changes to amortization expense and capitalization policy. As a result of the 2015 OEB Decision and Order, API recorded an additional regulatory liability of $93 in 2016, relating to the regulatory return calculated on the approved cumulative regulatory liability of $1,379. A reduction of the regulatory liability of $378 occurred during 2016 due to a repayment to API’s customers in the form of a rate rider, which is set to expire in December 2019. The cumulative regulatory liability balance as at December 31, 2016 was $843, of which $388 has been reported as current.

In 2015, as a result of the Transmission OEB Decision and Order, the Corporation expensed certain disallowed capital project costs in the amount of $1,250. These amounts were previously recorded as capital assets under construction.

The following table summarizes the costs associated with these regulatory adjustments:

	2016 $	**2015** $
Disallowed capital project costs	**—**	(1,250)
Transitional adjustments for API related to accounting changes to amortization expense and capitalization policy	**(93)**	(93)
Other regulatory adjustments	**(93)**	(1,343)

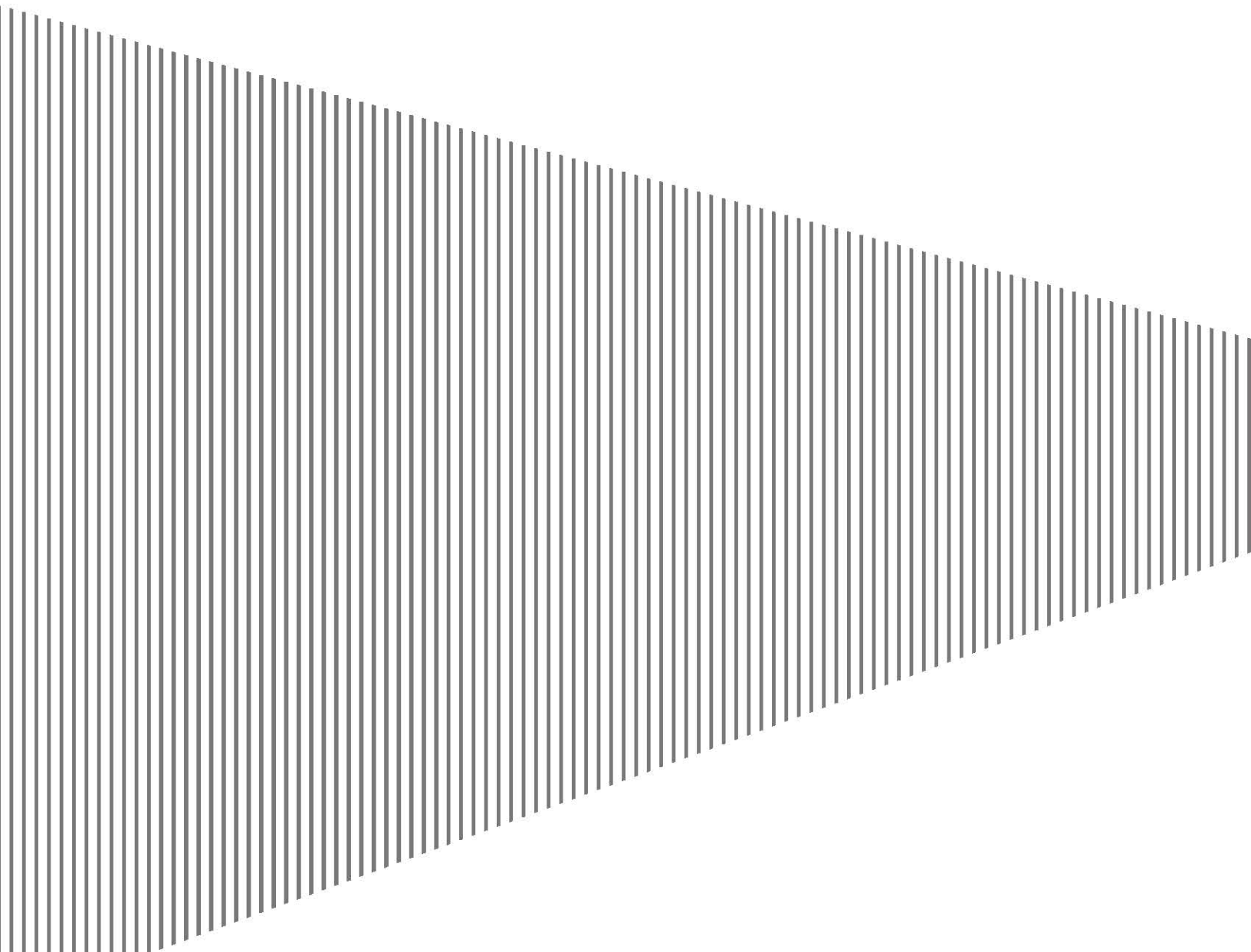
Regulatory assets and liabilities are not subject to a regulatory return; however, the balances include an accrual for interest recoverable/payable as permitted by the regulators. The purpose of the following table is to provide reconciliation between the regulatory assets and liabilities and the remaining rebate period:

Notes to consolidated financial statements

[in thousands of dollars, unless where otherwise noted]

December 31, 2016

	2016 $	2015 $	Remaining rebate period
Current regulatory assets			
Amounts approved in current rates	**540**	368	1 year
The Corporation of the City of Cornwall franchise revenue variances	**—**	303	1 year
	540	671	
Long-term regulatory assets			
Amounts approved in current rates	**1,626**	1,933	2 years
Retail settlement and other variance accounts	**1,980**	3,511	2 years
Smart meter variance account	**—**	7	
Future income taxes to be recovered from customers	**11,780**	10,150	Life of assets
Pension and other retirement benefits	**4,028**	4,125	EARSL
Other	**15**	—	2 years
	19,429	19,726	
Current regulatory liabilities			
Amounts approved in current rates	**—**	175	1 year
Ontario clean energy benefits	**—**	1,332	1 month
The Corporation of the City of Cornwall franchise revenue variances	**64**	—	1 year
Other	**388**	441	1 year
	452	1,948	
Long-term regulatory liabilities			
The Corporation of the City of Cornwall franchise revenue variances	**1,066**	1,186	2 years
Amounts approved in current rates	**132**	—	2 years
Retail settlement and other variance accounts	**3,151**	3,580	2 years
Other	**455**	754	3 years
	4,804	5,520	



WATAYNIKANEYAP POWER CORPORATION

FINANCIAL STATEMENTS

FOR THE PERIOD ENDED DECEMBER 31, 2013

WATAYNIKANEYAP POWER CORPORATION
FINANCIAL STATEMENTS
DECEMBER 31, 2013

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

The financial statements of Wataynikaneyap Power Corporation are the responsibility of management and have been approved by Board of Directors.

Management is responsible for the integrity and objectivity of the financial statements. Estimates are necessary in the preparation of these financial statements and, based on careful judgments, have been properly reflected. Management has established systems of internal control, which are designed to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for the preparation of financial information.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the financial statements.

The financial statements have been audited by Holukoff Chiarella in accordance with Canadian generally accepted auditing standards on behalf of the Shareholders. Holukoff Chiarella have full and free access to the Board of Directors.

DIRECTOR

DIRECTOR

Holukoff Chiarella

CHARTERED ACCOUNTANTS

Kevin Masse, B.Comm. (Hons), C.A.
(Practising as Kevin Masse Chartered Accountant Ltd.)
Ralph Orr, B.Comm. (Hons), C.A.
(Practising as Ralph Orr Chartered Accountant Ltd.)
Wayne H. Chiarella, B.A., C.A. (Retired 2011)
Sam Holukoff, C.A. (Retired 2005)

101 - 1180 Pembina Highway
Winnipeg, Manitoba R3T 2A4
Telephone (204) 452-6449
Fax (204) 452-3397

EXHIBIT "A"

INDEPENDENT AUDITORS' REPORT

To the Shareholders of
Wataynikaneyap Power Corporation

We have audited the accompanying financial statements of Wataynikaneyap Power Corporation, which comprise the balance sheet as at December 31, 2013 and the statements of operations and deficit and cash flows for the period then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian accounting standards for private enterprises, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility
Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian accounting standards for private enterprises. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2013, and its financial performance and its cash flows for the period then ended in accordance with Canadian accounting standards for private enterprises.

Holukoff Chiarella

WINNIPEG, MANITOBA
September 27, 2014

CHARTERED ACCOUNTANTS
LICENCED PUBLIC ACCOUNTANTS

WATAYNIKANEYAP POWER CORPORATION
BALANCE SHEET
AS AT DECEMBER 31, 2013

ASSETS

	2013
CURRENT ASSETS	
Cash in bank	$ 11
Deferred expenses	4,714,628
	$ **4,714,639**

LIABILITIES

CURRENT LIABILITIES	
Accounts payable	$ 1,695
Due to Shibogama First Nations Council	1,103
	2,798
Promissory note payable, Note 3	4,714,628

SHAREHOLDERS' EQUITY

SHARE CAPITAL	
Authorized	
Unlimited preferred and common shares	
Issued	
4 Common shares	4
DEFICIT	(2,791)
	(2,787)
	$ **4,714,639**

APPROVED BY THE BOARD:

DIRECTOR

DIRECTOR

WATAYNIKANEYAP POWER CORPORATION
STATEMENT OF OPERATIONS AND DEFICIT
FOR THE PERIOD ENDED DECEMBER 31, 2013

		2013
REVENUE		
Central Corridor Energy Group (CCEG)	$	2,529
EXPENSES		
Accounting and audit	$	1,695
Legal		3,605
Bank charges and interest		20
		5,320
NET LOSS FOR THE YEAR AND DEFICIT AT END OF THE YEAR	$	**(2,791)**

WATAYNIKANEYAP POWER CORPORATION
STATEMENT OF CASH FLOWS
FOR THE PERIOD ENDED DECEMBER 31, 2013

	2013
CASH FLOWS FROM OPERATING ACTIVITIES	
Net loss for the year	$ (2,791)
Change in non-cash working capital items	
Due to Shibogama First Nations Council	1,103
Promissory note payable	4,714,628
Deferred expenses	(4,714,628)
Accounts payable	1,695
	7
CASH FLOWS FROM FINANCING ACTIVITIES	
Issuing of shares	4
NET CHANGE IN CASH POSITION and CASH POSITION AT END OF YEAR	$ **11**

WATAYNIKANEYAP POWER CORPORATION
NOTES TO FINANCIAL STATEMENTS
FOR THE PERIOD ENDED DECEMBER 31, 2013

1. SIGNIFICANT ACCOUNTING POLICIES

Incorporation and Purpose

The company was incorporated under the Corporations Act of Ontario by Articles of Incorporation dated April 2, 2013 to be set up to pursue the transmission Development Project in Northwestern Ontario.

These financial statements have been prepared in accordance with Canadian accounting standards for private enterprises, and include the following significant accounting policies:

a) Financial Instruments

The company's financial instruments consist cash in bank, and accounts payable. Unless otherwise noted, it is management's opinion that the company is not exposed to significant interest, currency or credit risk arising from these financial instruments. The fair value of these financial instruments approximate their carrying values, unless otherwise noted.

b) Use of Estimates

The preparation of financial statements in accordance with Canadian accounting standards for private enterprises requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenue and expenditures during the reported period. Actual results could differ from management's best estimates as additional information becomes available in the future.

2. INCOME TAXES

At December 31, 2013 the company had unused non-capital losses for tax purposes of $2,791, which can be applied to offset future taxable income. The losses expire in 2033. The tax benefit of these losses has not been recognized in these financial statements.

3. PROMISSORY NOTE PAYABLE

Balance outstanding and owing on the Grid as defined by the Shareholders Agreement dated April 2, 2013. The principal balance owing is not subject to any interest.

Repayment

(a) Subject to Section (b), the Holder acknowledges and agree that: (i) the Issuer shall not be required at any time or from time to time to repay the Principal to the Holder in lawful money of Canada or any other legal currency; (ii) the Principal may only be treated as Recoverable Contributions pursuant to the terms of the Shareholders Agreement; and (iii) any Principal that is treated as a Recoverable Contribution pursuant to the terms of the Shareholders Agreement may only be offset against any Capital Contribution that the Holder may be required to pay to the Issuer in its capacity as a transmission customer of the Issuer. Any Principal that is not or cannot be treated as a Recoverable Contribution pursuant to the terms of the Shareholders Agreement shall be forgiven by the Holder.

(b) Notwithstanding Section (a), if a Customer Capital Contribution is not required to be made by the Holder, in its capacity as a transmission customer of the Issuer, to the Issuer, then the Holder may recover the Indebtedness from the Issuer over time for a term not to exceed 10 years.

4. SUBSEQUENT EVENT

Subsequent to year-end Central Corridor Energy Group, on behalf of 1876981 Ontario Inc., submitted a summary of expenses incurred from September 2008 through to June 2013, totaling $4,039,216. Once a final amount has been approved by the Board of Directors this will be set up as deferred expenses and a promissory note issued.

WATAYNIKANEYAP POWER CORPORATION
FINANCIAL STATEMENTS
DECEMBER 31, 2014

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

The financial statements of Wataynikaneyap Power Corporation are the responsibility of management and have been approved by Board of Directors.

Management is responsible for the integrity and objectivity of the financial statements. Estimates are necessary in the preparation of these financial statements and, based on careful judgments, have been properly reflected. Management has established systems of internal control, which are designed to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for the preparation of financial information.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the financial statements.

The financial statements have been audited by Holukoff Chiarella in accordance with Canadian generally accepted auditing standards on behalf of the Shareholders. Holukoff Chiarella has full and free access to the Board of Directors.

DIRECTOR

DIRECTOR

WATAYNIKANEYAP POWER CORPORATION
BALANCE SHEET
AS AT DECEMBER 31, 2014

ASSETS

	2014	2013
CURRENT ASSETS		
Cash in bank	$ 9,781	11
Deferred expenses	10,137,625	4,714,628
	$ 10,147,406	**4,714,639**

LIABILITIES

CURRENT LIABILITIES		
Accounts payable	$ 2,500	1,695
Due to Shibogama First Nations Council	9,288	1,105
	11,788	2,800
Promissory note payable, Note 3	10,137,625	4,714,628

SHAREHOLDERS' EQUITY

SHARE CAPITAL		
Authorized		
Unlimited preferred and common shares		
Issued		
4 Common shares	2	2
DEFICIT	(2,009)	(2,791)
	(2,007)	(2,789)
	$ 10,147,406	**4,714,639**

APPROVED BY THE BOARD:

DIRECTOR

DIRECTOR

Wataynikaneyap Power Corporation
P.O. Box 449
Sioux Lookout, ON P0V 2T0

Holukoff Chiarella
Chartered Accountants
101-1180 Pembina Highway
Winnipeg, MB R3T 2A4

Dear Sirs:

We are providing this letter in connection with your audit of the financial statements of Wataynikaneyap Power Corporation as at December 31, 2014 and for the period then ended.

We understand that your audit was made in accordance with Canadian generally accepted auditing standards and accordingly included such tests of the accounting records and such other auditing procedures as you considered necessary in the circumstances for the purpose of expressing an opinion on the financial statements. We also understand that such an audit would not necessarily disclose misstatements and irregularities, should there by any.

Certain representations in this letter are described as being limited to matters that are material. Items are considered material, regardless of size, if they involve an omission or misstatement of accounting information that, in the light of surrounding circumstances, makes it probable that the judgment of a reasonable person relying on the information would be changed or influenced by the omission or misstatement.

In connection with your audit of the financial statements of Wataynikaneyap Power Corporation for the year period ended December 31, 2014, we hereby confirm that to the best of our knowledge and belief:

1. We are responsible for the fair presentation of the financial statements of the organization prepared in accordance with Canadian generally accepted accounting principles.

2. We are responsible for adopting sound accounting policies, establishing and maintaining internal controls to, among other things, help assure the preparation of the financial statements in conformity to Canadian generally accepted accounting principles and our aforementioned basis of accounting and preventing and detecting fraud.

3. We have made available to you, all:
   - financial records and related data
   - minutes of the meetings of Council.

4. There have been no communications from regulatory agencies concerning noncompliance with or deficiencies in financial reporting practices.

5. We have approved the journal entries that were proposed by you in the course of your work and acknowledge that these journal entries have been recorded in the accounting records of the organization in the appropriate accounting period. There are no material transactions that have not been properly recorded in the accounting records underlying the financial statements. All financial statement misstatements identified and discussed with us in the course of the audit have been recorded.

6. There have been no:

   (a) Fraud or irregularities involving management or employees who have significant roles in internal control, whether or not perceived to have a material effect on the financial statements.

   (b) Fraud involving others that could have a material effect on the financial statements.

   (c) Violations or possible violations of laws or regulations (including the failure to file reports required by regulatory bodies) whose effects should be considered for disclosure in the financial statements or as a basis for recording a loss contingency.

7. We are aware of the environmental laws and regulations that impact on our organization and we are in compliance. There are no known environmental liabilities that have not been accrued for or disclosed in the financial statements.

8. There are no plans or intentions that may materially affect the carrying value or classification of assets and liabilities.

9. The following, where applicable, have been properly recorded or disclosed in the financial statements:

   (a) Changes during the period under review in the organization's accounting principles or practices.

   (b) Related-party transactions (e.g. transactions with unconsolidated subsidiaries, Chief and Councillors, directors, band members, management, and members of their immediate families) including sales, purchases, loans, transfers, leasing arrangements, guarantees and amounts receivable from or payable to related parties.

(c) Guarantees, whether written or oral, under which the organization is contingently liable.

(d) All assets to which the organization has title and all known liabilities of the organization at period end.

(e) Information regarding the terms and conditions, interest rate risk and credit risk of financial instruments. There were no derivative or off-balance sheet financial instruments held at period end.

(f) Other liabilities or gain or loss contingencies that are required to be accrued or disclosed (e.g. potential or pending claims, lawsuits, labour claims or negotiations or anticipated tax assessments).

(g) Major commitments such as capital asset purchase agreements, deferred compensation, bonuses, pensions and profit-sharing plans, purchase or sale of all or a portion of the business.

10. We have disclosed to you all significant customers and/or suppliers of the organization who individually represent a significant volume of transactions with the organization. Except as disclosed in the financial statements, where applicable, we are of the opinion that the volume of transactions (sales, services, purchases, borrowing or lending) done by the organization with any one party is not of sufficient magnitude that discontinuance would have a material negative effect on the ongoing operations of the organization.

11. The organization has satisfactory title to all owned assets, and there are no liens or encumbrances on such assets nor has any asset been pledged as collateral, except as disclosed in the financial statements, where applicable. Where the value of any asset has been impaired, an appropriate provision has been made in the financial statements.

12. Provision has been made for any material loss to be sustained in the fulfillment of, or from inability to fulfill, any sales commitments.

13. Receivables recorded in the financial statements represent valid claims against debtors for sales or other charges arising on or before the balance sheet date and have been appropriately reduced to their estimated net realizable value.

14. We have complied with all aspects of contractual agreements that would have a material effect on the financial statements in the event of non-compliance.

15. No events have occurred subsequent to the balance sheet date and through the date of this letter that would require adjustment to, or disclosure in, the financial statements.

16. We have provided all information on revenues and expenses and there are no additional revenues or expenses that have been reported by Windigo First Nations Council that should be included in or reported in these financial statements. We have provided information and documentation on all claims submitted and Promissory Notes being considered or approved by the Board of Directors.

17. The minute books of the organization are a complete record of all meetings and resolutions of the Council throughout the reporting period and to the present date.

18. We have responded fully to all inquiries made to us by you during your examination.

Yours truly,

WATAYNIKANEYAP POWER CORPORATION

Signature _____ DIRECTOR

Signature _____ DIRECTOR

Date August 26, 2015

SCHEDULE "G"

Response to #18(b) – (d)

See description of the Applicant's business plans in the cover letter to this application. It is anticipated that the Applicant will serve only the one load customer identified above, namely HORCI in respect of the Pikangikum First Nation Reserve. The Applicant's distribution facilities will consist of the one 44 kV and 25 kV line, running approximately 117 km from Red Lake to Pikangikum, along with one substation located approximately 18 km from the Pikangikum First Nation Reserve. This community is not currently connected to the grid. The planned distribution line would, absent any constraints, have an approximate total supply capacity of 30-45 MW, depending on distance and configuration. However, supply capacity to end-use customers is limited by the size of and number of transformers and lower voltage distribution feeders. For the planned distribution facilities, supply capacity is limited by upstream constraints with respect to the transmission supply to the Red Lake area. The System Impact Assessment for the connection of WPLP's planned facilities concludes that 5.8 MW of incremental load can be connected, which exceeds the expected requirements of the Pikangikum First Nation during the relevant 3-4 year period. The Applicant does not have pro forma financial statements for the distribution system.

As noted in the cover letter to the Application, the capital costs of developing and constructing the distribution facilities from Red Lake to the Pikangikum First Nation are expected to be paid for primarily through funding provided by INAC. As such, while WPLP currently anticipates that it will file an application for distribution rates in respect of the Distribution System through a cost of service application, the cost of service may be comprised primarily of OM&A costs. However, as the funding application process with INAC is ongoing at the time of this Application, the full extent of the funding to be received is not yet certain.

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Schedule ‘H’

Article re Energy Poverty in Pikangikum

How energy poverty devastates Pikangikum First Nation

Published on Apr 02, 2016

by Eric Bombicino



Pikangikum has relied on an unstable diesel generator system for decades, affecting basic infrastructure such as water, sewage and housing.

Eric Bombicino, a producer for The Agenda, travelled to Pikangikum, Ont., as part of the Access to Energy Journalism Fellowship administered by Discourse Media with financial support from the Waterloo Global Science Initiative (WGSI).

PIKANGIKUM FIRST NATION, Ont.— On a Sunday morning in February, Kurt MacRae banged on the door of a co-worker from Eenchokay Birchstick, the fly-in Ojibwa community's

only school. As Eenchokay's principal, MacRae was getting a head start on its breakfast program, which the school runs daily.

Kory Rowell, the school's 27-year-old vice-principal, eventually emerged from his residence, bleary-eyed and wearing a pair of jogging pants and an old t-shirt. He didn't complain about the early hour or the fact that it was -20°C. The two hopped into Rowell's truck to haul packages of oatmeal, cereal, granola bars and Pringles potato chips into the school's kitchen. Food insecurity is one of a number of concerns managed by school staff in the community 500 kilometres northwest of Thunder Bay.

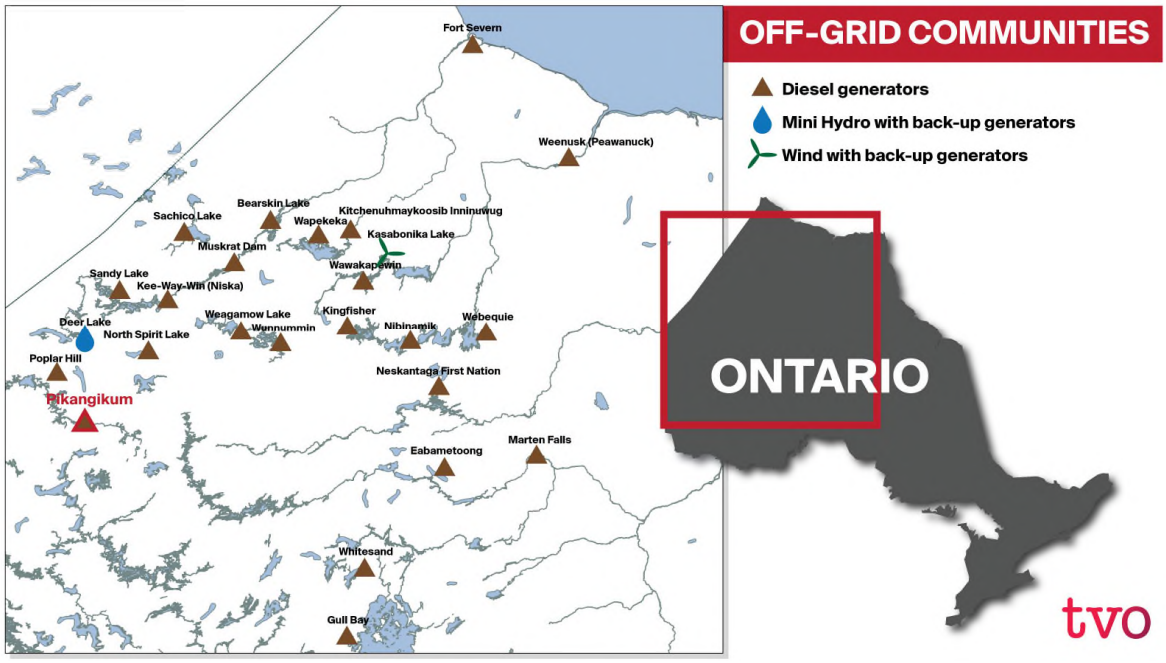
While they were bringing in the last box of food, the lights flickered and went out. MacRae exhaled loudly and shook his head: the erratic lights weren't just an immediate annoyance, but a threat of larger problems down the road. Just the week before, the reserve's main diesel generator broke down, requiring the community to operate on a system of rolling blackouts for several days. Should the outage affect the school's power, its kitchen's refrigerators wouldn't be able to store the food, posing a problem for the next day's breakfast — and, depending on the severity of the outage, the school might not be able to open at all.

For MacRae, this isn't an unusual concern. Almost constantly, he worries about whether staff will be able to open the doors of the school for Pikangikum's 750 students. This day ended up being no different: the next day the school had to stay closed due to the outage, and breakfast was not served.

An Ojibwa community of 3,000 people, Pikangikum First Nation has had roots in northwestern Ontario's Whitefeather Forest for generations. It experiences a host of issues, many of which stem from a history of colonialism and historical underfunding of vital community services. These root causes continue to have impacts on Pikangikum today, affecting education, healthcare, food security and employment.

For example, Pikangikum's fire response is woefully inadequate. A 2010 federal study found that people living on First Nations reserves were 10 times more likely to die in a fire than people in the rest of Canada. Devastatingly, that statistic was illustrated on Tuesday when a house fire killed six adults and three children.

"Our people are living in substandard living conditions and this is the result," Ontario Regional Chief Isadore Day said after the fire. "We need to bring our communities into the 21st century. Substandard is not a standard that we can live with any longer."



Another issue that weaves its way into almost every aspect of life in Pikangikum is a lack of power. As in 24 other remote First Nations reserves in Ontario, the veins of the provincial electrical grid don't quite reach the community, which instead relies on a rapidly aging generator system that runs on diesel that has been flown, trucked or shipped into the area at great economic and environmental cost.

To make matters worse, the reserve's main generator — now eight years past its expected 10-year lifespan — broke down earlier in February. Rene Keeper, a diehard Green Bay Packers fan who takes care of the generators for the community's Eshkotay Wahab Power Authority, said he hoped a new one could be flown in within a couple of weeks. Until then, the community would have to resort to timed blackouts, switching every two hours between homes on the east and west side.

The maxed-out energy system has prevented Pikangikum from making many of the infrastructure improvements it sorely needs. Eighty per cent of the reserve's homes do not have wastewater systems or running water. Its housing supply has tightened into a crisis, as the population grows by 100 people each year with few prospects for new builds. As many as 16 people might share a small home, requiring some families to sleep in shifts.

"Their ability to evolve and develop is curtailed by the fact they don't have this necessary resource," said Dr. Bert Lauwers, former deputy chief coroner of Ontario and author of the 2011 Chief Coroner of Ontario's review of 16 youth suicides that occurred between 2006 and 2008 in Pikangikum. "Having a good source of electricity is integral to having improved quality in their lives." In fact, one of the report's key recommendations was to connect the reserve to the provincial grid as soon as possible.

As the population grows, the generators age and blackouts roll through the community, there is hope in the form of discussions with a First Nations-owned power company looking to build a

massive transmission project in northwestern Ontario, and promised provincial funding to reduce reserves' reliance on diesel fuel. While some in Pikangikum are optimistic, others remain wary due to unkept promises from the past.

"If you had 3,000 people living near Toronto and they didn't have electricity, what would happen?" asked former chief Gordon Peters. "They'd get electricity with a year, months even."

The first time MacRae visited the home of a student at Eenchokay Birchstick School, he says he almost cried. Nine children, two teenage parents and two grandparents were sharing the tiny quarters. The children were huddled around an electric stove, its oven door left open to heat the home.

"They're not getting the right amount of sleep and it's really not creating success as they transition from the home into the school," he said.

Pikangikum currently has about 450 homes and requires at least 200 more to address its housing crisis, which will continue to deepen as the population grows. (According to Peters, the reserve has a retention rate of about 98 per cent — only two per cent of its people leave.)

Funding for these new homes doesn't currently exist. Even if Pikangikum were able to build them, the current diesel generator system wouldn't be able to power them, says Keeper.

In a council meeting in February, deputy chief Jonah Strang pointed out: "Young couples are still living with their parents and they are starting families. They need their own place."



Eighty per cent of homes in Pikangikum don't have running water. Many must use six public water sources.

The community's central hub also happens to be its only store, a Northern store outpost that houses a KFC and Pizza Hut. Other than the Chinese restaurant down the road, it is Pikangikum's main source of food. On most days, you'll see families packed into pickup trucks rumbling up and down the road that hugs the shoreline and leads to the store. Groups of people in the parking lot will share the day's news and a laugh, and teenagers and couples holding hands will line up to get a bucket of fried chicken. Often, however, power surges (a spike in the electrical current) and brownouts (a dip in the current) force staff to close the shop, leaving residents without a viable grocery store for hours on end.

These intermittent closures contribute to the food insecurity that plagues Pikangikum, like many remote communities in northern Canada, from high markups on prices to a low availability of healthier produce options. According to Peters, fresh products come in twice a week and don't last long. As is the case with housing, "there is not enough electricity in the community to accommodate the growth of the present store" or to build additional commercial spaces for potential small-business competitors, he said.

The water situation also affects food security in the area. Boil-water advisories are common, and most of Pikangikum's homes do not have running water or indoor toilets. Six water stations are located throughout the town, requiring families to haul sleds with buckets to fetch water for drinking, cooking and bathing. In the winter, this becomes a daily chore in temperatures as low as -40°C.

"When there is a power outage, which could last anywhere from five minutes to five hours, they have no stove to boil the water to make it safe," said Sylvain Langlois, a Metis worker from Pikangikum's health authority. This exacerbates the problem into a health concern, particularly for families that rely on powdered formula to feed infants.

In 2006, the Northwestern Health Unit published a study on Pikangikum's sewage and drinking water systems, finding that illnesses such as gastrointestinal, skin and urinary tract infections were more prevalent there than in other First Nation and non-aboriginal communities due to lack of safe water.

In 2014 the Pikangikum Working Group installed 10 running-water systems in the most underserved homes using $250,000 in private donations. The group was set to install another 10, but those plans were scrapped: the maxed-out power system couldn't handle the load of additional water heaters and pumps.

Engineer Bob White, who led the group, said the initial plan was to have the federal government match their funds, but Ottawa backed out. "They said they didn't have the money," said White, a member of Atlantic Canada's Kitpu First Nation who has worked in numerous developing countries. The government did, however, invest $40,000 to train Pikangikum workers for the project.

Seventeen years ago, Pikangikum came close to being connected to the power grid that has eluded the community for so long. "They were on the precipice of moving into the modern era," Lauwers said. In 1999, the federal department then known as Indian Affairs and Northern Development Canada approved a power line from Red Lake to Pikangikum, 90 kilometres away.

Within a year, 35 per cent of the planned hydro poles had been erected when federal funding for the project was halted abruptly. What happened, according to the band's former lawyer, Doug Keshen, is a "classic he-said, she-said scenario."



Eighty per cent of homes in Pikangikum don't have indoor toilets because of a lack of wastewater infrastructure. Many have outhouses, as pictured here.

In November 2000, the federal department notified Pikangikum Band Council that it would be taking over management of the council and its finances due to a series of incidents that included floods at the water treatment plant, a fuel oil spill at the school, and allegations of financial mismanagement. The chief and council refused to concede management, and sued the Minister of Indian Affairs and Northern Development, Robert Nault, who now serves as Liberal MP for Kenora, the riding in which Pikangikum lies. This set off a decade-long court battle against Nault, during which time many infrastructure projects — including the power grid connection, water and sewer projects — were shelved. Pikangikum eventually lost the suit in 2010.

In his ruling, Superior Court Judge John dePencier Wright wrote that "to this day, the power grid has not been completed. Power that could have been supplied at a cost of several hundreds of thousands of dollars continues to be supplied to this band at a cost of millions of dollars."

Energy from diesel is exorbitantly expensive compared to energy from the grid. According to Keshen, Pikangikum spent $7 million on diesel in the past year alone. Court documents from the case state that Pikangikum paid over $3.5 million for power from diesel in one year, which would have cost about a tenth of that if supplied from the provincial grid.

Had the grid been connected back in the early 2000s, these annual savings could have been funnelled back into the community or used to pay for the project itself.



The new $65-million school building is under construction and slated to be complete September 2016.

Aboriginal Peoples are the fastest-growing segment of the Canadian population, with almost half under the age of 25. According to Strang, between 60 and 70 per cent of Pikangikum's people are under 25. While the impact of a power grid on the future of a youth population might seem a tenuous connection in other parts of the province, here it is deeply felt.

For example, the lack of electricity affects education. "In the past, every five-year cycle, we would lose the equivalent of a full school year due to closures," said MacRae. Power outages are a major reason for the closures. Surges and brownouts are also a classroom liability — MacRae estimates they have destroyed thousands of dollars' worth of school technology such as laptops and audio-visual equipment.

A recent $65-million reconstruction of Eenchokay Birchstick school — a massive source of optimism and pride in the community — provided the building with its own generator and will help ease overcrowding issues, but creates the need for more teachers. MacRae is concerned about retaining the teachers he has, let alone recruiting more.

"Some teachers won't return because of the inconsistent power," he said. Most of Pikangikum's residents heat their homes with wood-fired furnaces, but teachers' residences rely on electricity. Power outages can last from several minutes to several days, forcing teachers to either move out or hunker down on their couches, as MacRae himself has experienced, huddled in layers of clothing until the electricity comes back on.

On a drive to tour the new Eenchokay Birchstick building, MacRae relayed a particularly grim, but honest, insight. "If students lose connection to the school, their risk [of suicide] exponentially goes up."

A teacher's job description in Pikangikum likely wouldn't match that of a counterpart in southern Ontario. "We spend a lot of time on mental health issues," MacRae said. "I think 30 per cent of our time at the end of the school year is actually focused on prevention and getting kids help." MacRae recently asked the Northern store to take pencil sharpeners and Gillette razors off the shelves and put them behind the counter; students were using them to cut themselves.

Pikangikum has become known not for its breathtaking views, world-class fishing or its tournament-winning hockey teams, but for suicide. In 2000, Pikangikum made national headlines when the Canadian Press reported it had the highest suicide rate in the world. In 2012, shortly after the release of the coroner's report, Maclean's magazine proclaimed the community the "suicide capital of the world."

However, suicide is a comparatively recent phenomenon in Pikangikum's history. According to the 2002 documentary *Back to Pikangikum*, it wasn't until the rise of gas sniffing in 1990s that suicide became prevalent. There were three in 1992, another three in 1993, eight in 1994, and 27 between 1995 and 2000.

The majority of the suicides reviewed in the Ontario coroner's 2011 report involved young people under the age of 16, and most occurred in clusters. When Eenchokay Birchstick school burned down in 2007, for example, there were six suicides in two clusters, the first two occurring two days after the fire. The report suggests that some youths may have viewed the school as a focal point for activity that provided them with friendship and "some reason for hope in their lives."

There's also the issue of prospects. The reserve's unemployment rate is 90 per cent, and likely higher for youth. Connection to the grid would be a boon for economic development and would provide young adults with job opportunities. According to a 2013 report by Lumos Energy for the Wataynikaneyap Power project, a grid connection would spur both public and private economic development, such as public agency operations and social services and commercial opportunities, including small business growth. The grid line would also lead to construction and operation jobs, skills development and experience.

The Pikangikum Working Group's water installations in 2014 had precisely that effect on a number of youth involved. For one young man in particular, learning how to install plumbing for running water "changed the way he carried himself," said Colleen Estes, a Christian minister who has worked in the community for almost two decades. "His self-esteem went up."

Almost 20 years later, rumblings of hope for a grid connection have begun anew. "I am glad Stephen Harper is gone," said former chief Gordon Peters. With the new federal Liberal government, Peters said he sees a light at the end of the tunnel.

In the past few months, both the provincial and federal governments have committed to spending billions on infrastructure and tackling climate change. The 2016 federal budget includes $11.9 billion in infrastructure spending over the next two years, and $8.4 billion over the next five years to help bring about "transformational change" for indigenous people. The province has committed to a cap-and-trade system to address climate change, and in March it announced a $13-million investment in two initiatives to help indigenous communities combat climate

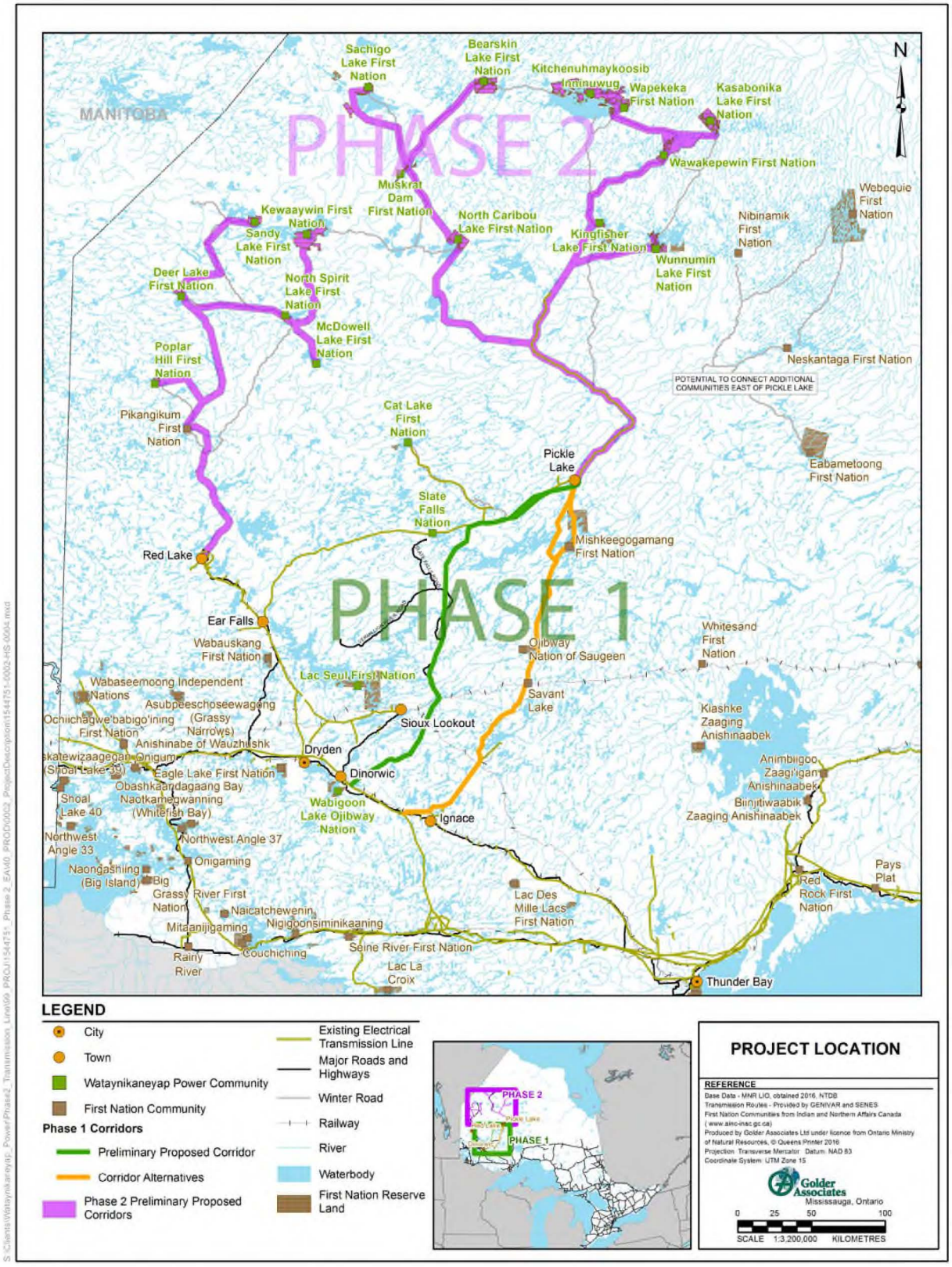
change, including $8 million to help switch from diesel to renewable energy sources. Getting a number of remote northern communities in Ontario off diesel would not only reduce greenhouse gas emissions, but would lower the risk of spills.

Last July, the governments of Manitoba, Quebec, Newfoundland and Labrador, Northwest Territories, Yukon and Ontario created a Pan-Canadian Task Force to reduce the use of diesel fuel to generate electricity in remote communities.

In 2014, the Independent Electricity System Operator, the agency responsible for planning Ontario's transmission lines, released a report that made the economic case for connecting 21 of the province's 25 remote First Nations communities, which would result in $1 billion in savings over 40 years.

Most important, Pikangikum has recently entered into discussions with Wataynikaneyap Power, a First Nations energy group that is working on a $1.35-billion, 1,500-kilometre transmission project to connect 16 communities to the grid in northwestern Ontario. The First Nations communities involved will be majority owners of the transmission facilities, and over time will retain full ownership of the systems. PricewaterhouseCoopers estimates the project will create 769 jobs and almost $900 million in social value.

Phase one of the Watay Power project, which will add capacity to an existing transmission line to Pickle Lake, is scheduled to be completed by 2018. Phase two, which will run through Pikangikum, is slated for completion in 2024. Eight years is a long time to wait for a grid connection that is 90 kilometres away in Red Lake, which explains why Pikangikum has been reluctant to sign on to the project. Both deputy chief Jonah Strang and Rene Keeper suggest, however, that this timeline may shrink, as discussions continue between the band council and Watay Power. For now, Pikangikum continues to wait.


PHASE 2
PHASE 1
MANITOBA
N
Sachigo Lake First Nation
Bearskin Lake First Nation
Kitchenuhmaykoosib Inninuwug
Wapekeka First Nation
Kasabonika Lake First Nation
Wawakepewin First Nation
Muskrat Dam First Nation
Kewaaywin First Nation
Sandy Lake First Nation
North Caribou Lake First Nation
Kingfisher Lake First Nation
Wunnumin Lake First Nation
Nibinamik First Nation
Webequie First Nation
Deer Lake First Nation
North Spirit Lake First Nation
McDowell Lake First Nation
Poplar Hill First Nation
Neskantaga First Nation
POTENTIAL TO CONNECT ADDITIONAL COMMUNITIES EAST OF PICKLE LAKE
Pikangikum First Nation
Cat Lake First Nation
Pickle Lake
Eabametoong First Nation
Slate Falls Nation
Mishkeegogamang First Nation
Red Lake
Ear Falls
Wabauskang First Nation
Ojibway Nation of Saugeen
Whitesand First Nation
Wabaseemoong Independent Nations
Lac Seul First Nation
Savant Lake
Asubpeeschoseewagong (Grassy Narrows)
Ochiichagwe'babigo'ining First Nation
Anishinabe of Wauzhushk
Sioux Lookout
Klashke Zaaging Anishinaabek
Dryden
Eagle Lake First Nation
Dinorwic
Obashkaandagaang Bay
Naotkamegwanning (Whitefish Bay)
Wabigoon Lake Ojibway Nation
Ignace
Animbiigoo Zaagi'igan Anishinaabek
Binjitiwaabik Zaaging Anishinaabek
Shoal Lake 40
Northwest Angle 33
Northwest Angle 37
Onigaming
Naongashiing (Big Island)
Big Grassy River First Nation
Naicatchewenin
Mitaanjigaming
Nigigoonsiminikaaning
Couchiching
Rainy River
Seine River First Nation
Lac La Croix
Lac Des Mille Lacs First Nation
Pays Plat
Red Rock First Nation
Thunder Bay
LEGEND
City
Town
Wataynikaneyap Power Community
First Nation Community
Phase 1 Corridors
Preliminary Proposed Corridor
Corridor Alternatives
Phase 2 Preliminary Proposed Corridors
Existing Electrical Transmission Line
Major Roads and Highways
Winter Road
Railway
River
Waterbody
First Nation Reserve Land
PROJECT LOCATION
REFERENCE
Base Data - MNR LIO, obtained 2016, NTDB
Transmission Routes - Provided by GENIVAR and SENES
First Nation Communities from Indian and Northern Affairs Canada (www.ainc-inac.gc.ca)
Produced by Golder Associates Ltd under licence from Ontario Ministry of Natural Resources, © Queens Printer 2016
Projection: Transverse Mercator Datum: NAD 83
Coordinate System: UTM Zone 15
Golder Associates
Mississauga, Ontario
0 25 50 100
SCALE 1:3,200,000 KILOMETRES

During one of our interviews, Peters took a bit longer to answer a question about a key recommendation made in the coroner's report on 16 youth suicides: that the reserve be connected to the grid as soon as possible

The usually animated former chief of Pikangikum sat in his chair, his sock feet firmly planted on the floor, and stared expressionless out the window of his office. Outside, snowmobiles zipped across the snow-covered Pikangikum Lake. Kids with skates and sticks slung over their shoulders crunched through the snow to a cleared patch of ice. His eyes watered; he began to slightly shake, but steeled himself.

Another former chief, Peter Quill, stepped in to answer, waving off the idea that a grid hookup was a cure-all solution to this particularly painful issue. Two of his grandchildren were mentioned in the report. He described all the problems in their house, problems that a grid connection would not solve. Considering the broader context, he said, "Maybe it's because we've been assimilated to another culture… we use this [English] language and it kills us as a person, it kills the spiritual part."

While a stable source of energy can offer Pikangikum opportunity, a platform for a community to grow and flourish, energy alone will not heal the community. It is not a magic bullet.

"It goes back to the very issue of colonization of First Nations people by Euro-Canadians, and their isolation in remote reserves," said Lauwers. In Pikangikum, people "feel a kinship and ownership and attachment to their land."

"Why would I want to move?" said Peters. "This is where I was born. This is where I will probably pass on. This is where my mother and father were born, and this is where they are buried. This is my home."

Photos by Eric Bombicino. Map by Michael Lehan.